BRITISH STANDARD

BS EN 62270:2004

Hydroelectric power plant automation — Guide for computor-based control

The European Standard EN 62270:2004 has the status of a British Standard

ICS 27.140

British Standards

National foreword

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This British Standard was published under the authority of the Standards Policy and Strategy Committee on 14 December 2004

Summary of pages

This document comprises a front cover, an inside front cover, the EN title page, pages 2 to 73 and a back cover.

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Amendments issued since publication

Amd. No.	Date	Comments

ISBN 0 580 45076 7

EUROPEAN STANDARD

EN 62270

NORME EUROPÉENNE

EUROPÄISCHE NORM

July 2004

ICS 27.140

English version

Hydroelectric power plant automation - Guide for computer-based control (IEC 62270:2004)

Automatisation
de centrale hydroélectrique -
Guide pour la commande
à base de calculateur
(CEI 62270:2004)

Automatisierung von Wasserkraftwerken -
Leitfaden zur computergestützten
Steuerung
(IEC 62270:2004)

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European Committee for Electrotechnical Standardization
Comité Européen de Normalisation Electrotechnique
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Central Secretariat: rue de Stassart 35, B - 1050 Brussels

Ref. No. EN 62270:2004 E

Foreword

The text of document 4/188/FDIS, future edition 1 of IEC 62270, prepared by IEC TC 4, Hydraulic turbines, was submitted to the IEC-CENELEC parallel vote and was approved by CENELEC as EN 62270 on 2004-07-01.

The following dates were fixed:

– latest date by which the EN has to be implemented at national level by publication of an identical national standard or by endorsement	(dop)	2005-04-01
– latest date by which the national standards conflicting with the EN have to be withdrawn	(dow)	2007-07-01

Annex ZA has been added by CENELEC.

Endorsement notice

The text of the International Standard IEC 62270:2004 was approved by CENELEC as a European Standard without any modification.

CONTENTS

INTRODUCTION 5

1 Overview 6
  1.1 Scope 6
  1.2 Purpose 6
2 Normative references 6
3 Terms and definitions 7
4 Functional capabilities 12
  4.1 General 12
  4.2 Control capabilities 12
  4.3 Data acquisition capabilities 21
  4.4 Alarm processing and diagnostics 22
  4.5 Report generation 23
  4.6 Maintenance management interface 23
  4.7 Data archival and retrieval 23
  4.8 Operation scheduling and forecasting 23
  4.9 Data access 24
  4.10 Operator simulation training 24
  4.11 Typical control parameters 24
5 System architecture, communications, and databases 25
  5.1 General 25
  5.2 System classification 26
  5.3 System architecture characteristics 27
  5.4 Control data networks 32
  5.5 Data bases and software configuration 36
6 User and plant interfaces 38
  6.1 User interfaces 38
  6.2 Plant interfaces 39
7 System performance 42
  7.1 General 42
  7.2 Hardware 43
  7.3 Communications 44
  7.4 Measuring performance 45
8 System backup capabilities 46
  8.1 General 46
  8.2 Design principles 47
  8.3 Basic functions 47
  8.4 Design of equipment for backup control 47
  8.5 Alarm handling 48
  8.6 Protective function 49
9 Site integration and support systems 49
  9.1 Interface to existing equipment 49
  9.2 Environmental conditions 49
  9.3 Power source 50

9.4 Supervision of existing contact status points 50
9.5 Supervision of existing transducers 51
9.6 Supervision of existing control output points 51
9.7 Grounding 51
9.8 Static control 51
10 Recommended test and acceptance criteria 52
10.1 Specific test requirements 52
10.2 Quality assurance 53
10.3 Acceptance 53
11 System management 53
11.1 Maintenance 53
11.2 Training 53
11.3 Documentation 54
12 Case studies 56
12.1 Automation of the Conowingo Hydroelectric Station 56
12.2 Computer-based control system at Waddell Pump-Generating Plant 58
12.3 Retrofit of TrŠngslet Hydro Power Station 62
12.4 Computer-based control system at Wynoochee Hydroelectric Project 67

Annex ZA (normative) Normative references to international publications with their corresponding European publications 71

Bibliography 72

Figure 1 – Relationship of local, centralized, and offsite control 14
Figure 2 – Local control configuration 14
Figure 3 – Computer communication network 27
Figure 4 – Multi-point data link versus LANs 32
Figure 5 – Star topology 34
Figure 6 – Ring topology 34
Figure 7 – Bus topology 35
Figure 8 – Conowingo control system overview 57
Figure 9 – System configuration 60
Figure 10 – Control system configuration 63
Figure 11 – Station control configuration after upgrading 66
Figure 12 – System configuration 68
Figure 13 – Local and remote interface 69

Table 1 – Summary of control hierarchy for hydroelectric power plants 13
Table 2 – Typical parameters necessary to implement automated control 24
Table 3 – Classifications of hydroelectric power plant computer control systems 26
Table 4 – Hydroplant computer control systems data communications attributes 35
Table 5 – Cable media characteristics 36
Table 6 – System performance 65

INTRODUCTION

Automation of hydroelectric generating plants has been a known technology for many years. Due to the relative simplicity of the control logic for hydroelectric power plants, the application of computer-based control has lagged, compared to other types of generating stations, such as fossil. Now that computer-based control can be implemented for comparable costs as relay-based logic and can incorporate additional features, it is being applied in hydroelectric power stations worldwide, both in new installations and in the rehabilitation of older plants.

HYDROELECTRIC POWER PLANT AUTOMATION – GUIDE FOR COMPUTER-BASED CONTROL

1 Overview

1.1 Scope

This standard sets down guidelines for the application, design concepts, and implementation of computer-based control systems for hydroelectric plant automation. It addresses functional capabilities, performance requirements, interface requirements, hardware considerations, and operator training. It includes recommendations for system testing and acceptance. Finally, case studies of actual computer-based automatic control applications are presented.

The automation of control and data logging functions has relieved the plant operator of these tasks, allowing the operator more time to concentrate on other duties. In many cases, the plant's operating costs can be significantly reduced by automation (primarily via staff reduction) while still maintaining a high level of unit control reliability.

Automatic control systems for hydroelectric units based on electromechanical relay logic have been in general use for a number of years and, in fact, were considered standard practice for the industry. Within the last decade, microprocessor-based controllers have become available that are suitable for operation in a power plant environment. These computer-based systems have been applied for data logging, alarm monitoring, and unit and plant control. Advantages of computer-based control include use of graphical user interfaces, the incorporation of sequence of events and trending into the control system, the incorporation of artificial intelligence and expert system capabilities, and reduced plant life cycle cost.

1.2 Purpose

This standard is directed to the practicing engineer who has some familiarity with computer-based control systems and who is designing or implementing hydroelectric unit or plant control systems, either in a new project or as a retrofit to an existing one. This standard assumes that the control system logic has already been defined; therefore, its development is not covered. For information on control sequence logic, the reader is directed to the IEEE guides for control of hydroelectric power plants listed in Clause 2 of this standard.

2 Normative references

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

IEC 61158, *Digital data communications for measurement and control - Fieldbus for use in industrial control systems*

ANSI C63.4-2001, *Methods of Measurement of Radio-Noise Emissions from Low-Voltage Electrical and Electronic Equipment in the Range of 9 kHz–40 GHz* [1]

IEEE Std 100-1996, *The IEEE Standard Dictionary of Electrical and Electronics Terms* [2]

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[1] ANSI publications are available from the Sales Department, American National Standards Institute, 11 West 42nd Street, 13th Floor, New York, NY 10036, USA.

[2] IEEE publications are available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA.

IEEE Std 485-1997, *IEEE Recommended Practice for Sizing Lead-Acid Batteries for Stationary Applications* (ANSI)

IEEE Std 610-1990, *IEEE Standard Glossary of Software Engineering Terminology* (ANSI).

IEEE Std 1010-1987 (Reaffirmed 1992), *IEEE Guide for Control of Hydroelectric Power Plants* (ANSI)

IEEE Std 1014-1987 *IEEE Standard for A Versatile Backplane Bus: VMEbus*

IEEE Std 1020-1988 (Reaffirmed 1994), *IEEE Guide for Control of Small Hydroelectric Power Plants.* (ANSI)

IEEE Std 1046-1991 (Reaffirmed 1996), *IEEE Guide for Distributed Digital Control and Monitoring for Power Plants* (ANSI)

IEEE Std 1147-1991 (Reaffirmed 1996), *IEEE Guide for the Rehabilitation of Hydroelectric Power Plants* (ANSI)

IEEE Std C37.1-1994, *IEEE Standard Definition, Specification, and Analysis of Systems Used for Supervisory Control, Data Acquisition, and Automation Control (ANSI)*

IEEE Std C37.90.1-2002, *IEEE Standard for Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems (ANSI)*

IEEE Std C37.90.2-1995, *IEEE Trial Use Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers (ANSI)*

IEEE 1379: 2000, IEEE *Recommended Practice for Data Communications Between Remote Terminal Units and Intelligent Electronic Devices in a Substation (ANSI)*

ISO/IEC 8802-3:2001, *Information technology – Telecommunications and information exchange between systems – Local and metropolitan area networks – Specific requirements – Part 3: Carrier sense multiple access with collision detection (CSMA/CD) access method and physical layer specifications*[3] (ANSI/IEEE Std 802.3, 1996 Edition)

ISO/IEC 8802-4:1990 (Reaffirmed 1995), *Information processing systems – Local area networks – Part 4: Token-passing bus access method and physical layer specifications* (ANSI/IEEE 802.4-1990 Edition)

ISO/IEC 8802-5:1998, *Information technology –Telecommunications and information exchange between systems – Local and metropolitan area networks – Specific requirements – Part 5: Token ring access method and physical layer specifications* (ANSI/IEEE Std 802.5, 1995 Edition)

3 Terms and definitions

For the purposes of this document the definitions provided here reflect common industry usage as related to automation of hydroelectric power plants, and may not in all instances be in accordance with IEEE Std 100-1996, or IEEE Std 610-1990, or other applicable standards. For more rigorous definitions, or for definitions not covered herein, the reader is referred to the appropriate IEEE standards.

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[3] ISO publications are available from the ISO Central Secretariat, Case Postale 56, 1 rue de Varembé, CH-1211, Genève 20, Switzerland/Suisse. ISO publications are also available in the United States from the Sales Department, American National Standards Institute, 11 West 42nd Street, 13th Floor, New York, NY 10036, USA.

3.1
analog-to-digital (a/d) conversion
production of a digital output corresponding to the value of an analog input quantity

3.2
automatic control
arrangement of electrical controls that provides for switching or controlling, or both, of equipment in a specific sequence and under predetermined conditions without operator intervention

3.3
automatic generation control (AGC)
capability to regulate the power output of selectable units in response to total power plant output, tie-line power flow, and power system frequency

3.4
automatic voltage control (AVC)
capability to regulate a specific power system voltage, via adjustment of unit excitation within the limits of unit terminal voltage and VAR capability

3.5
automation hierarchy
design and implementation of automation functions in a multilevel structure, such as local level, group level, unit level, etc.

3.6
availability
ratio of uptime (system functional) to uptime plus downtime (system not functional)

3.7
backplane
circuit board with connectors or sockets that provides a standardized method of transferring signals between plug-in circuit cards

3.8
bridge
device that allows two networks of the same or similar technology to communicate

3.9
centralized control
control location one step removed from local control; remote from the equipment or generating unit, but still within the confines of the plant (e.g. controls located in a plant control room)

3.10
closed loop control
type of automatic control in which control actions are based on signals fed back from the controlled equipment or system. For example, a plant control system can control the power output of a multi-unit hydroelectric power plant by monitoring the total plant megawatt value and, in response, by controlling the turbine governors of each unit, change the plant power output to meet system needs

3.11
computer-based automation
use of computer components, such as logic controllers, sequence controllers, modulating controllers, and processors in order to bring plant equipment into operation, optimize operation in a steady-state condition, and shut down the equipment in the proper sequence under safe operating conditions

3.12
control hierarchy
system organization incorporating multiple levels of control responsibility

3.13
control philosophy
total concept on which a power plant control system is based

3.14
data acquisition system
centralized system that receives data from one or more remote points. Data may be transported in either analog or digital form

3.15
database
collection of stored data regarding the process variables and processing procedures

3.16
data bus
control network technology in which data stations share one single communication system medium. Messages propagate over the entire medium and are received by all data stations simultaneously

3.17
device (electrical equipment)
operating element such as a relay, contactor, circuit breaker, switch or valve, used to perform a given function in the operation of electrical equipment

3.18
digital-to-analog (d/a) conversion
production of an analog signal whose magnitude is proportional to the value of a digital input

3.19
distributed processing
design in which data is processed in multiple processors. Processing functions could be shared by the processors throughout the control system

3.20
event
discrete change of state (status) of a system or device

3.21
expert system
computer programs that embody judgmental and experimental knowledge about an application. Expert systems are able to reach decisions from new, uncertain and incomplete information with a specified degree of certainty. Expert system abilities include: making logical inferences under unforeseen conditions; using subjective and formal knowledge; explaining the procedures used to reach a conclusion; growing in effectiveness as embedded expertise is expanded and modified

3.22
firmware
hardware used for the non-volatile storage of instructions or data that can be read only by the computer. Stored information is not alterable by any computer program

3.23
gateway
device that allows two networks of differing technology to communicate

3.24
local control
for auxiliary equipment, controls that are located at the equipment itself or within sight of the equipment. For a generating station, the controls that are located on the unit switchboard/governor control station

3.25
logic:(control or relay logic)
predetermined sequence of operation of relays and other control devices

3.26
manual control
control in which the system or main device, whether direct or power-aided in operation, is directly controlled by an operator

3.27
mean-time-between-failure (MTBF)
time interval (hours) that may be expected between failures of an operating equipment

3.28
mean-time-to-repair (MTTR)
time interval (hours) that may be expected to return a failed equipment to proper operation

3.29
modem
modulator/demodulator device that converts serial binary digital data to and from the signal form appropriate for an analog communication channel

3.30
monitoring
means of providing automatic performance supervision and alarming of the status of the process to personnel and control programs

3.31
offsite control
controls that are not resident at the plant (e.g. at a switchyard, another plant, etc.)

3.32
open loop control
form of control without feedback

3.33
proportional integral derivative (PID) [control system]
control action in which the output is proportional to a linear combination of the input, the time integral of input, and the time rate of change of input. Commonly used in hydroelectric applications for the control of a generator’s real power, reactive power, or flow

3.34
pixel
in image processing, the smallest element of a digital image that can be assigned a gray level

3.35
programmable logic controller (PLC)
solid state control system with programming capability that performs functions similar to a relay logic system

3.36
protocol
structured data format required to initiate and maintain communication

3.37
relay, interposing
device that enables the energy in a high-power circuit to be switched by a low-power control signal

3.38
remote control
control of a device from a distant point

3.39
reliability
characteristic of an item or system expressed by the probability that it will perform a required mission under stated conditions for a stated mission time

3.40
response time
elapsed time between the moment when a signal is originated in an input device until the moment the corresponding processed signal is made available to the output device(s), under defined system loading conditions

3.41
resistance temperature detector (RTD)
resistor for which the electrical resistivity is a known function of the temperature

3.42
scan (interrogation)
process by which a data acquisition system sequentially interrogates remote stations for data at a specific frequency

3.43
scan cycle
time in seconds required to obtain a collection of data (for example, all data from one controller, all data from all controllers, and all data of a particular type from all controllers)

3.44
serial communication
method of transmitting information between devices by sending digital data serially over a single communication channel

3.45
sequential control
mode of control in which the control actions are executed consecutively

3.46
supervisory control and data acquisition (SCADA)
system operating with coded signals over communication channels so as to provide control of remote equipment and to acquire information about the status of the remote equipment for display or for recording functions

3.47
user interface
functional system used specifically to interface the computer-based control system to the operator, maintenance personnel, engineer, etc.

4 Functional capabilities

4.1 General

Computer-based automation has enhanced hydroelectric power plant operation and maintenance activities. Many activities previously accomplished by plant personnel can now be performed more accurately, safely, and consistently by computer-based automation systems. Also, new tasks are within the capabilities of computer-based systems.

Power plant operators have long been responsible for manually performing control and data acquisition tasks. Relay logic type automatic control systems were, for many years, the only automated control assistance for operations staff. These systems were limited to unit control sequencing (start/stop) and were not easily changed, once installed. The quality of data acquisition has been subject to the limitations of available staff and human error.

Computer-based control and data acquisition systems have made major changes in the way these tasks are carried out. Power plant operator expertise has been supplemented in many plants by the computer, which can assist with unit start/stop sequencing and data logging; in other plants, the computer has replaced the operator altogether by performing these tasks. The online diagnostic, corrective, and protective capabilities of these computer systems continue to be developed.

Computer-based automation systems now allow plant owners to operate and maintain their plants in ways not possible before. Control algorithms based on criteria such as efficiency, automatic generation control, and voltage control allow more cost effective and safe operation of plants and interconnected power systems. It is now possible to acquire and process more data than in the past, so generated reports can keep operators and maintenance staff apprised of the total plant condition. Maintenance activities are enhanced by the computer’s ability to isolate problems, describe trends, and keep maintenance records.

Computer-based automation systems also permit operation of the power plant, switchyard, and outlet works (spillway gates, bypass gates and valves, fishways, fish ladders, etc.) from a single control point that can be local, centralized, or offsite. This one-point control has many advantages, including reduced operations staff, consistent operating procedures, and the capability to have all control and data available for reference during normal and abnormal conditions.

Subclauses 4.2 - 4.11 outline the functional capabilities of hydroelectric plant computer-based automation systems.

4.2 Control capabilities

4.2.1 Control hierarchy

A general hierarchy of control for hydroelectric power plants is defined in IEEE Std 1010-1987. The combination of computer-based and noncomputer-based equipment utilized for unit, plant, and system control should be arranged in accordance with Table 1.

Table 1 – Summary of control hierarchy for hydroelectric power plants

Control category	Subcategory	Remarks
Location	Local	Control is local at the controlled equipment or within sight of the equipment.
	Centralized	Control is remote from the controlled equipment, but within the plant.
	OffSite	Control location is remote from the project.
Mode	Manual	Each operation needs a separate and discrete initiation; could be applicable to any of the three locations.
	Automatic	Several operations are precipitated by a single initiation; could be applicable to any of the three locations.
Operation (supervision)	Attended	Operator is available at all times to initiate control action.
	Unattended	Operation staff is not normally available at the project site.

A decision is required on the extent of functions to be included in the computer-based equipment. At one extreme, the computer-based equipment may incorporate all aspects of local, centralized, offsite, manual, and automatic control. At the other extreme, the computer-based equipment may handle only automatic unit sequences and data acquisition, with all other functions, such as local manual control, handled by noncomputer-based equipment.

Manual controls are used during testing, and maintenance, and as a backup to the automatic control equipment. Generally, manual controls are installed adjacent to the devices being controlled, such as pumps, compressors, valves, and motor control centers. Transfer of control to higher levels is accomplished by means of local-remote transfer switches installed at the equipment. Often, capability to operate individual items of equipment is also provided at the unit switchboard while in the local-manual mode. If this capability is designed to backup the computer-based equipment, then additional interposing relays and other devices will be required. Alternately, with the high reliability of modern computer equipment, local-manual operation from the unit switchboard may be incorporated into the computer controls, thereby reducing control complexity. In this case, direct manual operation will still be possible at the equipment location. Further backup control considerations are described in 8.2.

For severe faults that require high-speed tripping of a unit, separate protective equipment is included in the unit control system. This protective equipment comprises relay-based, solid-state, or microprocessor-based protection for electrical and mechanical equipment and trip logic. These high-speed protective functions are generally not incorporated into the computer-based systems used for control.

Figure 1 illustrates the arrangement of control locations, typical functions at each location, and typical interchange of control and operating information. Local control, centralized control, and offsite control functions are described in 4.2.2–4.2.4.

