Instrumentation and control is an integral part of a coal-fired power station. A modern, advanced I&C system plays a major role in the profitable operation of a plant by achieving maximum availability, reliability, flexibility, maintainability and efficiency. These systems can also assist in maintaining emissions compliance. The I&C chain begins with sensors that detect measured values. Controllers receive these values, upon which a control strategy is activated. The response, where and when required, moves to final actuating control elements to modify the affected process. This loop repeats over and over during plant operation through a complex and multi-level communications schemes. ‘Smart’ field devices, including sensors and actuators, continue to be developed in order to simplify and improve the control process. The two main control platforms that are used in coal-fired power stations are the distributed control system (DCS) and the programmable logic control (PLC). Personal computer (PC) based hardware and software have only recently been introduced in power plant control. With the fast development, increasing power and reduced cost of personal computers, PC-based control is expected to become a further platform for future development and growth. Today new coal-fired power plants are, in general, built with modern, advanced DCS/PLC and a large number of existing coal-fired power stations have been retrofitted with advanced digital systems in many countries throughout the world.
<table>
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<th>Acronym</th>
<th>Definition</th>
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</thead>
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<tr>
<td>AC</td>
<td>alternating current</td>
</tr>
<tr>
<td>A/D</td>
<td>analogue-to-digital</td>
</tr>
<tr>
<td>ASP</td>
<td>application service provider (Internet/web)</td>
</tr>
<tr>
<td>ANSI</td>
<td>American National Standards Institute</td>
</tr>
<tr>
<td>APCS</td>
<td>adaptive predictive control system</td>
</tr>
<tr>
<td>ASCII</td>
<td>American Standard Code for Information Interchange</td>
</tr>
<tr>
<td>CAD</td>
<td>computer aided design</td>
</tr>
<tr>
<td>CAE</td>
<td>computer aided engineering</td>
</tr>
<tr>
<td>CARS</td>
<td>coherent anti-stokes Raman scattering</td>
</tr>
<tr>
<td>CIA</td>
<td>carbon-in-ash</td>
</tr>
<tr>
<td>CLENEF</td>
<td>intelligent temperature monitoring and control for clean and energy efficiency combustion processes</td>
</tr>
<tr>
<td>CMMS</td>
<td>computer-based maintenance management system</td>
</tr>
<tr>
<td>COBOL</td>
<td>Common Business Oriented Language</td>
</tr>
<tr>
<td>CPU</td>
<td>central processing unit</td>
</tr>
<tr>
<td>CRC</td>
<td>cyclic redundancy check</td>
</tr>
<tr>
<td>CRT</td>
<td>cathode-ray-tube</td>
</tr>
<tr>
<td>D/A</td>
<td>digital-to-analogue</td>
</tr>
<tr>
<td>DAS</td>
<td>data acquisition system</td>
</tr>
<tr>
<td>DC</td>
<td>direct current</td>
</tr>
<tr>
<td>DCS</td>
<td>distributed control system</td>
</tr>
<tr>
<td>DDGS</td>
<td>distributed digital control system</td>
</tr>
<tr>
<td>DDC</td>
<td>direct digital control</td>
</tr>
<tr>
<td>DFT</td>
<td>diagnostic function test</td>
</tr>
<tr>
<td>DIO</td>
<td>digital input/output</td>
</tr>
<tr>
<td>EMF</td>
<td>operation electromotive force</td>
</tr>
<tr>
<td>EMIR</td>
<td>Equipo de Muestreo Isocinéctico Rotativo—Rotating Isokinetic Sampling System</td>
</tr>
<tr>
<td>FRC</td>
<td>flow ratio control(ler)</td>
</tr>
<tr>
<td>GKM</td>
<td>Grosskraftwerk Mannheim AG (Germany)</td>
</tr>
<tr>
<td>GUI</td>
<td>graphic user interface</td>
</tr>
<tr>
<td>HMI</td>
<td>human-machine interface</td>
</tr>
<tr>
<td>HTTP</td>
<td>hyper text transfer protocol</td>
</tr>
<tr>
<td>I&amp;C</td>
<td>Instrumentation and control</td>
</tr>
<tr>
<td>IMS</td>
<td>Intelligent Manufacturing Systems</td>
</tr>
<tr>
<td>I/O</td>
<td>input/output</td>
</tr>
<tr>
<td>INGRES</td>
<td>interactive graphic retrieval system</td>
</tr>
<tr>
<td>IR</td>
<td>infrared</td>
</tr>
<tr>
<td>IS</td>
<td>intrinsically safe</td>
</tr>
<tr>
<td>ISA</td>
<td>The Instrumentation, Systems and Automation Society</td>
</tr>
<tr>
<td>kB</td>
<td>kilobytes</td>
</tr>
<tr>
<td>LAN</td>
<td>local area network</td>
</tr>
<tr>
<td>LCD</td>
<td>liquid crystal display</td>
</tr>
<tr>
<td>LDA</td>
<td>laser-doppler anemometry</td>
</tr>
<tr>
<td>LOI</td>
<td>loss-on-ignition</td>
</tr>
<tr>
<td>LSV</td>
<td>laser-light sheet visualisation</td>
</tr>
<tr>
<td>MMI</td>
<td>man-machine interface</td>
</tr>
<tr>
<td>MTBF</td>
<td>mean time between failure</td>
</tr>
<tr>
<td>MTTR</td>
<td>mean time to repair</td>
</tr>
<tr>
<td>NCV</td>
<td>net calorific value</td>
</tr>
<tr>
<td>OFA</td>
<td>overfire air</td>
</tr>
<tr>
<td>OIT</td>
<td>operator interface terminal</td>
</tr>
<tr>
<td>OLE</td>
<td>object linking and embedding</td>
</tr>
<tr>
<td>OPC</td>
<td>OLE for process control</td>
</tr>
<tr>
<td>OT</td>
<td>operator terminals</td>
</tr>
<tr>
<td>PA</td>
<td>primary air</td>
</tr>
<tr>
<td>PLC</td>
<td>programmable logic control(ler)</td>
</tr>
<tr>
<td>pc</td>
<td>pulsed coal</td>
</tr>
<tr>
<td>PC</td>
<td>personal computer</td>
</tr>
<tr>
<td>PID</td>
<td>proportional-integral-derivative algorithm</td>
</tr>
<tr>
<td>P&amp;ID</td>
<td>piping and instrumentation diagram</td>
</tr>
<tr>
<td>PGMAA</td>
<td>prompt gamma neutron activation analysis</td>
</tr>
<tr>
<td>PRB</td>
<td>Powder River Basin (coal)</td>
</tr>
<tr>
<td>PU</td>
<td>processing unit</td>
</tr>
<tr>
<td>PVS</td>
<td>particle velocity sizing</td>
</tr>
<tr>
<td>RISC</td>
<td>reduced instruction set chip</td>
</tr>
<tr>
<td>RTD</td>
<td>resistant temperature detectors</td>
</tr>
<tr>
<td>SCADA</td>
<td>supervisory control and data acquisition</td>
</tr>
<tr>
<td>SCAP</td>
<td>adaptive predictive control system</td>
</tr>
<tr>
<td>SMTP</td>
<td>simple mail transfer protocol (Internet e-mail)</td>
</tr>
<tr>
<td>SNMP</td>
<td>simple network management protocol</td>
</tr>
<tr>
<td>SU</td>
<td>server unit</td>
</tr>
<tr>
<td>TCP/IP</td>
<td>transmission control protocol (with Internet protocol (IP), the main protocol of the internet)</td>
</tr>
<tr>
<td>TGA</td>
<td>thermogravimetric analysis</td>
</tr>
<tr>
<td>TVA</td>
<td>Tennessee Valley Authority (USA)</td>
</tr>
<tr>
<td>WAN</td>
<td>wide area network</td>
</tr>
<tr>
<td>XRF</td>
<td>X-ray fluorescence</td>
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1 Introduction

Early devices used for control, measurement and protection in power plants were based on mechanical and electromechanical principles. Control panels were installed in close proximity to the boilers and machines up until the 1940s. As unit output increased the volume of instrumentation equipment with analogue indicators and hard wired switches became too unwieldy. Hence the shift to a central control room. Electronics became part of plant I&C in the 1960s. This was partly in response to the increasing influence of electronics, but also because the increasing physical size of plant presented significant difficulties for achieving stable control due to the distance/velocity lags in pneumatic transmission systems. Rapid development in instrumentation and control (I&C) technology followed and modular analogue hard-wire programmed control systems were introduced. In the mid 1970s the innovation of the ‘microchip’ and ‘desk top computer’ launched digital technology and screen-based operating environments. The first digital process computers were used to monitor the process, generate alarms and to calculate reference variables. Screens (video display units) were used for process observation and monitoring. The number of cables required for connections was reduced by using serial bus connections. Digital, distributed, bus-networked, microprocessor-based process control systems were first used in the 1980s. Distribute control systems (DCS) are a large-scale process control systems characterised by a distributed network of processors and I/O subsystems that encompass control, user interfacing, data collection and system management. Today I&C systems are based on international standards for microelectronics, information science and technology, and communications. Systems are open to allow the exchange of data with other systems, enable the incorporation of future technologies and maintain sub-system compatibility (Siemens Power Journal, 1997).

Modern instrumentation and control (I&C) systems enable the operation of a power plant in a safe and efficient manner while meeting the demands of the power grid system. Adequate safety and performance within plant operational constraint margins are monitored by the I&C system. Immediate indications and permanent records are made of plant status throughout. Alarm systems draw the attention of the operator to any deviation from the safety and operational constraints margins. In case of operational constraints violation, the plant is shut down by either the manual and/or automatic control provided by the I&C system. Numerous directives and standards (such as IEC61508) govern measuring instrumentation and control and communications protocols. These will not be discussed in this review but may be covered in a future Clean Coal Centre publication.

An important development in modern I&C systems has been the incorporation of diagnostic and optimisation software based on fuzzy logic, neural or Bayesian networks, knowledge-based and expert systems. These dedicated, plant performance improvement systems can increase process efficiency by improving plant heat rate and/or reduce NOx emissions or carbon-in-ash. This aspect of I&C will be visited briefly in this report. The topic was discussed in detail in a previous Clean Coal Centre publication by Soud (1999). Dedicated I&C and data acquisition systems for downstream air pollutant control devices such electrostatic precipitators (ESP) or flue gas desulphurisation (FGD) or selective catalytic reduction (SCR) technologies will not be covered in this review. Automation and control in coal preparation will not be addressed in this report but is discussed in detail in a previous Clean Coal Centre publication by Couch (1996).

This report will discuss instrumentation and control (I&C) in conventional, pulverised coal (pc) fired power plants. The advent and application of the Internet and the World Wide Web in the electricity generating business is excluded from this review but is presented in another Clean Coal Centre publication by Moreea-Taha (2001).

Deregulation in the electricity markets and increasing demand for improved plant efficiency and availability whilst maintaining or reducing operating and maintenance costs has led to the development of sophisticated I&C systems.
Control system technology in power plants has been under development, both at the theoretical and application levels, for several decades. More recently, extra impetus has been given to this area of power plant operation by the availability of increasingly powerful computing tools and greater understanding of the theoretical and modelling issues to be addressed.

Specialised handling and treatment is required for the many fuels used in power generation. Instrumentation and control (I&C) systems must be appropriate to the fuel used and the plant that processes it. The tasks of the I&C system in the power generation process, including fuel and ash handling, combustion (boilers including heat recovery systems), auxiliary systems and water treatment in coal fired power plants, will be discussed in this chapter. Plant auxiliary systems include fans, pumps, air heaters, tanks and piping. Boiler auxiliary systems, which are considered an integral part of the boiler, include the pumps within the boiler circuit and the valves required for boiler operation.

Coal-fired plants are the most widely used power plant today. They involve the combustion of coal producing high pressure (typically 2400–3500 psig, ~165–240 bar) and high temperature (>500ºC) steam which is used to drive a turbine at synchronous speed (3000 rpm in countries such as the UK with a 50 Hz supply frequency, 3600 rpm in countries (such as the USA) with a 60 Hz supply frequency) (Lindsay, 2001). The turbine drives an electrical generator. Plant instrumentation may be used as an aid to operation and/or a method of keeping records of coal use, steam and electricity generation. Automatic controls can reduce personnel requirements and maintain safety while maximising plant efficiency. The appropriate instrumentation must be used in order to provide accurate measurements and subsequently correct operational information. Instruments of the indicative type as well as instruments that record data over long periods are essential in order to keep an accurate record of plant operation.

In order to highlight how efficiency improvements can impact the profitability of a power station, an example of main boiler efficiency losses in a UK 500 MWe coal-fired unit are given in Table 1. In this case, carbon-in-ash loss is a large contributor due mainly to the retrofit low NOx burners. Overall cycle efficiency combines boiler efficiency and the steam cycle efficiency. Assuming a plant load factor of 90% and a fuel net calorific value (NCV) of 25 MJ/kg, this equates to an annual fuel burn of 1,424,000 tonnes per year. Supposing an efficiency improvement programme is carried out or a combustion process optimisation is applied that increases efficiency by 1% with no net impact on auxiliary power requirements, annual fuel consumption would be reduced by over 14,000 t/y. At UK domestic fuel prices of the year 2000 the savings would be over £415,000 in fuel costs alone. Fuel accounts for ~45–55% of the cost of electricity generated and 60–80% of the operating cost in pulverised fuel power plant. The reduction in fuel would also benefit significantly other areas such as fuel transportation, auxiliary power consumption, particulate control system performance and ash handling and disposal (AEA Technology Environment, 2000).

Instruments in power plants indicate boiler and turbine loading. They also show various steam and flue gas temperatures, air, flue gas and steam flow, feedwater and steam pressures and electrical outputs. Controllers activate valves, dampers and other equipment to carry out modifications in the plant operating parameters to achieve maximum efficiency. Franke and others (1999) discuss the aspects of design and of steam generators for the next generation of power plants and I&C measures for improved operation. Isles (1997) reported on how I&C cut operating and maintenance costs at the Stanwell coal-fired power station (4 x 350 MW) in Queensland, Australia.

I&C systems play a role in modifying, when required, many of the variables in pulverised coal combustion including:
- excess air;
- coal particle size, moisture content and feed rate;
- air distribution in the furnace;
- firing density (heat released in the active firing volume or per square area of furnace plan);
- pre-heated air temperatures;
- state of furnace walls (a partial function of the soot-blowing cycle).

Stoichiometric combustion is the complete oxidation of all combustible constituents of the coal, consuming 100% of the oxygen in the combustion air. Excess air is any amount above that theoretical quantity. This depends on the physical state of the coal in the combustion chamber, coal particle size, the

<table>
<thead>
<tr>
<th>Efficiency loss</th>
<th>%</th>
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<tbody>
<tr>
<td>Dry flue gas loss</td>
<td>5.04</td>
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<tr>
<td>Sensible heat loss</td>
<td>0.33</td>
</tr>
<tr>
<td>Carbon in ash loss</td>
<td>1.36</td>
</tr>
<tr>
<td>Unburnt gas loss</td>
<td>0.09</td>
</tr>
<tr>
<td>Radiation and unaccounted losses</td>
<td>1.36</td>
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<tr>
<td>Total boiler efficiency losses</td>
<td>8.18</td>
</tr>
<tr>
<td>Boiler efficiency</td>
<td>91.82</td>
</tr>
<tr>
<td>Turbine cycle efficiency</td>
<td>43.4</td>
</tr>
<tr>
<td>Overall, gross-on net cycle efficiency</td>
<td>39.85</td>
</tr>
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</table>

* net calorific value (NCV) basis

Table 1 Breakdown of major boiler efficiency losses for a UK 500 MWe coal-fired unit (AEA Technology Environment, 2000)
proportion of inert matter present and the design of the
furnace and coal firing equipment. Excess air at furnace
outlet in pulverised coal combustion is approximately
15–30% of theoretical air. If the measured excess air is below
15% or over 30% the task of the I&C system is to modify
the amount of secondary air introduced into the furnace to
balance that.

The maximum attainable temperature (adiabatic flame
temperature) is calculable in a suspension type furnace.
However, it is not possible to achieve. This is due to the
immediate long-beam radiative cooling which occurs in the
water-cooled chamber during the combustion process, which
makes it impossible to attain the adiabatic temperature. Flue
gas temperature measured at the furnace exit can be used
with some approximation to an arithmetic or logarithmic
average to calculate the temperature of the flue gas and fly
ash particles passing through the furnace. An advanced
control system can initiate staged combustion, biased firing
or fuel nozzle tilt (in tangential firing) to adjust furnace exit
temperature with load change, varying fuel or furnace-wall
state (as in dirtiness). This allows the control of superheater
or reheater outlet steam temperature or furnace nitrogen
oxide production or both.

2.1 Coal handling

Coal sampling, preparation and analysis is necessary to
design, monitor and evaluate the performance of the
combustion process. This is carried out in accordance with
national and international standards (for example see
Table 2). Continued coal flow to the pulverisers must be
maintained and controllable. Reliability of measuring and
sensing devices and accuracy of the transmitted data are
fundamental to optimum performance of the I&C system.
The coal should be crushed to a size that would promote
uniform flow rate to the mill by the feeder. Coal feeders
supply the pulverisers with an ongoing flow of raw coal to
meet system requirements. Two feeders considered efficient
gravimetric belt feeders and the overshot feeder. The gravimetric belt feeder
is widely used in steam generators which utilise
combustion control systems (I&C) that require individual
and accurate coal measuring and metering to the fuel
burners. Control systems in coal preparation plants are
responsible for consistent coal-feed operation and
maximum recovery of combustibles as well as optimum
reduction in minerals and sulphur. Advances in areas such
as online coal analysis, with the use of modern technology
can improve plant performance. The subject of coal
preparation – automation and control is discussed in detail
by Couch (1996).

### 2.1.1 Mills (Pulverisers)

Finely-ground coal is carried to the burners by a stream of
air. An appropriate process control system must be used to
monitor and control the mills which grind the coal and the air
stream carrying it. Fineness samples are analysed
periodically. Pulverising eventually causes loss of grinding
element material. Power for grinding and maintenance of the
grinding elements constitute the main costs of the pulverising
process.

Pulverised coal distribution systems used in the UK are
discussed by ETSU (1998). A typical control system for one
type of pulverised fuel mill (a pressurised ball mill) is shown
in Figure 1. Effective control of pulverised coal distribution
system involves accurate and reliable measurement/monitoring
of the following parameters:

- primary air flow;
- pulveriser differential pressure;
- coal/air temperature;
- tempering air temperature;
- pulveriser exhaust pressure;
- coal silo level for coal delivery;
- ash hopper;
- precipitator hopper levels.

Pulverising equipment and related auxiliaries including
strength of equipment, valving and inerting are designed in
accordance with set standards. Various process control and
safety devices are used to maintain the performance of the
equipment. Pulveriser output is controlled by regulating the
feed rate in response to load signal. Air flow and temperature
are kept in proportion to feed rate by automatic control.
Permissive interlocks for proper sequential operation of
equipment, flow alarms to indicate cessation of coal-flow to
and from the feeders, and load limiting devices to prevent
overfeeds in the mills are included in the control system
set-up.

Despite taking all these precautions, accidents are sometimes
(IPC) Wood River power station suffered a fire that destroyed
the common unit 4/5 control/computer rooms and
surrounding plant areas. The fire was a result of a coal mill
explosion. A total of 488 MW in generating capacity was lost
until the completion of a recovery project that allowed restart
of unit 4 in 6 months and unit 5 in Autumn 1997. Franczak
and others (2000) describe in detail the aspects of the

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<table>
<thead>
<tr>
<th>Table 2</th>
<th>Standard American Society for Testing Materials (ASTM) coal analyses (Elliot, 1989; 1994)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proximate</td>
<td><strong>Ultimate</strong>*&lt;sup&gt;†&lt;/sup&gt;</td>
</tr>
<tr>
<td>Moisture</td>
<td>Moisture</td>
</tr>
<tr>
<td>Volatile matter</td>
<td>Volatile matter</td>
</tr>
<tr>
<td>Fixed carbon†</td>
<td>Fixed carbon†</td>
</tr>
<tr>
<td>Ash</td>
<td>Ash</td>
</tr>
<tr>
<td>Sulphur</td>
<td><strong>Oxygen</strong>&lt;sup&gt;‡&lt;/sup&gt;</td>
</tr>
<tr>
<td>Gross calorific value‡</td>
<td></td>
</tr>
</tbody>
</table>

* by definition, the moisture content is not part of the ultimate analysis, but it is commonly used. Occasionally, the moisture content may be included as hydrogen and oxygen; if so, approximately one-ninth is hydrogen and eight-ninths is oxygen. Chlorine is now also commonly used in the ultimate analysis.
† obtained by difference
‡ Gross calorific value (GCV) Btu/lb (kJ/kg), or higher heating value (HHV)
recovery projects including the methods used to assess plant damage and challenges associated with replacing damaged control systems and cables.