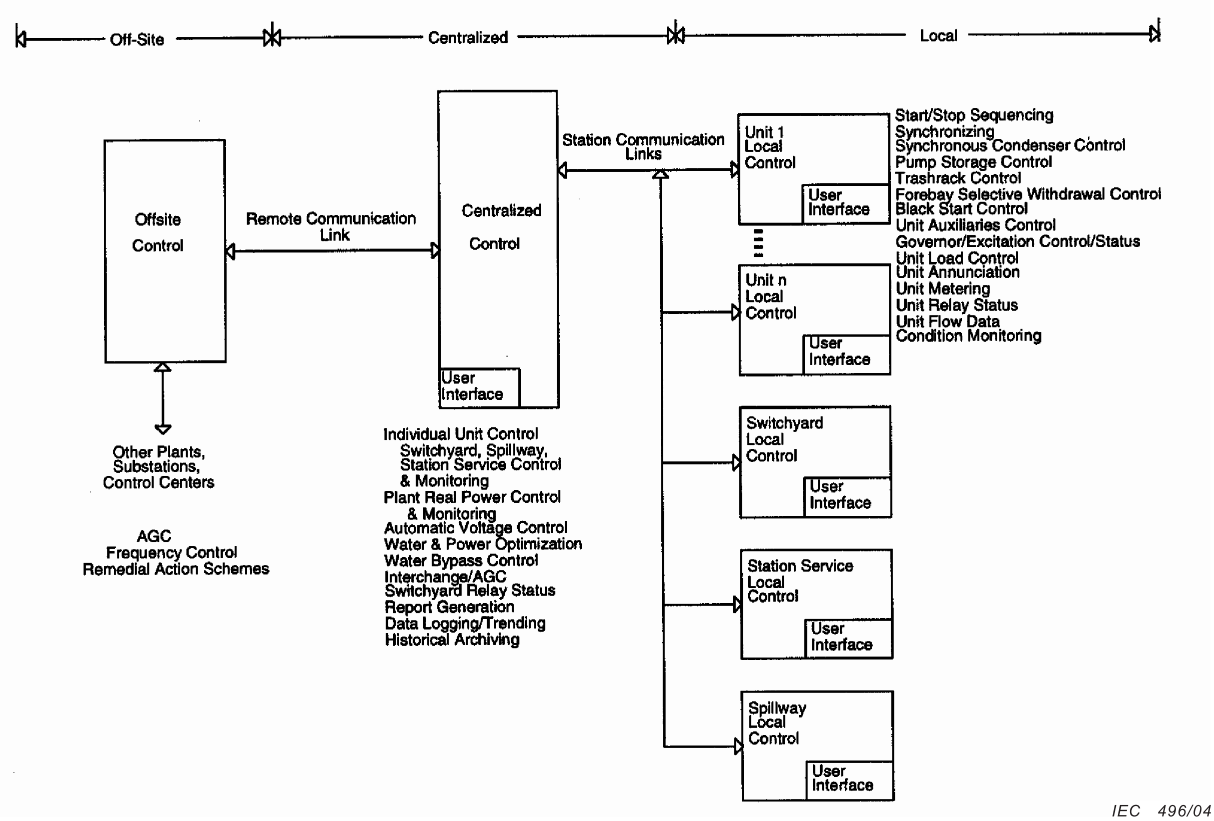


Figure 1 – Relationship of local, centralized, and offsite control

4.2.2 Local control

Local control can be provided by equipment located near the generating unit itself. The local unit computer is part of this equipment and backup manual control may be desired depending on the operator's design philosophy. Where there are multiple units in a plant, one computer is typically allocated to each unit. The local unit computer interfaces to higher level plant or offsite computers exchanging control signals and data without the need for additional wiring. Figure 2 illustrates the local control configuration.

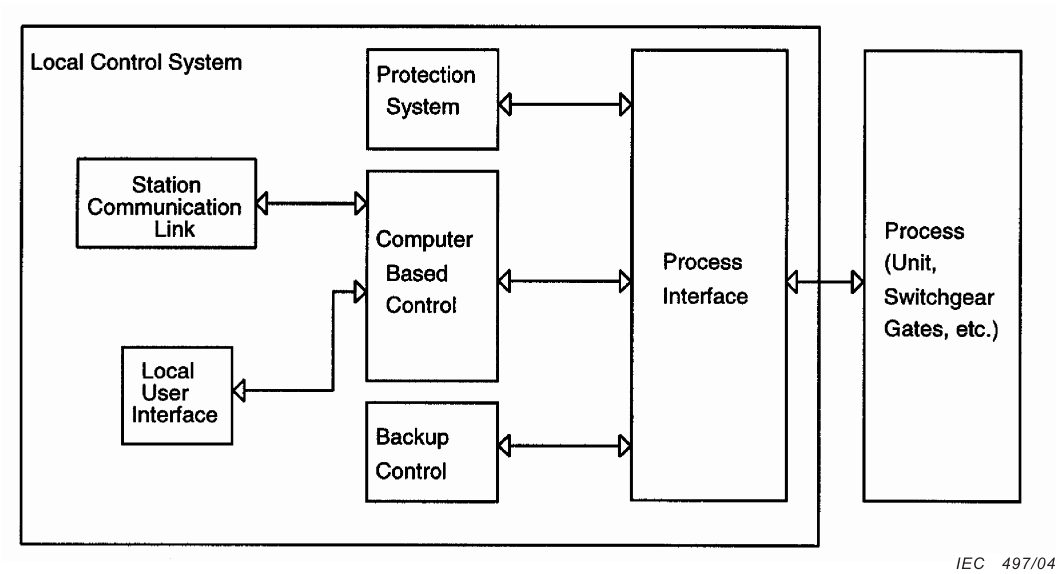


Figure 2 – Local control configuration

4.2.2.1 Start/stop sequencing

One of the most obvious uses for computer-based automation in power plants is for automating unit start/stop control sequencing. Older designs that use electromechanical relay-based start/stop sequential logic are being replaced with modern computer automation systems. The computer is programmed to completely start or stop the unit when directed by higher level control or by the operator. The computer system controls the generator's electrical and electrical/mechanical auxiliary systems to start or stop the unit. Inputs to the computer are unit and plant status points that are constantly monitored for change during the sequence. The computer can continuously monitor and display more status information than an operator can assimilate so that control actions, such as abort sequences, can be initiated immediately, without operator reaction time. Because the computer is programmable, modifications to the sequence control can be made relatively simply, even after the plant is operational. Computer-based start/stop sequencing is cost-effective, reliable, and easy to maintain, compared to older electromechanical relay systems. Some owners of hydroelectric plants may not be comfortable with full computer automation of the start/stop sequencing. In these cases, the start/stop sequencing can be made more conservative by containing breakpoints in the sequencing to allow for operator intervention or permissive action.

The computer system can also monitor the control sequence and provide troubleshooting information identifying where in the sequence a failure occurred. The computer can then pause in the sequencing to suggest operator intervention or to implement the corrective action. This diagnostic capability can speed up the process of correcting the problem and returning the unit to service. Systems with very high-resolution time stamping can provide sequence-of-events recording that can be used to augment and analyze the protective and control relay actions.

One of the most important features is the automation system's capability to provide diagnostic information in the event something fails to operate during the start sequence. This information can be used to isolate the problem and get the unit online as fast as possible.

Examples of some of the equipment controlled and monitored during the start/stop sequence are as follows:

a) intake gate or inlet valve;
b) governor hydraulic oil system;
c) gate limit position;
d) gate position;
e) high pressure oil system for the thrust bearing;
f) mechanical brakes;
g) cooling water system;
h) excitation equipment;
i) unit speed;
j) protective relaying status;
k) unit alarms;
l) unit breaker status.

4.2.2.2 Synchronizing

Synchronizing has traditionally been performed either manually or by a dedicated automatic synchronizer unit. Today, automatic synchronizers use computer technology to optimize their performance.

In some cases, the synchronizing function is performed by the plant computer-based automation system. Synchronizing is a critical function that requires accurate and reliable monitoring of voltage magnitude, frequency, and phase angle. Not all systems can provide the synchronizing function as part of the computer-based automation system. The advantages of the synchronizing function being internal to the automation system include less plant wiring, less maintenance, reduced installation costs, and much better diagnostic capabilities. For security, a synchrocheck relay is typically used as a permissive for the circuit breaker close.

4.2.2.3 Synchronous condenser mode

Hydroelectric generating units are often used in synchronous condenser mode where real power output is negative (the unit is running as a motor) while the unit is online and excited. One reason for this is to provide reactive power control, as described below. Synchronous condenser mode is generally dispatched according to prevailing power flow conditions, but can be regulated automatically by the computer-based control system to achieve optimal real and reactive power capability and maximum transmission utilization.

In cases where a turbine is located below the tailwater level and runs as a synchronous condenser, the water is expelled from the runner area by compressed air to reduce power losses and turbine wear and tear. The computer-based automation system can control the auxiliary devices and monitor the generator during this mode of operation. For example, the automation system can override the reverse power relay during this mode of operation.

Another purpose of synchronous condenser operation is to provide readily available, real-power spinning reserve dictated by power system operating requirements. Computer-based control schemes can be useful in efficiently and automatically performing this mode of operation.

4.2.2.4 Pumped storage control

The computer-based automation system can provide the complete control necessary for a unit to operate in pumping or generating mode. The system can control the switchgear and related equipment necessary to run the unit in either mode. Some basic features easy to implement in a computer-based control system include providing a run time summary of units in the pump mode, providing an automatic restart timer feature in the event the unit fails to start properly, and determining which unit should be started to balance the run time between multiple units. All these features can be implemented at the power plant level and would involve control of the units directly or through unit controllers based on the configuration of the automation system. The main advantages of using a computer-based system to control the pumped storage mode of operation includes easy maintenance, easy modifications, and available diagnostic information.

4.2.2.5 Turbine operation optimization

There are numerous possibilities for optimizing individual unit turbine operation through the application of custom software algorithms. Depending on the parameters monitored and control sequences needed to achieve the operating mode, algorithms can be created to enhance unit operation.

Typical algorithms and monitored parameters are as follows:

a) *Efficiency maximization*. Head water level, tail water, gate position, blade position (Kaplan turbines), flow, unit kW output, unit reactive power output.
b) *Minimization of unit vibration or rough running zones*. Gate position, blade position, unit vibration.
c) *Minimization of cavitation*. Gate position, blade position, flow, hydraulic head (head water level, tail water level) turbine manufacturer’s cavitation curves (or scroll case sound level).

4.2.2.6 Trashrack control

The computer-based automation system can be used to monitor the water level differential between the water level on the outside and the inside of the trashrack and to use this information to operate automatic trashrack cleaning equipment. The information provides operations personnel with appropriate data about the condition of the water flow through the trashrack to allow them to make informed decisions. One of the most important functions that the system can provide is the ability to automatically lower the flow through a unit by decreasing the generated power whenever the trashrack differential exceeds a predetermined value. In this way, the automation system can be used to ensure that the trashrack equipment is not damaged.

4.2.2.7 Forebay selective withdrawal control

Environmental regulations often prescribe an optimal temperature for downstream flow to assist local fisheries. In installations where a large impoundment exists, it is often possible to draw either bypass flow or unit flow from different temperature levels of the reservoir using slide gates or other water level selection equipment. Slide gates, for example, are positioned at various heights along the intake structure, which allow water to be drawn from various levels in the reservoir. Computer algorithms can be written to monitor downstream river temperature and to control that variable to a predetermined set point. This is accomplished by monitoring temperatures at reservoir elevations and varying the flow mix to achieve the desired downstream temperature. Slide gate control can also be helpful in regulating the amount of dissolved oxygen in the downstream flow.

4.2.2.8 Black start control

Hydroelectric powerplants play a critical role in helping reestablish power systems after a major outage. Such outages can leave the plant isolated from the system with no generators running and, therefore, no station service power. Black start capability (i.e. starting the plant without normal station service power) for restoring the plant, and ultimately the power system, is vital. Computer-based automation systems can play a role in accomplishing this black start. The computer system can be activated manually or automatically in such conditions to begin a black start control sequence. Automatically, the system can monitor plant and system conditions, start units, and restore station service power. Subsequently, the entire plant can be brought back to full operation and the power system can be restored.

The capability to start a unit under black start conditions is usually a function of the physical devices in the powerplant rather than the automation system. An auxiliary power system, such as an emergency generator or station batteries, must be available to provide power to the unit’s auxiliary systems in the powerplant to ensure a black start will be successful.

Hydraulic and pneumatic systems must be operational for the automation system to provide black start capabilities. The advantages of black starting under computer-based automation are similar to those found in a normal start condition.

4.2.3 Centralized control

Centralized control refers to a common control location from which plant functions can be initiated and plant operating information can be collected and displayed. The purpose of centralized control is to consolidate control and monitoring at a common location in order to facilitate efficient plant operation and to carry out control functions best handled at the plant level. An important example of efficiency derived from centralized control is the economy of minimizing the number of operating staff required during attended operation of the facility. Centralized control also provides a link between the offsite control facilities and the in-plant facilities. The following clauses describe typical functions provided by the centralized control system.

4.2.3.1 Control of individual units

A number of the functions available at the unit local control system may be made available at the centralized control location. The extent of duplication between centralized and local control functions will depend on the operating philosophy of the utility or owner and the capability of the plant data network. Typical unit control functions able to be initiated at the centralized control location are as follows:

a) automatic start and synchronization;

b) automatic stop;

c) emergency shutdown;

d) speed setpoint;

e) power setpoint;

f) voltage and reactive power set point.

4.2.3.2 Switchyard, spillway, and station service control

A number of the functions at the switchyard, spillway, and station service local control systems may be made available at the centralized control location. Again, the extent of duplication with local control is an operational decision. Typical functions provided at the centralized location are as follows:

a) circuit breaker open/close synchronization;

b) disconnect switch open/close;

c) transformer tap changer control;

d) spillway gate open/close;

e) plant real-power control.

The computer system can be used to maintain the plant or individual unit power output based on different operating criteria. If a plant or unit is to maintain a predetermined power level it can be essentially block-loaded by the computer, and power output will be very accurately maintained at that level regardless of other variables, such as head changes.

Similarly, a plant or unit can be tied to a certain discrete demand and be assigned the task of exactly satisfying that demand in order to allow other units to be block-loaded. When this swing unit trips offline, it is necessary for one or more of the remaining units to transfer from the block-load mode to the swing unit mode to pick up the variable load. Computer-based control systems can automate this control scheme.

A joint power control scheme is often employed in which the desired plant power output is allocated equally among the individual units selected for joint power control. In this case, the plant control scheme includes functions for unit selection, balancing of individual unit power setpoints, control of joint power setpoint, and frequency bias (regulation).

4.2.3.3 Plant voltage/var control

Plant voltage and corresponding plant var output may be controlled by dispatch of individual unit voltage setpoints or by means of a joint voltage control scheme. The joint voltage control system maintains a desired high voltage bus or line voltage by allocating var generation among individual units selected for joint voltage control. The joint voltage control system may include functions for unit selection, control of joint voltage setpoint, and transformer tap position or line drop compensation.

4.2.3.4 Water and power optimization

As maximum utilization of the water resource becomes more and more important to power producers, power plant operators are striving to optimize water usage and power production. Automated water resource management, such as scheduled water releases for minimum water flow and fish water needs, is an excellent application for the computer control system. Accurate, timely, and recorded release information is retrievable through an automated system.

It is also possible to optimize the use of water for given power requirements by computer-based unit, plant, or system efficiency algorithms. For example, knowing the individual generator, turbine, and penstock efficiencies and the hydraulic head and flow, the onsite computer can direct the optimal loading of the units to meet the overall plant load requirement while achieving the best possible plant efficiency. As the hydraulic head changes, operating efficiencies will change and it may be necessary for the computer to reallocate unit load to maintain best achievable overall plant efficiency while satisfying the total demand.

4.2.3.5 Water bypass control

Minimum downstream water flows are often dictated by irrigation and environmental requirements. Water release through bypass mechanisms can be done automatically and more efficiently through the computer. Accurate, real-time control of valves and gates to provide exact flows based on current head and other conditions is possible rather than relying on simple open or closed control.

4.2.4 Offsite control

Offsite control refers to plant control activity from one or more control centers remotely located from the hydroelectric plant. Plant operations performed from such centers are usually one component of an integrated power dispatch and system operation strategy. Personnel at the offsite control location are normally responsible for operating several powerplants and substations, and will probably interface with other control centers (regional, power distribution system, or other power producers).

Some of the system control functions that are generally performed by offsite control centers are:

a) periodic megawatt (MW) and megavar (MVar) adjustments to maintain power system operation in accordance with requirements and criteria established by coordinating bodies (e.g. regional reliability councils);
b) maintain generation reserves in accordance with criteria established by coordinating bodies to assure power system stability;
c) energy interchange scheduling;
d) automatic generation control, including time error control and frequency control (these require coordination with other control areas with which the system may be interconnected);
e) hourly load forecast;
f) transmission line loading (system power flow);
g) power sales control adjustments.

The interconnection of power systems, and the need to control generation and power flow throughout such systems, has led to the design and installation of networks of hierarchical computer-based control schemes that allow system dispatchers to direct power generation at many plants. The computer-based automation systems at individual hydroelectric plants are often integral parts of these power system-wide computer-based control systems used for interconnected power system operation.

When considering automation of hydroelectric plants, it is important to determine how the proposed computer-based plant control system will interact with the offsite power system control computers. Since specific control capabilities can be programmed into computers at various levels in a hierarchical control scheme, an overall philosophy of system control must be established first. The control capabilities and data requirements for the local plant computer can then be defined.

Subclauses 4.2.4.1–4.2.4.4 describe typical functions performed by offsite control systems that impact the control requirements of the hydroelectric powerplant.

4.2.4.1 Control of individual generator sets and selection of centralized control functions

A number of the control functions implemented in the local control system at the hydroelectric plant are made available to, or usable by, the control system at the offsite location. The number and type of plant control functions available at the offsite system will depend on the power system operating philosophy, agreements among power system and plant operating agencies, and the amount and quality of plant and system data available to the offsite control system. Individual and centralized unit control functions available for use by the offsite control system may include those listed in clauses 4.2.3.1 and 4.2.3.3–4.2.3.5.

4.2.4.2 Switchyard, spillway, and station service control

The control functions available at the offsite location will be similar to those listed in 4.2.3.2.

4.2.4.3 Automatic generation control (AGC)

Computer-based AGC, normally executed at one control center in a regional power system, provides the capability to regulate the real power output (megawatt) of selected generators or power plants in real-time. Megawatt setpoints are periodically adjusted by the AGC system to meet requirements for correcting the area control error (ACE), and other constraints.

For the regional control center to be able to allocate a plant’s share of the ACE [station control error (SCE)] in a correct and timely manner, the center’s control computer must receive data from the plant. Inputs to the algorithm that calculates the ACE include: Tie-line power flows; scheduled power generation; power plant outputs; time error bias; power system frequency bias. The amount of the ACE assigned to each individual plant (SCE) as a desired change in generation level depends on the plant’s assigned level of participation in ACE correction. Plant participation in turn depends on the plant’s share of system generation, capability to vary generation, water availability, constraints on changing plant discharge and forebay and tailwater elevations, among other factors.

The amount and type of data and the frequency of update must be established early in the design cycle of the plant control system, and becomes an important design parameter. It is usually critical that generation change allocations to the plant do not violate environmental or equipment limit constraints. A well-designed plant control system will not allow control actions that will result in such violations; however, lack of plant control response has the undesirable effect of slowing needed generation changes, and of causing reallocation of changes to other plants in the center’s control area. Such reallocations may upset plant generation scheduling and water use planning at all plants affected.

Power setpoint signals are transmitted to selected power plants either as a plant scheduled generation, or individual unit scheduled generation, depending on the utility’s practice, or the operating agreement between plant operator and system control center operator if they are owned or controlled by different entities.

Operator interfaces to the plant control system are provided so that individual units may be placed on AGC operation, or removed from AGC operation and placed on local control.

4.2.4.4 Remedial action schemes (RAS)

A number of remedial action schemes are provided in modern power systems, normally controlled from offsite area control centers. Typical schemes include the following:

a) automatic generation shedding based on transmission line configuration (for transient stability);
b) automatic generation shedding to help correct large-scale system overfrequency;
c) voltage transient boost capability for dynamic stability;
d) braking resistor application for transient stability;
e) load shedding to help correct system underfrequency.

To implement these schemes, various signals will be transmitted between the offsite area control center and the plant for arming and triggering corrective action schemes. The update and response time of the plant control computer system are critical and must be carefully considered in implementing remedial action schemes.

4.2.4.5 Data integrity

Reliable power plant data is important to system operation. If even one plant reports erroneous generation, operation of the whole power system is affected by the error until the problem is identified and faulty data corrected, either by the temporary expedients of manual override or substitution of an alternate data source.

The designer of the plant control system must assess the reliability requirements, including the impact that faulty data will have on operation of both the local control system and the offsite control system. The plant control systems should be capable of dealing with failures that impact plant and power system generation.

4.3 Data acquisition capabilities

Hydroelectric plant computers can enhance the acquisition of data from the equipment and systems at the facility. The availability and flexibility of modern computer input hardware and data acquisition software make the collection and manipulation of large amounts of plant data possible.

Data can be acquired directly from plant devices such as transducers and contacts, but given the communication capabilities of computer-based equipment such as dataloggers, sequence-of-events recorders, and digital fault recorders, the plant computer can, if a common protocol is available, acquire data directly from these intermediate data collection systems. This data can be displayed for operator’s use, used in the computer control logic, uploaded to higher level control computers, or stored for future report generation.

4.3.1 Analog

Analog signals can be monitored at fixed intervals by the system for control purposes. For the purpose of data acquisition, the number of samples per unit of time is usually configured according to the parameter being monitored. Some critical quantities such as bearing temperature, hydraulic pressures, or vibration may be sampled more frequently than quantities that do not have the potential for rapid change, such as water level. Trending displays of selected analog quantities is a powerful capability of the computer system.

Several methods of collecting data from analog signal inputs are as follows:

a) *Constant interval*. Data is stored at a constant time interval.
b) *Report by exception*. The quantity is constantly monitored, and while the variable remains within certain limits, infrequent reporting of data takes place. When the quantity is out of range, data is reported at predetermined intervals until a steady-state condition exists.

c) *Variable interval monitoring triggered by event occurrence*. This method monitors and stores signal values at a rate that changes as the result of an event. If no unusual event occurs, older data is overwritten by new data and constant interval storage takes place. Upon initiation of an event, the data collection rate will be increased to provide extremely fine time resolution and all data points stored for future review. This method is very useful for troubleshooting and research into equipment characteristics, but could require extensive memory.

In all cases of analog monitoring, limits can be assigned to each parameter to alarm, shut down, or initiate some other action when a value is out of range. Limits can be absolute, or may include a rate of change of the variable. The computer system has a high degree of flexibility in the recording, alarming, and processing of analog data.

4.3.2 Discrete

Most automation systems offer sequence of events recording for discrete (on/off) status inputs. Ideally, the system should provide time stamping in sufficient resolution to provide the information required to analyze the proper operation of the high speed equipment used in modern powerplants. Computer systems with this sequence-of-events capability are often preferred because they eliminate a stand-alone sequence-of-events recorder and all of the associated additional duplicate wiring and maintenance. Discrete events, alarms, and status points can be time-tagged and saved in a database for future analysis. Examples of discrete status inputs are as follows:

a) event points such as relay operation, unit shutdown, or operator action;

b) alarm points such as low pressures, high temperatures;

c) status points such as breaker position, control switch position.

4.3.3 Fire detection data

Modern design and operating philosophies for hydroelectric plants include increased emphasis on fire detection. The data acquisition capabilities of computers are very useful for monitoring plant fire detection systems, providing the ability to acquire fire detection data, filter it through software, and provide plant personnel with knowledge-based courses of action. In addition, fire protection control actions such as closing doors and shutting down ventilation fans can be initiated by the computer. Since fire regulations vary and can require separate fire protection control, local regulations should be checked prior to inclusion in the plant computer system.

4.3.4 Plant security data

Plant security is becoming more important to owners working to minimize vandalism, unauthorized entry, and the effects of natural events that might jeopardize the safe and proper operation of the facility. Security information displayed at centralized operators’ stations makes it easier and safer for plant personnel to respond to security breaches. For unattended plants, the transmittal to offsite locations of such security information is used to dispatch personnel to investigate the cause. The computer on site also can be programmed to control responses to the security breach, such as turning on lights or alarms, or activating cameras.

4.4 Alarm processing and diagnostics

Accumulating large amounts of plant status and alarm data is not very useful unless the information can be processed in such a way to enhance operation and maintenance activities. The capabilities of the computer can be used to sort, select, prioritize, interpret, and display information in ways that were not possible before.

Modern power plants are designed to provide status and alarm indication of virtually all electrical and electrical/mechanical systems in the plant. This massive amount of information can be overwhelming, and even counterproductive, if it is not processed and presented properly. When major plant problems occur, multiple alarms are inevitable.

Knowledge-based programs can filter alarms for the operator and even interpret alarm groupings to identify the probable event that generated them. Expert system programming can assist plant operations and maintenance personnel in the location and solution of problems.

4.5 Report generation

Raw data collected by the computer system is necessary for the generation of reports that are used for operations and maintenance decisions. Computer database management and document preparation capabilities are becoming powerful tools for increasing plant efficiency. The multi-tasking capabilities of the computer provide report generation capability while accomplishing real-time control and monitoring of plant functions. Computer-based documentation capabilities include the following:

a) *Sequence-of-events recording*. Inputs (events) are scanned and time-tagged to the nearest millisecond to provide after-the-fact information to analyze faults and other high-speed events.

b) *Automated operator's log*. Hourly, daily, and weekly electrical and mechanical data, traditionally logged manually by the operator, can be recorded automatically.

c) *Historical data recording*. Important data are recorded in such a way as to permit analysis of plant operation over various cycles of operation. Such data can be used to improve the computer control. For example, optimum efficiency algorithms that control plant operation in response to dynamic plant and power system conditions can be developed or improved by studying the historical data records.

d) *Trend reporting*. Data is reported for trends in equipment operation that indicate problems that may need maintenance attention. Also, water and power data can be analyzed for trends that may be useful for system operation or planning.

4.6 Maintenance management interface

Data collected via the computer system can be used effectively as input to more sophisticated computerized maintenance management systems (CMMS). CMMS that are condition-based or predictive-based need current information on the condition of equipment in the plant; information that may already be collected in the plant computerized automation system. The automation system can double as a data collection point for data needed for control and protection functions, as well as for data needed to trigger maintenance activities, from the CMMS system, by out-of-limits conditions. Further details of data sharing are outside the scope of this guide.

4.7 Data archival and retrieval

The long-term archival and retrieval of hydroelectric plant operations data is important. Complete, accurate, well-organized data on water levels and flows, power generation, and plant maintenance is required for regulatory and environmental purposes. In the past, records were kept manually and storage of data in virtually unusable format and in unsafe and inaccessible locations was common.

Retrievability of useful information was sometimes difficult and could be costly. Well-planned and operated computer-based automation systems in power plants can help relieve this problem. Useful data can be collected, collated, stored, and retrieved in ways that take up less space and time. Significant planning is required to anticipate the long-term data storage needs, and consideration should be given to format of data stored, the expected amount of data that will be collected, and the most appropriate storage media.

4.8 Operation scheduling and forecasting

Automation-collected hydro-meteorological data can be used for operation scheduling and forecasting. Information such as weather data and runoff data can be used for near- and longer-term predictions of power generation capability that affect scheduling and forecasting on an individual plant or system-wide basis.

4.9 Data access

As computer-based automation systems are implemented in power plants, management has direct access to data. This increased availability of data (unit availability, total plant output, etc.) helps streamline management decision making. Automation makes data readily available at all times to all departments with computer access. Data flow and information access are increased thus promoting higher efficiency. In order to protect the integrity of the control system and its data, the computer system can restrict access to authorized persons.

4.10 Operator simulation training

Computer-based hydroelectric plant control systems may include realistic operator training in plant operation. Offline simulation of normal and abnormal operating conditions can be provided that expose the operator to a wide variety of possible plant conditions. Being able to simulate emergency conditions in realistic fashion through the computer system can enhance the operator's response in real emergencies. Where plant normal-status operation training is desired, actual current plant conditions, status, and quantities can be displayed while the operator/trainee practices operating procedures.

4.11 Typical control parameters

Table 2 gives selected examples of input and output parameters that are necessary to implement some of the computer-based control capabilities discussed in this clause. This listing is neither complete nor exhaustive, but is merely illustrative of implementation particulars that should be considered when designing an automation system.

Table 2 – Typical parameters necessary to implement automated control

Control action	Inputs	Outputs
Unit start/stop	Gate limit Gate position Breaker status Governor hydraulics Unit speed Unit protective relays Generator voltage	Brake release Gate operator Cooling water valve Exciter Start circuit Unit selection Breaker trip/close
Unit synchronizing	Unit speed Gate position Gate limit Breaker status Generator voltage Bus voltage	Breaker select Breaker closing Unit select Power adjust Voltage adjust
AGC	Unit status MW MVar Unit protective relays Set point	Unit selection Power adjust
Synchronous condensing	Draft tube depression MW MVar	Power adjust Excitation Draft tube depression Unit selection
Turbine optimization	Head Blade angle Gate position MW head MVar Flow	Gate operator Power adjust Unit selection

Control action	Inputs	Outputs
Trashrack control	Differential pressure	Trash raking system Power adjust Gate operator
Black start	Protective relays Bus voltages Generator status Breaker status Generator voltage Unit power	Generator start Unit synchronizing Breaker close (dead bus) Power adjust Voltage regulator Unit selection Breaker selection
Base load control	Unit status MW MVar Gate position Gate limit Set point	Power adjust Gate operator Unit selection
Voltage control	Unit status Breaker status MW MVar Bus voltage Set point Generator voltage	Voltage regulator Unit selection
Remedial action schemes	RAS initiation Generator selection Breaker status Unit status System frequency	Breaker trip Breaker selection
Forebay selective withdrawal	Water temperatures Gate position	Gate operator Unit select

5 System architecture, communications, and databases

5.1 General

System architecture defines the structures and relationships among the components of the hydroelectric power plant automation system, including its interface with the operational environment. Architecture includes hardware components, software components, configurations, networks, performance, reliability concepts, and maintainability of the automation system. Performance, reliability, and maintainability aspects of the system are covered in other clauses of this standard. These aspects of the system are dependent upon the system architecture. System architecture for a hydroelectric power plant must consider such factors as the number, size, and types of turbines and generators in the plant; whether the plant is generation-only or pumped storage; the plant's auxiliary systems, and whether or not the plant is designed for attended or unattended operation. A wide range of hardware components, networks, software components, and database alternatives are available to configure cost-effective architectures to meet the automation system's design goals. Open system architectures offer the advantages of ease of expansion, ability to accommodate changing technologies, and immunity to premature obsolescence.

5.2 System classification

5.2.1 Overview

Advances in computer technology provide a user with the choice of a variety of system architectures for configuring hydroelectric automation systems. No attempt has been made to describe all configurations and systems available, but rather to focus on systems currently employed or envisioned to find future use in hydroelectric plant automation applications.

5.2.2 Hydroelectric plant automation classification

There are two general classes of system architectures used in hydroelectric plant automation systems. One class of systems uses proprietary hardware and software, and makes little or no provision for interoperation with other hardware and software. For discussion purposes, these are termed closed systems.

The other general system class is an integrated system, with all plant control and monitoring components having a common data communication structure supported by common hardware and software structures. The trend in these control systems is towards open systems. From a practical sense, open systems or the openness of a system relates to the ability to replace hardware, modify software, and expand system capabilities without a wholesale reconfiguration of the control system. Attributes of open systems are interconnectivity of the hardware and software, portability of the software, and interoperability of applications and systems.

Examples of applications and major components of the two general system classes are shown in Table 3. For contrast, a traditional supervisory control system is included to illustrate similarities and differences. Again, from a practical sense it should be noted that neither fully closed nor truly open systems exist. Rather, a spectrum of systems exist, all with some ability to communicate or function with other systems.

Table 3 – Classifications of hydroelectric power plant computer control systems

System type	Applications examples	Major components
Traditional supervisory control	Hardwired supervisory control systems	Master stations Nonprogrammable remote terminal units
Closed	Stand-alone systems (proprietary, single-function controllers)	Proprietary controllers Proprietary operator console stations
Open	Hydroelectric power controllers (systems) Large scale energy management systems SCADA systems (microprocessor-based)	Programmable logic controllers on communications networks Networked PCs or workstations End user programmable remote terminal units

5.2.3 Functional and geographic distribution

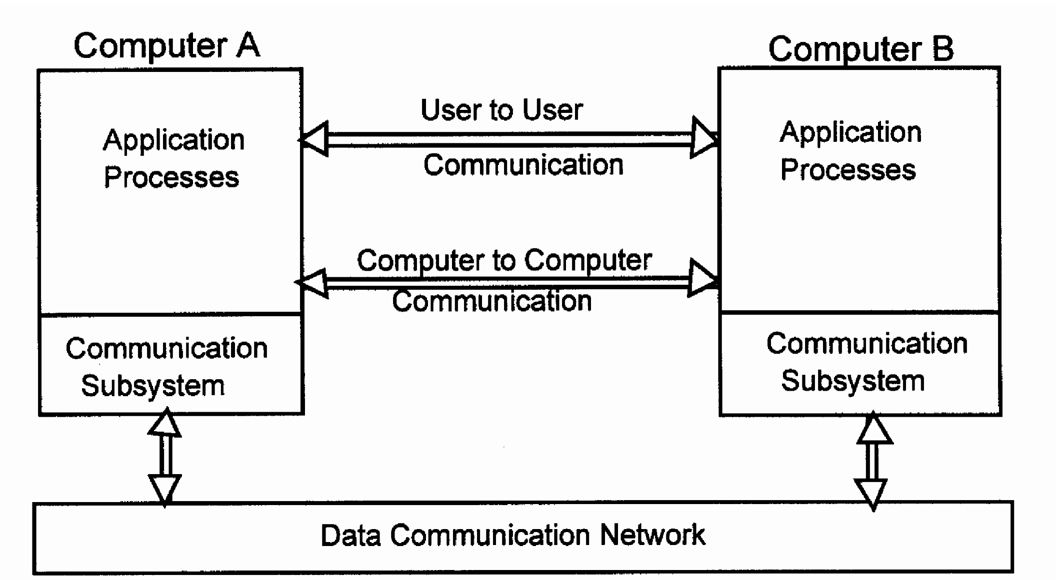
The terms *functional distribution* and *geographical distribution* are frequently used in describing characteristics of automation systems. Geographical distribution refers to the physical layout of the equipment comprising the automation system. Functional distribution refers to the performance of tasks within the functional groups of a hydroelectric power plant, (e.g. generator/turbine units, switchyards, etc.).

5.3 System architecture characteristics

5.3.1 General

Any discussion of characteristics of system architectures for hydroelectric automation systems requires some basic understanding of the data communication structures (and related standards) that allow communication between computers. A communication network is the system that permits the linking of resources so information can be passed to where it is needed.

Although physical separation of the communicating computers varies considerably from application to application, in general, a computer communication network can be represented diagrammatically, as shown in Figure 3.



IEC 498/04

Figure 3 – Computer communication network

At the heart of any computer communication network is the data communication facility. The application processes (APs) vary widely between systems (different languages, operating systems, etc.) and implementing hardware. Systems communicating only within their family are referred to as closed systems. Examples of closed systems are shown in Table 3. These proprietary packages do not address the problem of universal connectivity or open systems architecture.

To alleviate the problem of connectivity, the International Standards Organization (ISO) formulated a reference model. The resulting Open Systems Interconnection (OSI) is concerned with structuring the communications software needed to provide a reliable, data transparent, communication service (independent of any specific manufacturers' equipment or conventions) capable of supporting a wide range of applications. The objective is to provide a model for exchanging information among systems open to one another through the mutual use of standards. The model provides a tool for describing, designing, implementing, standardizing, and using communication networks.

The IEEE 802 family of standards deals with the two lowest layers – the physical and data link layers – of the ISO OSI Reference Model. These standards describe the relationship among these systems and their relationship to ISO's OSI Reference Model.

5.3.2 Open system standards

To ensure a degree of system longevity and flexibility, it is desirable to conform to open system attributes of hardware interconnectivity and software portability. To achieve this goal it is recommended that industry standards or widely supported vendor specific *de facto* standards be employed.

Hardware interconnectivity standards apply to system backplane and peripheral connection standards. As an example, typical backplane standards are VME Bus (IEEE Std1014-1987), and EISA Bus (*de facto* standard). Peripheral connection standards are broken into two broad groups, parallel and serial. An example of a typical parallel connection standard is the Small Computer System Interface (SCSI); a typical serial connection standard is the TIA/EIA series of standards RS232, RS422 and RS485 (industry standards).

Software portability relates to the operating systems, programming languages, and user interfaces with the hydroelectric automation system. Ideally, the hydroelectric automation software should be capable of being moved from one vendor's hardware to another, if required, although this ideal is yet to be realized. Standards (industry and *de facto*) promoted by the Open Software Foundation focus on software portability issues. Examples of standards in this area include the IEEE Portable Operating System Interface Standards (POSIX®) Series, OSF/DCE (Distributed Computing Environment), and Motif (window management environment *de facto* standards).

An implementation of the OSI reference model applicable to communications within electric utilities is the Utility Communications Architecture (UCA), under development by the Electric Power Research Institute (EPRI), in the U.S. UCA specifies a standard for each layer of the OSI reference model and references a set of implementer's agreements, developed by users and implementers of OSI products, to assure interoperability of applications and systems. Work is underway to address the need for utility-specific implementer's agreements for the use of the Manufacturing Message Specification (MMS), which is used within UCA for control and data acquisition applications.

5.3.3 Networking and communication considerations

5.3.3.1 General

The two lowest layers of the OSI reference model are the physical layer and the data link layer. For communication to higher layers within the OSI reference model (e.g. to a utility area-wide control system from a hydroelectric plant automation system), the next layer – the communications layer – may be involved.

5.3.3.2 Communications and network layer considerations

Availability and successful operation of the data communication network is essential to the reliability of a hydroelectric automation system. There are a number of important concepts to evaluate when considering a communication data network for a hydroelectric power plant data acquisition and control system, some of which are as follows:

a) *Data links*. Communication among major system elements should use bit serial communication links.
b) *Adherence to industry standards*. The data network should conform to formal and informal (de facto) industry standards to provide for the widest selection of mutually compatible equipment, and ensure long service life.
c) *Availability*. The data network should be designed for maximum availability. This will require fault tolerant design concepts and possibly even a redundant network.
d) *Correct operation*. The data network should, as a minimum, use error detection techniques to prevent the acceptance and use of corrupted data. Error detection without correction implies either loss of the data for the reporting cycle, or a request for retransmission of the data.

e) *Data transmission speeds*. The data system design should consider the amount and type of data to be transmitted, and the time constraints on the data, for example time sensitive control algorithms. Time constraints include consideration of worst case data transmission activity such as complete update of a plant data base during a period of maximum control system activity after a control system element failure, a plant equipment failure, a power system disturbance, or a combination of these events.

f) *Environmental considerations*. The control data network system should operate acceptably in the expected operating environment. The equipment may be subjected to electro-magnetic interference (EMI), radio frequency interference (RFI), and temperature and humidity changes. Data networks with physically long paths may have ground potential differences between terminals of the network during fault conditions.

g) *Data network operation*. There are several network control protocols to consider in the design of a data network. Each has advantages and disadvantages to be compared and evaluated considering the volume of data expected, the response time necessary, and achievement of simple system operation.

h) *Offsite data communications*. The design of the offsite data communication links should accommodate the type and volume of data to be transmitted and received, and the communication facilities available to carry the data. Industry standards should be followed, allowing the use of widely available and compatible equipment.

5.3.3.3 Data communication functions

5.3.3.3.1 Monitoring and control

Monitoring equipment. In a digital control system, data from monitored equipment travels over the communication link (or links) to the data acquisition and control system node requiring the data.

Data from the controlled equipment is in one of two forms: discrete data such as contact positions representing alarms and/or events, switch positions, or equipment status; and continuously variable (analog) data. Discrete data is used as equipment status information for operating programs, operator interface display programs, and can optionally be used for sequence of events (SOE) recording. Discrete data may also include information from position encoders, transformer load tap changing equipment, and contact closure or pulse inputs from watthour measuring instruments.

Analog data is sensed at the process interface, converted to a digital representation of its analog value, time tagged, and placed in the data base of the control system node where it is sensed. Analog data can be used to generate alarms. A rate of change greater than a reasonable value or a value beyond acceptable limits for the equipment can be used to generate alarms, with the analog data time tag providing time of occurrence information.

Controlling. In a digital control system, control action can be initiated either as a result of application program results within the control node near the controlled equipment (the local node), or by action of the station control node. If the local node initiates control action, the communication network is not used. If the control action is initiated by the operator via the operator interface, or by the station control node, the communication network is used.

Typical control actions in a hydroelectric plant result in starting and stopping turbine-generator units, closing circuit breakers, controlling unit load and generator voltage, opening and closing spillway gates, and operating auxiliary equipment, including station service breakers and transformer tap changers. Control actions are initiated at the operator interface or by the station control node, transmitting the control command to the local node over the communication network.

5.3.3.3.2 Control node configuration and initialization

The system control nodes' application programming may include both software and firmware, and the control programming may use proportional, integral, and derivative (PID) and other control algorithms.

The control node configuration software, or the PID loop parameters, should not be accessible to change by all users of the control system. There should be a system security provision permitting alteration of the software only by those authorized. An automatic audit trail should exist documenting the changes and their implementer.