2.2 Boilers

Parameters that should be continuously measured, monitored and controlled in coal combustion boiler/burners include (ETSU, 1998):

- pulverised fuel flow rate;
- mill/pulveriser feeder speeds;
- boiler pressure;
- drum pressure;
- re heater pressure;
- boiler temperature distribution;
- superheater temperature;
- re heater temperature;
- economiser temperature;
- steam temperature;
- burner tilt angle (where appropriate);
- burner flame;
- economiser O2 and CO levels;
- O2 levels at air heater inlet & outlet;
- heat exchanger differential pressure;
- carbon in fly ash.

Boiler tuning is carried out at most power plant to achieve efficient operating O2 levels, low ash carbon content and low NOx emissions. Effective combustion diagnostics can identify equipment and operating constraints quickly and hence improve the performance of the plant. Boiler tuning in coal-fired power station often involves a wide variety of activities including (Thompson and others, 1997):

- optimising boiler efficiency:
  - reducing excess air and dry flue gas losses;
  - reducing carbon-in-ash content (or LOI);
- improving burner zone combustion conditions:
  - adjust burner and pulveriser settings for good flame characteristics and carbon burnout;
  - modify the fuel and air flow to each burner to achieve uniform combustion;
- adjusting boiler combustion controls to optimise dynamic load response without compromising stability at steady operating conditions:
  - adjusting soot-blowing cycles to improve heat absorption and reduce tube erosion;
  - repair of soot-blowers and operation adjustments to improve ash deposit removal;
  - combustion uniformity improvements to reduce local ‘hot spots’, slagging and fouling;
  - minimising thermal losses and casing air in-leakage;
- optimising boiler combustion conditions to satisfy emissions constraints:
  - adjustments to boiler controls and operating parameters for the best trade-off between boiler efficiency/performance and NOx, CO, and opacity;
  - instrumentation calibration and relocation (if necessary) to obtain measurements most representative of boiler combustion conditions;
- modification of boiler firing practices to improve unit availability and reliability:
  - burner zone air/fuel ratio (that is staging) and combustion uniformity modifications to minimise

Figure 1  A typical control system for one type of pulverised fuel mill (a pressurised ball mill) (ETSU, 1998)
furnace wall corrosion, particularly on units fitted with low NOx burners and overfire air (OFA); improving combustion conditions to accommodate a wider range of coal quality without slagging and fouling derates.

According to Thompson and others (1997) failure to establish uniform combustion conditions in the burner zone can have major economic impacts in terms of increased fuel use, emissions, slagging, fouling or even unit derates and plant outages in extreme situations. Common causes of non-uniform combustion include uneven coal and air flow distributions. The following actions may be taken to improve boiler combustion tuning:

- measure coal fineness, primary air and coal flow distribution;
- optimise mill performance;
- improve coal fineness;
- characterise air in-leakage between the furnace and economiser exit;
- balance coal flow to individual burners;
- balance air flow;
- adjust secondary air dampers to achieve a uniform air/fuel ratio at each burner;
- reduce air infiltration;
- improvement instrumentation and their placement;
- bias mills (for O2, NOx and LOI optimisation);
- adjust overfire air (OFA) dampers and burner/OFA tilt position for effective carbon burnout.

Thompson and others (1997) conclude that the use of real time combustion diagnostics analysers allows boiler tuning to be performed quickly and cost-effectively compared to conventional manual methods.

The main task of an I&C system is to monitor and ensure that the boiler is able to achieve the following efficiently and safely:

- evaporate water to steam at high pressure;
- produce steam at exceptionally high purity using stationary, mechanical devices to remove the impurities in the boiling water;
- superheat the steam to a specific temperature and maintain that temperature over a designated range of load;
- reheat (re-superheat) the steam returned to the boiler after expanding through the high-pressure stages of the turbine and maintain that reheat temperature constant over a specified range of load;
- provide the required mass steam flow to the turbine to meet required load demand;
- reduce the gas temperature leaving the unit to the required level to achieve high thermal efficiency and to ensure that it is suitable for processing in the emission control systems downstream of the boiler.

Boiler output in terms of heat energy depends on many factors apart from the quantity of steam. The duties of I&C system include maintenance of these parameters at set values to achieve maximum boiler performance. These being:

- temperature of feedwater entering the economiser;
- steam pressure and temperature at the superheater outlet;
- quantity, temperature and pressure of steam entering and exiting the reheater.

In coal-firing, fly ash which consists of several chemical elements and compounds, can have a detrimental impact on furnace performance. At high temperatures and depending on the quantity and fusion temperature, the fly ash impact and can adhere to surfaces within the furnace causing slag build-up. Chemicals in the fly ash may cause deterioration in the materials, such as alloy steels, used in superheaters and reheaters. Sulphur compounds can cause corrosion and plugging.

Boiler sootblowers are required to clean the heat absorbing surfaces to continue appropriate heat transfer and to avoid plugging, which can affect gas flow and cause load limitation in the boiler. Boiler configuration and the probable fouling characteristics of the coal ash used affect the choice of the sootblower design. Retractable sootblowers are used to clean superheater, reheater and economiser sections. Sootblower media are in general steam or compressed air both of which are effective in removing deposits. Large utility plants utilise a large number of sootblowers. Automatic control systems are installed in such plants to accomplish automatic sequential operation once ash deposition patterns have been established. Ideally, such systems would respond automatically to conditions of load, temperature, pressure and coal ash content to achieve efficient boiler operation. However, the number of input variables, the validity of the signals and the complexity of the process manipulation can limit the efficiency of these systems. Essential parameters for the sootblowing control package include:

- equipment to start each sootblower in the system automatically;
- means to cancel the operation of any sootblower in the system;
- ability to determine which sootblowers are to be operated and their programmed operating sequence;
- complete capability to monitor and display the operation of each sootblower;
- in case of sootblower system malfunction, the ability to prevent or abort the operation of any sootblower;
- method to select and alter sootblowing routines as dictated by the boiler cleaning requirements;
- operate a number of sootblowers simultaneously;
- manual override function of the automatic routines.

Schlessing (1999) discussed the optimisation of soot blower operation with a logic control-based programme in a German power plant (see Section 10.4.2).

### 2.3 Fans

Plant I&C systems monitor and when necessary modify the operating conditions of plant fans. There are two types of fan used in coal-fired power plant, centrifugal and axial flow fans. Fans fall into five categories which combined can account for more than half of the total boiler power requirements. They are sometimes used to control steam temperature and a number of small fans are used for sealing and cooling of the ignitors, scanners and other equipment.
Tasks of instrumentation and control (I&C) system

Some fans push with pressure while others pull by creating a vacuum. The five fan categories are:

- primary air fans which supply the air necessary to dry and transport coal either directly from the mills to the furnace or to an intermediate storage bunker;
- forced draught fans which supply the air necessary for combustion;
- induced draught fans, typically installed downstream of the particulate control system, move the combustion gas away from the boiler;
- gas recirculation fans that draw gas from between the economiser outlet and the air pre heater inlet and discharge it into the bottom of the furnace;
- fans for the cooling towers that cool the water from the turbine condenser.

Forced and induced draught fans circulate air through the boiler and stack optimising use of heat. Of all fans in a power plant, the gas recirculation fan has the heaviest duty. A robust and reliable fan design is very important to withstand a combination of heavy fly ash load and rapid temperature changes.

The main components of a fan are a bladed rotor and a casing to hold the incoming air or gas and direct its flow. Fans provide the necessary energy to the moving gas to overcome resistance to flow and continue their motion. The amount of energy depends on the volume of gas moved, the resistance against which the fan works and efficiency of the device. Hence two paramount factors in fan performance are pressure and volume. Table 3 shows the effect of fan parameters on performance capabilities.

Fan capacity control can be performed by the I&C system varying fan output through:

- control of the aerodynamic flow into or within the fan;
- control of the speed of the fan;
- dampers; or
- vanes.

The second method is potentially the most efficient form of capacity control depending on the efficiency of the speed control system. Variable-speed motors may involve the use of electronic controllers which alter the speed of the driving motor in response to demand signals from the distributed control system (DCS). Variable-speed motor systems can result in operational improvements, especially in reliability, to large induced draught fans. Their benefits include:

- reduction in erosion;
- reduction in mechanical shock at start-up;
- adjustability of speed to any point within the operating speed range;
- at reduced running speeds, potential reduction in fan system problems (foundation, ductwork and noise);
- reduction in electrical power surge on motor start-up;
- reduction in station service.

The main disadvantage of adjustable speed drives is their cost which increases with unit size. Also the requirement of additional components to the drive train necessitates careful consideration of the system dynamics to avoid torsional oscillations or other problematic phenomenon. One such phenomenon is the ‘stall condition’. The angular relationship between air flow impinging on the blade of a fan and the blade itself is known as the ‘angle of attack’. In axial flow fans when this angle exceeds a certain limit, the air flow over the blade separates from the surface and centrifugal force then throws the air outwards, towards the rim of the blades. This action causes a build-up of pressure at the tip of the blade. This pressure increases until it can be relieved at the clearance between the tip and the casing. Under these circumstances the operation of the fan becomes unstable, vibration sets in and the flow starts to oscillate. The risk of ‘stall’ increases if a fan is oversized or if the system resistance increases excessively. For each setting of the blades there is a point on the fan characteristic beyond which stall will occur. If these points are linked, a ‘stall line’ is generated. If this is included in the plant control system (DCS) it can be used to warn the operator that the condition is imminent and then to shift operation away from the danger region. The actual stall line data for a given fan is usually provided by the manufacturer (Lindsay, 2000).

Surge protection may be required with centrifugal fans. This is a form of instability which may arise if the fans are operated near the peak of their pressure (flow curve). A small movement either way can cause the pressure to increase or decrease unpredictably. The point at which this phenomenon occurs is called the ‘surge limit’ and it is the minimum flow at which the fan operation is stable. The control system unless designed with surge protection in mind may need to be adapted to deal with the condition if and when it arises.

Single or multi-bladed dampers can provide different forms of draught control. Multi-bladed dampers are more costly but they offer better linearity of control over a wider range of operation. Linearity is the adherence of device response to the equation \( R = KS \), where \( R \) =response, \( S \) =stimulus and \( K \)=a constant. Designing a control system for optimum performance over the widest dynamic range is simplified if the relationship between the controller output signal and the

<table>
<thead>
<tr>
<th>Table 3 Effect of fan parameters on performance capabilities</th>
<th>Axial</th>
<th>Centrifugal</th>
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<tr>
<td><strong>To increase volume:</strong></td>
<td>increase blade tip diameter</td>
<td>increase wheel width</td>
</tr>
<tr>
<td></td>
<td>increase rotational speed</td>
<td>increase rotational speed</td>
</tr>
<tr>
<td><strong>To increase pressure:</strong></td>
<td>increase blade-root diameter</td>
<td>increase wheel diameter</td>
</tr>
<tr>
<td></td>
<td>increase rotational speed</td>
<td>increase rotational speed</td>
</tr>
<tr>
<td></td>
<td>increase number of stages</td>
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resultant flow is linear. A system is linear if the principle of superposition holds and non-linear if the principle of superposition fails. It is possible to linearise the command flow relationship under both manual and automatic control by the design of the mechanical linkage between the actuator and the damper. Linearising is the mathematical process by which a non-linear model is made linear for the purposes of the analysis. However, this requires careful design of the mechanical assemblies and nowadays it is considered simpler to build the required characterisation into the DCS. Adjustment of vanes at the fan inlet is another method of draught control. Such vanes are operated via a complex linkage which rotates all the vanes through the same angle in response to the command signal from the DCS.

2.4 Pumps

Pumps are integral machines in a single unit in a power plant. Types of pumps include (Palm, 2001):
- boiler feed pump to circulate water to the boiler;
- condensate pump to collect condensed steam and feedwater to boiler feed pumps;
- feed water booster pumps that feed water to the boiler feed pumps;
- circulating water pumps to maintain cooling water flow to turbine condensers.

Water flow through a feed valve into the boiler is delivered at pressure by one or more feed pumps. Boiler feed pumps are large horizontal pumps usually driven by electric motors. The motor is coupled to the pump through a hydraulic coupling which acts like an automatic transmission. Condensate and circulating water pumps are medium sized vertical pumps also driven by electric motors. The motor is coupled, in general, directly to the pump which may be 10–15 ft (3–4.6 m) below the surface. Feed water booster pumps are medium size horizontal pumps driven by electric motors that are also directly coupled to the pump (Palm, 2001).

Feed pumps deliver water to the boiler at high pressure. The flow into the system is controlled by one or more feed-regulating valves. Variable-speed pumps, unlike fixed speed pumps, enable the control system dynamics to be linearised over a wide range of flows. These pumps are therefore preferred because they improve controllability and contribute towards operational cost savings. Advantages of using a variable-speed pump include (Lindsley, 2000):
- improvement in efficiency because of reduced pressure loss;
- reduction of pumping power;
- reduction of feed-valve wear due to erosion when operating at low flows;
- improved control due to the valve operating at its designed pressure drop;
- improved control offered by the ability to operate with constant loop gain.

Variable-speed pumps are more costly than fixed-speed but the difference in capital cost is offset by the revenue savings that are gained, particularly if the boiler operates at reduced through-puts for a significant time over its lifespan.

2.5 Heaters

Design of heaters depends on the specific duty the heater is to perform. Heaters should withstand high pressures and temperatures >500°C (1000°F) and require strong and oxidation resistant alloy tubing. Thick walls in all tubing are also necessary depending on the steam pressure. External corrosion can be a problem and must be considered during tube design (Singer, 1991).

The function of a superheater is to raise boiler steam temperature above saturation temperature. Steam enters the superheater in an essentially dry condition. Absorption of sensible heat increases the steam temperature further. In the re heater, the steam is reheated again to reach the required temperature. Economisers improve boiler efficiency by extracting heat from the flue gas discharged from the final superheater section of a radiant/reheat unit. In the economiser, heat is transferred to the feedwater, which enters at a temperature lower than that of saturated steam. Economisers are usually arranged for a downward flow of flue gas and upward flow of water. Air heaters cool the flue gas before it is discharged through the stack. The heated air is used to dry the coal and hence increases combustion fuel firing efficiency and raises the temperature of the combustion incoming air. The latter increases the rate of combustion and helps raise adiabatic temperature. For air heater sizing, air and gas flows and temperatures have to be calculated as well as allowable static pressure losses.

A constant primary steam and reheat temperature over the anticipated operating load range is required to maintain turbine efficiency over a wide load range and avoid fluctuations in turbine metal temperature. A boiler must be equipped with the technology to control and maintain such steam temperatures over the required range. Unless controlled, steam temperatures will rise as steam output increases. Following are methods that can be used with the I&C system to regulate steam temperature:
- manipulation of the firing system (putting one or more burners out of service) where effective heat release occurs at a higher or lower level of the furnace. This affects the heat absorption pattern in the furnace and consequently the furnace gas exit temperature;
- desuperheating by spraying water into the piping before, between or after the superheater or reheater sections;
- in gas recirculation, a portion of the combustion gas is recirculated to the furnace and are added to the flow of gas passing the heaters;
- gas bypass around some of the installed heating surface that is excess in certain parts of the load range. This is to prevent these surfaces from absorbing heat from the bypass gas so that the desired steam temperature is achieved without using other means.

2.6 Water technology

Water quality is critical in high pressure utility boilers.
Prevention or reduction of damage from corrosion, scaling and contamination of steam can be achieved by:

- maintaining recommended water treatment for both the boiler-water and feedwater systems;
- controlling oxygen concentrations in the feedwater;
- complying with operating procedures during start-ups, shut-downs and outages;
- maintaining a boiler free from significant amounts of deposits by periodic chemical cleaning.

Suspended solids and dissolved solids concentrations in water as determined by conductivity are also important. Continuous monitoring and measurement of these parameters is usually performed by specialised devices that are part of the water treatment system package. Techniques of water treatment are discussed in detail by Singer (1991). Upon receiving data from the measuring devices, the control system generates the data and alarm signals which are fed into the main plant distributed control system (DCS).

During the start-up of a high pressure boiler, deaeration and pH adjustment are a must to assure that corrosion resulting from contaminant in feedwater does not occur. A deaerator removes the excess oxygen from the system. Adequate steam is necessary for the deaerator during unit start up so that oxygen is purged from the feedwater. Two control functions are required of the deaerator: these are maintenance of steam pressure at optimum value and keeping the storage vessel roughly half full of water. To minimise the formation of corrosion inducers, the oxygen concentration in the feedwater should be maintained at <5 ppb during unit operation. Use of dissolved oxygen monitors is important particularly during load swings and start-up operation. Plant control systems should be set up to evaluate and ensure that all sources of oxygen contamination are eliminated. As for control of boiler-water pH, small deviations from the recommended values can result in tube corrosion while large deviations can lead to the destruction of all furnace wall tubes in a matter of minutes (Singer, 1991).

Steam conditioning devices, such as desuperheaters and steam conditioning valves are important components in power plants. They are designed and constructed in various complex configurations, required to operate over wide ranges of conditions and involve complicated three-dimensional flow fields where droplets and vapour interact. These devices normally utilise sprays of cooled water to regulate or control the temperature of superheated steam. They are found in turbine bypass systems, condenser dump systems, boiler attemperator systems, auxiliary steam systems, export steam systems, inerting systems, heat exchangers and dryers as well as numerous other utility applications. Despite the wide application of steam conditioning equipment, fundamental aspects of spray cooling remain essentially empirical thus making optimisation and proper installation difficult in situations with limited experimental data. According to Schoonover and others (1999), in recent years, considerable effort has been devoted to the mechanistic modelling of the transport phenomena involved in these systems. Without understanding to be gained from such efforts, prediction of system performance and accurate temperature control for the various operating conditions will remain highly uncertain.

Schoonover and others (1999) report on the use of computational fluid dynamics (CFD) to develop a computational tool to investigate the complicated heat and mass transfer that occurs where using spray cooling for steam conditioning devices. In 1999, an experimental facility was constructed to provide verification data for the CFD-based computer models. The authors conclude that application of this model provides an insight into the physical environment downstream of the injection point and allows proper selection, application and installation of steam temperature devices thus improving reliability, flexibility and efficiency for the power plant.

Finally, in the past, coal-fired power plants used to operate, according to their design, in a steady production rate generating electricity continuously at full load. Manual plant control followed by analogue systems (using 4–20mA standard) were capable of operating such plants successfully. Nowadays load variation is a common practice in most coal-fired power generating facilities throughout the world. Research is currently ongoing for the training of neural networks for load forecasting (Agosta and others, 1996). Modern I&C systems with distributed, digital and analogue control can facilitate the efficient operation of plants with continuous load-variation.
3 Elements of I&C

Historically, instrumentation and control (I&C) systems were hardwired with a dedicated controller to every control device. Commands and set points were given to the controllers via specific sets of control knobs or push buttons. Recorders were used to make a permanent record, in analogue values (4–20 mA), of plant operation based on continuous monitoring. Equipment status was displayed to the operator by meters, gauges, lights and alarm lamps. Power plant operation required experienced operators who knew when and how to operate plant components via a large control desk. Due to space limitation, not every control loop was brought to the central control room. Air cylinders and electric motors which were remotely operated allowed the plant operator to respond to changing plant requirements. Some components were controlled manually by hand-wheels and hanging chains (Tütken, 1996). Panel board instrumentation were the link between the operator and plant operational elements. More recently, electronic displays such as cathode-ray-tubes (CRTs) have replaced the panel-board instrumentation. Modern power plants are highly automated. Automation based on advanced, digital, control systems results in higher total plant availability and greater fuel-efficient operation. Modern I&C systems provide the means to operate the major plant systems from a central location. Greater demand for increased plant efficiency and availability as well as decreasing operating and maintenance costs have led to the development of sophisticated I&C systems. Availability of components in the I&C system can be calculated as follows:

\[
\text{availability} = \frac{\text{MTBF} \times 100}{\text{MTBF} + \text{MTTR}}
\]

Mean time between failure (MTBF) is a common statistical measure of the expected life of equipment.