5.3.3.4 Control data communication requirements

5.3.3.4.1 General

The control data communication network requirements include: time constraints; dependability; safety; data communication network transparency; diagnostics; and maintenance. The following discussion applies mainly to distributed types of control systems with their various nodes connected by one or more communication networks. It is applicable to closed systems insofar as these systems use data communication networks among their various elements.

5.3.3.4.2 Time constraints

5.3.3.4.2.1 Process data availability

Ideally, the current value of the data from each process input, analog or discrete, should be instantaneously available to the requesting application program. In practice, delays between the time the data appears at the process input terminals and the time it appears in the plant data base are unavoidable.

5.3.3.4.2.2 Data transport delays

There are a number of sources of data delay. For a digital control system, the first delay occurs in transmitting process data from the input terminals to the data base of the system control node nearest the controlled process (the local node). For analog data, the filtering and a/d conversion process introduce the first delay. For discrete inputs, the scan process is the first, and usually least important, (apart from the contact bounce filter), source of delay. If the local node performs closed loop control, other delays in data transmission become less important, or less critical to the local control process.

Another delay occurs between the local node and any other node utilizing this data. This delay includes time to format the data for use by the communication network, time to queue the data for transmission and time for the local node to execute the data communication system transmission protocol and transmit the data.

A source of delay occurs with transmission of data to an offsite control system at a dispatch center. The communication network control protocol used by the network to the offsite system may introduce another unpredictable delay.

5.3.3.4.2.3 Control command execution

System security requires error-free, correct performance of control actions, for example the control command must not be misinterpreted by the local control node. Rather than chance incorrect control operation, it is better to reject the command, and ask for it to be repeated, or wait for the next command. To achieve this security level, sophisticated error detecting codes are used, as well as automatic checkback to verify command validity.

If checkback before operation is used, the effective transmission time of the control command is more than doubled. The transmission time may be unpredictable because if the intended receiving node is transmitting data at the time a command is sent, there is a delay in its command retransmission for verification. If the control command sequence requires a checkback verification, further delays are introduced.

5.3.3.4.2.4 Overall control system delays

Power plant response to offsite control commands such as AGC inputs requires accounting for the amount and type of plant data used by the offsite system to determine its control requirement for the plant. Delay in transmission of data to the offsite system from the plant data base is the sum of all delays in getting the data from the local node to the plant data base node.

5.3.3.4.3 Dependability

Data communication network dependability is a broad term covering hardware reliability and availability, data transmission error detection and correction, and software reliability. For critical systems, redundant data communication networks and/or other fault-tolerant design features may be required. Fault-tolerant data networks should be designed so that failure of any single element of the data network does not cause the entire network to fail. The hardware should exhibit excellent availability and be capable of being quickly repaired and returned to service after a failure.

Data errors due to noise or other influences on the transmission medium must be detected and corrected if possible, or the data must be quickly retransmitted. Excessive errors will increase data transmission times, and lead to problems associated with inadequate transmission network capability.

5.3.4 Safety

Plant, equipment, and personnel safety require the control system to not issue, or permit execution of, an incorrect command caused by data errors or equipment failure. To achieve safe operation, the data network must be reliable and have error detection capabilities. Each network topology (see discussion in 5.4.2) has its own set of pros and cons regarding safety issues. There are a number of techniques used to assure reliable data communication regardless of the network topology used. If a specific data communication link fails, it should not cause failure of the entire data communication network. The system should be able to automatically reconfigure itself and continue transmission of data to remaining operable components. Critical data that are required for life or plant safety systems (e.g. dam spillway gates, etc.) should receive priority in reconfiguration schemes.

5.3.4.1 Data network transparency

Data network operations should be transparent to plant operators and to equipment outside the terminals of the data network. All data transmission functions, including error detection and correction, formatting for transmission, and preparation for presentation to control system nodes should be done by the data network equipment without attention from the control system nodes.

5.3.4.2 Diagnostics

The data communications network should include diagnostic software for both online and offline functions. Monitored online functions include data network performance and alarming for excessive channel errors and channel failures. Offline functions should include tests of each hardware element of the system, transmission medium tests, and verification of the data network error detection and correction features.

5.3.4.3 Maintenance

The data communications network should be easy to maintain, preferably without interruption of the data transmission function. Completely redundant, independent data networks are desirable, so the control system remains operable if one of the networks fails. Further, a failure of a single element should not precipitate a total system failure. Redundancy provides a means for effecting system repairs and provides a method for system tests or training.

5.4 Control data networks

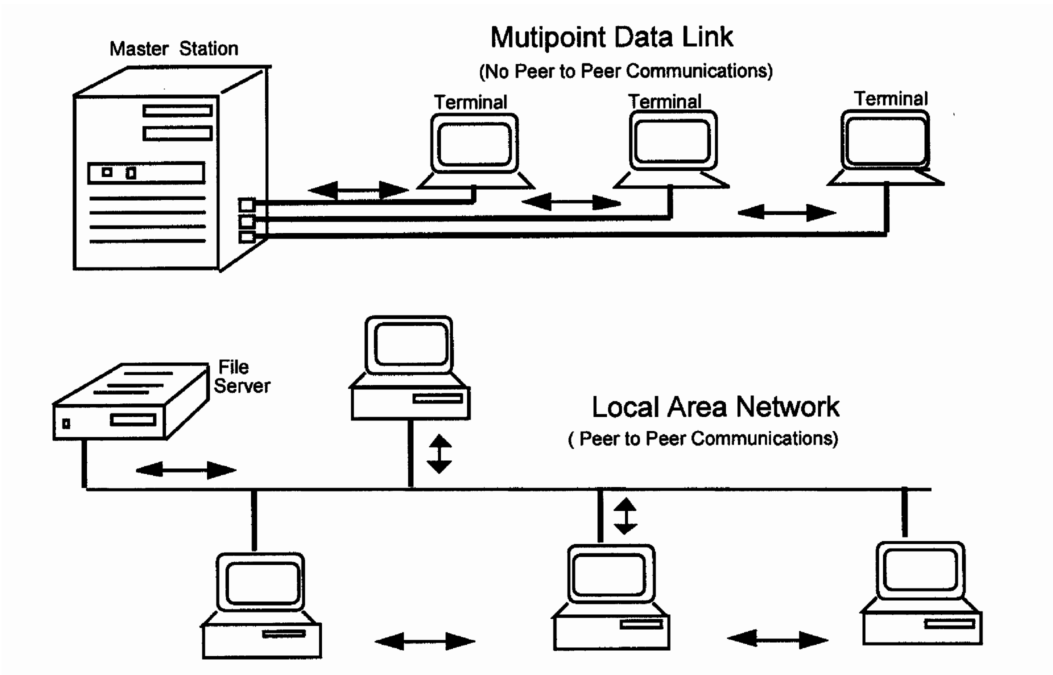
5.4.1 General

There are two general classes of control data networks finding application in hydroelectric automation systems. Both are Local Area Networks (LANs), one being configured to a set of IEEE Standards (IEEE 802 series) with the IEEE 802.3 (Ethernet) standard finding widescale application in hydroelectric automation systems. Two other standards from the IEEE series (802.4 and 802.5) involving token passing protocols likewise find application in these same systems. A second category of networks covers a broad range of proprietary bus topologies. Proprietary topologies find application in both segregated and integrated systems. This clause briefly discusses features of the two classes of control data networks.

5.4.2 Local area network (LAN) topologies

5.4.2.1 General

The local area network differs from a conventional multi-point data network in several significant ways. With a multi-point data link, a computer typically communicates with a number of relatively simple terminals. Communication is controlled by the computer, and transmission occurs only between the terminals and the computer at relatively slow speeds. With a LAN, each device attached to the communication medium is a relatively intelligent machine, and any device attached to the LAN can communicate with any other device on the network at very high speed. Figure 4 contrasts the physical differences between multi-point data links and local area networks.



IEC 499/04

Figure 4 – Multi-point data link versus LANs

5.4.2.2 LAN characteristics

- *Station Relationships*. With a typical LAN, all stations accessing the common communication facility are peers on the network; there is generally no distinction made between primary stations and secondary stations.
- *Message Exchange*. A LAN is designed to give the appearance of supporting multiple message exchanges at any given time between various pairs of stations, although in actual practice only a single message can be transmitted at any given instant.
- *Transmission Speed*. Transmission speeds are very high, typically in the millions of bits per second.
- *Distance*. A LAN is designed to support communication over a limited geographic area, for example within a powerhouse or control dispatch center.
- *Transmission Medium*. A LAN typically uses private, user-installed wiring as the communication medium.
- *Extensibility*. A LAN is designed to transparently become part of a wide area network (WAN). This allows communication over an unlimited geographic area.

5.4.2.3 Classifications of local area networks

Many hardware and software systems are available for implementing local area networks. All share the general characteristics just discussed but all are implemented in different ways. In general, LANs are classified according to the following criteria:

a) network topologies;

b) transmission media;

c) transmission techniques;

d) access protocols.

5.4.2.4 Network topology classification

5.4.2.4.1 General

The network topology relates to the logical way in which stations are interconnected. The three major topologies are the ring, the star, and the bus, described in 5.4.2.4.2 - 5.4.2.4.4.

5.4.2.4.2 Star topology

With the star topology (see Figure 5), all stations are connected through a central control point. The *Multipoint Data Link* shown in Figure 4 is an example of a star topology. True star topologies are seldom used in modern networks. TokenRing and 10BASE-T Ethernet use cabling schemes that resemble a star topology. However, TokenRing is electrically a ring topology, and 10BASE-T Ethernet is electrically a bus topology.

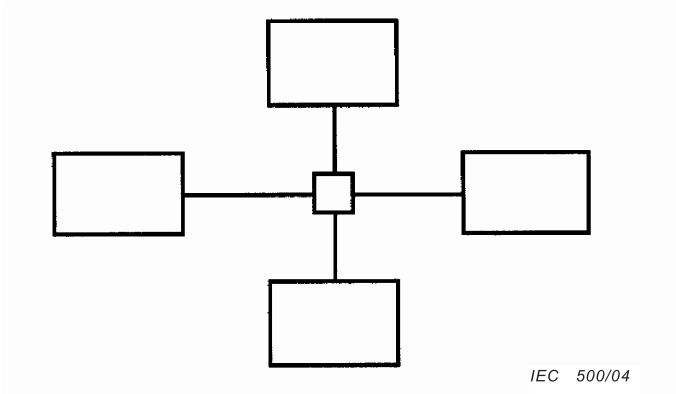


Figure 5 – Star topology

5.4.2.4.3 Ring topology

With a ring, (see Figure 6), each station is connected to the next one to form a closed loop. Each station has a transmitter and receiver, and data is transmitted in one direction around the ring. In a regular ring configuration, the communication media is connected point-to-point to each node, with each node acting as a repeater. The arrangement precludes bidirectional communication since the transmitter of one node is connected to the receiver of the next node. This characteristic makes the ring topology favorable for fiber optic media, a unidirectional communication medium. Token Ring topologies are covered in ISO/IEC 8802-5: 1995, and find application in hydroelectric automation systems.

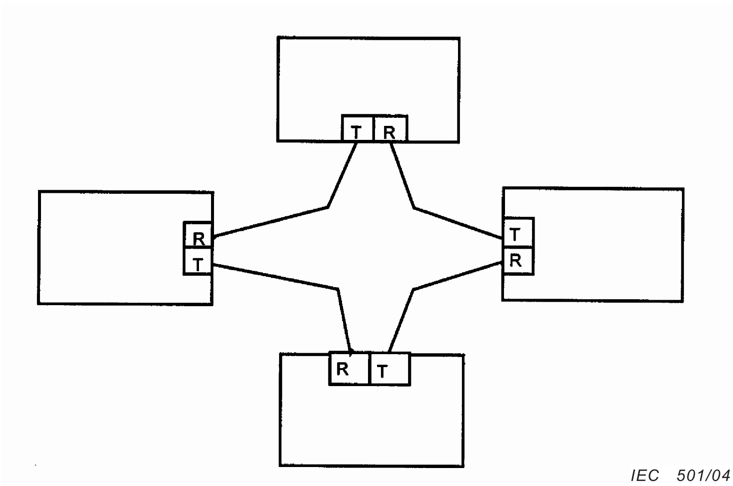


Figure 6 – Ring topology

5.4.2.4.4 Bus topology

With a bus (see Figure 7), all stations are attached to a single cable. Standard and ThinNet Ethernet, 10BASE5, and 10BASE2 are examples of a bus topology.

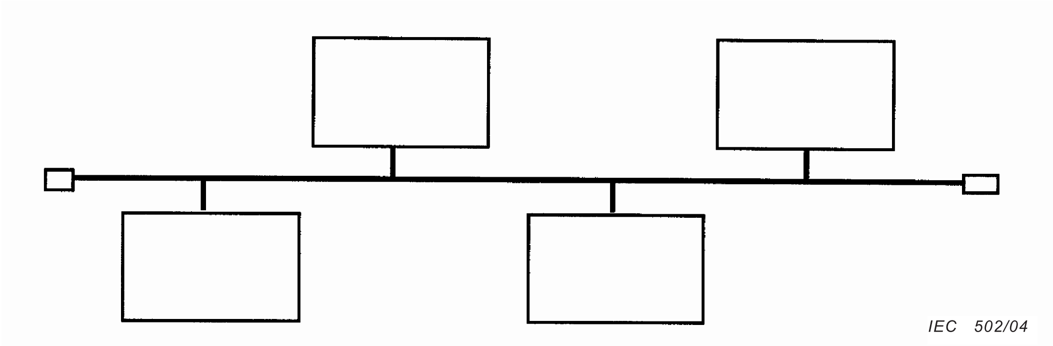


Figure 7 – Bus topology

5.4.2.4.5 Topologies employed in hydroelectric automation systems

Topologies employed in closed hydroelectric automation systems are usually based on manufacturer's proprietary systems (for a discussion of backplane standards, see 5.3.2). General characteristics of typical proprietary systems are described in 5.4.2.6. Bus, ring, and star topologies all find application in control systems. A cursory comparison of communication data networks employed with hydroelectric automation systems is shown in Table 4.

Table 4 – Hydroplant computer control systems data communications attributes

Traditional supervisory control	Central computer (master) communicating with nonprogrammable RTUs over wire, fiber, radio or microwave; dedicated communications channels Star topology
Closed	Small scale systems Proprietary networks Proprietary communications links
Open	Unlimited scale systems Open system architectures (IEEE 802 series networks)

5.4.2.4.6 Proprietary bus topologies

Some digital control system vendors provide proprietary data links for equipment modules of their own make. Some may provide complete systems, with process I/O devices and controllers included on the proprietary network data link. Most, however, provide a standard gateway to interface their proprietary data link to an industry standard such as ISO/IEC 8802-3: 1996 (Ethernet), a Manufacturing Automation Protocol (MAP) network, or other protocols developed by other standards writing entities (ISA, DOD, etc.).

Proprietary data communication networks (and in some cases, bus structures) are used with some closed control systems having dispersed elements. Normally, for these closed control systems, the user will not have to be concerned with the network capability; the vendor will have ensured that all elements are working together to provide the necessary performance. However, should the closed system be of a new design with no performance record, the user should verify that the data communication network has the design capacity to perform as specified, and obtain performance guarantees from the vendor.

If the closed control system requires communication with another system in the plant, the design must have provisions to ensure that the proprietary data communication network can interface with other systems, either through a bridge or a gateway. For the interface arrangement, data transmission speed will be a consideration.

Proprietary data communication network protocol may be a factor in reusing existing remote terminal units (RTUs) when partially replacing or expanding an existing control system. Older systems almost invariably used proprietary data formatting and communication protocol. In this instance, it will probably be necessary to use a gateway between the two systems.

A further discussion of proprietary control systems and data communication networks may be found in IEEE Std 1046-1991.

5.4.3 Physical transmission media

Media types used to implement network topologies include unshielded twisted pair, shielded multiple twisted pair, coaxial cable, twin axial cable, or fiber optic cable. The choice of media for a hydroelectric automation application depends on isolation characteristics, transmission bandwidth, signal attenuation, access methods, cost, and immunity to noise. The installation methods used with metallic media have a significant influence on the immunity of circuits to noise (e.g. use of cable trays dedicated only to control cables will significantly increase the immunity to noise of the affected circuits). Table 5 provides a relative comparison of some critical parameters of the various media. It should be noted that the cost of fiber optic cable and equipment is dropping, relative to other physical transmission media. The generally superior characteristics of fiber optics combined with its dielectric isolation make fiber optics well suited for application in power plant control systems.

Table 5 – Cable media characteristics

Cable type	Noise immunity	Transmission speed	Transmission length
Shielded, multiconductor twisted pair	Poor	Slowest	Short
Coaxial cable, both baseband and broadband	Good	Fast	Long
Twin-axial cable	Good	Faster	Long
Fiber optic	Best	Fastest	Long

5.5 Data bases and software configuration

5.5.1 Open systems and data bases

As open systems become a more popular choice for a control system architecture in the hydroelectric plant control system industry, database management systems have become the subject of more intensive study. Formerly, database systems were a given–they came with the system, were vendor proprietary, and could not be interfaced with software from other vendors.

There are four main types of database management systems, which are distinguished by the way they organize data. The data organizations are hierarchical, network, relational, and object-oriented.

a) *Hierarchical*. In a hierarchical database, the relationships between records are extremely limited. If a more extensive (network) relationship is required for an application, then the application has to manage the relationships through programmatic manipulations, leading to a system that is very difficult to maintain.

b) *Network*. In a network database, any record can be related to any other record. The network model permits complex connections among data at extremely high efficiency while supporting a high volume of users. The performance of a network database is dependent upon the identification and organization of relationships during the design process. The network model is particularly inflexible in terms of permitting changes after the initial design.

c) *Relational*. The relational model implements relationships between data as occurrences of rows, columns and tables. New fields and modifications to the initial database can be accomplished with a minimum of restructuring. Relationships among record types are established dynamically, permitting new applications to be easily accommodated. The relational model has the benefit of being associated with a firm theoretical description.

d) *Object-oriented*. This database design is an emerging technology that is growing to fill the deficiencies of the relational model. Object-oriented databases permits data to be shared externally during database execution, providing excellent speed and simplicity. The object-oriented database lacks the firm theoretical base that the relational model possesses.

5.5.2 Real-time vs. nonreal-time database designs

Hydroelectric automation systems require both real-time and nonreal-time database designs. Real-time designs must be capable of supporting database access requirements of the user interface (UI), SCADA, automatic generation control, event recording, etc. These tasks all must be accomplished in several milliseconds.

Nonreal-time database designs are needed to support historical functions, trending, reporting, and other nonreal-time requirements. These functions require massive amounts of data processing that usually dictates a design at odds with real-time requirements.

Unfortunately, commercially available databases have been inadequate to meet the real-time needs of the automation system and power systems environment. This has forced vendors to develop highly specialized proprietary databases to link with a very limited set of external hardware and operating systems. These systems can accurately be described as closed systems preventing interface with other hardware and software. Any expansion or modification of the system must be referred to the original vendor or one must develop in-house expertise to perform the changes desired.

While automation system vendors must rely on their proprietary database designs to satisfy real-time demands, there is an increasing movement to incorporate commercially available databases to provide nonreal-time functionality. Reporting, trending, maintenance scheduling and other offline functions can be very adequately provided by popular database designs that provide a broad range of user defined characteristics and interfaces.

Often it is possible to retrofit a relational database to an existing system to provide user defined flexibility in reporting and other management tasks. When designing the linkage between the nonreal-time commercial database and the automation system vendor's proprietary database, data transfer in both directions must be included.

The benefits of using commercially-available database management systems include the following:

a) direct linkages to supporting relational database information is available;

b) plant operation data is available (through a utility's wide area network) to other groups within the operating utility;

c) reporting formats can be easily changed to meet changes in plant operational documentation.

5.5.3 Software configuration

5.5.3.1 Custom software

In the custom software area there are several options, as follows:

a) *Dedicated*. The software changes are closed to the end user.

b) *Configurable*. The software has features that can be changed by the user's software maintenance personnel. These changes are normally of the form of turning on or off a feature that is already in the software through a software key or password.
c) *Programmable*. The software has features that can be changed or added by the user's software maintenance personnel.

5.5.3.2 Commercially-available software

The custom software described in the previous clause is normally available only as part of a turnkey automation system. In contrast, commercially available software can usually be purchased as part of a turnkey system or directly by the power plant owner. In the latter case, the owner will have to make provisions for the installation and configuration of the software. Spreadsheets, database managers, and operator interface software packages are all examples of commercially-available software being used as part of the power plant automation system.