Mean time to repair (MTTR) is based on factors such as the diagnostic tools available to locate the source of a fault, availability of spare parts, the work involved in removing the faulty component and replacing it. Using the MTBF/MTTR formula shows that availability of a system with a MTBF of 80,000 hours and an 8 hour MTTR is 99.99%.

A computer controlling a power plant is in command of a fuel handling and feeding system, a mixture of gases, high steam pressures and temperatures and turbine generators (Swanekamp, 2000b). According to Markkula (1995), reliability of a modern automation system is in the order of 99.98%.

3.1 Components and tools

Plant I&C systems are used to measure the values of relevant parameters and control operation of the power generation components such as boilers. These systems perform measurement, control functions, monitoring and continuous regulation. They control system drivers, safety devices, interlocking systems and the widely used processing of measurement data (such as registration, calculation and trends). Automation systems are also used in environmental control (emission measurements, exhaust emission, water quality).

Piping and instrumentation diagram (P&ID)

A piping and instrumentation diagram (P&ID) is a drawing or blueprint of the systems in a section of a plant mirroring the original design of the plant and its operation. The P&ID shows the components needed to run, monitor and control specific processes. It does not describe the combustion process or plant procedures. Changes or additions to the system, for example installing new pumps, must be appended to the system’s P&ID to reflect actual plant operation. P&ID are also known as process and instrumentation diagram or process and control diagram (InTech, 2001a).

I&C components

I&C equipment and systems in power generation require:

- supervisory control and data acquisition (SCADA) systems;
- process control computers;
- distributed control systems;
- programmable logic control;
- instrumentation including measuring apparatus (such as converters);
- water level control and monitoring;
- a protected power-supply system for the electronics.

SCADA is a common function in process control applications where programmable logic controllers (PLCs) control functions but are monitored and supervised by another system (often a DCS). A PC-based data acquisition system (DAS) depends on the system elements shown in Figure 2. Data acquisition software first came onto the market in the 1970s with the introduction of large-scale control systems. Today, these software are available for all control platforms including DCS-, PLC- and PC-based control. Data acquisition software collect and measure electrical signals.

![Figure 2 System elements of a PC-based data acquisition system (DAS) (National Instruments, 1999)](image-url)
from sensors, transducers, and test probes or other field devices and input them to a computer for processing. They also collect and measure the same type of electrical signals with analogue, digital or serial input boards plugged into a PC and possibly generate control signals with analogue, digital, and/or serial output boards in the same PC.

Plant alarms system

Annunciators, dedicated alarm systems that continually monitor the combustion and control process, have been used in the past to alert the operator to any critical situations in a plant. With the advent of digital I&C systems with DCS and PLC the use of these systems reduced. However, Gladfelter (2000) comments that alarm recognition and response has suffered and hence annunciators are being reintroduced. A further appeal in using new annunciator systems is that their output can be fed into the DCS/PLC. There are four main reasons behind the return to using such dedicated alarm systems including:

- alarms sounded on a standard light-box annunciator system are difficult to ignore. They are easy to see and more importantly to recognise;
- alarm systems when linked to the DCS provide cost effective levels of reliability and redundancy;
- annunciation systems can produce printed records of all alarm events;
- light-box systems are available with varying levels of sophistication and have a modest cost.

The alarms event data, recorded in the DCS, allow operators to check process status and alarm trends from remote locations, also to determine how well the alarms are being responded to (Gladfelter, 2000). For detailed information on plant alarm systems see EEMUA (1999).

Interchangeability and interoperability

In modern I&C, plant data measurement and automation systems must be able to share timely information with other systems and applications throughout the facility. An open industry standard interface provides interoperability between disparate field devices, automation and other systems. Interoperability is the ability to ‘mix and match’ different field devices and host systems from various manufacturers without sacrificing functionality of the new device or the existing control system (Swanekamp, 2000a).

Integrating the wide mix of technologies that use many different proprietary protocols from a host of different suppliers can be problematic. A power plant can incorporate many information technology (IT) subsystems including computer-based maintenance management system (CMMS), performance monitoring, process optimisation, emissions monitoring, regulatory compliance reporting, combustion control, predictive maintenance, outage management, reliability/availability data, financial spreadsheets and human resources administration. In addition, according to Swanekamp (1998), almost every instrument in a plant today is sold equipped with its own comprehensive electronics package for process control and equipment diagnostics. Integrating all these requires systems interoperability and communications standards. Interoperability between field instruments, the DCS and the PLC results in easier installation, lower cost, reduced maintenance and greater plant efficiency.

Over the years, numerous proprietary interfaces were developed for devices and control systems to permit access to real time information. Microsoft’s dynamic data exchange (DDE) protocol became a commonly used interface. DDE is a standard software protocol in Microsoft Windows for interprocess communication. It is used when applications send messages to request and share data with other applications such as spreadsheets. However, performance and reliability limitations were encountered when using DDE to pass real-time data between devices in the control systems. An open industry standard interface defined as OPC (object linking and embedding (OLE) for process control) was developed. Today, OLE, a high performance, robust and reliable protocol has replaced DDE. OPC server and client applications can communicate and exchange data between computers distributed across a network (National Instruments, 1999). OPC is discussed further by Byres and Miller (2000). Many suppliers nowadays offer DCS, PLC and PC-based process control with improved interoperability.

Another important factor in system application is interchangeability which allows the replacement of a device from one supplier with an exact duplicate device from another manufacturer.

In the past the hardware and software used in plant I&C was supplied by vendors who developed their own proprietary hardware, operating systems and communications protocols. Today, the electric power industry relies heavily on off-the-shelf components that are based on standards generated by the computer industry. This is because all major power plant control system suppliers use modern high speed personal computer and standard operating systems. The following characteristics are essential to the nature of any plant control system (Zink, 1998):

- deterministic and reliable behaviour;
- real-time element communications capability;
- redundancy;
- time resolution of events sequences.

The information technology (IT) chain in a power plant begins with a sensor and ends with a final-control device. The main area of modernisation has occurred in the control centre/room. More recently, emphasis has been on the development of ‘smart’ field devices such as thermocouples, pressure gauges, pH meters, valve controllers and damper actuators. Information technology for electricity generation, including coal, from 1999 to 2004 is the subject of an in-depth review by Makansi (1999).

3.2 I&C system set-up

Power plant automation hierarchy can be divided into three categories (Markkula, 1995):
- Basic controls consisting of open and closed loop controls and data acquisition. Basic control tasks include process measurements, safety interlocks and protection, connections to external systems such as gas turbine, boiler or steam turbine own control systems, individual control of motors and on/off control valves, closed loop control and sequential control of individual process sections.

- Plant level controls are responsible for controlling start-up and shut-down sequencing, load changes in the plant and disturbance management functions. Lausterer and Kallina (1995) discuss the development of a computer-based, predictive load margin calculator for the optimal start-up of a coal-fired power plant.

- Plant information management which entails long term data storage, continuous process performance monitoring, plant production and profitability monitoring and report generation.

![Sub-systems of a traditional I&C system](British-Electricity-International, 1991)

**Figure 3**  **Sub-systems of a traditional I&C system** (British Electricity International, 1991)
The sub-systems of a traditional I&C system are shown in Figure 3. Data of plant operating conditions are provided by plant mounted sensors (S) and their associated transmitters. A typical 660 MW plant requires about 5000 sensors. Actual plant conditions are regulated by plant-mounted actuators (A). These adjust the position of valves controlling the flow of fluids or dampers and other devices which carry out primary control of the plant. Sensors and actuators are situated in hostile environments which can result in operational problems.

Transmitters and actuators are also subject to electrical and radio frequency interference, factors which have to be considered during their design. The associated manual and automatic control equipment, together with the central monitoring system are interconnected by a marshalling and cabling system. Modern day I&C systems utilise fibre optics in some areas. The total system is powered from supply systems that must provide electrical power and compressed air of appropriate quantity, quality and integrity. Reliability of power supplies is paramount as all these systems are dependent on power supplies for their operation. I&C systems as with other items of a power plant require quality assurance at all stages from design to replacement when obsolete (British Electricity International, 1991).

Design and installation of an I&C system in a coal-fired power station is a complex matter that requires careful and comprehensive administration. When complete the system should be fully supported by complete documentation to enable effective plant maintenance. In the first step the requirements, that is specifications, of the I&C system must be clearly set up. According to Lindsley (2000) functional specification is a process-related definition of what the functions required of the system are. Typical functional specification describes the plant as a whole and then discusses the control loops with the required accuracy, response time and dynamic range of each loop. Technical specification of the I&C system explains how the functions should be achieved. A technical specification describes the system configuration in terms of the electronics and computer technologies to be used. This type of specification should include the following (Lindsley, 2000):

- the size, type and number of operator displays to be provided;
- the overall system configuration;
- method of programming;
- the physical environment in which the equipment will be expected to operate;
- the performance requirements of the system;
- available power supplies;
- safety requirements.

Each item of equipment on a coal-fired power plant site must be identified by a method that allows it to be uniquely defined, specified, purchased, installed, commissioned and maintained. Although there are many systems of identification, the Kraftwerk Kennzeichen System (KKS), translated as power station designing system, is the method widely used in Europe. Power station design systems define everything in a plant from the smallest component to the largest and include the buildings that contain it all. For further information on KKS see Lindsley (2000).
4 Measurements and devices

Measurement is the act of assigning a value to some physical variable. In the ideal measurement, the value assigned by the measurement would be the actual value of the physical variable intended to be measured. However, measurement errors bring an uncertainty in the correctness of the value resulting from the measurement. To give some measure of confidence to the measured value, measurement errors must be identified, and their probable effect on the result estimated. Uncertainty is simply an estimate of a possible value for the error in the reported results of a measurement. Research continues in all areas of data measurement throughout the power plant to obtain the most accurate and reliable measurements possible to feed into the I&C system in order to achieve maximum plant performance. Instrumentation, such as sensors, to carry out these measurements must be accurate and reliable and, especially in hostile environments such as a coal-fired power plant, robust. Also all instrumentation in power plant have construction and performance requirements set by national and international standards. These standards will not be discussed in this review.

Gas analysis, for example, has traditionally concentrated on emission measurement which entails extraction methods primarily. Current trend is to measure gas concentration within the combustion process which is difficult due to high temperatures, heavy dust loadings and the variety of gas mixtures generated within the furnace. New instruments and measurement techniques are continually under development to obtain in situ, accurate values that are fed into the I&C system.

All measurements are relative as they depend on the accuracy and calibration of the instruments that make the measurements. Measurements may be in a range that is defined by lower and upper limits or a span which is the numerical distance between the lower and upper limits of a range. Measurements are also made under static conditions, also known as steady state or equilibrium conditions, or dynamic conditions, also known as unsteady state. Instrument calibration is to determine the outputs of a device that correspond to a series of inputs to the same device. The data thus obtained are used to (Platt, 1996):

- determine the locations at which scale graduations are to be placed;
- adjust the instrument output to the desired value or values. For example, a temperature transmitter for measuring a range of 0 to 200°F (–18 to 93°C) required an output signal range of 4 to 20 milliamperes (mA). The instrument is calibrated accordingly;
- ascertain the error by comparing the actual output against what the output should be.

Among the most important variables to measure in coal-fired power plant are temperature, pressure, flow, level and position measurements.

4.1 Temperature

Reliable temperature measurement, of air and water, is essential to ensure plant safety and combustion quality. To avoid problems resulting from failure of temperature sensing units, it is often a plant requirement to have duplicated temperature monitoring equipment with a logic system to choose the valid reading (Power, 1996). Temperature can be measured only by indirect methods, generally by transferring heat to an instrument which can respond to that energy. Any physical property that changes with temperature in a reproducible manner can, in principle, be used to measure temperature. In practice, electrical and expansion effects are two commonly used properties (British International Electricity, 1998).

Measuring devices

Thermocouples and resistance temperature detectors (RTD) are the most popular sensors used to measure and control power plant temperature (Power, 1996). Thermocouples constitute two dissimilar wires, joined together, that generate a voltage proportional to temperature when their junction is heated. Different types of thermocouples offer a wide temperature range, from near absolute 0 K (–459 F) to over 2255 K (3600°F). RTD offer a temperature range of 78 K (–320°F) to about 1122 K (1560°F). Thermocouples are faster in heat response and less subject to vibration compared to RTD. However, RTD are more accurate and stable at ambient to moderate temperatures. Thermocouples are generally chosen in coal-fired power plants where vibration is prevalent and steam temperatures can be over the RTD tolerance level. Meanwhile, high temperature RTD are under development. Sensors do not measure temperature directly. They measure an output that is temperature-dependent. For thermocouples the dependent variable is voltage. However, since thermocouples do not bear a strictly linear relationship with temperature over the entire range, a diode or transmitter is paired with the sensor to linearise the output and thus improve accuracy (Power, 1996).

Thermocouple material has to suit the temperature range and environment in which they are used. The metals used in thermocouple manufacturing are base metals and rare metals. Choice of material is influenced by:

- resistance to mechanical and chemical deterioration in the operating environment;
- need for a relatively high change in operation electromotive force (EMF) output per degree change in temperature;
- constancy of calibration which is dependent on freedom from contamination and mechanical strain;
- reproducibility in that each thermocouple should have similar characteristics, so that the system does not require recalibration when a new thermocouple is fitted.
In coal-fired power plants the most commonly used thermocouples are of type K (up to temperatures of 1100°C) and type E (up to 900°C). When selecting a type of thermocouple for any application the following factors must be considered (British Electricity International, 1991):

- the maximum process temperature to which the thermocouple will be subjected must not exceed the maximum stated operating temperature of the materials;
- the thermocouple should have the highest signal output for the temperature range in which it is to be used;
- the change in output for a given temperature variation should be fairly constant;
- the material combination should afford the maximum interchangeability, stability and life-span.

Different materials are used today in thermocouple manufacturing including nickel chromium iron alloy, nickel chromium silicon and chromium nickel (stainless steel). For detailed information on thermocouples see British Electricity International, 1991.

In coal-fired power plants, the millivolt signals obtained from thermocouples usually require some processing before they can be used for indication, recording or control purposes. Hence, transmitters are specified for all applications where the readout devices are remote and where they are used in conjunction with automatic control loops. These transmitters can be located in a plant equipment room or on the plant floor itself.

Suzuki and others (1995) discussed the application of expert systems for steam temperature monitoring and control in coal-fired power plants in Japan. Expert systems provide mechanisms for incorporating large amounts of expert knowledge from plant operators and other experts into software applications that make the expertise available online to end users. These expert systems typically identify and diagnose strategic problems based on input data and provide corrective advice (Bangham and others, 1993).

### 4.2 Pressure

Pressure is the measure of applied force compared with the area over which the force is exerted. A pressure regulating valve is a valve that can assume any position between fully open and fully closed or that opens or remains closed against fluid pressure on a spring loaded valve element to release internal pressure or hold it and allow it to build, as desired. A pressure relief device uses a mechanism that vents fluid from an internally pressurised system to counteract system over pressure. The mechanism may release all pressure and shut the system down (as does a rupture disc) or it may merely reduce the pressure in a controlled manner to return the system to a safe operating pressure (as does a spring loaded safety valve) (IICA, 2001).

**Pressure measuring devices**

Pressure measuring instruments are used in large numbers in coal-fired power plant. Pressure can be expressed as absolute pressure (above complete vacuum), gauge pressure (above atmospheric pressure) and differential pressure (D/P) which is the comparison of two pressures without expressing either in absolute terms. The standardised industry measurement unit for pressure is bar, which is equivalent to 10² N/m² or Pascal, for high pressures and millibar (mbar) for low pressures. There are two types of measuring devices: liquid columns and expansion elements. Although liquid column type devices were installed and still operate in older power plants expansion elements are preferred at the modern power generating facility.

In expansion element type devices the element is usually metallic and its movement, which indicates the applied pressure, is either directly coupled by mechanical links or indirectly by an electrical transducer connected to a readout device. Expansion elements include the slack diaphragms, stiff diaphragms, capsules, bellows, bellows and spring, and Bourdon tube. The Bourdon tube is a commonly used pressure element. It is a flattened tube with one end closed and the other end brazed or welded into a metal block to which the pressure to be measured is connected. The application of pressure to the inside of the tube tends to force the flattened walls apart, which results in the Bourdon tube tending to uncoil and move at its free end. This movement is transmitted by means of a mechanical link to an indicating mechanisms, in the case of a direct reading gauge or to an electrical transducer for remote transmission. There are six basic types of transducers in common use including potentiometric, differential transformer, inductive coupling, strain gauge, variable capacitance and vibrating wire transducers. These are incorporated in pressure transmitters installed on power plant for continuous monitoring. For a detailed discussion of these transducers see British Electricity International (1991). Materials used for expansion elements depend on the medium being measured and the pressure range of the measuring device. The materials frequently used for elements of both pressure gauges and transmitters include phosphor bronze, beryllium copper, stainless steel, brass and high nickel alloy.

Pressure measuring devices fitted in coal-fired power plant are direct reading pressure gauges (used for local plant indications only), electrical pressure transmitters (used for all pressure measurements for inputs to control system) and pressure switches. Pressure switches are measuring devices used to switch electrical or pneumatic signals when a predetermined pressure setting is reached.

Exposure to high temperatures can be problematic for pressure sensors. Suppliers have therefore developed new transmitters that can withstand the high temperatures in coal-fired power plant. In addition, since the mid 1980s manufacturers of pressure sensors continue to develop devices that facilitate migration from analogue to digital communication.

### 4.3 Flow

Flow can be measured by flow rate or flow volume. Flow rate is the integrated velocity of the individual stream lines...
making up the total velocity profile across a conduit. Flow volume is the total volume of fluid which has passed through a conduit over a given period.

Measuring devices

There are numerous flow meters available on the market for measuring flow in power stations. The most popular types and flow measurements performed by the different types is shown in Figure 4. The most widely used flow meters in coal-fired power generation, the D/P type (see Figure 5), consist of a primary component that forms the restriction in a conduit, impulse pipework and associated valves connected to tapping points, and a device to measure the differential head produced across the restriction. Types of primary components used for continuous flow measurement are orifice plates, nozzles and venturi tubes. For most applications in coal-fired plant the orifice plate is acceptable as the primary component. The nozzle is preferred for steam flow applications because it has a longer life than the orifice plate in the steam pipeline environment. The venturi tube is often used for air or gas flows, and any applications where head loss must be kept to a minimum. The higher the pressure differential the higher is the net pressure loss of the system, that is energy loss. Hence, pressure differential should be kept as low as possible from an efficiency point. Flow pattern differs for each type of primary component and the pressure differential for each type depends on its shape, size and configuration of pressure tapping points (British Electricity International, 1991).

Thermal dispersion flow meters are becoming popular in coal-fired power plant (Lindsley, 2001). These devices operate on the principle of measuring the cooling of a heated tube as fluid flows across that tube. This cooling effect, or heat loss (thermal dispersion) is directly related to the mass flow of the fluid travelling over the heated tube. In a typical configuration, two thermal wells are used normally containing precision platinum resistance temperature detectors (RTDs). Heat is applied to one RTD either with a

![Figure 5](image-url)  A pressure difference flow measuring system showing the pressure variation pattern along the pipe (British Electricity International, 1991)

![Figure 4](image-url)  Popular basic types of flow meters (British Electricity International, 1991)
separate heater or through self-heating with a current. This RTD is the ‘active’ RTD. The second RTD measures the process temperature and is called the reference RTD. By supplying the active RTD with constant current, power or heat, a differential temperature is created at low flow conditions, and decreases with flow. Measuring the differential temperature (ΔT) with an electronic circuit that inverts and linearises the (ΔT), results in a signal that is directly related to the mass flow of the fluid. Other device configurations are discussed by Kresch, (1999).

As thermal dispersion flow meters have no moving parts or orifices to clog, the technology has proven rugged and reliable in harsh environments. However, not all gas applications are ideally suited for thermal dispersion flow technology because device operation depends on the cooling rate of a fluid and changes in fluid composition can affect the readings, adversely. In particular, moisture can cause false readings as liquids are far more efficient in dissipating heat than gas. Applications that have continuous stream of liquids, such as wet stream or wet scrubber gas, are not suitable for thermal dispersion meters. On the other hand, applications using gas containing water vapour are candidates for thermal dispersion, as long as the gas remains a vapour. Gases such as the preheated and recirculated air in a coal-fired power plant, which contain fly ash, are ideal applications for this technology. Despite the gas containing fly ash the flow elements do not foul and cope easily with the high temperatures and erosive conditions. For more information on thermal gas dispersion see Kresch (1999) and Shannon (1999).

Flow meters can be affected by the conditions outside and inside the metering system conduit. Influencing factors outside the conduit include temperature, humidity, hostile environment, vibration, spraying water, electrical interference, accessibility and false heads due to piping runs. All devices are subject to the first six environmental factors. Accessibility is necessary in flow meters firstly to ensure that the device can be located in the line and that enough headroom is available to enable the primary component to be lifted clear of the pipe and secondly to make maintenance easier. Conditions inside the conduit are affected by conduit configuration and the properties of the fluid being measured. Measuring equipment performance is dependent on flow meter type, range, accuracy, linearity, repeatability, pressure loss and dynamic response. Other factors important in flow meter acceptability are remote transmission of measurement, cost, reliability, installation and life and maintenance of the device.

Menezes (1999) discusses improving power plant safety and efficiency through better D/P flow measurements. He states that a traditional D/P flow meters that can achieve 1% accuracy and repeatability in a laboratory will typically provide 3–7% in actual, installed conditions. To obtain 1% mass flow accuracy and repeatability during operation Menezes (1999) recommends applying the following ‘best practices’:

- D/P transmitters that provide high accuracy in actual operating conditions;
- pressure and temperature compensation as these parameters vary in any steam gas or flow application and even minor variations can have a major impact on mass flow accuracy;
- dynamic compensation of the primary flow element to correct for operation away from the design/sizing conditions.

4.3.1 Pulverised fuel (pf) flow

Pulverised fuel (pf) flow instrumentation can be used in the diagnosis of problems and, in combination with a control device for pf or air distribution, can contribute towards optimising plant efficiency. Significant advances have been made in recent years in the development of instrumentation for online measurement of pf flow rate, distribution and control in coal-fired power plants. There are a number of technologies commercially available for pf flow measurement in utility coal-fired power generating plants. These include the ABB Automation UK PFMaster, the Promenon PIFLO Microwave System, the SWR Engineering Myflo KSR 100, TR-Tech Int Oy Electric Charge Transfer (ECT) Star, the ClampOn and Acoustica and M&W Asketeknik Automatic Coal Flow Monitor (ACFM). The principles and capabilities of each technology and other issues relevant in choosing a particular system to suit a particular need are discussed in detail by Miller and others (2000) and DTI (2001a). These technologies are capable of providing an estimate of the relative or absolute pf flow rate and of particle velocities. Preliminary results with devices that are capable of providing a qualitative indication of pf size distribution are promising. Although a number of these techniques for measuring coal flow have been tried, utilities remain unsatisfied with any that are offered commercially. Their reliability and accuracy still needs to be improved (Flynn, 2001). At present instruments continue to be based on methods that involve measurement of the electrostatic properties of the pf stream or on microwave based sensors.

Pf size distribution measurement methods currently used for measuring coal powder particle size include optical methods (see Mahajan and others, 1995), acoustic/vibration methods and electrostatic methods. The majority of these are not suitable for online applications. Pf mass and velocity measurement are usually carried out with electrostatic pf mass flow sensors, microwave-based, acoustic and extractive methods. Online application of these methods also remains, in general, impractical. Fuel distribution in the past has been mainly based on fixed geometry device and improving coal feed design to divide the flow into alternate directions into the boiler. Variable geometry devices are currently under development. These devices aim to resolve the main problems associated with fixed geometry fuel distribution control such as the design of a device must be optimised for a single operating condition, pf distribution cannot be adjusted online and performance variation with wear. Yan and others (2000) discuss the use of a new electrostatic sensing technology for the online continuous measurement of the velocity of powder and bulk solids in pneumatic suspensions.

Monitoring pf and air flow in a boiler can optimise the combustion process. A direct indication of pf mass flow
following the coal milling plant can provide an accurate value of energy input to the furnace and allows for improvements to be made in the transient control of the unit. Development of pf flow meters that provide absolute mass flows will assist operator/I&C system in controlling the combustion process. Currently, individual mills are controlled locally, based on assumed primary air and coal feed characteristics in a feed-forward control loop. Inaccuracies in such control strategies can occur due to differences in mill characteristics. Applying feed-back control loops by using pf flow metering to provide an output signal from the mill can provide more reliable data and improve current practice control strategies. For detailed information on pf flow (including metering), pf size distribution, control and sample installations see Miller and others (2000).

Laux and others (2000) state that proper air and coal metering at the burners is the key component for all future advanced combustion systems. They report that for continuous boiler optimisation, online measurement of fuel flow in each conduit is required for online optimisation of the air and coal balance at each burner. The Electric Charge Transfer Technology (ECT), recently developed by Foster Wheeler Energy Corporation (USA) in partnership with TR-Tech International Oy (Finland), measures the electric charges present in any two phase flow transport and uses the signals to determine, online, the characteristics of the flow including:

- relative coal distribution between the conduits (the system can also be configured to measure flow velocity and absolute flow in each conduit);
- occurrence of unsteady flow phenomena in coal conduits that can cause problems (high rate data collection allows monitoring of such situations);
- particle size distribution and mill performance (that is maintaining coal fineness).

In the ECT system, three antennae, made of hardened steel for long operational life, are connected together and installed through the wall of one existing conduit and inserted into the coal stream. The receiving antennae, in each coal conduit, are connected to a signal conditioning unit housed in a cabinet. The signal conditioning unit is connected to a computer (PC) for data processing and analysis. Proprietary software determines the balance between the conduits of one mill. The software also displays the results to the operator and feeds the data via a network to the plant DCS system or a continuous combustion optimisation software that runs on a separate computer. According to Laux and others (2000) the advantages of the ECT system include:

- all information is continuous and online;
- the technology is not affected by coal type, moisture and ash content or coal roping;
- system electronics can be located up to 1000 ft from the conduits;
- antennae in the coal conduits are abrasion resistant, passive and do not require power supply;
- mill outage requirements for installation is short.

The ECT technology has been applied in seven utility steam generating facilities confirming system viability for real-time coal balancing applications. Effect of ECT optimisation on NOx emissions and carbon-in-ash (CIA) in a tangentially fired boiler are shown in Figure 6 (Laux and others, 2000).

Cutmore and others (1993) and Abernethy and others (1998) reported the development and plant trial of ultrasonic and microwave techniques for the online measurement of coal mass flow as well as the commercial application of a microwave gauge for the online measurement of unburnt carbon in fly ash in Australia. Letcavits and Earley (2000) discussed the combustion optimisation of a 150 MWe boiler utilising fuel and air flow measurement and control. Low frequency microwave technology was also used in this case for online measurement of individual burner fuel flow. Keech (1999) reported on the successful laboratory trials of an advanced, programmable, multitasking, fast signal processor that is capable of cross-correlating and processing pf signals from two sensors simultaneously. The system is planned to be tested at industrial scale.

### 4.4 Level

Level measurement of both liquids and solids in plant items is necessary in power stations. Simple point level measurement requirement is for a ‘level switch’ to provide signals for alarms or control purposes when material reaches a certain level or falls below a predetermined level. Other applications include the continuous measurement of level over a predetermined range and for the transmission of the readings, that is signal, to a remote indicator or control device. Measurement of water level in the boiler drum is particularly important with regard to control and safety.

### Measuring devices

According to the British Electricity International (1991), there are several types of level measuring equipment including differential head (manometric) systems, Hydrastep probes, capacitative, ultrasonic and float devices, vibrating...
probes, falling weight, load cell weighing systems and Hydratec probes. Differential pressure (D/P) transmitters (also known as differential head systems) have been the predominant instruments in coal-fired power plants for liquid level measurement. In this system a differential pressure measuring device is employed to measure the head of a liquid in a vessel, the level being proportional to the head. Pressure difference can be measured either by a standard device connected directly to the vessel by piping, or the device can be filled with liquid on its high pressure side, and contained within the measuring chamber by a diaphragm. The diaphragm is welded to a flange and is connected to a mating

![Diagram](image-url)

**Figure 7** Electrical connection for a Hydrastep system using two side arm pressure vessels (British Electricity International, 1991)
flange fitted at the base of the vessel. When pressure is applied, by the head of the liquid in the vessel, the process fluid sealing diaphragm transmits the applied pressure through the liquid fill to the measuring expansion element of the measuring device, which is similar to that found in the standard measuring device. Pressure difference measuring devices must have a very low volumetric capacity to ensure that any possible swings in boiler pressure, that result in changes in water level, do not result in the measuring device displacing water from the reference column, thereby causing errors in measurement that will occur until the water in the column is made up to the full required head. Modern trend is to welding pipelines that were previously flanged due to increasingly demanding environmental and safety regulations.

Hydrastep systems are used in general for measuring and indicating the level of water in boiler drums. In these devices, a side arm pressure vessel is fitted with a number of individual electrodes spaced at discrete intervals over the height of the device. The electrodes detect the existence or absence of water at each electrode position. The distance between the electrodes decides the accuracy of the system. The tip of the electrode is made of titanium and is insulated from the metal of the pressure vessel body by means of a high purity ceramic insulator. Electrode assembly and associated seal have to withstand the full operating pressure, temperature and any rapid fluctuations of these parameters. The pressure vessel body is earthed so that the resistance measurement of the steam or water in contact with the tip of the electrode is made between the whole surface of the tip and earth. Figure 7 is a diagram of a Hydrastep system in a preferred arrangement in power plants, that is using twin side arm pressure vessels, A and B, mounted at the two ends of a drum. The figure includes the set-up of the electronic equipment which transforms the digital output obtained from the electrodes into a columnar display control room. Each pressure vessel has its own associated equipment including a detecting unit, power unit, logic unit and display unit. Detector units are located in the plant near the side arm pressure vessels. The logic and power units are in the equipment room near the control room while the display units are in the control room.

Differential head or manometric systems are the preferred method of measuring water level in boiler drums for control purposes as they have better resolution that other systems, such as Hydrastep, thus making them a better choice when using automatic control loops.

Capacitance measuring systems are used for solids measurement, such as level of fly ash settling in electrostatic precipitator hoppers, and other applications mainly dust measurement, depending on the temperature limits of the sensing probes (maximum of ~250°C). Other devices include the vibrating probe system, the tuning fork probe, falling weight, ultrasonic and load cell systems.

Technology development in level sensing since the beginning of the 1990s has been rapid mainly with the introduction of microprocessor signal conditioning and ‘smart’ electronics. Smart electronics are those that allow the transmitter to communicate with the control system by applying a digital protocol. Most however continue to apply the analogue (4–20 mA) mode. Benefits of using smart electronics are higher accuracy, better transmitter diagnostics, and the ability to calibrate the device at any point along the communications wiring system leading to easier/faster commissioning. This is expected to become more widespread with the advent of the Fieldbus communication technology (see Chapter 5). Many of these modern smart electronics, unlike D/P systems, have the ability to utilise a redundant sensor to check the operation of the primary sensor’s calibration and therefore can carry out the entire operation from the control room or other remote location (Power, 1996).

4.5 Position

Position measurement instruments are required to provide signals for automatic control, interlocking, alarm, tripping systems and continuous indication of plant operation. They are fitted either to the relevant plant item or incorporated in the actuator moving the plant item. Where the device is fitted to a plant item it is exposed and vulnerable. If the device is incorporated in an actuator, that is connected to the plant item by a link, there is a chance that the link may become disconnected at the actuator or at the plant regulating unit. If this occurs, an incorrect reading will be obtained from the positioning device mounted in the actuator. This will show the position of the actuator but bear no relationship to the position of the plant regulating unit that is in operation resulting in serious consequences. Mechanical and environmental damage can also affect the performance of the device. Traditionally, the majority of actuators were coupled direct to plant regulating devices, such as valves and sometimes dampers or vanes, and the position measuring device was fitted in the actuator thus reducing its exposure to damage. More recently, modern linear actuators are used in automatic control loops. These linear differential transformers are built in to the push rod providing reliable systems that are not prone to environmental or operational damage (British Electricity International, 1991).

Measuring devices

There are two main types of position measurement devices in power plants. Electrical transducers are used where a continuous reading of the position over the full movement of the plant item is required. Electrical switches are used where a number of predetermined positions, for example open and closed positions of valves or dampers, is the target. Different types of electrical transducers and switches are used in power stations. The linear differential transformer is the preferred position measuring device in applications where the position of the plant item is constantly altering and requires continuous measurement. In general, it is specified for use on plant regulating units that form part of automatic modulating control loops as it has no rubbing surfaces and therefore does not wear during operation. Other devices include the wire-wound potentiometer and the plastic film potentiometer.

Optical transducers are also commonly used for position transmission (Lindsley, 2001). These devices convert the
radiated light from an optical instrument into an electrical signal. Optical sensors range from sophisticated photomultipliers to simple, solid-state diodes. Examples of optical transducers include:

- the vacuum photodiode: relatively insensitive but has a high frequency response on the order of 1 megacycle. It is used for measuring high-intensity, rapidly varying light energy;
- the gas photo-tube: similar to the vacuum photodiode in that it has a low spectral sensitivity. However it passes a much lower frequency response, in the order of 10 kHz and has a higher device current. It also has a nonlinear output and thus is not suited for analytical measurements. It is normally used as a trigger device;
- the photo-multiplier: has a rather large gain, making it extremely sensitive. It can have a spectral sensitivity as high as $10^{-13}$ lumen with a range of $10^{-4}$ to $10^{-13}$ Watts. The photo-multiplier also has fast frequency response (100 MHz) and can be used from about 200 to 1500 nm.

As with other plant instrumentation it is important to ensure that the environment conditions to which these position transducers are subjected are within limitations specified for the device. Electric switches may be of the electromechanical type or proximity operated. Electromechanical switches consist of electrical contacts that are opened and closed (or changed over) mechanically by means of an actuating mechanism. Proximity switches operate without physical contact either by magnetic or inductive sensing.
5 Plant instrumentation

The I&C system instruments include (British Electricity International, 1991):

- plant-mounted transducers or sensors and associated systems for continuous measurement of operating conditions such as temperature, fluid pressure, flow and level, position of equipment, boiler furnace flame condition monitoring and the analysis of chemical compounds in the gases and steam turbine instrumentation;
- control actuators that move the correcting elements or components, that is dampers and valves, to control thermal and other conditions in the plant.

Plant instrumentation systems continue to be developed to be less intrusive, achieve greater accuracy in measurements, improve performance and be more cost effective. Retrofit of plant instrumentation requires plant outage for removing old instruments, making preparations necessary to install new instrumentation for example emptying conveyors to retrofit new flow meters, rewiring, mounting and calibrating new instruments, and integrating them into the existing control system or a new one and restarting and testing the new set-up. Bökenbrink and others (1997) discuss the replacement of I&C system in 81 outage days at the Weisweiler, 2245 MW gross total capacity, lignite power plant in Germany.

5.1 Sensors

Sensors are the devices that detect either the absolute value of a physical quantity (heat, light, sound, pressure, motion, flow and so on) or a change in the value of the quantity and convert the measurement into an electrical input signal for an indicating or recording instrument. Sensors are also known as primary detectors and sensing units (ISA, 2001). They provide:

- signals that drive conventional indicators or computer-based displays in the control room/centre and other locations;
- ‘measured value’ signals to closed loop automatic controls;
- signals to automation, protection and interlock systems. Most of these signals are of the on/off type from devices that indicate the position of plant actuators and switchgears.

Transducers convert physical phenomena to electrical signals. For example, thermocouples, resistance temperature detectors (RTDs), thermistors and Integrated Circuit (IC) sensors, convert temperature into a voltage or resistance. A thermocouple is a temperature sensor created by joining two dissimilar metals. The junction produces a small voltage as a function of the temperature. An RTD is a metallic probe that measures temperature based upon its coefficient of resistivity. A thermistor is a semiconductor sensor that exhibits a repeatable change in electrical resistance as a function of temperature. Most thermistors exhibit a negative temperature coefficient. Thermistor outputs are nonlinear and output is specified as the voltage range over a defined temperature range (x volts at 50°C to y volts at 0°C) (National Instruments, 1999). IC are sometimes referred to as a chip (that is, a device that contains a microelectronic circuit within a single package – a whole system rather than a single component – such as a resistor, transistor, etc). In terms of IC sensors it means that the device not only contains the ‘sensor’, but signal conditioning circuitry too (Wardle, 2001). IC temperature sensors are linear and their output is expressed as mV/°C. For example, a 10 mV/°C sensor will output 250 mV at 25°C (National Instruments, 1999). The functional elements of a monitoring system that receives the signal through a chain begins with the sensor that detects the physical variable value followed by the transformer, converter, logic and then the local monitoring unit. The information then passes through, either directly to an alarm signals or actuating elements, or via the main monitoring centre (Szabó, 1994).

Output from sensors must often be conditioned to provide signals suitable for the data acquisition system board. Signal conditioning accessories amplify low-level signals, isolate, filter, excite and bridge complete transducers to produce appropriate signals for the DAS board. Table 4 lists common transducers, their electrical characteristics and basic signal conditioning requirements (National Instruments, 1999).

According to Swanekamp (2000a), conventional sensors such as Pitot-tube type and ultrasonic devices are considered as intrusive and demanding compared to modern optical sensors which are designed to be more accurate and cost effective.

In 1993, Jensen and others, reported the results of experiments on four laser based instruments in 1.3 MW pulverised coal flames. The purpose of the project was to provide a set of measuring data that can be used to validate computer codes for the simulation of coal flames and to test laser equipment applied to measurements in pulverised coal flames. These were the:

- laser-doppler anemometry (LDA) for velocity measurement;
- particle velocity sizing (PVS) for particle sizing;
- laser-light sheet visualisation (LSV) for flame visualisation;
- coherent anti-stokes Raman scattering (CARS) for temperature measurement.

Jensen and others (1993) found that LDA measurements were applicable with good accuracy in the entire furnace. However, in large furnaces, where measuring is at greater distances, a water-cooled probe with the front lens mounts in the tip would be needed. The CARS equipment showed that reliable measurements could be performed outside the visual flame. However, the authors state that CARS required further development before the technology could be used in
large furnaces. The LSV technique was used to show the fuel distribution in the near burner field. It showed the local concentration of particles and gave a fast qualitative but no quantitative information. The PVS technique was found inadequate to make measurements in the 1.3 MW flame in its configuration. However, modifying the optical system and mounting the equipment in a water-cooled probe, thereby reducing the transmission length, could make measurement possible. Jensen and others (1993) concluded that of the four laser techniques tested LDA, CARS and LSV gave reliable results. However, only two of these techniques, the LDA and LSV, were ready for use in large pulverised coal furnaces.

Diode lasers, a new development in combustion sensor technology, use semiconductor diodes as their light source. They emit specific frequencies of infrared light and detect the type and quantity of molecules in a path. The laser beam shines through a collection of gases in a chamber and a diode laser sensor detects the frequencies at which some of the emitted light gets absorbed in transit. Diode lasers also use water as a thermometer as a water molecule can absorb light at more than one frequency, but how much it absorbs at each frequency depends on its temperature. Using diode-laser beam to compare absorption at two different, carefully chosen frequencies allows the inference of water temperature which approximates that of the entire gas mix (InTech, 2001b).