Commercially-available software provides flexibility and has many options. Because of its availability, the user has support from not only the original vendor, but other users and possibly other vendors. The most common options are as follows:

a) *User configurable*. The user has all of the documentation necessary to change the software operation or to add new code that is linkable to the rest of the software. The user has the ability to add features or change options, but cannot change features in the original code without the aid of the original vendor.
b) *User programmable*. The user has the source code as well as the documentation for the software and can modify it as needed using internal staff or any contractor the user wishes, or the user can implement his/her own software to be added to the system.
c) *Full graphics*. The user has the ability to generate pixel and/or vector graphic images on the displays in any form. The software has sophisticated artwork generation and real-time display of these images under system control. Often, full graphics are implemented in a windowing operating environment.
d) *Online configurable*. The features mentioned above can be done by authorized personnel sitting in front of the online and running system. That is, authorized personnel can change the configuration of the running system as they wish.

6 User and plant interfaces

6.1 User interfaces

The most critical interface for a power plant automation system is the User Interface (UI). The plant interfaces discussed later in this clause are important to the automation system in order to perform effective monitoring, annunciation, control, etc., but the UI is crucial to the success of the system. If the operator is not able to use the system easily and conveniently, the system will never be used properly or cost effectively. The operator's needs are critical to the successful operation and use of a power plant automation project. UIs offering the look and feel of a personal computer may be desirable to reduce special training.

In order to make the system acceptable to the operations personnel, care must be taken in the selection of the hardware and software used. The hardware options are numerous for both input and output devices as well as the workstations to be used.

6.1.1 Input devices

Input devices are not mutually exclusive and may be combined to incorporate desired features. Typical devices include the following:

a) *Trackballs*. Pointing devices for menu driven software. Trackballs are normally used in conjunction with a standard ASCII keyboard and/or numeric keypad and occupy very little desktop space.

b) *Mice*. Similar to track balls, they are normally used in conjunction with an ASCII keyboard and/or numeric keypad. A mouse requires more desktop space than a trackball since the mouse must be moved in order to move the cursor on the screen.

c) *Light pens*. A pointing device for menu-driven software. Light pens normally use an ASCII keyboard and/or a numeric keypad for data entry and require no desktop space.

d) *Keyboards*. Normally installed on all workstations for data input and system control. Desirable features for keyboards and numeric keypads include standard key layouts and tactile feedback. They need to be well constructed to withstand continuous use. They should be waterproof and dustproof. Keyboards using layouts similar to the familiar PC will minimize the chance for confusion arising from the use of a nonstandard keyboard.

e) *Touch screens*. Useful for cursor positioning but not well suited for data entry.

f) *Speech recognition*. This input technique is a leading edge technology. It has many disadvantages at present such as speaker dependency, large error or misinterpretation rates, large memory needs, and extensive processing time.

6.1.2 Output devices

As with input devices, various output devices may be combined to incorporate desired features. Some typical devices are as follows:

a) *Printers*. These devices range from dot matrix units to letter-quality line printers in both black and black-plus-color models. They are used for hard copy output of the computer data for reports or historical records.

b) *CRT screens*. These output devices are on most UI systems and are the primary output device for the computer. They range from small monochrome units to large color units with millions of color combinations.

c) *Speech synthesis*. Provides the operator with a phonetically-based audible message output.

d) *Mimic boards*. Graphical displays or map boards used to represent the configuration and data of the plant or system. Mature technology units range from manual displays with movable parts to fixed displays with lights to indicate equipment status. New technology units include displays of system data in graphical form and large projection screens with computer generated displays.

6.2 Plant interfaces

The plant to computer-based control system interfaces are important to the success of the automated hydroelectric power plant’s control system. There are many types of hardware interfaces, each with specific requirements that must be addressed as the system is designed, installed, and tested.

6.2.1 Types

Examples of plant interfaces include analog transducer signals, dry contacts (i.e. contacts without sensing voltages) and digital data. This clause covers several generic types, but the coverage is not complete because installations may have special application requirements to meet unique concerns. This discussion addresses the analysis process for any plant interface.

6.2.1.1 Digital, contact, and pulse inputs

Digital or contact inputs should meet minimum criteria for operations at the voltages and current loads anticipated. The current required to drive the input circuitry should be adequate to ensure false indication changes do not occur due to noise. The current should be as low as possible to conserve power and reduce heat generation. Wetting voltages (e.g. those voltages required to sense the status of dry contacts) may be provided by the control system or the field device.

Contact bounce in the input signal can cause erroneous data in the system. Digital inputs should have filters to detect only sustained input signals. These filters may be in the hardware or the software. Filters must be selected in accordance with time tag accuracy. Simple low-pass filters can introduce undesirable delays. Voltage levels for logic detection should be sufficient to prevent erroneous readings.

Digital inputs may also serve the functions of pulse accumulators or counters. This function is normally in software or firmware at the I/O. Accuracy, counting, and pulse accumulation rates should be sufficient for the intended use.

Another variety of digital inputs comes in the form of a parallel (e.g. binary coded decimal) data. The quantity of wire conductors, noise immunity, and hand shaking requirements should be considered when making accommodations for these inputs.

Serial digital inputs (e.g. EIA RS232, RS422) are frequently used as an interface to newer transducers. Considerations for interfacing with such inputs are covered with other communications issues in 7.3.

Digital input status indicators, often LEDs, may be provided. These indicators ease I/O and control circuit troubleshooting.

6.2.1.2 Digital and contact outputs

Digital or contact outputs provide data and control contacts for external circuits. These contacts must have sufficient current and voltage rating for the external load. These ratings must often be considered in total for a given card or group of I/O as well as for individual circuits. Wetting voltage is typically provided by the external circuit. The ability of the solid-state devices in the output circuitry of the I/O to absorb the required current (without thermal instability of the devices) is a function of temperature (heat generation).

Where higher current ratings are required, interposing relays are typically installed. The current ratings are then those of the interposing relays.

Digital outputs may be latched, momentary, or maintained. These functions may be implemented in software or in the output relay. Digital output status indicators – usually LEDs – may be provided, similar to those on input I/Os.

The failure state of digital outputs should be defined and specified. Digital output failure may be critical in some applications.

6.2.1.3 Analog inputs

Analog inputs may be low-level (e.g. 0-1 mA dc, 4-20 mA dc, 1-5V dc, etc.) current or voltage, resistance, or thermocouple signals. Resistance or millivolt (thermocouple) inputs may be scaled to engineering units by the I/O processor, or a separate RTD or thermocouple to current or voltage converter located with the I/O.

The I/O is often capable of providing the loop power supply for analog inputs. Voltage, tolerance, stability, and loading should be considered.

Scaling accuracy, resolution, deadband, and thermal stability should all be specified to meet the needs of the applications. Thermocouple and RTD replications should meet the standard accuracy for these devices. Open thermocouple detection is often desirable. Common and differential mode rejection ratios should also be specified.

When multiplexing technology is used, the multiplexing hardware should be solid-state and not electromechanical. Multiplexing schemes must be fast enough to ensure that the most recent values are available when required for all control loops.

6.2.1.4 Analog outputs

Analog outputs are typically low-level voltage or current. Accuracy, resolution, deadband, and thermal stability should all be specified. Similar to digital outputs, the condition or value of analog outputs upon failure may be critical in some applications.

6.2.1.5 Analog-to-digital/digital-to-analog conversion

The accuracy of any analog input or output depends on the conversion between the computer's digital data system and the analog information. The conversion is typically performed by multi-bit A/D converters. Conversion accuracy and resolution are a function of the number of A/D converter bits and I/O amplifier design. Further, the accuracy is affected by temperature-induced drift. Thus, A/D resolution, input accuracy, and temperature stability should all be specified.

6.2.1.6 Field devices and field bus standards

Another major source of interface signals are those originating from intelligent electronic devices (IED) and intelligent field devices (e.g. a field device capable of measuring more than one parameter and transmitting the measured parameters over one pair of wires). Intelligent field devices and field bus systems are a developing set of specifications enabling replacement of the traditional 4-20 mA instrument communication system and associated devices while retaining the existing instrument wiring. The resulting reduction in field devices and the sharing of wiring reduces installation costs. Standards covering intelligent field devices and field bus systems are developed by several standards organizations including IEEE, International Electrotechnical Commission (IEC), Instrument Society of America (ISA), and National Electrical Manufacturers Association (NEMA). IEEE 1379 is applicable to multipoint data communications between IEDs and RTUs in utility substations. A commonly used field bus standard is IEC 61158. A number of proprietary and de facto standards also find widespread use.

6.2.2 Sources

The sources of information to be interfaced to control systems are numerous and not all are covered in this subclause. The most common ones are highlighted, as follows:

a) *Digital Input Signal Monitoring*. Usually accomplished by sensing the state of relay contacts using the station battery or a voltage supply to detect the opened or closed status of the contact. The output devices are normally solid-state or electromechanical relays that are energized or de-energized by the control system.

b) *Analog Input Devices*. Normally transducers that convert potential transformer (PT) and current transformer (CT) signals to quantities such as megawatts or megavars. In existing plants, control system analog outputs may drive display panels or strip chart recorders for operator observation.

c) *Parallel Input Devices*. Usually shaft encoders or digital panel meters. The output devices are digital panel meters or process controller modules. These interface sources are in many cases bidirectional, i.e. they are both input and output devices. Typically, these devices use a Binary Coded Decimal (BCD) encoding scheme, and range from a 4-bit wide (1 BCD digit) bus to 32-bit wide (8 BCD digits) bus, plus control lines.

d) *Serial Sources*. Normally bidirectional devices with built-in intelligence, providing both input and output capability. The devices consist of smart watthour meters, shaft encoders, temperature transducers, etc.

6.2.3 Input/output protection

All inputs and outputs should be specified to withstand the Surge Withstand Capability (SWC) test, as described in IEEE C37.90.1-2002, without any false operations. The SWC test has proven to be a reliable means to identify noise problems similar to those found in a hydroelectric powerhouse. Other test considerations, such as RFI, are covered in 10.1.1.

6.2.4 Collection process

The data collection process involves all of the aspects discussed above as well as some considerations that are internal to the control system as opposed to the interface itself.

6.2.4.1 Scan rate

The scan rate deals with the rate at which the data is moved from the interface to the database, or from the database to the interface.

6.2.4.2 Archival rate

The archival rate of the control system is normally the rate at which data is stored for long-term, historical purposes. This rate varies dependent on data type, in order to save storage space, retrieval time, and analysis efforts. For example, the archival rate for temperature data does not need to be as often as that for electrical data.

7 System performance

7.1 General

Performance of the control system may be judged in terms of hardware performance and software performance. There are situations where the boundaries between these two are not clear. In addition, software performance often depends on the performance of the hardware system on which it is operating. Software performance is evaluated by overall system performance. This clause discusses hardware performance and the performance of the overall system. System performance is based on the following four criteria:

a) *Security*. The ability of the system to prevent unintended operations, misinterpreted communications, and computational errors. The security of the system is a function of error rates, checking and correction, redundancy, and communications protocols.

b) *Reliability*. The rate of failure of hardware, system function, and software. Measured as the availability of the system.

c) *Speed*. The rate at which the control system performs functions. This includes response to inputs, operator commands, and system events.

d) *Input/output integrity*. The accuracy of input detection and conversion to internal system units, output conversion from internal units to output values, input recognition, and time tagging if performed at the input.

Often these criteria are affected by factors outside the control of the system supplier and are dependent on system design. These may be communications equipment and systems, power supply systems, environmental factors, software, or other items that interface with the system that are provided by the end user or others in the process of implementation. Performance criteria must be established for the system and carefully refined to govern work provided by all parties involved with system implementation.

Hydroelectric applications of control systems have their own unique requirements. These range from specific software applications for efficient operations, environmental extremes, remoteness from available service personnel and replacement parts, and unattended operation. Each of these must be taken into account for the specific application and performance criteria developed. There are a number of mutually exclusive factors that must be recognized and evaluated to determine an optimal solution for the application. Factors to be considered are as follows:

a) control stability versus responsiveness;

b) robustness versus complexity;

c) accuracy versus tuning difficulty;

d) capital versus operating and maintenance costs.

In addition, cost must be weighed as a factor in establishing performance requirements in any of these areas. Typically, the higher the performance required of the system, the greater the system complexity, and the greater the cost.

7.2 Hardware

7.2.1 Input/output (I/O) subsystem

Input/output characteristics are critical to the proper operation, installation, reliability, and maintenance ease of the control system. The I/O subsystem provides the protective buffer between the harsh electrical environment of the plant and the electrically sensitive environment of the digital computer.

The input/output subsystem should be able to accurately convert between digital and analog signals in the computer system, and general plant digital and analog parameters. In addition, the input/output system may perform time-tagging, scaling, and unit conversion functions. Isolation and protection functions are also part of the input/output. I/O devices will be provided with single or multiple processors on the I/O card or board, or within the terminal cabinet. These processors control communications with the host system, and perform input scaling, time-tagging, and unit conversion if resident in the I/O.

Performance considerations for various applications include the following:

a) portability and the exchange of I/O cards from one I/O location to another. This can reduce spare parts requirements;
b) availability of I/O cards to be replaced under power. This avoids the need to shutdown an entire I/O location to change one card;
c) Sequence-of-Events (SOE) time tagging at the I/O locations; accuracy and resolution;
d) availability of I/O signal types and levels that support the field device signals to be used;
e) support of redundant field devices, capability for redundant I/O from field device to the database and operator interface;
f) I/O diagnostics available at the card, for example card failure or I/O failure indicating LEDs, or through software in the system.

7.2.2 Control processing systems

The control processing system may be made up of a single-chip microcomputer or chip sets supporting single or multiple microprocessors. These often take the form of dedicated control units (embedded microprocessor), programmable logic controllers, or microcomputers. These processors are the central device in the control system.

Considerations in processor performance are processor speed, bus bandwidth, and memory type. These parameters control the speed of operation of the control system. The system performance characteristics discussed later in this guide are functions of these parameters.

Memory is a critical part of the processing system. Memory may be chip-based or media-based. Media may be fixed or removable disks, magnetic tape, or CD-ROM. The amount of program and database storage directly affects processing speed and response. The amount of data or archival memory affects the amount of data that can be stored, and to a lesser extent the speed of data storage, trending, reporting, and archiving functions. Sufficient memory should be provided for the maximum program, database, and data archives anticipated. An additional spare amount above that is desirable.

Many processing systems operate in a multi-tasking or time-sharing environment. These processors are generally more responsive to changes in parameters and control actions. Interrupt-driven systems provide similar response, but may have slower, lower-priority processes. Generally, control processes and actions are assigned levels of priority that dictate the frequency and priority over other functions.

Other considerations fundamental to system performance are:

a) *Response to loss of power*. Loss of memory or program is significant on loss of power. This governs restart time for the system. Actions on restart are critical in the application of the system. Spurious control actions, setpoint changes, etc. should be avoided on shutdown and restart. Output states on shutdown and restart must be setable and predictable. Storage of programs and databases in nonvolatile memory prevents the need for reloading on start-up, thus shortening failover or restart time.

b) *Failure practices*. The practice of tripping the unit on control system failure should be reviewed. Most hydroelectric units operate in stable situations with few rapid actions that are a function of the control system. With maintenance of remote generated setpoints, and coordinated unit restarts, it is often possible to maintain generation assuming proper shutdown and protection circuits can operate independent of the control system.

c) *Communications to other processors*. Input from other processors and computer systems may be needed for proper control operation. Setpoints may be received from a generation dispatch system, for example. The speed and priority of these communications are a function of their importance in the system operation. Communications to data gathering systems, or supervisory control may be less important.

d) *Processor redundancy/fault tolerance*. For increased reliability, control processors may be configured as dual, triple, etc. redundant systems. In dual systems, primary and backup units are provided. In a distributed system, some or all of the controllers may be redundant. Proper failover hardware and software can provide a bumpless transfer in control without loss of data. The backup unit may have a replica database, and be monitoring conditions and signals online, or may reload the database and scan all points on switchover. The former provides almost seamless transfer.

e) *Maintenance*. In redundant systems, the backup unit should be able to be taken out of service for maintenance without disrupting the primary processor.

f) *Expandability*. Expandability to add additional processors and other support chips such as numeric coprocessors is desirable in many systems. For small systems this may be only the addition of memory, or media drives. For larger systems, this can be the addition of processors or processing computers to create a distributed networked computing system.

7.3 Communications

Communications between the central or distributed processors and the I/O, and to other computer systems is a main function in system performance. The type of communications and the media chosen affect how quickly data can be gathered and control functions completed. Data transfer rates, message security, error checking and correction are typically implemented in the communications system.

Communications between the central processor and remote I/O can be separate from communications to other computer systems, or may be on a common network. The communications method for the remote I/O may need to be more secure, and faster than typical data networks can supply. This is highly dependent on system application.

Communications hardware must support the communications method chosen. This includes modems, interface cards to the processor and I/O, and the communication medium, whether fiber optic, cable, or radio. Communications hardware and software are required at each I/O location and at the central processing site for systems that use distributed I/O.

Communications may use completely-redundant equipment, only-redundant communication media, or nonredundant systems. In redundant systems, no single device failure should disrupt communications. Redundant media systems without redundant support hardware, or redundant hardware systems with single media should have automatic failure sensing and switchover functions.

Communications should be transparent to the user. All error checking and correction should be performed without alerting the user, other than providing error statistics and alarms on excessive failures. Considerations that should be addressed in communications systems include the following:

a) distance between drops with and without the use of repeaters;
b) media options available, and the use of multiple media within the system;
c) the ability to disconnect communications drops without system disruption;
d) the ability to perform maintenance and troubleshooting on system components with minimum disruption to system communications. This is typically confined to single drop locations in nonredundant systems;
e) message and data security on open network systems, or systems where the network may be accessed using public communications.

7.4 Measuring performance

The first measure of performance is to determine if the system provides the required functions. This is discussed in Clause 10, which discusses the various parameters and functions that may be specified and tested to provide a given level of performance.

7.4.1 Reliability

System reliability is a function of the mean time between failures (MTBF), and the mean time to repair, (MTTR). The MTBF is affected by the redundancy of hardware, and the reliability of each individual component. Reliability and availability studies may be performed.

Typically, MTBF data for computer systems is taken at the card or board level, rather than at the component level. MTTR times are a function of spare parts availability, the availability and expertise of repair personnel, and administrative, travel, and transport time. The availability of a given system or subsystem is commonly defined as follows:

Availability = MTBF/(MTBF + MTTR)

7.4.2 System response time

The response of the control system to field events and operator-entered and program-generated commands is critical to system application. When a desired function must happen rapidly, delays in program execution can cause serious problems. Response to operator commands as reflected at the operator interface is a prime factor in operator satisfaction. Waiting too long for control actions to be implemented, for displays to be generated, or for reports to be printed can create great frustration in the user.

Response time is a function of system loading at the time of the event or control action. Worst case and typical case loadings can be developed to evaluate the application of a control system. Criteria must be established for the speed at which the system must respond in order to provide adequate control. The following are considered in developing the worst case and typical case system loading conditions:

a) the number or percentage of I/O that is simultaneously changing. This is particularly important in evaluating catastrophic situations where many field parameter changes and alarms may be happening simultaneously such as on a unit trip;
b) the number of operators that are requesting or regenerating screen displays at the time;
c) the number of logs or reports that are being printed at the time.

7.4.2.1 Response to field events

This measure is the time it takes an input change at the I/O, including remote I/O, to be detected, locally processed, communicated, and processed and stored at the central processor. With distributed types of control systems this may include the time to communicate to one or more operator interfaces and display the change.

In addition to single events, the time required to scan all inputs and update the system database may be measured. This demonstrates the speed of the communications, processing, and storage subsystems.

7.4.2.2 Response to operator or program commands

This response measures local as well as global actions. The global actions again take into account the communications subsystem. Typical response times evaluated include the following:

a) time for system to either acknowledge receipt or act on operator keystrokes, or other input device actions;
b) execution of commands from the time entered at the operator interface to when they are completed at the output device;
c) regeneration of a displayed screen, or generation of a new screen;
d) update of the dynamic data on a displayed screen.

7.4.2.3 Internal program response

Criteria may be established for the operation of various internal programs. These can include efficiency calculations, start/stop sequences, report generation, trend creation, and special calculation or control programs that are key to system operation.

7.4.2.4 System initialization and failover times

The time that it takes the system to initialize after start-up, power loss, and/or failover is often critical. This is a function of the media that the operating program is stored on, the circumstances of the shutdown and the standby capabilities of the system. Parameters such as cold start, or restarting an already running system (e.g. “warm boot”) may be evaluated.

8 System backup capabilities

8.1 General

This clause deals with backup facilities that are installed to make it possible to operate essential functions in the plant when the computer-based control system is not functioning. Backup systems are different from control system redundancy in that they allow an operator to deal with plant emergency situations. Redundancies in the computer system, such as dual control processors, are discussed in 7.2.2 of this standard.

As the modern computer-based control equipment has very high reliability, it is obvious that the facilities for backup control should be limited to functions that are essential for the safety of the plant and functions that are necessary for operation of the units under emergency conditions. The backup facilities generally are not intended for long-term operation of the plant.

8.2 Design principles

Although the design of equipment for backup control requirements depends to a great extent on local plant conditions, the general hierarchical control concepts discussed in 4.2.1 provide a basis for establishing plant specific backup needs. Normally, since some form of manual control is provided for testing and maintaining the plant's generating equipment and auxiliaries, a common approach to provide automation system backup is adaptation of the manual capability to cover the backup requirements. Though adding some costs and complexity to the automation system, these costs and complications can be minimized through proper design and equipment selection.

During normal operation, the control and supervisory functions are carried out by the computer-based equipment and separate equipment is used for the protective functions. When the backup control is used, it is assumed that the protective equipment is in operation. In case of a severe fault in the plant, the protective equipment will disconnect or stop the process equipment concerned.

The backup control provides manual control of the plant. The operator controls the different process equipment via devices located close to the equipment. Frequently (particularly in existing plants), capability to manually operate individual unit and plant equipment exists at a unit switchboard. To reduce the equipment and cabling needed, the control should, in general, be designed with no interlocks, and it should be up to the operator to check the conditions before operating. Instruction manuals or checklists should be available.

8.3 Basic functions

In a hydroelectric power plant, it is essential that the following functions can be carried out under all conditions:

a) emergency stop;

b) operation of spillways;

c) operation of high voltage circuit breakers and isolating switches;

d) starting and stopping of generator/turbine units;

e) operation of the intake gate/turbine isolation (shutoff) valve.

To guarantee the safety of a hydroelectric power plant, it is most important that it be possible to operate the spillway gates in case of a fault in the computer-based equipment. Backup control for circuit breakers and disconnecting switches of the switchyards should be provided. For the turbine/generator units, it should be possible to start, run, and stop the units manually to maintain production during emergency conditions.

8.4 Design of equipment for backup control

8.4.1 Turbine/generator units

For the backup control of a hydroturbine/generator unit, it should be possible to manually start all auxiliary equipment, open the wicket gates and bring the unit up to rated speed, connect the excitation and synchronize the unit to the grid. After the synchronization it should be possible to adjust load and reactive power.

Auxiliary equipment such as pumps, fans, valves, etc. should be provided with devices for test operation. The operating devices are normally push-buttons or control switches that are mounted close to the controlled equipment; no separate position indicators are required. Before start and after stop of the unit, the operator will operate the auxiliary equipment according to checklists by using these devices for test operation.

To bring the unit up to rated speed and for synchronization, it is necessary to perform several operations in sequence. For this reason, devices for operation of the following functions are normally grouped in a unit switchboard close to the unit:

a) open/close for the start/stop solenoid;

b) open/close for the turbine wicket gates;

c) operation of the field breaker;

d) increase/decrease excitation;

e) operation of the generator circuit breaker;

f) operation of the brakes;

g) operation of the intake gate/turbine isolation (shutoff) valve;

h) instruments for load, reactive power, voltage and speed.

Position indicators should be provided for control equipment operated from the unit switchboard. Synchronizing instruments may be stand-alone, portable or multiplexed using a selector switch. From the unit switchboard, it should be possible for the operator to start and stop the unit and adjust unit load and reactive power.

8.4.2 Circuit breakers and isolating switches

For circuit breakers and isolating switches in high-voltage switchyards, the backup control should be carried out from a panel containing the control devices for the circuit breakers and isolating switches associated with the unit. With backup control, no interlocks are included and the operating devices are connected directly to the breakers or switches.

The control panel should be designed similarly to the turbine/generator unit switchboard. The location of the panel depends on the local conditions, but it is suitable to mount the panel in or close to the cubicles containing the protective equipment for the controlled breakers and switches.

8.4.3 Spillways

For spillways, backup control should be arranged according to the same principles as for the units and the switchyard. However, the design of the equipment has to be adapted to local conditions. The distance between the power house/control room and the spillways; the time allowed before opening in case of a load rejection, etc. are factors that influence the design.

The backup control should include facilities for opening and closing of the gates, position indication for the gates, and also indication of the head water level.

8.5 Alarm handling

It can be costly to provide backup for alarm handling by computer-based equipment if the requirements are overly ambitious. Due to the high availability of computer-based control systems, the backup control will be used infrequently and only for short periods. For this reason, the backup alarm system should be as simple as possible and provide only a limited number of group alarms. As an example, two group alarms can be regarded as sufficient for one turbine/generator unit.

A common problem encountered when designing a backup alarm system is that most indicating devices only provide one dry contact wired to the control equipment. A well-designed backup system should be capable of using one input to drive both the primary and secondary side of the I/O, thus avoiding the need for additional interposing relays and transducers. A typical approach is to use diode isolation from the normal inputs. The signals from the diodes are then grouped together and connected to an alarm unit.

8.6 Protective function

Any protective function provided through the computer-based control system should be accommodated in the backup system if it is essential to the safe operation of either the plant or an individual unit. Those functions that are not essential should be identified to the local operator to ensure awareness of the necessity to monitor affected instrumentation.

9 Site integration and support systems

Prior to implementation of an automation system into an existing plant the designer should study the site conditions and ensure that interfaces and other circumstances are compatible with proper operation of the automation system. This clause identifies some features that often need such study.

9.1 Interface to existing equipment

An evaluation of existing equipment should be performed. The designer should pay particular attention to the likely interface equipment to the automation system. For example, if voltage raise and lower outputs from the automation system will be connected to the generator excitation equipment, the characteristics of the excitation equipment need to be documented. For instance, the time interval between initiating a voltage change command and the resulting change in generator voltage should be obtained. In addition, equipment operational limits (e.g. turbine cavitation limits, generator capability limits, etc.), and hydraulic data (e.g. spillway gate and turbine discharge data), should be obtained. Often such information is at least partially available from the operations staff. Once collected, the information should be incorporated as reference material into the requirements for the automation system.

9.2 Environmental conditions

Typically, a wide range of environmental conditions can be found in a hydroelectric powerhouse. Certain elements (such as data communication equipment) of an automation system are often designed to operate satisfactorily over a wide range of environmental conditions. Other elements (such as disk drives) can be particularly sensitive to such conditions as dust and vibration. Care should be exercised when determining the location for each element of the automation system.

In some cases it may be necessary to provide air conditioning and other protection for the automation system. If that is not practical, the specifications for the automation system should clearly describe the ambient temperature limits over which the equipment must operate. Care should be exercised to locate all equipment items in places that are accessible. Areas that are subject to extreme conditions of dust, vibration, or moisture should be avoided. Hazardous areas should also be avoided unless the equipment is certified to be operated in such locations.

A less apparent source of environmental influence is the introduction of system noise that can be induced by sources of electromagnetic interference (EMI) and radio frequency interference (RFI). Specifically, equipment should not be located in areas with substantial EMI or RFI. Additionally, care should be taken to prevent the introduction of this interference through connecting cabling, grounding, and similar features.

Older computer equipment was usually expensive and difficult to replace. Special fire protection equipment was often designed to extinguish a fire in such computer equipment. With the rapid decline in the cost of computer equipment, however, many newer systems do not warrant special fire protection. The designer should evaluate the need for such equipment and use it if appropriate.

When performing the environmental conditions evaluation, the requirements of making the automation system compatible with the site should be weighed against making the site compatible with the automation system. For example, if a desired location for equipment experiences a wider temperature range than is normal for automation system equipment, the difficulty in adding a temperature controlled room for the equipment should be compared with the increased cost and complexity of specifying automation system equipment to operate over a wider temperature range.

9.3 Power source

A reliable power source is an important consideration for proper operation of an automation system. The station dc battery is such a source of power. Some automation system items (such as data communications equipment) can be powered directly from the station battery.

Automation system components often include standard computer system devices that only operate on a.c. power. Since hydroelectric powerhouses occasionally lose a.c. power, a reliable alternate a.c. power source should be considered, because some of the automation system features (such as sequence-of-events recording) could be vital during such occurrences. In order to provide reliable power to the automation system devices, an inverter is used to convert power from the station battery to a.c. power. Battery chargers powered by the station a.c. power keep the batteries charged while providing enough d.c. power to maintain the inverter load. If an inverter is used, it should include a bumpless static switch that automatically transfers the power source for the automation system to the station a.c. power source in the event of an inverter failure. Also the inverter should be designed to produce an a.c. output with waveform deviation and waveform characteristics consistent with the requirements of the supplied loads. Appropriate failure detection and alarming should be specified for the inverter.

An evaluation (as described in IEEE Std 485-1997) should be performed to ensure that the station battery will have enough capacity to operate the automation system along with all other d.c. loads for the specified time periods. Although no universal standard exists for the period of time the automation system should continue to operate after loss of station a.c. power, a period of half an hour is typically considered adequate. A capacity test should be performed to verify the battery condition. The battery charger sizing should also be evaluated. The chargers must be capable of supplying the d.c. system load while charging up the battery in the required time period. If the evaluations show that larger batteries or chargers are required, consideration should be given to improving automation system efficiency instead. Reducing other d.c. loads is another option.

9.4 Supervision of existing contact status points

Most automation systems include large numbers of contact status point inputs. These contacts can be found in protective relays, manually-operated control switches, level switches, position switches, and numerous other devices. To the extent possible, the contacts should be used directly as inputs to the automation system and not be tied through auxiliary relays. If trouble contacts in protective relays are connected in parallel with annunciation equipment, care should be exercised to ensure that there is no interference between the automation system and the annunciation equipment.

When one side of the status contacts is tied to a power source from the station battery, the automation system should provide electrical isolation between the inputs. This is to prevent sneak paths between inputs when either side of the battery input is disconnected from one of them.

9.5 Supervision of existing transducers

Although an automation system can be configured to adapt to just about any electrical signal as an input, the benefits of standardized inputs should be a priority. The accuracy of existing transducers should also be studied to determine whether or not they meet system accuracy requirements. Although there are no universal standards for transducer outputs, the most commonly used power system transducers provide a 0 - ±1 mA signal as an output. The process control industry, on the other hand, has more or less agreed upon the use of 4 - 20 mA as a standard transducer output. Both of these ranges have worked satisfactorily in hydroelectric powerhouse applications and should be given due consideration.

Different transducer outputs typically require different input circuits on the automation system. Therefore, keeping the types of transducer outputs to a minimum should reduce the complexity of the automation system and make it easier to add or reconfigure the inputs after the equipment is placed in operation.

9.6 Supervision of existing control output points

The specific characteristics of each output point to be supervised should be determined. Output points include such functions as close/trip, raise/lower, and start/stop. Since older speed level motors and breaker trip circuits sometimes require relatively high levels of inductive current to be switched, the output circuits must be capable of reliably switching this current throughout the life of the automation system. One method of dealing with these high inductive current circuits is to use interposing auxiliary machine tool type relays on such outputs.

9.7 Grounding

Each equipment rack in which automation system components are located should be separately connected to the powerhouse ground mat via a large gauge wire. During power system fault conditions, a large potential rise can occur between different locations within a powerhouse due to the large current flowing through the ground. Since this potential rise can show up between the different items of equipment, communication circuits that connect the items should be specified to withstand the maximum potential rise between the equipment items. The use of fiber optic cable as a communications path between equipment items is one method by which concerns resulting from this potential rise can be eliminated.

Shields are often used on analog signal cables between the transducers and the automation system. For maximum effectiveness, each shield should be tied to the signal common potential at the transducer end of the cable. If there are termination or junction boxes between the transducer and the automation system, each shield circuit should be maintained as a separate, continuous circuit through such junction or termination boxes. The shields should then be left unterminated at the automation system equipment end. In some existing situations, the shields may have been all terminated to ground potential at the automation system equipment end. Unless noise problems have been observed in the existing equipment, it is usually better to leave the shields in their existing scheme.

9.8 Static control

Many components in automation systems can be damaged by static discharges if not properly managed. Well-designed equipment should be immune to static problems in the normal operating configuration. Damage from static discharges is most likely to occur during system maintenance. Some equipment is designed to minimize static problems and the designer should give appropriate preference to such equipment.

Although usually not a hazard, it is also desirable to take measures to avoid static shocks resulting from operator contact with equipment items. Typical measures to avoid such shocks are use of antistatic carpet and proper grounding for all devices that an operator may contact.

10 Recommended test and acceptance criteria

Compliance with the specification requirements will be accomplished by inspections, design reviews, and tests. Equipment acceptance will require all tests to be successfully passed. Design reviews should be held to insure that there is a good understanding between the manufacturer and the engineer during the design phase. Inspections should be performed by the engineer to verify the suitability of the design during the fabrication phase. Then tests should be performed by the manufacturer and witnessed by the engineer to verify the design, construction, and performance of the equipment.

10.1 Specific test requirements

10.1.1 Factory acceptance test

A factory acceptance test should be performed prior to shipment of the equipment. A field test should be performed after the equipment is installed and prior to acceptance. The factory test should demonstrate proper operation of all furnished software and hardware. A test procedure should be prepared by the manufacturer and approved by the engineer prior to commencement of the factory test. Specific requirements for the factory test should include but not be limited to the following:

a) surge protection testing of each type of input and output point, as is described in IEEE Std C37.90.1-2002. This test is performed to demonstrate that the types of electrical stimuli encountered in the powerhouse environment will not degrade the operation of the automation system;
b) susceptibility to radiated electromagnetic interference, as described in IEEE Std C37.90.2-1995. This test is performed to demonstrate that hand-held radio transceivers carried by operators will not degrade the operation of the automation system;
c) emission of radio noise as described in ANSI C63.4-2001. This test is performed to demonstrate that the automation system will not generate emissions that might degrade the operation of nearby equipment;
d) application of appropriate signals to each input point to verify their operation;
e) running of programs adequate to test the proper operation of each output point. Tests should be included to demonstrate that all output points revert to a specified configuration in the event of an automation system failure;
f) demonstration of major features of system components (CRTs, printers, disk drives, etc.);
g) demonstration that data base is sized for the ultimate system and implemented for all variables;
h) demonstration of system performance while running all applications software during simulated worst case conditions;
i) demonstration of system diagnostics;
j) if an automatic failover is required upon malfunction of an automation system element, testing should be performed to demonstrate proper operation of the failover process;
k) demonstration of operator interface software;
l) demonstration of each applications software routine.

10.1.2 Field test

The field test should confirm that no degradation has occurred during shipment and installation. It can also be used as a design verification. A test procedure should be prepared by the manufacturer and approved by the engineer prior to commencement of the field test. The following are recommended:

a) application of appropriate signals to each input point to verify their operation;
b) running of programs adequate to test the proper operation of each output point;

c) demonstration of major features of system components (CRTs, printers, disk drives, etc.);
d) demonstration of system diagnostics;
e) demonstration of operator interface software;
f) demonstration of each applications software routine;
g) demonstration of system availability.

10.2 Quality assurance

A quality assurance program should be established during the manufacturing phase and continued through final acceptance. The quality assurance program should provide policy and procedures for general manufacturing inspections in support of at least the following:

a) receiving inspection;
b) engineering change control;
c) component sampling plans;
d) quality control inspection and reporting;
e) test equipment calibration;
f) software configuration control.

10.3 Acceptance

When all documentation has been approved and all tests have been successfully passed, a final examination of the equipment should be made, and if it is found to be in compliance, the equipment should be accepted.

11 System management

11.1 Maintenance

Maintenance can be provided either by the owner, the manufacturer or by a maintenance service. Some factors to consider in making such a choice are as follows:

a) manufacturer's recommendation;
b) time needed to get maintenance service on site;
c) impact of downtime;
d) alternatives if maintenance organization discontinues support;
e) impact if in-house staff are not available.

11.2 Training

The supplier is a good source to develop and execute a training plan for the user. This plan will allow the user to become self-sufficient in all aspects of operations, software maintenance and development and hardware maintenance to the board level. Video recording may be effectively used for refresher training.

11.2.1 Training plan

The training plan should include the following information on individual courses:

a) outline;
b) duration and scheduling;
c) location (e.g. user site, manufacturer's site);

d) qualification of instructors;
e) objectives;
f) prerequisites;
g) content;
h) training material (handouts);
i) audiovisual aids;
j) special equipment, tools, etc.;
k) ratio of hours of classroom to hours of hands-on laboratory experience.

11.2.2 Courses

The emphasis for each course should take into consideration the relationship between the students and their relationship to the computer-based control system. Possible courses to be considered in the training plan are as follows:

a) *System operation.* Instruction in the daily operation of the equipment, including the interpretation and use of system interactive controls and displays, the operation of peripherals, how to recognize system problems and take corrective action, and how to manually failover the system.
b) *Hardware maintenance.* Instructions in how to maintain, troubleshoot, repair, and adjust the equipment to the board level.
c) *CPU software.* Instructions in how to efficiently use and program the software supplied and utilized with the CPU equipment furnished with the system, including the real-time operating system, assembly languages, instruction set, loaders, assemblers, compilers, macro language and usage, higher-order languages, machine functions and control machine services, system build, and program debugging.
d) *System software.* Instruction in how to efficiently use and maintain the system software supplied as part of the system, including communications software, report generation, display generation, data base modification, and failure detection software.
e) *Application software.* Instruction in how to efficiently use and maintain the applications programs supplied as part of the system.
f) *Refresher courses.* Based on experience and user needs

11.3 Documentation

Documentation should be provided that adequately describes the system such that the design can be verified. Documentation should also be provided such that it can be used to support installation, testing, system activation, hardware operations and maintenance, and software maintenance and development.

11.3.1 Design documentation

During the initial phase of the system design, the supplier should prepare a system design specification that serves as the base line for the hardware and software systems configuration and performance. This standard should provide details on how each of the functional requirements of the system will be met. Additional design documentation should include details of the man machine interface, hardware drawings, and any information necessary to show how the equipment can be integrated into the user’s facility. The items that follow should be included.

a) Operator interface:
    1) keyboard layout and operation;
    2) CRT format;
    3) cursor control philosophy;

4) display callup philosophy;
5) use of color, flashing, inverted video, etc.;
6) display building;

b) Functional documentation:
1) outline drawings, including dimensions and arrangements;
2) system block diagrams showing nomenclature, equipment types, model numbers and input/output provisions;
3) input/output lists with ranges, labels, and other related specific information.

11.3.2 System support documentation

Documentation should be furnished that will allow the user to fully support the equipment throughout its life. In addition to the requirements described in 11.3.1, the following are typical of the items furnished to meet this requirement.

a) Hardware drawings:
1) external connection diagrams showing the details of all wires connected to user's equipment;
2) power and environmental requirements for each equipment item;
3) site preparation procedures, including: equipment grounding, cable routing, equipment handling, mechanical assembly, etc.;
4) spare parts list.

b) Software documentation:
1) hierarchical list of software, including revision level;
2) program design standards;
3) configuration control methodology;
4) program requirements specifications;
5) program descriptions;
6) program interface control;
7) acceptance test procedures and test reports;
8) annotated source code program assembled listings;
9) maintenance, reference and user's manuals.

c) Operations and maintenance data:
1) operations data including specific operating instructions, functional description of operating parts, and special precautions;
2) maintenance data, including instructions for dismantling, assembling, repairing, adjusting, and trouble-shooting all mechanical and electrical equipment; parts catalogs; elementary and connecting diagrams; control and interlock system diagrams; and a list of special tools required. Instructions for dismantling, assembling, repairing, testing, and adjusting should include recommended clearances, voltages, amperages, trouble-shooting procedures for printed circuit cards and any other items needed for maintenance of the equipment. The trouble-shooting procedures should include step-by-step diagnostic procedures for each function performed. Electrical data should include waveforms, component identification, photographs, test points, and parts lists.

12 Case studies

12.1 Automation of the Conowingo Hydroelectric Station

12.1.1 Background

The Conowingo Hydroelectric Station went into service in 1928. It is located in Maryland on the Susquehana River, approximately 6 miles south of the Pennsylvania border. There are 11 units in the station; seven Francis turbines with 40 MVA generators and four propeller turbines with 61.8 MVA generators.