A modern signal reading technique based on the use of a diode laser, fibre optics and signal control adapts the laser light specifically to the gas that is being measured thus eliminating interference from other gases. The system is composed of three main components: sensors, hybrid cabling and a central unit. The sensors are most commonly installed in a cross-duct position where a mean gas is obtained from the measured path. Fibre optics convey the signals to and from the analyser which are located at long distances from the process. The fibre optic cables used are adapted into hybrid cables with insulation to make them robust and durable to withstand tough environments. Figure 8 gives a diagrammatic view of the measurement process. The laser unit is placed inside a central unit from where the laser light is conveyed to the measuring point via the fibre optic cables. After the light passes through the measuring path, the obtained measurement signals are returned to the central unit as optical signals. These are then compared with the equivalent signal from a reference cell built into the central unit which contains a known concentration of the gas to be measured (AltOptronic, 2001).

Advantages of this technique include (AltOptronic, 2001):
- in situ method that does not interfere with the process;
- real-time process control;
- response time below 1 s;
- automatic self calibration;
- minimal maintenance requirements;
- measurements in raw gas with high dust load and at high temperature;
- high precision;
- no interference problems with other gases.

In Japan, the Fiber Integrated Spectral-analysis System (FISS) was developed in 1995. FISS comprises optical probes, optical fibres, an optical measurement unit and a computer (see Figure 9). Following a series of pilot scale tests FISS was applied to a full scale 600 MWe boiler. The application of the system resulted in reductions in unburnt

<table>
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</table>

* since a thermocouple measures temperature in relation to that of a cold junction, corrections must be made for any variation in the temperature of the cold junction.
carbon-in-ash, flue gas O\textsubscript{2} content, ammonia and power consumption of fans. FISS was declared effective for monitoring flame quantitatively, boiler tuning and improving overall boiler efficiency (Miyamae and others, 1995).

For environmental applications, monitors for the presence of CO, CO\textsubscript{2}, NO and NO\textsubscript{2} (NO\textsubscript{x}) and SO\textsubscript{2} in power plants include optical techniques such as infrared (IR) absorption spectroscopy, chemiluminescence and flame ionisation. A new technology based on IR technology has been developed more recently. The nondispersive infrared spectroscopy (NDIR) technology enables the measurement of the concentration of each of several gases in a mixture. For more detail see Ropson and others (2000) and Weathers and others (2000). Rinke and others (1996) discuss the development of instruments in gas analysis that use ultraviolet (UV) and IR technology. Spelman and others (1999) report the design methodology for a non-intrusive, radiative emission based sensor that monitors NO concentration levels in the flue gas.

### 5.1.1 Fibre optics

**Fibre optics** are a new development in sensor technology. Optical fibres are made from either glass or plastic. Most are roughly the diameter of a human hair and they can be several kilometres long. Most physical properties can be sensed with fibre optics including light intensity, displacement (position), temperature, pressure, rotation, sound, strain, magnetic field, electric field, radiation, flow, liquid level, chemical content and vibration. A most important advantage over traditional copper wiring or cable is their ability to transmit data digitally and at much higher speed. An optical fibre consists of a core, cladding and coating. Light is transmitted along the centre of the fibre (the core), from one end to the other and a signal is imposed. Bandwidth, which is a main advantage of fibre optics, measures the data-carrying capacity of an optical fibre and is expressed as the product of the data frequency and the travelled distance (typically MHZ-km or GHz-km)

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**Figure 8**  Diagrammatic view of a modern signal reading technique based on the use of a diode laser, fibre optics and signal control (AltOptronic, 2001)

**Figure 9**  Components of the Fiber Integrated Spectral-analysis System (FISS) (Miyamae and others, 1995)
In power plants fibre optics current application areas are digital data communication between plant instrumentation and control system and sensing. Various aspects of fibre optics are discussed in detail by Bhatia and others (1998), Gulati (1998), Krohn (1998), Johnson (2000b) and Eklund and Rydholm (2001).

Despite recent developments, most of the sensors currently used in the power industry are of the conventional type. Therefore problems encountered with sensors continue to be the same, for example sensor drift. Smart sensors including fibre optic and wireless still depend on conventional sensing technologies to measure the process parameter. However, there is no new sensor technology that can provide drift-free and sturdy sensors that can tolerate the temperature, humidity and vibration environments in a coal-fired power plant. Objective assessment of the accuracy, response time, residual life and other instrumentation characteristics remains questionable today (Mitchell and Hashemian, 2000).

### 5.2 Analysers

Chemical composition is the determining factor in defining coal quality. Online analysis in coal preparation plants has become a common practice over the last 20 years or so (O’Connor and others, 1993). Moisture and ash content is monitored using microwave based meters that are based on dual energy transmission method. Elemental analysis cannot be performed by such meters. Increasingly stringent environmental requirements to reduce air pollutant emissions has led to continuous research and development of new technologies determine, online, for example sulphur content in coal. Online analysis of coal was the subject of a previous Clean Coal Centre report by Kirchner (1991). There are numerous ongoing research projects on online analysis of coal today. The subject will be visited in this section.

It has been established that a prompt gamma neutron activation analysis (PGNAA) technique can be utilised to obtain high accuracy online sulphur data. However, devices based on PGNAA technique are expensive and in many cases require a sampler to measure conditional material flow. This makes the technology difficult and economically unjustifiable (Bachmann, 2000).

Coal analysis with X-ray fluorescence (XRF) is a new development that bridges the gap between the PGNAA technique and the dual energy transmission method. An XRF analyser is mounted on a slow moving transfer belt that may be installed after a primary sampler or on a secondary reject belt. The radiation source is an X-ray tube. The tube irradiates the coal which travels underneath the analyser while a highly sensitive sensor detects the radiation coming back from the coal surface. The radiation detected by the sensor is characteristic of the composition of the coal. The technology has been installed at the US Tennessee Valley Authority’s (TVA) Paradise plant which has two feed belts each fitted with a mechanical sampling system. The primary sampler is transferred on a slow moving belt. The link between a data evaluation computer that was installed in the control room and the microwave moisture sensor was made with fibre-optic cabling. A series of tests were conducted in Nov 1999. Most of the data obtained was from a blend of 90% Western Kentucky coal and 10% Powder River Basin (PRB) coal. Calibration of the results for moisture ash and sulphur content were computed while calorific value was derived from the moisture and ash content, assuming a constant moisture and ash free calorific values. Measured precision calculation results using XRF technology are shown in Table 5. TVA expressed satisfaction with the results by ordering a second XRF-based, PCI XCA 75 technology. A data acquisition and specification software produced computed quality values and updates trend plots continuously based on spectra acquired every 180 seconds of coal flow. A user interface is provided with the system where the data are given in Microsoft Excel tables. These results can be connected to the plant PLC via an Ethernet link and using standard Excel spreadsheet functions (Bachmann, 2000).

Online coal analysis continues to be a major area of research and development in governmental institutions, industry and academia in all countries firing coal for power generation (Vourvopoulos, 2000). Belbot and others (1999; 2000; 2001) report on the development of a neutron generator-based, online coal analysis system that is capable of measuring the major and minor chemical elements contained in coal. A prototype analyser has been built that is self calibrating independent of the coal seam. The first commercial model continues to be developed in 2001. The system uses nuclear reactions produced from fast and thermal neutrons. It also utilises neutron activation of isotopes with half-lives of seconds or minutes. Measured parameters include sulphur, calorific value, ash, sodium, chlorine, moisture, carbon, oxygen, silicon, iron, calcium, aluminium and hydrogen. The online elemental coal analyser, ‘NUMAT’, operates on the principles shown in Figure 10 and offers (Vourvopoulos, 2001):

- analysis of coal-blends as well as single seam coal;
- no parameter resetting is required (that is no down-time) when coal feed changes from one seam to another;
- direct measurement of carbon and oxygen;
- measurement of calorific value without prior knowledge of the MAF heating value;
- determination of sulphur content for compliance with the US Environmental Protection Agency (EPA) regulations;
- online measurement of sodium with a 200 ppm minimum detection limit;
- measurement of other major and minor chemical elements in coal;
- reduced radiation hazard during maintenance as radiation is produced only when the analyser is in use;
- simple, easy to use touch-screen user interface;
- integrated computer control with diagnostics.

Incomplete combustion is costly as it reduces plant efficiency and increases carbon-in-ash as well as emissions. It can also be dangerous. This can be controlled by installing a continuous CO analyser on the outlet of a boiler and regulating the air to fuel ratio controls to maintain a constant outlet flue gas CO content (Heselton, 2000).
5.2.1 Unburnt carbon-in-ash

Fly ash is a fine, heterogeneous powder consisting of spherical crystalline- or glass-phase particles of variable alumina, silica, iron oxide and a number of irregular porous fragments of unburnt carbon or char. Fly ash carbon concentration is determined conventionally by loss on ignition (LOI). LOI is a procedure based on the weight loss of a fly ash sample when oxidised at over 700ºC. Inaccuracies in this procedure can arise due to the assumption that the oxidation of unburnt carbon is the sole cause of the measured weight loss. Fly ash carbon analysis can also be performed by an off-site laboratory using chemical or thermogravimetric analysis (TGA). Complex automated carbon monitors have also been developed. However, these are costly and do not necessarily offer improved performance (Waller and Brown, 1995).

The amount of carbon in fly ash indicates the efficiency of the combustion process. It also decides the fate of the fly ash by-product as the carbon content of ash is an important parameter in its sale. Waller and Brown (1995) reported the development of an offline instrument that detects carbon in fly ash using photo acoustic effect. In this system, a sample of fly ash is placed in a photo acoustic cell and irradiated by a near-infrared (IR) diode laser. The corresponding acoustic wave that arises from periodic heating and cooling of the sample is detected by a sensitive microphone. This is then processed through an amplifier and recorded by a PC-based data acquisition system (DAS). The strength of the photo acoustic signal is related to the concentration of unburnt carbon in the fly ash sample. The precision of the process is limited by the calibration standards. Waller and Brown concluded that this procedure of fly ash measurement provides the power generating industry a new instrument for the optimisation of coal combustion. The use of photo acoustic effects in carbon-in-ash monitoring is also discussed by Novack and Brown (1998). Experience of microwave based systems for measurement of loss on ignition in coal-fired power plant is reported by Trerice and others (1998).

5.3 Actuators

Plant components such as valves and dampers used to control the flow of fluids require a means of changing their position in order to carry out their function. This can be achieved manually by using hand-wheels or linkages, or a form of powered mechanism can be used to deliver the necessary operating torque or thrust. This device is known as ‘an actuator’. Automatic control of plant necessitates the fitting of the majority of plant correcting components with actuators. Actuators must be capable of providing sufficient power and speed to drive the plant correcting component under all operating conditions. Actuators have two main applications:

- two-position operation (also known as end to end operation), for example isolating dampers which are required to be either fully open or fully closed;
- modulating operation where the position of the correcting element is continuously variable, and in some cases accurately related to a demanded position, that is acting as a ‘positional servo’. A servo motor is a continuous positioning device that requires feedback to the motion controller to accomplish closed-loop control of positioning and velocity.

Actuators may be required to move a correcting element from
one extreme position to the other in a very short time or to accelerate the element and to change from one velocity to another in a particular time interval. Actuators may be divided into three categories including hydraulic, pneumatic and electric. Choice of actuator type is dependent on technical and economic requirements. For detailed information on actuators see British Electricity International (1991).

All actuators are operated by a form of demand signal. Control actuators respond to signals from:

- manually-operated controls mounted in the control room or on local panels, for example opening and closing of valves;
- the output of a closed loop automatic system.

Electro-pneumatic converters (I/P converter) convert the electronic commands from the DCS (generally 4–20 mA) to pneumatic form (usually 0.2 to 1 bar g) that can be used by a pneumatic actuator. This functionality can be incorporated in the positioner itself (an electro-pneumatic positioner) or a discrete converter may be used (Lindsley, 2000).

Micro-processor-based diagnostic technologies, developed over the last decade, can improve the performance of actuators, valves and dampers. New tools are being designed to diagnose and calibrate control valves (Power, 2001).

Control valves are sometimes the final control elements in the plant control loop. These devices modulate the flow of fluids along the various pipelines and in and out of the different plant processes, based on signals from the DCS. A control valve package includes the valve, an actuator and a positioner that work together, as an integral unit, to modulate flow. Major components of a valve include the body, trim and seat. The body is a pressure vessel with an orifice that allows for the flow of liquids and gases from tanks and piping. The trim consists of the orifice’s moving parts that modulate the flow of which the particular importance is the closure member which could be a plug, ball, disk or gate. The position of the closure member within the orifice dictates the amount of flow at any given time. The seat consists of stationary material anchored around the orifice. It provides a surface for the closure member to seal off flow when the valve is in the fully closed position. Seats are typically metal or a soft polymer. Control valves are either rotary or linear. An actuator provides the force for moving the closure member to open and close the valve. The positioner is a device for varying the actuator to assist the closing member of the valve to produce the desired rate of flow at any given time. It compares the actuator’s current position with its most recent impact signal. Then it adjusts the pressure applied to the actuator. This adjusting cycle continues. Modern digital valve positioners are capable of responding constantly to the control signal, many times per second, thus improving dramatically the speed and accuracy of positioning compared to conventional pneumatic or electro-pneumatic technology. Certain problems can cause rapid valve deterioration including excessive noise, vibration, cavitation, corrosion and erosion. Use of appropriate proprietary metallurgy and trim geometry can reduce these problems (Hauhia, 2000). Homoly (2000) and Smith (2001a) also discuss digital valve positioners in power plant applications.

Conventional upgrading of field devices to improve measurement accuracy and/or device reliability is achieved by using a combination of the following three approaches (Mawhinney and Menezez, 2000):

- using more robust transmitters that have a smaller rate of failure. For example a plant with 400 transmitters each with a mean time between failures (MTBF) of 100 years can expect about four transmitter failures each year. MTBF is a common measure of the expected life of equipment such as transmitters. Upgrading to higher quality transmitters with an MTBF of 400 years will reduce this to one failure each year;
- improving measurement accuracy and repeatability minimises conflicting operational indications that can contribute to operation judgement errors. For example to maintain the ratio between fuel and air flow rates users, in general, operate with an excess air ‘safety buffer’, that is a system with a 5% flow measurement uncertainty requires a minimum 5% safety buffer. Improving flow measurement accuracy from 5% to 1% will result in improved consistency and provide the user with an opportunity, with increasing environmental or safety risks, to improve combustion efficiency and reduce excess air and therefore reduce losses from unbalanced combustion;
- employing ‘best practices’ in device installation and maintenance. For example using long impulse lines in a differential pressure flow meter installation increases the likelihood of impulse lines plugging and freezing. Using shorter impulse lines or converting to a direct mount installation improves both measurement performance and reliability and usually reduces cost.

Most transmitter failures are detected by the output of the transmitter, either failing off-scale high or off-scale low. More difficult failures to detect are when the output of the transmitter is within normal range, and the measurement is failed on-scale. On-scale failures tend to be associated not with the transmitter itself but with the rest of the measurement system.

Today, ‘smart’ transmitters with diagnostic capability allow the user to diagnose field devices and increase plant availability remotely. An important feature for the successful application of these devices is if the diagnostic data are accessed via a PC online in the maintenance area or at a local console of a modern control system. Open digital protocols, such as Foundation Fieldbus, and asset management software are used by the user to access the information in an economic and convenient way. Transmitter diagnostics facilitate predictive plant maintenance.

There are three methods for plant maintenance (Mawhinney and Menezez, 2000):

- reactive: fixing instrumentation when they break;
- preventive: regularly scheduled maintenance to prevent failures;
- predictive: maximise performance time and fix the equipment just before they break.
Plants in general operate with a combination of reactive and preventive maintenance. Operators also use data from the DCS to predict measurement failures. According to Mawhinney and Menenez (2000), although this approach is good to predict the overall health of the boiler, a diagnostic located in a transmitter has a better chance of detecting a problem with the measurement system before it causes a failure. Such devices can contribute towards reducing unscheduled outages and improve overall plant availability. Frerichs (1999) also presents predictive maintenance methods adopted by power generating facilities to locate sensors, controllers and actuators that require attention/maintenance. Wilson (1999) examines performance enhancement solutions and strategies for reducing plant operating costs with reactive/preventive/predictive maintenance and use of intelligent field devices. Smith (2001b) discusses the combination of predictive and preventive maintenance methodologies and using diagnostic and performance data, maintenance histories, design data and operating logs to determine the condition of plant equipment.

5.4 Switchgear and distribution

Switchgear and power distribution boards are used for either energy distribution or motor control. They facilitate protection, switching, control and measuring of electrical components. Choice of instrumentation depends on their respective tasks, for example, safety disconnection, load switching, power switching, consumer switching and protection against over-current and personal hazards. In general, a combination of several devices (for example contactor and fuse) is used for a certain task. Other components include (Reichert and Ballat, 2000):

- contactors used for switching;
- thermal over-current relays to protect the drives from over-load;
- measuring equipment that detect data;
- singular devices that are used to operate and announce specific functions.

According to Reichert and Ballat (2000), disadvantages in using the above methods include their rigid combination and their insufficient accuracy especially of the protection components (such as thermal relays). Also, separate wiring is required for the transmission of a switching command or a measured value in each case which can lead to the operator making restrictions in order to reduce cost. Intelligent switchgear technology can alleviate these problems by providing:

- accurate protection parameters that are adaptable to changing process conditions;
- reduction in equipment variety by using universal system components;
- simplification of the complex point-to-point wiring by using a serial bus system for inter-communication and with an advanced process control system;
- self-monitoring and automated error messaging with simple handling and operation.

Development of a modern switchgear control system that can be programmed and configured for special tasks is discussed by Reichert and Ballat (2000).

5.5 Interfaces

The term ‘interface’ describes a device that provides the necessary connection and communication between all input/output (I/O) apparatus, including sensory and actuating mechanisms, and the controller. I/O is the transfer of data to/from a computer system involving communications channels, operator interface devices, and/or data acquisition and control interfaces. Interface types can be divided into four categories; wiring, digital, analogue (4–20 mA instruments) and serial communication. Figure 11 illustrates the move from conventional wiring practices to the modern serial communication interfaces (Offner, 2000). Wireless communication is a very recent development in I&C and will not be discussed in this report.

5.5.1 Wiring/cabling interfaces

Wiring interfaces join devices with high-density connectors to discrete termination points. A plain PLC or controller connection is achieved with a wiring interface. Any additional functionality is best described by a digital interface for any digital (or discrete) signals. On/off signals that input to, or output from, a controller must invariably adapt in some way or operate at different voltage.

5.5.2 Digital/analogue interfaces

Digital interfaces supply on/off motion capability and are available in either electromechanical or solid state as relays or power contacts. If a varying signal of a 0–100% range is required in a control system, analogue interfaces provide the link. Temperature, current, voltage, power, frequency, pressure, flow, power factor, speed and load-cell outputs are all signals that require higher resolution than simply on or off capability. Most control loops are usually converted to a standard 4–20 mA and, although other signal levels are currently in use, 4–20 mA continue to represent the accepted standard relied on for exact measurements. Analogue processing circuitry is complex. While, modern PLC I/O cards allow 32 digital signals, only eight 4–20 mA loops are possible in the same size package. Where the analogue card is designed to process frequency, its maximum handling capacity is limited to four channels. An analogue interface allows differing signals to be converted to the standard 4–20 mA input card. Since these signals can include temperature, pressure, power and frequency and are application-dependent, the various component signals represent the final signal with a 16–mA range (4–mA is the zero level; 20–mA equals 100% level and 0–mA indicates an open circuit or line break) (Offner, 2000).

5.5.3 Serial communication

Serial communication allows modern controllers to
Plant instrumentation

a) conventional wiring practices

controller

terminal blocks

b) system cabling approach - wiring interface

front adapter

active module

passive module

c) interposing relays - digital interfaces

digital signals include:
TTL, 5 VDC, 12 VDC,
24 VDC and 120 VAC

controller

electro-mechanical and solid-state relays

d) signal conditioning - analogue interfaces

analogue signals include:
0-20 mA, 4-20 mA,
0-10 V, ±10 V,
0-50 mA

controller

signal conditioners

e) serial communication - serial communication interfaces

controller

serial communications include:
TTY, RS-232, RS-422 and RS-485

communicate with high-level control systems. A module is often used to assist in converting standard signals to a fibre optic link or the interfacing device. There are numerous standard communication protocols in use, irrespective of a serial communication signal’s own protocol, thus allowing conversion of the serial language between any two devices.