The unit governors required several manual operations in the start-up and operation of the units, placing a significant burden upon the operating personnel at the station. Synchronizing was often rough because of degraded governor performance. Coordination of unit operation based upon river flow, net head, and system power demand placed additional burdens upon operating personnel. Previously, attempts to operate the units from the offsite system load dispatchers had failed to perform acceptably. This was due to the inaccuracies in the old speed and position feedbacks, and the complexity of the required interface equipment.

In 1992, an automation project was begun, based upon the evolving needs of the station. An economic analysis of the various options indicated that in order to justify the expenditure, the project would need to accomplish the following:

– integration of the operation of the seven Francis units into a single operator station in order to reduce the required operators staffing;
– capability of offsite operation by the *System Load Dispatcher* to coordinate the operation of the seven Francis units.

12.1.2 System hierarchy

Figure 8 shows an overview of the control system designed to automate the Conowingo station. The scope of this project included replacement of the unit governors with digital unit controllers, and the installation of a digital station control.

12.1.3 System architecture

The station controller chosen for this automation project was a VME bus-based system with a triple redundant fault tolerant operating system with three CPU modules. Communication to the unit controllers is accomplished through redundant fiber optic communication using the ModBus™ protocol in a star topology. Each ModBus™ network includes a graphical user interface that is used to start, stop, and operate the units.

12.1.4 Functional capabilities

The new digital unit controllers integrated many of the functions previously accomplished by relay logic and operator actions. These functions include:

– start/stop sequencing;
– synchronizing;
– online control;
– real power control;
– reactive power control;
– synchronous condense mode control.

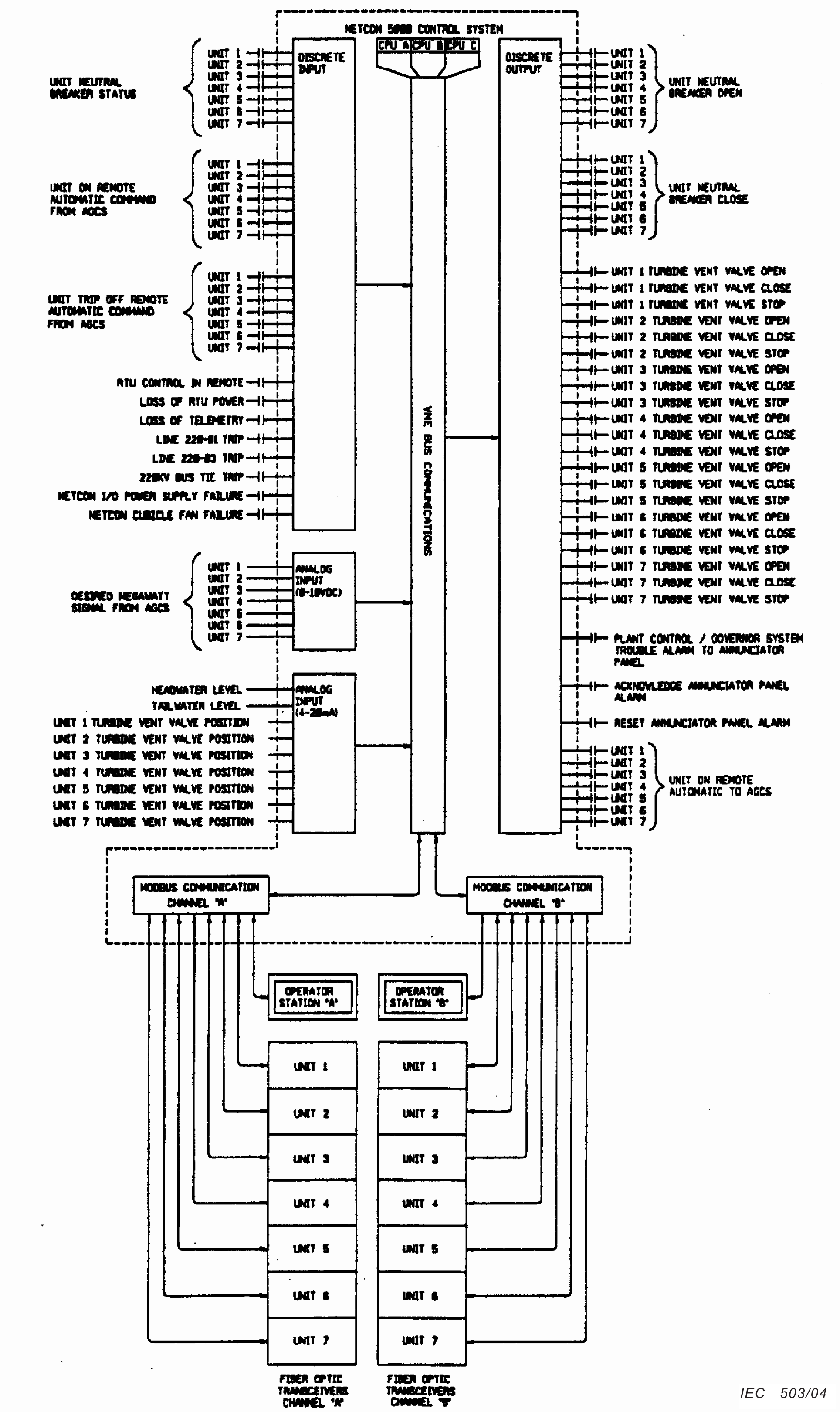


Figure 8 – Conowingo control system overview

The station controller coordinates the operation of the seven Francis units at Conowingo. The functions performed by the station controller include:

– automatic generation control interface;
– plant real-power control;
– plant reactive-power control;
– data acquisition;
– alarm displays;
– report generation;
– data archiving.

12.1.5 Interfaces

The primary human/machine interface in the new control system at Conowingo was chosen as a pair of CRT graphic terminals with both keyboard and mouse inputs. A laser printer provides hard copy reports. The majority of information transferred between the unit controls and the station controls is handled by redundant fiber optic ModBus™ network connections. However, some analog and digital signals provide the station controller with direct access to certain critical information about the units and the station.

12.1.6 System performance

The primary performance concern of the station controller is reliability. For this reason, a triple redundant fault tolerant system was chosen for the central processing unit. Redundant fiber optic communications to the unit controllers, along with redundant operator stations, assure uninterrupted control of the station. The hardwired I/O connected to the station controller is divided into two separate groups such that no single failure can cause loss of control to more than four of the seven units. The station controller is designed so all data is updated at least once per second.

12.1.7 System backup capabilities

Although the normal mode of operating the Conowingo station is through the station controller, provisions have been made at the unit controllers for local operation of the units. Control switches and indicators were provided at the units to allow only the basic operational functions to be performed.

12.2 Computer-based control system at Waddell Pump-Generating Plant

12.2.1 Abstract

This case study provides an overview of a microprocessor-based, open architecture, computer-based control system (CBCS) for the U.S. Bureau of Reclamation’s Waddell Pump-Generating plant, located north of Phoenix, Arizona.

Control hierarchy, system architecture, functional capabilities, interfaces, system performance, backup, site integration and support, test and acceptance criteria, and system management will be outlined, as well as design objectives and alternatives.

12.2.2 General

The Waddell Pump-Generating Plant was constructed with a generating capacity of 16 MW and a pumping load of 32 MW by the U.S. Bureau of Reclamation for Central Arizona Project, northwest of Phoenix, AZ, for the purpose of providing irrigation water, water storage, and hydroelectricity. There are four variable speed pumps operating at 4,16 kV, and four, two-speed pump generators operating at 13,8 kV. Unit commissioning took place from the fall of 1992 to the summer of 1993. The plant is connected to the utility grip through an adjacent 230 kV – 13,8 kV – 4,16 kV switchyard operational since the spring of 1992.

12.2.3 Control hierarchy

Unit control is available as follows:

– in local-manual mode from the hardwired control board at the unit;
– in local-automatic mode via the hardwired relay logic in the control board;
– in remote-automatic mode from the computer/PLC package at the unit control board;
– from any other computer location at any other unit;
– from the plant control console in the control room through the PLC interface;
– from the plant control PC in the control room;
– remotely (offsite) through the computer-based control system (CBCS) via supervisory control type communication links through a wide area network.

Plant control is available from any computer location.

Switchyard control is available as follows:

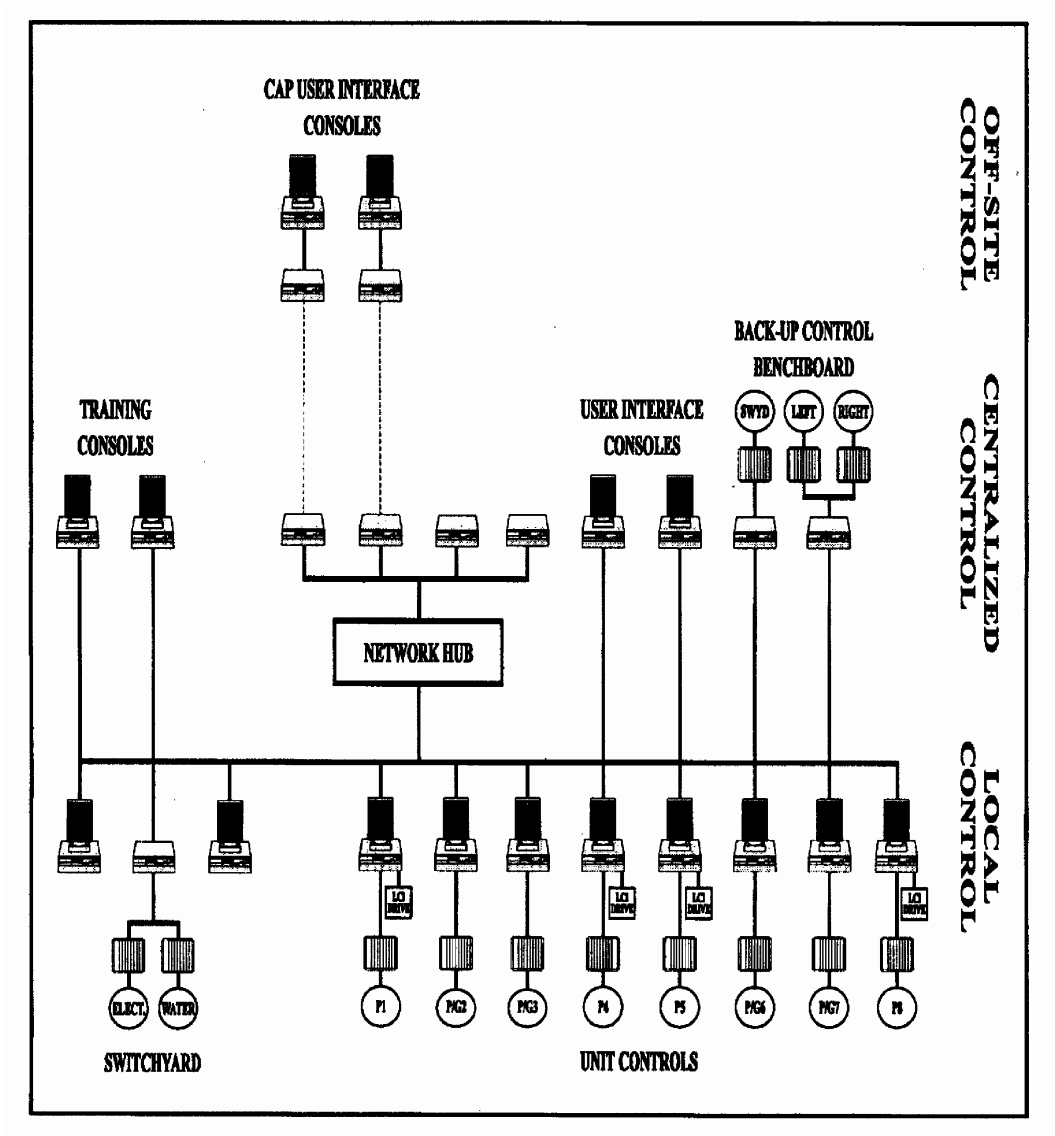
– from the hardwired control board in the switchyard control building;
– from the PC/PLC package in the switchyard control building;
– from any computer location at any unit;
– from the plant control console in the plant control room;
– from the plant control PC in the control room;
– remotely (offsite) through the CBCS via supervisory control type communication links.

12.2.4 System architecture

System architecture is configured as follows:

a) uses open architecture system, i.e. made up of hardware and software that is commercially available (not proprietary);
b) hardware configured around the IBM-compatible computer using MS-DOS;
c) system comprises 25 PCs and 15 programmable logic controllers (PLCs) connected by a fiber-optic network;
d) Unit Control Computers: one industrial-grade PC, with color monitor, paired with a PLC at each unit control board;
e) Plant Control Computers: four PCs with high-resolution monitors, mice, and keyboards located in the climate-controlled plant control room;
f) Switchyard Control Computer: three PCs paired with two PLCs located in the switchyard control building provide switchyard control and water release control;
g) Offsite Control Computers: four PCs located approximately 40 km (25 mi) away, arranged in a token ring network communicate via redundant paths to the plant computers. Communication links operate at 56 000 b/s and 9 600 b/s;
h) includes networking software and database management software.

For the configuration of the control system refer to Figure 9.



IEC 504/04

Figure 9 – System configuration

12.2.5 Functional capabilities

a) *Unit control computers*. Start/stop control, closed loop speed and megawatt control, and device interlocks as well as alarm handling, data indication, device identification.

b) *Plant control computers*. Closed-loop control of plant megawatt output in generate mode and water discharge in both generate and pump modes. Capable of starting and stopping units at predetermined times. Operator interface and logging of alarms and events.

c) *Switchyard control computers*. Circuit breaker and disconnect switch control, alarm monitoring, data indication, and control of water inlet tunnels and bypass lines.

d) *Offsite computers*. Any function performed at the plant can be performed from the offsite computers.

Historical data collection of unit, plant, and switchyard data takes place continuously providing a database accessible from any computer location. Report generation and historical trending software are integral to the system [1]. [4]

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4 The figures in square brackets refer to the bibliography.

12.2.6 Interfaces

Interfaces are implemented as follows:

a) CRTs, keyboards, and mice at most locations;
b) A color graphics printer and a dot matrix printer are connected to the file server and to any computer in the system can access the graphics printer;
c) Color graphics displays use 640 × 480 resolution.

12.2.7 System performance

Uses the ISO/IEC 8802.5-1998 Token Ring network that operates at 16 Mb/s.

12.2.8 Backup

Backup is implemented as follows:

a) file server accesses two redundant disk drives where identical data is stored. If one drive fails, the other automatically takes over;
b) because control is distributed, stand-alone unit control with the remainder of the computer system down is possible;
c) two plant control computers operate continuously, backing up each other in the event of failure. Two other plant computers with associated PLCs provide a redundant I/O path to the whole plant and switchyard;
d) two computers in the switchyard control building serve as backup to the control room as an operator station;
e) any function provided by the system can be accessed or performed by any computer at any location.

12.2.9 Site integration and support

Site integration and support is implemented as follows:

a) CBCS system was specified and installed in a newly constructed plant, thus the system and the I/O were well integrated and compatible;
b) I/O operate from battery backed-up dc systems and computers operate from uninterruptible a.c. power;
c) status input contacts generally operate from the annunciation control bus while outputs operate via auxiliary relays into 125 V d.c. control circuits;
d) because the PLCs are connected to each other by a fiber optic network, programming and diagnostics can be performed for any PLC from the associated PC.

12.2.10 Test and acceptance criteria

Testing procedure and criteria were generated by the vendor in accordance with the specifications and control flow diagrams. Testing was conducted in the following three phases:

a) *First phase.* Individual hardware testing of the unit control boards, control room control panel, and switchyard control boards.
b) *Second phase.* Complete factory acceptance test of the automatic control software while simulating the above hardware.
c) *Third phase.* Site acceptance test demonstrating the integration of software and hardware.

Total test time accounted for approximately 12% of the total control design, development, and manufacturing time.

12.2.11 System management

Full documentation and training on the system were provided by the manufacturer.

12.2.12 Design objectives and alternatives

Design objectives and alternatives were as follows:

a) to take advantage of the state of the art in industrially-applied computer software and hardware and apply that technology to the power industry;
b) to use commercially-available components to provide a system that can be maintained and upgraded without reliance on one particular vendor or a dated hardware and software design;
c) to use modular design to permit expansion and to be upgradable at reasonable cost;
d) to include two degrees of redundancy;
e) to be thoroughly supported and maintained;
f) to have features and response times consistent with a dedicated control system.
g) to utilize fiber optic communication because it is immune to noise in the power plant environment and provides dielectric isolation for PC protection.

12.3 Retrofit of TrŠngslet Hydro Power Station

12.3.1 Abstract

This case study provides an overview of the retrofit of the control system for the TrŠngslet Hydro Power Station in Sweden. An accident in the station, resulting in flooding of the existing control equipment, resulted in a decision by the utility to install a new computerized control system. The utility requirements for the distributed control system as well as the experiences from the implementation and operation are described. Control system philosophy and implemented functions are also covered.

12.3.2 General

TrŠngslet, in the upper part of the river DalŠlven, is Stora Power's largest hydropower station. Like most of the large hydropower stations in Sweden, TrŠngslet is situated underground, 140 m below the surface. The station has three units, of which two were commissioned in 1960, and the third in 1975. The units have a total installed capacity of 330 MW, operating for peak load production. The storage capacity is 880 million m^3 and the average annual production is 700 GWh.

The station is supervised and controlled from a control center that is 130 km away. The new control equipment was designed and installed in 1985-1987.

12.3.3 Control equipment requirements

When investigating different solutions of replacing the existing control equipment of conventional relay type, the following functions were regarded as most important:

a) load sharing between the three units in order to optimize the power production;
b) water flow calculations for each unit, including measurement of water levels and head losses;
c) recording of events with precise time resolution;
d) presentation of information regarding operating conditions along with automatic report printouts of energy values;
e) compatibility with existing remote control center.

12.3.4 Control hierarchy

Unit control is available as follows:

a) in local-manual mode from the hard-wired control board at the unit;
b) in remote-automatic mode from the central control room or the control center;.
c) from supervisory control functions on the station control level.

Besides these controls, there are (on the object level) control devices for individual objects. Station control, including operators' communication, is carried out from the central control room.

12.3.5 System architecture

The system is built up with the following components:

a) four process stations for unit control and station control;
b) one operator station with two visual display units (VDU) and two printers. One of the printers is located in the administration building on ground level;
c) communication network based on a proprietary communication network that is a multi-drop link network built with twisted pair cable. The transmission speed is 153,6 kb/s;
d) offsite control is performed from a control center 130 km away via a remote terminal unit (RTU) in the plant. The RTU is hardwired to the computerized control system.

For the configuration of the control system refer to Figure 10.

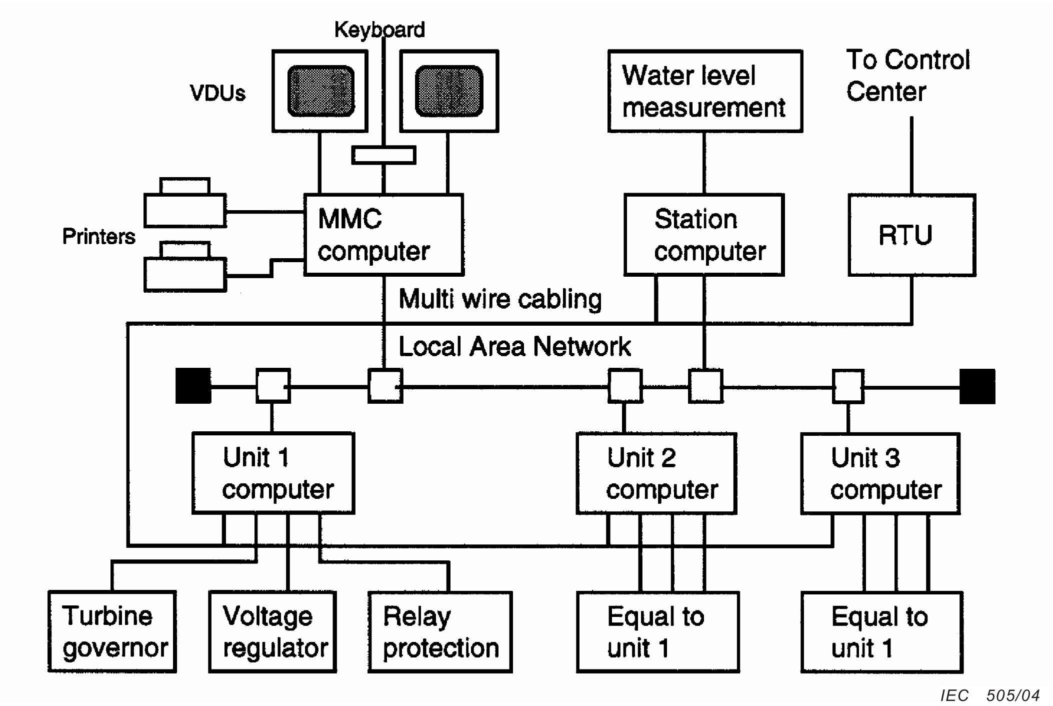


Figure 10 – Control system configuration

12.3.6 Functional capabilities

12.3.6.1 Unit control computers

Unit control computers implement the following functional capabilities:

a) signal processing and time tagging of events;
b) automatic start/stop control;
c) auxiliary systems control;
d) vibration limitation;
e) stator current limitation;
f) excitation control;
g) turbine governor control.