A reliable and secure communications system between the devices and the control centre/room is of utmost importance in utility plants if power management and control decisions as well as actions are to occur on time and efficiently. Data communication failure can result in major problems in a power generating facility. There are many communication systems available and I&C suppliers recommend, supply and design the appropriate system for each plant. These systems use open digital protocols to transmit information. Recent industrial communication/networking systems include Foundation Fieldbus, DeviceNet, Profibus, Modbus, Interbus, AS-i, Ethernet, the transmission control protocol/Internet protocol (TCP/IP) and others (see Table 6). Brownlee and Lemanowicz (2001) describe several of these open standards intended for different applications within an I&C system. InTech (2001c) and Pinto (2000) provide information on how to choose and overlapping between some of these technologies.

Fieldbus Technology

The introduction of the Fieldbus Foundation technology has led to a redistribution of automation functions. A bus is the group of conductors that interconnect individual circuitry in a computer. Typically, a bus is the expansion vehicle to which Input/Output (I/O) or other devices are connected. Fieldbus technology, is an all-digital, serial, two-way communication system used to connect process measurement/value, such as sensors and actuators, and controllers. At the basic level in the hierarchy of plant networks, it serves as a local area network (LAN) for the instruments used in the control process and has a built-in capability of distributing the control application across the network. Benefits of Fieldbus technology include remote communications with the information network, device condition trending, intelligence to calculate specific parameters and self diagnostics of field devices. The main reason for slow application of Fieldbus technology is the lack of an international Fieldbus standard and despite the ratification of Foundation Fieldbus as part of the European Committee for Electrotechnical Standardisation (CENELEC) standards for field communication in 1996 (Child, 1996).

Fieldbus technology relocates functions from the automation system to the field devices. This relieves some of the burden on the automation processor and is also of advantage in the development, configuration and commissioning phases. In addition, a large percentage of customary cabling is eliminated. In the long term, Fieldbus is expected to replace existing 4–20 mA analogue standard. In Fieldbus technology, simple functions and particularly those that can be directly assigned to field components are relocated to the corresponding field unit (see Figure 12). This reduces some of the tasks of the automation processor. Fieldbus assumes...
the task of communication and reduces the amount of required cabling. Function relocation results in a downsizing of the automation system. The ability of Fieldbus to transmit information such as transmitter scaling, maintenance history and operational status provides plant operation and maintenance personnel with useful data for improving maintenance practices.

Fieldbus technologies most widely used are the ‘Profibus’ technology as per EN 50170 which is the European standard and supported by the Profibus User Organisation (PNO) and suppliers such as Siemens AG (Germany). The Fieldbus Foundation FF technology, advocated by North American DCS vendors such as Fisher-Rosemont Inc (USA) and ControlNet International, promoted by Rockwell Automation (USA). Suppliers of the Fieldbus technology in general provide products that support more than one standard (Swanekamp, 2000a; Köhler and König, 1997). For detailed information on Fieldbus technology visit their website www.fieldbus.org.

Control networks, such as ARCnet and ControlNet, link automation processors such as DCS and PLC. Field networks such as Foundation Fieldbus, DeviceNet, Profinet, Modbus and others replace point-to-point wiring of remote I/O, sensors, actuators and other I/O devices with a multi-drop, bus wiring scheme. Ethernet-based-networking is a new development in process control especially at the field.
networking level. Main advantages include the low cost of Ethernet network cards and their high speed and reliability combined with Ethernet’s widespread familiarity, as it is the technology used to link desktop PCs to local area networks (LAN). The main disadvantages of using Ethernet in field devices at the sensor and actuator level is cost and power consumption of the Ethernet interface (Caro, 1999).

Figure 13 shows choice of networks for information, field device and control levels tasks. Standards and application of Fieldbus technology and Ethernet are discussed in greater detail by Noble (2000).

5.6 Plant safety

Explosions are a hazard that is ever present in coal combustion due to the presence of gas and dusts at high temperatures. Thus there is an absolute requirement for specialised equipment and disciplines that have to be used and followed to prevent such occurrences. There are also many regulations with regard to plant safety that have to be adhered to. In coal-fired power generation, instrumentation are used to monitor the combustion and other process parameters such a temperature, pressure, flow and level. These and other specialty instruments come in contact with combustible and highly explosive materials such as combustible dust.

Sensors in sensitive areas have to be protected by means of using explosion-proof designs, intrinsically safe construction or use of purge or pressurised housing. Instruments that have a low probability of actually coming in contact with gas or combustible dust may be protected by using techniques such as encapsulation/hermetic sealing or non-sparking design.

Explosion may be prevented in many ways including the limiting of the amount of electrical energy available in hazardous areas. Controlling electrical parameters such as voltage and current requires the use of energy limiting devices known as intrinsically safe (IS) barriers. These limit the levels of power available in a protected barrier thus eliminating the possibility of a spark or excess electrical heat.

Figure 14 Set-up of a typical and an automated facility with IS systems and a latest generation IS barrier combined with I/O hardware (Babiarz, 1998)
occurring. IS barriers were first used at the turn of the 20th century in the coal mining industry in England and have become a commonly used protective technique in Europe. IS was introduced into code of practice in the USA in the last decade (Johnson, 2000a).

Figure 14 shows the set-up of a typical and an automated facility with the following combination of inputs and outputs (Babiarz, 1998):

- digital inputs (D/I) – 50%;
- analogue inputs (A/I) – 25%;
- digital outputs (D/O) – 15%;
- analogue outputs (A/O) – 5%;
- other I/O (such as thermocouples or RTDs) – 5%.

These I/O are controlled by PLC connected through I/O hardware, intrinsically safe barriers, marshalling cabinets and extended wiring to sensors in hazardous areas.

Babiarz (1998) reported on innovations including two types of commonly used barriers. Passive devices that require grounding for safety or isolated units which contain additional electronics for isolation and signal conditioning. More advanced intrinsically safe products reduce total installed cost by combining IS barriers with I/O and eliminating extra hardware. These new systems are called intrinsically safe remote I/O. These can be mounted almost anywhere in hazardous or ordinary locations reducing wiring requirements and terminations (see Figure 14). Signals are processed by remote I/O electronics and transmitted to a memory module through a communication link that is normally mounted on the backplane that holds the electronics. The signals are updated every 5 ms and stored for collection and transport to the main control system. The IS remote I/O system is connected to a controller and data are relayed back and forth by simple two-wire or fibre optic link. These systems use digital communication and provide faster and more accurate readings and can use the latest serial communication technologies.
6 Control

The I&C system provides the manual and automatic control to start up the plant. Once plant is operational and generating power, the automatic closed loop (modulating) control is engaged. Subsequent control is effected by variation of the desired value setting of the loops, either by an operator or by an automatic ramp function. In modern power stations, the sequence and modulating control is implemented by computer-based systems. To provide reliable service, computer systems employ redundancy and distribution which reduce loss of information to the operator in the event of equipment fault. Measurements of the various physical qualities of the flue gas such as temperature, acidity (pH), humidity and pressure are used as a basis for adjusting the many process devices including dampers, valves and nozzles. Actuators were discussed in Chapter 5. This feedback of information is used to control the process, manually or automatically. For example gas conditioning towers typically measure the exit temperature and use that measurement to adjust valves automatically to control the flow of water to the injection nozzles. This chapter is based mainly on British Electricity International (1991), Platt (1998) and Lindsley (2000).

6.1 Theory

Control in a process including coal combustion is made possible by a measured variable signal being ‘fed back’ from the process to the automatic control system or operator. The appropriate corrective action is then taken by comparing the measured value with a desired value. Data are hence input/output to and from the process to the control system. The measured value is then subtracted from the desired value to produce a deviation based on which the corrective action is determined. The control action can be taken by the computer system (automatic control) or the operator (manual control).

The simplest boiler control system involves ‘open loop’ control where the operator adjusts a regulating element either because the measured value signal is unavailable or is suspect. The main elements in manual, open loop, control of plant includes:
- connecting cable from the desk controls to the actuator and regulating element;
- plant combustion process that is being regulated;
- measured value signal transmitted from the plant;
- the operator.

Where an automatic control system is monitoring the performance of plant, by observing transmitted signals and operating plant controls in response to these, ‘closed loop’ control is being performed (see Figure 15).

Figure 16 shows the elements in a ‘closed loop’ (feedback control) system. A control algorithm (controller or regulator) compares the feedback signal with a desired output and calculates the control action to be taken in order to have the feedback signal as close as possible to the desired output value. In some cases an additional sensor can be used to measure one of the disturbances. The additional information can also be fed to the controller (see Figure 16). Where this is applied the controller is able to change the control action

![Figure 15 Diagrammatic representation of a closed loop control](British Electricity International, 1991)
even before the disturbance makes the output deviate from
the desired trajectory which would not be the case if only
feedback control was used (Desbiens and others, 1999).

In any process, a delay occurs between the initiation of a
change and the response to that change at another point in a
loop. This characteristic can determine the nature of the
control action which has to be applied. One type of delay
occurs most frequently where a change is transmitted, from
one point in the loop to another, by a part of the loop which
is flowing or moving. This type of delay appears as a straight
time lag between the change and the response to it and is
identified as a ‘distance velocity’ or ‘transport’ lag. The delay
is known as ‘dead time’ involving a periodic change to which
the response is also periodic but shifted in phase. Where there
is capacity in a system, such as mass having thermal capacity,
the flow into and out of it is usually subject to a resistance,
for example in pipes and valves. In this delay, at some time
following change initiation the flow changes and after a
further period of time (time constant) the flow will have
changed further. This type of delay is known as a ‘first order’
or ‘exponential’ or ‘simple’ lag. Figure 17 shows the system
response to a step change combination of a ‘transport lag’
and a ‘first order’ lag.

A ‘deadband’ or ‘dead zone’ is a finite band of measurement
for which no controlling output is produced. A ‘lost motion’
or ‘backlash’ in actuating mechanisms is a common reason
for such a dead zone. If there is a deadband, response to an
input signal will be subject to a delay which is a function of
the rate of change of the measured parameter and the size of
the deadband. In modern, digitally controlled applications a
deadband, wider than the inherent resolution obtainable with a measuring and controlling device, is deliberately imposed. This applies to both positive and negative values of the deviation. When the true value of the deviation, of either sign, is less than the deadband, the deviation is registered in the control system as null (zero) and the deadband is imposed as in Figure 18. When the true deviation exceeds the deadband, the control system sees the value as the difference between the deviation and the deadband. Within the deadband, the control system sees this value as zero too.

Such a deadband is applied to the input of a control algorithm and is referred to as an ‘input deadband’ (British Electricity International, 1991).

The three forms of control actions which combined together result in the two- and three-term control algorithm are proportional action (P), integral action (I) and derivative action (D) (collectively known as PI and PID). Proportional determines speed of response of the loop, integral (also known as reset) forces the loop to line out at its set point (eliminating offset or droop) and derivative action which enhances the process stability margin which, in turn, permits the controller gain to be increased to obtain a faster response (Smith, 2000).

Combining the PID actions in the control system results in the following equation:

\[
V = -\frac{G}{H} \Theta - \frac{GT_D}{H} d\Theta/dt + V_0
\]

This form of algorithm is known as absolute or whole value algorithm. Where V is the output control signal, G is the gain of the controlling element, \( \Theta \) is the input deviation signal, \( V_0 \) is the constant value of the output at some time \( t \), \( T_1 \) is known as the ‘integral action time’ as it represents the integral action over a period of time and \( T_D \), known as, the ‘derivative action time’. In the equation, an output V is generated by performing an operation, or a combination of operations, on an input variable \( \Theta \). As the gain G, appears in all three components, it can be put in front of the bracket, and each of the three constants G, \( T_1 \) and \( T_D \) can be varied independently without affecting the effective value of the other two. This is important for tuning a control system to obtain a required performance. A controller which generates a control algorithm of the above form will accept either an electrical or pneumatic input signal. The range of the signal will correspond to the range over which the controlled condition is likely to vary in normal plant operation. The output signal can also be either electrical or pneumatic and the range of the signal will in general correspond to the full stroke of the actuator. The arithmetic relationship between output and input is determined by the scaling of the gain G. Most control systems nowadays are required to operate over a wide range of generated electrical load. Provision has therefore to be made for adapting the values of the optimum gain, integral and derivative action times to the MW capacity being generated, or some other parameter which is representative of load (British Electricity International, 1991).

Transfer function is the relationship between the output and input of an element that includes both gain and phase change of that element. The transfer function of a number of elements in series is the product of the individual transfer functions of the elements. Control transfer function = \{controller transfer function\} x \{interface transfer function\}. Where the actuator interface acts as an integrator, the controller transfer function is of the form:

\[
V = -G \left( 1 + \frac{(T_1 + T_2)s}{1 + T_1 T_2 s^2} \right) \Theta
\]

(that is, a combination of proportional, derivative and second-derivative action, PID). This form of algorithm is known as incremental.

One of the main advantages of modern electronic technology and modern computing techniques is that modern control systems can generate output commands that conform faithfully to the algorithms developed for plant control. Other advantages include robustness, reliability, low power.

---

**Figure 18** Input and output signals deadband
(British Electricity International, 1991)
consumption and minimum drift. Eki and others (1999) presented a comparison between the various control methods for a thermal power plant main control system.

6.2 Control system design

The main control system design may be one of the following (Lindsley, 2000):
- boiler following control (demand signal fed primarily to the turbine);
- turbine following control (demand signal fed primarily to the boiler);
- co-ordinated unit control (demand signal directed to both boiler and turbine).

In boiler following control mode, the power demand signal modulates the turbine throttle valves to meet the load while the boiler systems are modulated to keep the steam pressure constant (see Figure 19). In such systems, the turbine responds first to any changes and the boiler control system reaction follows to increase or reduce the firing to restore steam pressure to the set value. The boiler control system involves monitoring combustion and manipulating all variables in order to achieve maximum efficiency and minimum emissions. The system covers many functions including primary air inlet dampers control, furnace pressure and oxygen control, throttle pressure control, air-, steam- and fuel-flow controls, feeder speed and exhauster control, steam temperature control, reheat temperature control, drum level control and furnace pressure control. In turbine following operation, demand is fed directly to the boiler and the turbine throttle valves have the task of maintaining a constant steam pressure (see Figure 20).

The turbine control system has three main functions. The first is to control the speed and rate of acceleration of the turbine during start-up from zero to sync speed, typically 3600 rpm in North America and 3000 rpm in Europe. Secondly, control the power out and speed of the turbine after it is connected to the electrical grid. Finally, provide for a safe shut-down or trip of the turbine when any of several potentially dangerous events occur. The most dangerous being over-speeding of the turbine which can cause a complete failure of the turbine blades and rotors. The turbine control system achieves its purpose by manipulating valves that admit steam into the turbine (Taft, 2000). With co-ordinated unit control, power demand is fed to the boiler and turbine in parallel (see Figure 21). This is considered a sophisticated technique which requires the use of fast, powerful and versatile computer systems. Such a main control system design demands considerable knowledge of the details and limitations of the major plant equipment. In addition, a co-ordinated unit control system has to match the configuration and characteristics of the power generating facility due to the complex nature of plant operation.

6.3 Pneumatic control

In pneumatic control, clean and dry compressed air is the medium used for the control and measurement of plant

![Figure 19 Boiler following control system (Lindsley, 2000)]
Figure 20 Turbine following control system (Lindsley, 2000)

Figure 21 Co-ordinated unit control system (Lindsley, 2000)
Instrumentation and control in coal-fired power plant

6.4 Electronic (analogue) control

Electronic controllers receive an electrical signal of a measured value (usually 4–20 mA DC) that is transmitted from the plant. This is compared with a set value that is either generated within the controller or transmitted as an electric signal from another device. The controller then produces an output control signal that conforms to equations such as discussed in Section 6.1. The control coefficients including proportional band, integral action time and derivative action time (PID), can be adjusted with the use of trimming controls mounted on the case of the controller.

There are two types of controllers:

- single module controllers, also known as single loop controllers, in which all functions including auto/manual transfer and input signal conditioning are performed within a single electronic module that can be mounted on a desk or panel;
- modular control systems where a range of different modules that provide a function or a group of functions needed for control are connected together as appropriate. The modules are mounted in a standard rack usually located remotely from the operator control units and indicators.

A traditional controller generates the appropriate control algorithms with integrated circuits, in particular with operational amplifiers. Modern controllers generate the control algorithms with microprocessors.

6.5 Digital (microprocessor) control

Development of the microprocessor and user friendly operating systems in the 1970s resulted in the increasing use of digital control in power plants. At that time, commercial hardware and software available to the power industry were few. This led to some utilities adopting their own pattern of digital control hardware and software including programming languages supported by the operating system and enabled their engineers to write their own programmes. Thus, ‘the Control Centre’ emerged comprising many computers (control centres) that carried out several control loops on boiler/turbine generating unit. The following criteria were adopted for allocating loops for control centres:

- no control centre may be dependent on measured value data received from another;
- manual control of all loops served by any one control centre must be within the capability of the operator;
- all software used by an individual control centre resides in the memory of that unit and all signals associated with that software are connected to the input/output hardware of that control centre.

Control design has to incorporate the necessary methods for interfacing with pneumatic, hydraulic and electronic actuators.

In the 1990s, suppliers began to offer plant automation...
systems built on standard operating systems with open architecture such as Microsoft Windows NT and UNIX rather than supplier proprietary software. In the year 2001, the Linux, free, open operating system was used for the first time to convert key information technology systems in the Southern Illinois Power Cooperative’s, Marion III, 272 MW coal-fired power station (Swanekamp, 2001). Linux is based on the C programming language and allows writing a C or C++ and control I/O through many drivers including parallel and serial I/O, Modbus, Devicenet, Profibus, Interbus, CanOpen, ControlNet and AS-i (InTech, 2001d).
The main areas of control theory application to be discussed in this Chapter are mill control, fan control, feedwater control and finally valve control.

### 7.1 Mill control

Coal-fired power plants utilise several mills each of which has its own control sub-system. An integral part of boiler control system is its ability to handle applications where a single controller sends commands to several sub-loops in parallel, and where any of the sub-loops may be isolated from the controller. In coal-fired power generation, each mill has to be operable under manual or automatic control independent of the others. This is a challenging task for the plant DCS. The master demand is fed in parallel to several sub-loops, one for each mill group. On start-up all of these are under manual control. When the mill reaches a throughput of about 50% of its capacity and automatic control becomes possible the master demand may be switched into service. Up to that point, the control system is unaware of which mill group is to be transferred to respond to the master signal. Also each group may be operating at a different throughput from any other.

During the loop transfer from manual to automatic control or vice versa, the plant must not be subject to sudden disturbance. A bumpless transfer is where the changeover from a manual to automatic signal is equal. To achieve this a common practice is to make the controller output follow, or track, the manual demand so that when the system is switched to automatic the signal to the actuator is not subjected to a sudden change. Where a single controller positions a single actuator such a technique is feasible, however, where one controller commands several sub-loops other techniques must be adopted. A solution in such conditions is ‘freezing’ the master demand while the transfer is effected and gradually ramping one signal up or down to match the other. This is a problem not usually recognised by DCS suppliers but is necessary to resolve if the system is to operate smoothly and with minimal operator intervention. Where a solution is provided, the DCS manufacturer are required to demonstrate its applicability on an existing power plant (Lindsley, 2000).

Coal mill manufacturers agree to defined performance guarantees for coal mills. A control strategy has to be applied to each mill that feeds the boiler. Demand is fed in parallel to all the mill sub-systems with facilities for biasing a signal to any one of them with respect to the others. Geometry of a mill, the amount of coal in the mill and the volume of air flowing through it determine the drop in pressure within the mill. High pressure drop within the mill may be experienced due to a high coal load in it or a high air flow through it or a combination of both (see Figure 23). The air flow rate bears a square-law relationship to the differential pressure across the mill. The differential pressure across a restriction, such as a flow nozzle or an orifice plate, also has a square-law relationship with the air flow. The characteristic curve therefore relating the mill differential pressure and primary air differential pressure is a straight line. This is known as the ‘load line’ and is specific to a given design of mill operating under defined conditions. The manufacturer defines the correct load line parameters and scales for a given design of mill (Lindsley, 2000).

According to Lindsley (2000), some control systems operate on the principle of comparing the two differential pressure signals and modulating the feeder speed to keep the relationship between the two in line with the load line. Variable ratio gearboxes or variable-speed motors can be used to vary the speed of the feeder. In some control systems, the speed of the feeder data are fed back to the master system to indicate coal flow and thus provide a degree of closed-loop operation. Type of coal is not a parameter that such a system deals with. Another disadvantage with such systems is that they cannot deal with changes in the primary air flow. If the primary air flow changes such a system has to wait for a change in steam pressure before a correction in the system can be made. One method of overcoming such a problem is to provide closed-loop control of the primary air flow. In such a control system, changes in primary air flow are detected and immediate reaction is taken. Flow control dampers are adjusted to correct air flow and subsequently disturbances to steam production in the plant are minimised. As in the previous system, a feeder speed signal that represents fuel flow is fed back to the master system to provide closed-loop correction of feeder speed changes. In both the systems discussed here the control system adjusts the feeder speed after a change is detected in the primary air flow. This can lead to delayed response to changes in demand. Figure 24 shows a closed loop control system that adjusts the feeder speed in parallel with the primary air flow. The diagram also shows some practical refinements such as a
the use of two actuators can increase costs such a set-up mechanically and positioned by a single actuator. Although cold air. In some system set-ups the two dampers are linked to control the hot air flow and the other to control the flow of

Pressurised mills require two dampers for this purpose, one technique used in both pressurised and suction mills. streams to achieve the required temperatures, is the control

fires and explosions in the mill. Mixing of hot and cold air

efficiency is reduced while high temperatures can result in

Temperature of the air within the mill must be maintained within specific limits. At low temperatures combustion efficiency is reduced while high temperatures can result in fires and explosions in the mill. Mixing of hot and cold air streams to achieve the required temperatures, is the control technique used in both pressurised and suction mills. Pressurised mills require two dampers for this purpose, one to control the hot air flow and the other to control the flow of
cold air. In some system set-ups the two dampers are linked mechanically and positioned by a single actuator. Although the use of two actuators can increase costs such a set-up allows for a greater degree of operational flexibility since it allows for the opening of each damper to be biased with respect to the other from the central control room. A sophisticated control system or the operator is thus enabled to optimise mill performance and maintaining the mill temperature at the correct value. In suction mills, only one damper needs to be adjusted to admit cold air into the stream of hot air being drawn into the mill by the exhausters (Lindsley, 2000).

Salvador-Camacho and others (2001) discuss the methodology and results of a milling optimisation programme developed in Spain. The scope of the programme includes the operational optimisation of different pulverisers (bowl and ball) grinding a variety of coal types. The ultimate objective of the programme is to reduce operating costs and environmental impact of coal-fired power generation. The EMIR (Equipo de Muestreo Isocinéético Rotativo –Rotating Isokinetic Sampling System) technology, that gives a more accurate and easier characterisation of coal and air supplies to the boiler, was developed. Research continues to develop specialised software tools for milling system optimisation by providing online reliable evaluation and advice to plant operators.

7.2 Fan control

Throughput of two fans operating together can be regulated by a common controller or by individual controllers for each fan. Single controllers cannot ensure that each fan delivers the same flow as its partner. However, such a configuration is simple to tune compared to two controllers which interact and make optimisation more complex/difficult. Where applicable, a cross-limited system is the simplest set-up for driving the fans. However, with multi-burner installations, the flow must be controlled for each burner or group of burners. The desired-value signal for the pressure controller is derived from steam flow based on a characteristic defined by the system design. This is carried out so that the pressure in the windbox changes over the boiler range. A maximum selector unit ensures that the pressure-demand signal does not fall below a predetermined minimum value (Lindsley, 2000).

The control system responsible for the draught (fans) operation in a power plant must ensure that an adequate air supply is available for the combustion of the fuel and that the combustion chamber operates at the pressure determined by boiler design. Profile of air and gas pressures through a steam generating unit are shown in Figure 25. Another function of all plant fans is the purging of the furnace in all conditions when a collection of unburnt coal or combustible gases could otherwise be ignited accidentally. Such operations are required prior to light-off of the first burner when the boiler is being started, or after a trip. Figure 26 shows the pressure profile in a balanced draught unit before and after a trip. Notice that the magnitude of the drop in furnace pressure at the peak of the excursion is higher than those at the FD fan discharge and the ID fan inlet. This is because of the difference in flow conditions at the time of the excursion.

The furnace draught control system must ensure that forced draught fans operate in balance with the induced draught fans
Instrumentation and control in coal-fired power plant

7.3 Feedwater control

The objective of feedwater control is the safe and cost-effective supply of enough water to the boiler to match the evaporation rate under the widest practicable range of plant operating conditions. The three factors that affect the supply of feedwater are steam flow, feedwater flow and the level of water in the drum. The level of water in the drum provides an immediate indication of the water contained by the boiler. The target of the feedwater control system is to keep the level of water in the drum at approximately the midpoint of the vessel. According to Lindsley (2000) this can be achieved by:

- maintaining a flow of water into the system at a value which matches the flow of steam out of the system. In this case the flow is controlled by maintaining the rate of water flow through a valve at a figure that is directly proportional to the demand signal from the controller. A disadvantage of this system is that it only matches the...
steam- and feed flow rates. If at the outset the drum level is below the desired value that is where it will remain. This is because the feed into the boiler will always match the steam flowing out of it and there is no mechanism for introducing the small excess of feed over steam or the slight deficit, that is needed to correct the drum level error; or

- adding a third element to the previous system which is a measurement of feedwater flow. In this set-up a drum-level controller is trimmed by a signal representing the difference between the feed flow and steam flow signals. A gain block is introduced to compensate for any difference between the ranges of the two transmitters. In most cases the steam flow and feed flow signals will cancel out and the drum level controller will be modulating the feed flow to keep the level at the set point. The application of the feed flow measuring element will compensate for any variations in feed flow, whether these are due to pump characteristics or other factors. Such a system is recommended despite being more costly where accuracy of control is required.

Internal tube corrosion and deposition are major causes of forced outages, hence all plants must use a feedwater and boiler-water treatment and control system. Water treatment and corrosion problems are discussed in detail by Singer (1991) and Jonas (2000). The relationship between cycle thermodynamics, chemistry and corrosion are useful in identifying trouble spots. They can be illustrated in a Mollier (enthalpy versus entropy) diagram (see Jonas, 2000) that shows cycle parameters including the steam expansion line for a typical fossil fuel fired power plant. Feedwater/boiler water control to reduce corrosion and deposition is achieved with oxygen control and pH control. Oxygen control is the most important element in feedwater control. Oxygen concentration must be regulated to minimise the formation of pre-boiler corrosion products that become deposited on the heat-transfer surfaces in the boiler. Small deviations from the recommended boiler water pH limits will result in tube corrosion. Large deviations can lead to the destruction of all furnace wall tubes in a very short time. In order to achieve the required oxygen and pH level controls, a comprehensive water analysis programme must be maintained to assure that feedwater and boiler water chemistry is within prescribed limits. Although automatic and continuous analytical instruments are preferred where such analysers are unavailable or not operational water tests must be conducted daily for pH and oxygen in the feedwater and for pH, PO₄ and total solids in the boiler water. A condenser leak-detection system is of particular importance in any high-pressure steam cycle. Many potential tube failures can be avoided by continuous monitoring of the control of the water and steam systems throughout the power station (Singer, 1991).

A tube-temperature monitoring system monitors the metal temperatures of superheater and reheater tubing. The measured temperatures are compared against predetermined alarm levels which are based on oxidation limits and stress rupture limits. Increasing the temperature of a given superheater element by just 12°F (6.7°C) can reduce its time-to-failure from 115,000 hours to 76,000 hours. Based on the

7.4 Valve control

New digital valve controllers are available, featuring two-way digital communication, proportional-integral-derivative (PID) control and valve diagnostics and system integration. These devices depend on microprocessors to perform a servo-control algorithm for either the valve or the positioner. Modern computers can optimise final-control functions; characterise smart final-control devices at the valve; provide diagnostics for electronic to pressure (I/P) converters; electronics modules, valves and communications systems; communicate with the DCS system and store valve-specific maintenance information (Giovando, 2000).

According to Swanekamp (2000a) these controllers are becoming more widely used in the market with the increasing acceptance and use of Fieldbus technology. As more processing power is placed in such field devices, Fieldbus is expected to gradually displace some control functions that are currently performed in the DCS which will result in a major shift in future control system architecture. It is expected that the digital valve controller market will increase from ~122,000 units to over 350,000 units by the year 2005. A benefit of using digital valve controllers is that plant technicians can conduct signal-response step tests within 10 minutes compared to substantial offline time required for disassembly and visual inspection of conventional or standard valves (Swanekamp, 2000a). The successful use of digital valve controller in the 41 year old lignite/gas fired Lewis & Clark power plant in Montana (USA) is discussed by Swanekamp, 2000c).
8 I&C data management

The vast quantity of information from the plant monitoring and control systems of plant operational data are stored in large databanks. The data are mostly archived for long term trending and analysis. More recently, optimisation processes have been using the stored historical information and feeding it into knowledge based, expert systems to fine tune the combustion process, reduce emissions and improve overall plant performance and hence profitability. Neural networks are also used to build models that can be trained using experimental input and output or actual data from the plant databases. Data management of the I&C system itself, that is the system quality assurance, I&C reliability consideration, evaluation of I&C hardware, obsolescence of the I&C system and designing for replaceability, and contract strategies for procurement of I&C systems are not covered in this report but are discussed in detail by British Electricity International (1991).

8.1 Data sources

The large amount of available data are from a variety of sources and have variable accuracy and frequency. The data can be (Cliff and others, 1996):

- measured: can take the form of a temperature derived directly from operating equipment through to an accounting invoice for the price of coal. The data can be measured in real time, on a predictable schedule or an ad hoc basis. Accuracy of the measured data depends on the accuracy of the measuring device as well as the timeliness of the measurement;
- estimated: typically used where accurate measurement is either difficult or not justifiable. The estimating technique may be based on other measured variables, historical data, or at random. Accuracy of the estimate is typically adequate for its use;
- forecast: include predictions of load demand, maintenance and overhaul requirements, weather forecasting and so on. The data are typically forecast for a given reporting period (shift, month, year) and is based on past experience and the measurement and observations of external factors such as current and predicted economic activity;
- interpolated data are used to complete the gaps of data that is measured on a period basis or is interpreted from other measured data. Values for the various measurements are interpolated from the measured data for times between actual measurement;
- calculated data are derived from all other data sources and can include production levels, control algorithms, emissions predictions and other information used in power plant operation. Because calculated data are derived from all other data sources, it relies on the accessibility and accuracy of all used data for its value.

In a coal-fired power station the data comes from sensors and measuring devices, observations and manual data determination, human actions and third party sources. The data reside on a number of platforms including the PLC, DCS, remote terminal units and logs and spreadsheets. Maintenance and engineering data resides in log books, reports and spreadsheets on stand-alone or small networks of computers. Accounting inventory and personnel data in general reside on another network of computers. Management information such as long term rate and load forecasting, capital expenditure budgets and multi-plant or network-wide data and forecasts reside in files, reports and on the operator’s PC which may be remotely located. The evolution of data and communications standards has resulted in the development of ‘open’ system architectures that facilitate the integration of all the disparate data sources. Such an integrated system would allow for effective power plant management systems and improve plant financial performance (Cliff and others, 1996; Lobner, 1999).

8.2 Retrieval and display

Operator interfaces in process control began as levers and valves. During the twentieth century complex electrical switches and dials supplanted past operator interfaces. Today the operator workstation is where the data are reviewed. It consists of screens on which plant information can be observed, keyboards or ‘mouse’ devices that allow the operator to send commands to the system. Printers are used for data retrieval in the forms of graphics or to provide operational records, a log of all plant events or alarms.

Cathode-ray-tube monitors (CRT) and the occasional touch-screen monitor have been used in control rooms for the past 20 years (Lechleitner, 2000). A touchscreen is a computer input device that enables users to make a selection by touching the screen, rather than typing on a keyboard or pointing with a mouse. Computers with a touchscreen have a smaller footprint, can be mounted in smaller spaces, have fewer movable components and can be sealed. Finally touching a screen is more intuitive than using a keyboard or mouse and hence results in lower training costs (Morse, 1998).

CRTs link the operator with historical and current process information through micro-processor based distributed control systems (DCS). New, flat screen CRTs are being developed. These are easier to look at for long periods of time and are well suited for touchscreen applications. CRTs offer good viewing angles and multi-resolution versatility. Flat panel liquid crystal display (LCD) monitors and gas-plasma displays are gaining ground in applications where CRTs have traditionally been used. The shift from CRT to flat panel LCD is expected to accelerate especially for graphic monitors and graphic and PC-based operator interface terminals. The trend will be driven by improving brightness, colour capability, viewing angles, narrow depth compared with CRT and falling prices for flat panel technologies (Intercolor, 2000).
Mean time between failure (MTBF) is a common measure of the expected life of equipment including monitors. To be meaningful for electronic products, MTBF should be specified at a specific temperature. MTBF is calculated based on the equation: \( \phi = \frac{T}{r} \); where \( \phi = \text{MTBF/hour} \), \( T = \text{total test time for all units for failed and non-failed items} \), and \( r = \text{total number of failures occurring during test} \). For example, a total of 12 monitors were tested for 1 year at 24 h per day (105,120 h = 12*8,760 h/y). During this time, two monitors failed. The demonstrated MTBF is therefore: \( \phi = \frac{105,120}{2} = 52,560 \text{ h} \) (Intercolor, 2000).

Since the introduction of electrical/electronic control devices and systems, hazardous areas have presented a special challenge in the design of operator interfaces. An electrical fault in such an area can cause an explosion resulting in plant downtime, damage or even loss in human life. Purged enclosures are the traditionally used systems for the safe usage of CRT monitors in hazardous areas. In a coal-fired power plant, these are the areas that have the potential to become hazardous due to the presence of combustible dusts. Leichleitner (2000) discusses the development of flat panel display systems as effective operator interface solution for hazardous areas.

Operator displays associated with a control system involve exhibiting vast amounts of information. Hence accommodating such information and control facilities on display units can result in a cluttered appearance of screens. However, there are methods of simplifying or combining several units which are identical in their operation and using one group of operations at a time on the screen. For example, mill groups are carbon copies of each other. They vary only in respect to a tag numbers for each item and the dynamic information relating to each area of the plant. It is therefore reasonable to display one mill group at a time on the screen, allowing it to be started, adjusted or stopped as required. However, to avoid errors it must be very clear and unambiguous which group is displayed at any time. In addition to the one mill group display, a master display should allow viewing the status of the entire set of mills feeding the boiler (Lindsley, 2000).

An important consideration, whatever type of screen is used, is the screen update time. This is the time between the occurrence of an event and its appearance on the screen. If the computer/screen system loading increases this time can become extended which can be problematic as the operator needs to be made aware of each event as soon as it occurs so that corrective action may be taken where required.
In today’s competitive business situation power generating facilities and their component plants are required to be operated at optimum performance levels. However, research and development spending has been reduced by the power and energy industries in response to uncertainties regarding deregulation and the resulting increased emphasis on short-term profits. Power plant owners now require payback periods of less than 2–3 years to justify any non-regulated plant improvement investment. Application of advanced controls will have the highest payoffs in the areas of improving efficiency, reducing emissions, increasing the number of megawatts that a generating unit can produce, and enhancing the ability to control the unit in response to instantaneous market demands (Wolk Integrated Technical Services, 1999).

Today conventional control systems are designed using mathematical models of physical systems. A mathematical model, that captures the dynamic behaviour in a process, is chosen. Then control design techniques are applied, aided by computer assisted design (CAD) packages, to design the mathematical model of an appropriate controller. The controller is then developed via hardware or software and used to control the physical system. The procedure may take several iterations. The mathematical model of the system must be built such that it can be analysed with available mathematical techniques. It must also be relatively accurate to describe the important aspects of the relevant dynamic behaviour; its task being to approximate the behaviour of the plant within a set operating point (Antsaklis, 1997). A typical plant control system block diagram is shown in Figure 27.

Proportional-integral-derivative (PID) control (see Section 6.1) has been the major control scheme to date in the power generating industry. These controllers examine the instantaneous error between the process values and the set points. The proportional term causes a larger control action to be taken for a larger error. The integral term adds to the control action if the error has persisted for some time and the derivative term supplements the control action if the error is changing rapidly with time. PID systems do not anticipate the long term effects of the present control action or of the effects of previous control actions to which the process has not yet responded. Such fixed parameter PID controllers have been evolving to include adaptive features that can cope with the processes that have time-variant or non-linear characteristics (Gough, 2000; Gough and Kay, 2001). For more information on past, present and future of PID control see Quevedo and Escobet (2000).

More recently, control based on fuzzy logic and computational fluid dynamics (CFD) modelling is becoming more accepted in power plant control structure. Fuzzy control was introduced in the early 1980s to mimic the control actions of an operator experienced in analysing and controlling problems in a plant. In the early 1990s the fuzzy controller based on the concepts of a PID controller was introduced. Fuzzy models can be obtained using a number of techniques (see Jantzen and others, 1999). Fuzzy logic used in a boiler control system is based upon linguistic rules. An example rule is ‘if level is too low, close outlet valve’. The rule-base of a fuzzy controller from which the combustion process is run is formed similarly. In 1995, automatic and model based methods were being developed that implement such fuzzy ‘if then’ rules in fuzzy logic controllers (Markkula, 1995). Application of fuzzy logic control technology in power generation is discussed by Tarabishi and Grudzinski (1996). Tarabishi and Grudzinski (1996) state that the main benefits of using fuzzy logic for control are that they are easy to design and implement as well as being generally more robust than conventional controllers. Fuzzy control and controllers are discussed in detail by Jantzen and others (2000). An introduction to the theory of fuzzy logic and adaptive systems, design steps for the development of fuzzy-logic based systems and using fuzzy logic for the start-up of a steam generator in a power plant are presented in the publication by INFORM GmbH (2001). Application of CFD-based modelling approaches in the design of new plants or modifying existing facilities as well as for the simulation of pilot-scale burners and full-scale boilers are detailed in a study published by the Clean Coal Centre by Moreea-Taha (2000). The study also discusses the capabilities and limitations of CFD for accurately predicting levels of NOx production during coal combustion. Xu and others (2000) discussed using the results of CFD and simplified heat transfer modelling in the design of new pulverised coal-fired boilers.

Power plant control is typically designed on the basis on two distinct platforms (Swanekamp, 1998):

- the distributed control system (DCS) which is designed to replace panel board controllers and recorders and handles massive amounts of inputs/outputs (I/O) for continuous process control (such as flow and temperature regulation);
- the programmable logic controller (PLC) which was developed to replace hardwired relays and mechanical timers. The PLC performs efficiently the high speed, discrete control (such as motor on/off circuits and chemical feed in water treatment plants).

## 9.1 Distributed/digital control systems (DCS)

Distributed digital control systems (DCS) are the main choice of engineers for overall combustion control in coal-fired power plant as all the process engineering requirements are met by the DCS system. The DCS monitors individual processes continuously and coordinates overall plant performance to maintain plant efficiency and reduce operating costs. It controls the conversion of primary energy into electrical energy so that the power requirements of the
consumer are met at any time while the process is running safely. As electrical energy cannot be stored in large quantities, power generation must follow the power consumption directly which can vary greatly. This highly dynamic process requires quick reaction times and as these cannot be provided by manual operation these tasks are performed by the DCS. The exact task of the DCS is to establish specific process conditions and variables and keep them even during faults. The whole process and hence each device passes through three operational phases; start-up, load operation and shut-down. Common DCS functions include graphic operator interfacing via CRT or flat panel LCD, remote on/off capability, data monitoring and trend charting within a central control room. Actual function control is distributed to the remote units throughout the plant for execution by dedicated devices.