12.3.6.2 Station computer

Station computers implement the following functional capabilities:

a) signal processing and time tagging of events;
b) load sharing (active and reactive) between the units;
c) water flow calculations;
d) control of 50 kV and 10 kV switchgear;
e) selection of synchronizing;
f) control of auxiliary power supply;
g) reports.

12.3.6.3 Operator station for Man Machine Control (MMC) functions

For operation and supervision, the following two main display types are implemented:

a) process displays;
b) trend displays.

In addition, the following are further displays providing information about the system and its maintenance:

a) system status displays;
b) object displays;
c) system dialog displays.

The following are process displays on the station level:

a) station display;
b) overview diagram;
c) switchyard diagram;
d) auxiliary power supply diagram;
e) event list;
f) fault signal list;
g) trend displays.

The following are process displays on the unit level:

a) unit display;
b) starting sequence;
c) stopping sequence;
d) starting deblocking;
e) temperatures;
f) vibration measurement;
g) trend displays.

12.3.7 Interfaces

12.3.7.1 User interface

a) Color visual display units (VDU), functional keyboard, and trackball
b) Printers

12.3.7.2 Process interface

a) Digital inputs and outputs for 48 V dc, opto-isolated
b) Interposing relays only when higher output ratings were required, and as isolating barriers for signals from high-voltage switchgear
c) Analog inputs for 4 - 20 mA or signals and 100 ¾ platinum RTDs

12.3.8 System performance

Table 6 – System performance

Resolution for time-tagging of events	Better than 10 ms
Typical performance times for MMC system	
Display change	3 s
Presentation of binary signal change in the process:	1 s
Control operation from order to process output	1,5 s
Updating of analog values (cyclic)	3 s or 9 s

12.3.9 Backup

a) Manual control of units from the unit control board
b) Manual control of high-voltage circuit breakers from mimic panel in the control room
c) Manual operation of individual objects out in the process

12.3.10 Site integration and support

The control equipment contract was awarded to a single contractor who assumed overall responsibility for the supply and installation of the system.

12.3.11 Test and acceptance criteria

Factory and site acceptance tests were carried out according to the test program agreed upon between the supplier and the utility.

12.3.12 System management

Full documentation and training on the system were provided by the manufacturer.

12.3.13 Experiences

From the design, installation and the operation of the system, the following conclusions can be made:

a) System requirements achieved;

b) Fast introduction of operators;

c) System improvements by operators and technical staff;

d) Improved plant information;

e) Backup equipment used only for maintenance;

f) Improved production economy.

12.3.14 Upgrading of the system

Five years after the initial commissioning, the system was upgraded to meet new requirements. The CPU of the station computer was upgraded to a later hardware and software version that gave higher performance and better communication facilities. The configuration on the station level was changed as shown in Figure 11.

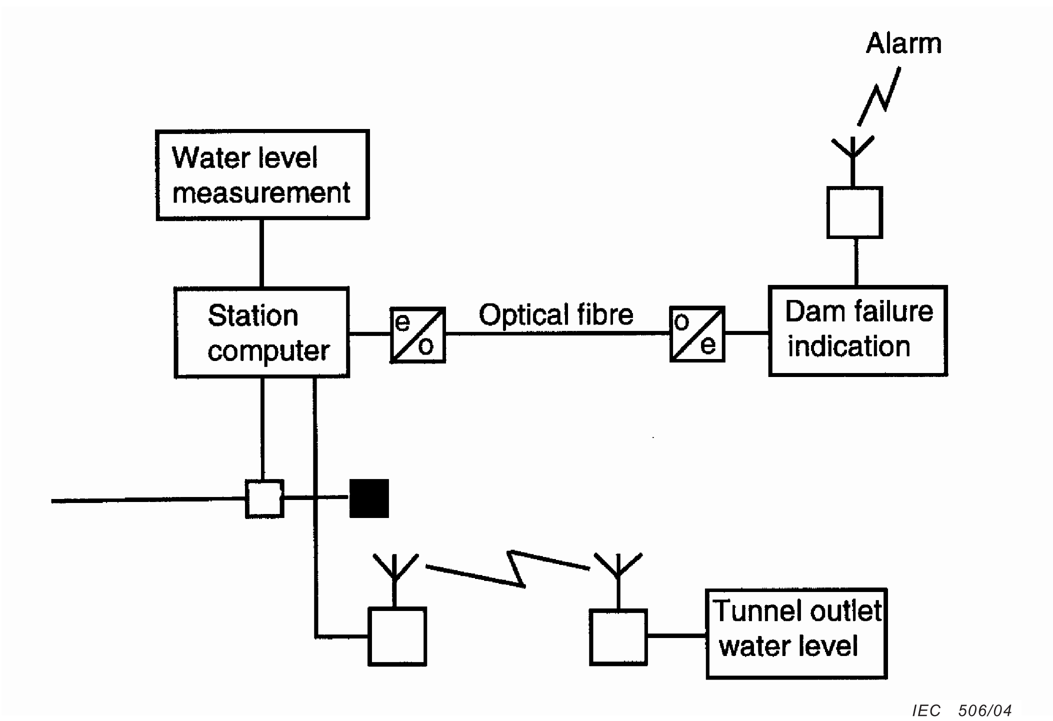


Figure 11 – Station control configuration after upgrading

The upgrading was comprised of the following equipment items:

a) new station computer;

b) equipment for tunnel outlet water level measurement with serial communication to the station computer via radio link;

c) equipment for dam failure indication with separate equipment for alarm sending;

d) serial communication between the station computer and the existing equipment for water level measurement.

Features of the new station computer are as follows:

a) higher CPU performance;
b) improved communication facilities;
c) existing I/O boards were used;
d) easy transfer of application software from the old to the new station computer;
e) function for group alarm added.

The upgrading was carried through with very little impact on the rest of the control system [2].

12.4 Computer-based control system at Wynoochee Hydroelectric Project

12.4.1 Abstract

The Wynoochee Hydro Project main control system is a microprocessor-based system designed to be fully automatic with a remote SCADA interface linking the plant to the utility's dispatch system. The following case study employs the standard to describe the features, function and capabilities of the plant.

12.4.2 General

The Wynoochee Hydroelectric Project is owned and operated by Tacoma Public Utilities and located in Washington State. The plant capacity is 19,4 MVA, and the major equipment is a single Kaplan turbine-driven synchronous generator operating at 327,3 r/min. The control system is PC/PLC-based. Interconnection is provided with a 13,7 km (22 miles), 34,5 kV transmission line connecting to a 69 kV Tacoma Public Utilities substation.

12.4.3 Control hierarchy

The functional capabilities that were required of the system determined the ultimate design and equipment selection for the control system. The system contains the following functions and various modes of control:

a) *Local-Manual Mode*. Provided by a hard wired control board located adjacent to the unit.
b) *Local-Automatic Mode*. A redundant PLC-based system communicating with a proprietary protocol on a fiber optic medium.
c) *Remote-Manual Mode*. Provided through separate RTU hardware used by the utility system wide to gather generating information.
d) *Remote-Automatic Mode*. Provided by a PC-based SCADA system communicating directly to the local PLC network from the operations and maintenance building

12.4.4 System architecture

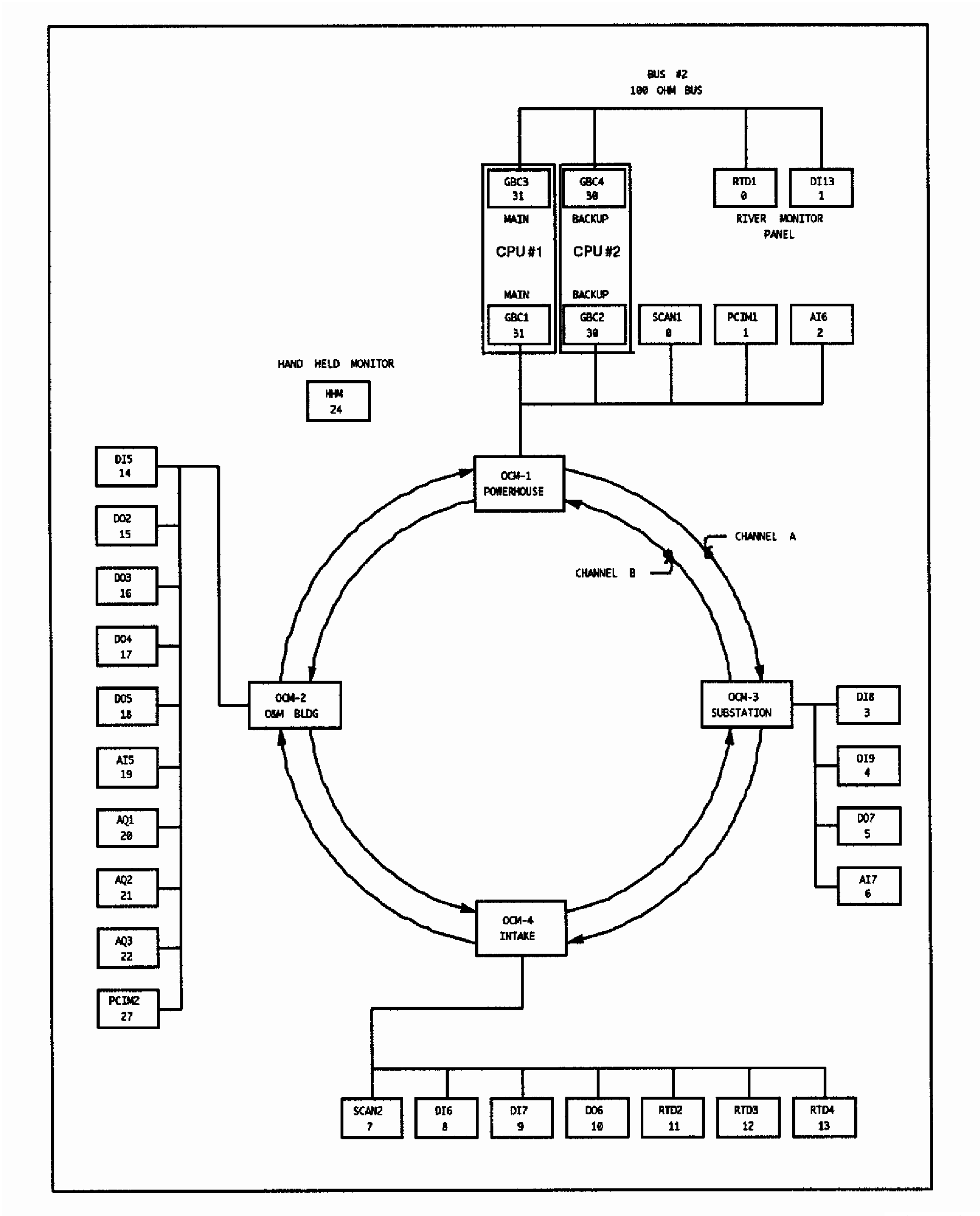
System architecture is configured as follows, and as illustrated in Figure 12:

a) the unit control is PLC-based;
b) the two PLCs are located in the powerhouse in the main control switchboard and configured as a primary and a hot backup;
c) both the primary and standby PLCs receive all real-world inputs and fault reports;
d) the communications is a redundant proprietary bus network operating at 153,6 kBd extended;

e) there are four primary I/O network drops off the bus: the powerhouse, substation, intake structure, and the O & M building;

f) the optical communication modules, the interface between the fiber optic network and the remote I/O, provide diagnostic monitoring and fault-tolerant, self-healing communications;

g) remote communications are available through modem links with compatible PCs.



IEC 507/04

Figure 12 – System configuration

12.4.4.1 Functional capabilities

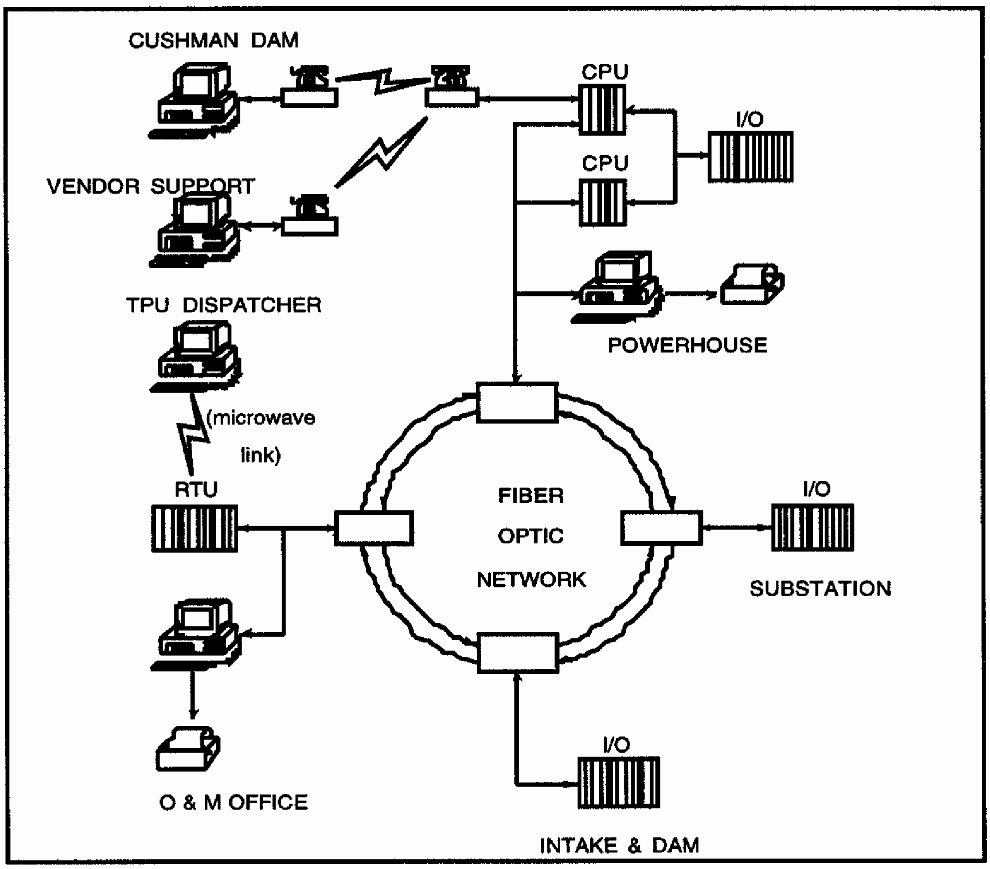
The primary control mode of the system is unit flow control in order to control the downstream flow regime for stability of fish habitat. The flow-ramping algorithm is sensitive to river stage as well as flow through the turbine to ensure a linear rise and fall of the river during loading and unloading operations.

The functional capabilities of the system include:

a) start/stop sequencing;
b) synchronizing that is enabled by the automatic system, but the actual synchronizing function and synch check is provided through a separate proprietary device;
c) flow control algorithms that are sensitive to river temperature and seasonal flow characteristics are the key control modes;
d) alarm annunciation and archival storage;
e) data logging and archival storage;
f) remote control capabilities;
g) voltage control;
h) reactive power control.

12.4.5 Interfaces

a) Remote SCADA CRT interface
b) Local CRT interface
c) Handheld monitor that permits mobile access to remote I/O and network bus characteristics
d) Local printer for event logging
e) Remote printer for data and event logging, as shown in Figure 13



IEC 508/04

Figure 13 – Local and remote interface

12.4.6 System performance

Uses a proprietary bus network operating at 153,6 kBd over fiber optic cable.

12.4.7 Backup

Backup is implemented as follows:

a) dual-fiber optic network operating in a redundant mode with self-diagnostics and self-healing communications;
b) network is configured in a ring topology where communications can be routed in either direction to ensure communication link integrity;
c) each I/O drop is controlled by an Optical Communication Module (OCM) to monitor I/O integrity and network interface tasks;
d) dual PLCs that are configured in a hot standby mode. Both CPUs receive all inputs and simultaneously execute identical programs. Upon a failure of one, the plant control immediately defaults to the backup unit;
e) manual control of the unit from the Unit Control Switchboard.

12.4.8 Site integration and support

The installation was provided under a water-to-wire contract where a primary contractor assumed responsibility for the supply, installation and support of the system. Continuing control system support is provided directly to the utility from the control supplier following the expiration of the one year warranty. In addition to the supplier's support, additional hardware support is provided by the hardware manufacturer.

12.4.9 Test acceptance criteria

Testing procedures were provided by the vendor of the control equipment in accordance with the specifications. The testing was conducted in two stages:

a) *Stage 1*. Factory testing of all hardware, software, and networking systems. All requirements were tested against the vendors' functional specifications and the customers design specifications.
b) *Stage 2*. On-site testing and calibration of all hardware and software during an extended period of acceptance operation of the unit.

12.4.10 Design objectives and system requirements

a) To utilize commercially-available, industrialized computer hardware to achieve automatic control in a hydroelectric power plant environment.
b) To achieve continuous and reliable control of the downstream fish habitat at a minimum cost.
c) To provide remote access to both the plant and historical operational information.

Annex ZA
(normative)

Normative references to international publications with their corresponding European publications

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

NOTE Where an international publication has been modified by common modifications, indicated by (mod), the relevant EN/HD applies.

Publication	Year	Title	EN/HD	Year
IEC 61158	Series	Digital data communications for measurement and control - Fieldbus for use in industrial control systems	EN 61158	Series
ANSI C63.4	2001	Methods of Measurement of Radio-Noise Emissions from Low-Voltage Electrical and Electronic Equipment in the Range of 9 kHz - 40 GHz	-	-
IEEE Std 100	1996	The IEEE Standard Dictionary of Electrical and Electronics Terms	-	-
IEEE Std 485	1997	IEEE Recommended Practice for Sizing Lead-Acid Batteries for Stationary Applications (ANSI)	-	-
IEEE Std 610	1990	IEEE Standard Glossary of Software Engineering Terminology (ANSI)	-	-
IEEE Std 1010	1987	IEEE Guide for Control of Hydroelectric Power Plants (ANSI)	-	-
IEEE Std 1014	1987	IEEE Standard for a Versatile Backplane Bus: VMEbus	-	-
IEEE Std 1020	1988	IEEE Guide for Control of Small Hydroelectric Power Plants (ANSI)	-	-
IEEE Std 1046	1991	IEEE Application Guide for Distributed Digital Control and Monitoring for Power Plants (ANSI)	-	-
IEEE Std 1147	1991	IEEE Guide for the Rehabilitation of Hydroelectric Power Plants (ANSI)	-	-
IEEE Std C37.1	1994	IEEE Standard Definition, Specification, and Analysis of Systems Used for Supervisory Control, Data Acquisition, and Automatic Control (ANSI)	-	-
IEEE Std C37.90.1	2002	IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems (ANSI)	-	-

Publication	Year	Title	EN/HD	Year
IEEE Std C37.90.2	1995	IEEE Trial Use Standard for Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers (ANSI)	-	-
IEEE Std 1379	2000	IEEE Recommended Practice for Data Communications Between Remote Terminal Units and Intelligent Electronic Devices in a Substation (ANSI)	-	-
ISO/IEC 8802-3	2001	Information technology - Telecommunications and information exchange between systems - Local and metropolitan area networks - Specific requirements Part 3: Carrier sense multiple access with collision detection (CSMA/CD) access method and physical layer specifications	-	-
ISO/IEC 8802-4	1990	Part 4: Token-passing bus access method and physical layer specifications	-	-
ISO/IEC 8802-5	1998	Part 5: Token ring access method and physical layer specifications	-	-

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[2] “Retrofit Of TrŠngslet Hydro Power Station,” Sven Andersson and Sven O. Lindstršm, 91 SM3368EC.

[3] IEEE 94EH 03921 PWR , IEEE Tutorial Course: Fundamentals of Supervisory Systems, IEEE Power Engineering Society.

[4] IEEE 95TP103, IEEE Tutorial Course: IEEE Communications Protocols, IEEE Power Engineering Society.

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