A typical DCS system configuration is shown in Figure 28. The cabinets house the processors that execute the control functions. These cubicles also contain the interface and I/O cards as well as the necessary power supply units (PSUs). PSUs are usually duplicated or triplicated with automatic changeover from one to another in the event of the supply failure. An alarm signal is incorporated in the system to alert the operator to a PSU failure otherwise the DCS will continue to operate with a diminished power supply reserve and any further failure could result in plant downtime. A reliable, that is stable and un-interruptible, source of power

Figure 27 A typical plant control system block diagram (Apostol and others, 1996)
9.2 Programmable Logic Control (PLC)

PLCs are highly reliable, special-purpose computers used in industrial monitoring and control. They were originally designed as easy-to-program, flexible, low-cost replacement for relay-based and solid-state, hard-wired discrete logic systems. PLCs typically have proprietary programming and networking protocols and special-purpose digital and analogue I/O ports. In power plants, PLCs have been utilised in water treatment systems, bottom and fly ash systems, burner control systems, particulate capture control systems, condensate polishing systems and chemical waste management systems.

According to Platt (1998), logic control is control that causes actions to be taken or not taken in a process depending on whether certain process conditions, operator actions or control system actions occur or do not occur. Logic control makes use of a logic system, which is a combination of binary elements that decide automatically on the proper response to a certain set of conditions. In logic control, every part of the logic system (that is each input event, each logic function element and each output response) is either Yes or No, On or Off, True or False or 1 or 0 (in binary signals).

Logic control is appropriate for any process system that uses on off devices to initiate or terminate normal or emergency operations (Platt, 1998).

Hughes (2001a) explains that regardless of size, cost or complexity all PLCs share the same basic components and functional characteristics. A PLC always consists of a processor, an I/O system, a memory unit, a programming language and device, and a power supply. The processor or central processing unit (CPU), consists of one or more standard or custom microprocessors and other integrated circuits that perform the logic as determined by the application programme, performs calculations and controls the outputs accordingly. The CPU has two areas of memory that the PLC user can access. These are programme files and data files. The programme files store the control application programme, sub-routine files and error files whilst the data files store data associated with the control programme including I/O status bits, counter and timer preset and accumulated values and other stored constants or variables. The I/O system provides the physical connection between the process equipment and the microprocessor. In this system, various input circuits or modules are used to sense and measure the physical quantities of the process such as motion, level, temperature, pressure, flow and position. The processor controls various output modules, based on the data received or the measured values, to drive field devices such as valves, motors, pumps and alarms. The inputs from field devices or sensors supply the data that the processor needs to make logical decisions to control the process. The output signals from the PLC drive the control devices to regulate the process. The memory stores the control program that determines how the input and output data will be processed in the PLC system. Memory stores individual pieces of data called bits. A bit has two states: 1 or 0. Memory units are usually specified in thousands or kilobyte (kB) increments.

![Figure 28 A typical DCS system configuration](Lindsay, 2000)
where 1 kB equals 1024 words. PLC memory capacity varies from less than 1000 words to more than 64,000 words depending on the manufacturer. Complexity of the control plan determines the amount of memory required. The **programming language** allows the user to communicate with the PLC via a **programming device** which is a PC with the programming software loaded on its hard drive. Different programming languages can be used to convey the control plan which is a set of instructions that are arranged in a logical sequence to control the actions in a process. Types of PLC languages include ladder-logic, structured text (such as Boolean logic), ladder logic with advanced functions and sequential function chart. Finally the **power supply** converts alternating current (AC) line voltages to direct current (DC) voltages to power the electronic circuits in a PLC system. Power supplies rectify, filter and regulate voltages and current to supply the correct amounts of voltage and current to the system (Hughes, 2001a).

According to Faber and Vavrek (1993), the logic development in a PLC using relay ladder logic is understood by electrical engineers and has been a major factor in its rapid acceptance and current popularity in the power generating industry. They also have hardened I/Os and processors which allows the system to be placed near the process inside a local panel. PLCs also offer remote I/O capability providing a significant saving in cable and conduit installations. The heavy duty digital outputs available from hardened I/O, in many cases, eliminate the need for auxiliary relay. PLCs offer a number of man-machine interfaces, from traditional push button and indicating light sub-panels tied to the system through a link to sophisticated touch-screen CRTs and graphics. Traditionally, PLCs operated independently. However, as the need for more rapid exchange of information and greater connectivity among systems increased, interfacing the PLC with the plant wide distributed control and information system became a more important consideration in power plant control systems.

There are five standard PLC programming languages including ladder logic diagrams, function block diagrams, sequential function charts, statement lists and structured text. PLC is discussed in detail by Hughes (2001b). State logic is an advanced PLC language where the primary elements are ‘tasks’ comprised of one or more ‘states’. Tasks can execute simultaneously or in parallel, but only one state is active at any time. Because the logic in the non-active states is ignored, state logic reportedly is more efficient than relay ladder logic. Developers also report that state logic includes better diagnostics, data handling and the ability to add special high-level tools (Swanekamp, 1998).

Today in PLC, programming in C, a modern day computer programming language, is considered to be faster than the traditional ladder diagram (PLC logic programme) for looping and complex branching of control instructions.

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**Table 7** Some of the advantages and disadvantage of integrated and segregated plant control systems (Faber and Vavrek, 1993)

<table>
<thead>
<tr>
<th></th>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Integrated systems</strong></td>
<td>All data is universally available for control, monitoring (including alarms), operator displays, data acquisition, performance monitoring and other functions.</td>
<td>The control and monitoring tasks of a large generating station could potentially exceed the capacity of some systems.</td>
</tr>
<tr>
<td></td>
<td>Hardware types are minimized, greatly reducing spare parts inventories, training requirements, trouble-shooting and maintenance procedures</td>
<td>Selection of a commercially available DCS will require trade-offs among the various features offered by each of these systems.</td>
</tr>
<tr>
<td></td>
<td>Software structures are uniform throughout the system.</td>
<td>A design defect in one portion of the system may be duplicated throughout the integrated system.</td>
</tr>
<tr>
<td></td>
<td>Gateways are eliminated, thus eliminating the associated hardware and software.</td>
<td>Application of a fully integrated control system will generally require more comprehensive front end engineering than will a comparable segregated system.</td>
</tr>
<tr>
<td><strong>Segregated systems</strong></td>
<td>Control systems may be purchased with the associated mechanical hardware package, taking advantage of pre-engineered control schemes.</td>
<td>Data is not available throughout the plant without special effort.</td>
</tr>
<tr>
<td></td>
<td>Responsibility for control of various portions of the plant can be placed with the party most familiar with the control of that equipment or process.</td>
<td>A non-uniform operator interface consisting of multiple independent devices is typically encountered.</td>
</tr>
<tr>
<td></td>
<td>The type of control equipment used can be matched more closely to the process or equipment under control.</td>
<td>Coordination or duplication of functions across system boundaries is difficult.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Greater quantities of spare parts and training are required.</td>
</tr>
</tbody>
</table>
Complex mathematical algorithms, data storage and question functions can be developed as C sub-routines as well as main programmes (C&I, 1999).

Although using a hybrid DCS/PLC system may resolve the weaknesses of either system it can be problematic particularly when the equipment is supplied by many vendors. The differences between DCS and PLC in human/machine interface (HMI), programming environments, communications protocols, levels of security, maintenance support and so on makes system integration very difficult. HMI is the means by which an operator interacts with the automation system, often a graphic user interface (GUI). However, today each platform is incorporating features that were formerly the exclusive domain of the other. The distinction between the two plant control platforms is becoming less transparent as vendors introduce DCS with embedded PLC and unified DCS/PLC systems. Such systems offer the features of both control platforms in one integrated package. Modern, advanced DCS have discrete calculation capabilities and use open (non-proprietary) communications. Meanwhile new PLC include PID loops, greater memory, better math features, improved network capability and expanded instruction sets. The improvements allow new PLC to use relay ladder logic and high level programming languages. Convergence of the two control platforms, DCS and PLC, has facilitated easier system integration. Many vendors today use common interfaces to bypass the difficulty of dissimilar devices.

Faber and Vavrek (1993) reported the advantages and disadvantages of integrated versus segregated control systems (see Table 7). In their study of modern power plant controls including DCS and PLC they concluded that a power station’s control systems can no longer be considered independent entities. Integration of these systems will result in a more sophisticated overall plant control.

9.3 Personal Computer (PC) based control

PC-based hardware and software have only recently been introduced in power plant control. These systems, in general, utilise operating systems such as Windows NT or Windows CE or UNIX and offer a high level of interoperability. Embedded PC technology is an even more recent development that promises more powerful, reliable and robust control (Swanekamp, 2000b).

There are two types of PC-based control:
- soft logic (for example Windows NT);
- hard real-time deterministic control

Microsoft Windows NT is a general-purpose operating system that can provide fast response time. Hard real-time control uses PLC core for the control foundation and runs in the foreground (equipment control and safety being of highest priority); and Windows NT which runs in the background (graphic user interface (GUI), information and communications). A firewall is set up between hard real-time control and Windows NT in order to ascertain that Windows functions cannot interruption control and as leverage for Intel Processor memory protection. PC-based control architecture is shown in Figure 29. For more information on PC-based control see ISA (2000) and Steeplechase Software (1999).

According to Swanekamp (2000b), Ovation is an example of a fully PC-based power plant control system that eliminates proprietary operating schemes and vendor-specific hardware.

![Figure 29 A PC-based control architecture](Steeplechase Software, 1999)
It promises to reduce the risk of obsolescence that is often associated with proprietary control system. Swaneckamp (2000b) sees the switch to PC based control as inevitable as each new PC generation is cheaper, more robust and faster. He states that the Pentium PC hardware outperforms fast PLC by a margin of about 20:1.

9.4 Adaptive/predictive control

Adaptive control is a set of techniques for the automatic, online, real-time adjustment of control loop regulators designed to attain or maintain a given level of system performance where the controlled process parameters are unknown and/or time varying. The use of digital signal processing in control loops offers many advantages including (Renard, 1998):

- wide range of alternative strategies for controller design and mathematical modelling, freedom to use regulation algorithms that are more complex and offer higher performance than PID;
- technique is suitable for process control applications involving time delays;
- automatic estimation of process models for different operating points;
- automatic adjustment of controller parameters;
- constant control system performance in the presence of time-varying process characteristics;
- real-time diagnostics capability.

According to Renard (1998), adaptive control is based entirely on the hypothesis that the process to be controlled can be mathematically modelled and the structure of this model (delay and order) is known in advance. The determination of the structure of a parametric system model is thus a vital step before going on to design an adaptive control algorithm. The identification technique should be selected by a specialist in automatic control. The capabilities of adaptive control algorithm depends, to a large extent, on the faithfulness with which the model represents the system and its behaviour. The main advantage, in practical terms, of adaptive control appears to be the capability to ensure quasi-optimal system performance in the presence of a model with time-varying parameters. Once the model and its structure have been identified a control strategy is selected. The selected strategy must yield a satisfactory control law in the case where the system model and its environment are fully determined. The adaptive control algorithm is then designed in accordance with the structure of the system model and the selected control strategy. Figure 30 shows the basic principles of adaptive control. The performance rating of a system is measured and compared to the design goal. The adaptive system modifies the parameters of the adaptive controller in order to maintain the performance rating close to the desired value.

The reduction in computer costs over the past few years and their increasingly enhanced performance has led to active research into adaptive control algorithm development. The control improvements possible with adaptive controllers have also become more significant due to increasing economic pressures and environmental concerns as better combustion control can often increase profitability and reduce pollution (Gough and Kay, 2001). Gough (2000) discusses an advanced predictive-adaptive process controller that is designed for processes with long delay times and long time constants such as steam superheat temperature control in utility boilers. Skoncey and Tobias (2000) examined enhanced boiler control with advanced predictive modelling as control tools in boilers fitted with reburning technology for NOx control. For detailed information on NOx control see Soud and Fukasawa (1996). An in-depth study of adaptive control was carried out by Astrom and Wittenmark (1994). Adaptive control of systems with actuator and sensor non-linearity is discussed in detail by Tao and Kokotovic (1996).

In 1990, the Spanish utility Iberdrola replaced a conventional control system with the Adaptive Predictive Control System (APCS, also known as SCAP) technology to optimise the operation at the Pasajes de San Juan coal-fired power station (214 MW). APCS combines the operation of an adaptive predictive control system with a logic system for analogue and digital signals. In this technology, instead of process control with PID which responds to system errors, changes in the combustion process variables is predicted. A control action is then applied that makes the predicted derivation equal to the desired derivation. Thus oscillations of conventional PID control systems are eliminated and a stability in the process is achieved. Optimisation of the Pasajes de San Juan plant included maximising plant efficiency and lifespan, reducing operational and maintenance costs and increasing plant safety as well as availability. The project consisted of two stages. In the first stage, an APCS feasibility and suitability study for coal-fired power generation was carried out followed by a second installation stage (Pérez and others, 1995).

Pérez and others (1995) presented the results obtained with APCS optimisation system at the Pasajes de San Juan facility as follows:

- APCS minimised the oscillations produced as a result of any perturbation, both ordinary and exceptional as well as during load changes. This was expected to result in increasing plant working life and safety of the unit;
- APCS permits the operation of the plant in a complete

![Figure 30 Basic principles of adaptive control](Renard, 1998)
automatic mode during start-up and shut-down of the power station in conventional or continuous load variation.

APCS (SCAP) was deemed to have demonstrated the ability of predictive adaptive control to stabilise plant operation during load changes and optimise its performance during continuous operation (Pérez and others, 1995; Pérez and others, 1997).
A large number of existing coal-fired power plants throughout the world are controlled by panel-mounted, single loop controllers. Some are pneumatic, some analogue electronic and others digital electronic. Until recently, in general, the I&C systems in these plants was based on technology consistent with the age of the units (see Table 8). However, since deregulation in many countries and increasing competitiveness, a large number of existing coal-fired plants have undergone major I&C retrofit programmes in order to make their lifespan longer and their operation profitable and hence viable.

### 10.1 Traditional I&C systems

The state of instrumentation in older plants limits plant operational optimisation. For example, operating at a temperature of 1% above design can result in over a 25% reduction in boiler tube life whilst operating at a temperature of 1% below design can impact heat rate. In addition, reliable and accurate information on the combustion process can assist the operators in minimising air pollutant emissions whilst maximising plant efficiency. According to Swaneckamp (2000b), most existing coal-fired plants are not equipped with online analysers for accurate measurement of coal flow or heat content. Thus heat rate figures are based on estimates. However, online analysers that can achieve the required accuracy and reliability are currently being developed. Development in instrumentation has also focused on improving the processing and signal conditioning. For example, sensors remain essentially unchanged since the 1960s and 1970s, modern sensors should be applied to measure air flow velocity in exhaust stacks and air ducts.

Cost benefit analysis of upgrading I&C systems show that amortisation is achieved within a few years due to higher efficiency and availability of plant as well as optimised personnel deployment, reduced maintenance costs and extended intervals between inspections (Hoffman and Wetzl, 1995). Hence attracting and retaining experienced I&C personnel is an important issue in a highly automated coal-fired power plant. Dasch (2001) states that with proper engineering, installation and support, an open architecture system can return a utility’s investment within two years.

Performance gains expected from I&C upgrade are quantifiable but calculating the impact of an upgrade on overall power plant economics is difficult. Economic benefit from such an equipment upgrade results from the interaction of many complex economic and plant performance parameters including (Gay and others, 2001):

- configuration and performance characteristics of the power plant;
- operational profile (that is, expected variations in loads and ambient conditions);
- electricity sales and fuel purchase contract stipulations;
- prices of fuel, electricity, make-up water and other variable costs.

Gay and others (2001) describe the application of a plant optimisation software that performs a plant upgrade benefit analysis in combined cycle facilities. The result of the calculations is a plant operating in a maximum profit mode. This is because the optimisation software determines the most profitable plant operational mode and plant control settings.

The driving force behind the upgrading of traditional I&C systems in general are:

- to address issues of obsolescence of the previous I&C equipment;
- to extend the operating life of power units and power stations by an additional 15 to 20 years;
- to satisfy regulatory requirements with regard to primary and back-up control during normal operation;
- to improve energy-generation efficiency and increase energy output;
- to reduce operation and maintenance costs;
- to improve working, servicing, and safety conditions;
- to meet emission and plant discharge standards.

### Table 8 Existing conventional, pulverised coal fired power plants (>50 MWe) by age (where known) (IEA Coal Research, 2001a)

<table>
<thead>
<tr>
<th>Period plants built</th>
<th>Number of units</th>
<th>Capacities, GWe</th>
</tr>
</thead>
<tbody>
<tr>
<td>1991-2000</td>
<td>579</td>
<td>176</td>
</tr>
<tr>
<td>1981-1990</td>
<td>831</td>
<td>228</td>
</tr>
<tr>
<td>1971-1980</td>
<td>831</td>
<td>245</td>
</tr>
<tr>
<td>1961-1970</td>
<td>865</td>
<td>160</td>
</tr>
<tr>
<td>1960 and before</td>
<td>631</td>
<td>65</td>
</tr>
</tbody>
</table>

### Table 9 Summary of survey results of planned plant outages to retrofit, add, upgrade or install I&C in Europe (Power Engineering International, 1995)

<table>
<thead>
<tr>
<th>Country</th>
<th>No of I&amp;C projects</th>
</tr>
</thead>
<tbody>
<tr>
<td>Austria</td>
<td>2</td>
</tr>
<tr>
<td>Belgium</td>
<td>1</td>
</tr>
<tr>
<td>Czech Republic</td>
<td>2</td>
</tr>
<tr>
<td>Denmark</td>
<td>1</td>
</tr>
<tr>
<td>Estonia</td>
<td>1</td>
</tr>
<tr>
<td>Finland</td>
<td>4</td>
</tr>
<tr>
<td>Germany</td>
<td>19</td>
</tr>
<tr>
<td>Norway</td>
<td>1</td>
</tr>
<tr>
<td>Russia</td>
<td>1</td>
</tr>
<tr>
<td>Slovenia</td>
<td>1</td>
</tr>
<tr>
<td>Spain</td>
<td>5</td>
</tr>
<tr>
<td>Sweden</td>
<td>1</td>
</tr>
<tr>
<td>Switzerland</td>
<td>13</td>
</tr>
<tr>
<td>Ukraine</td>
<td>1</td>
</tr>
<tr>
<td>United Kingdom</td>
<td>6</td>
</tr>
</tbody>
</table>
In 1995, Power Engineering International reported on the planned plant outages that include replacing, adding, upgrading or installing new I&C system for power generation in Europe. Summary results of the study report was based on is given in Table 9. Power generating units using fossil fuels were found to have a clear majority of most planned I&C outages.

10.2 Modern I&C systems

Modern DCS systems provide many benefits in a plant including (Binstock, 1995):

- advanced control techniques;
- open communication between all parts of the process;
- unified plant control (that is, control of the total generation process and not only the separate control of many individual sub-processes);
- simplification of training, service, and spare parts through the use of control and information system;
- high resolution automated graphics which allow zooming into any part of the plant to obtain real time information and control;
- generation of meaningful trends and reports.

Advanced control systems and diagnostic devices including smart sensors, transmitters, processors, controllers, indicators, recorders, switching devices, converters, filters, data acquisition and diagnostic systems constitute the base of a modern I&C technology. Technological advances in computer systems, fibre optics, laser technology, information processing, neural networks, Bayesian analysis, fuzzy logic and diagnostic systems (embedded in semiconductor chips and supported by high-capacity, high-speed, low-cost computers) are providing the means to apply advanced control in coal-fired power plants. The use of such modern I&C can also limit emissions of pollutants such as CO₂, SO₂ and NOx (Mookerjee, 2000).

Instrumentation is identified as a key research and development subject in the US DOE Vision 21 programme which includes the industry, academia and other US governmental stakeholders. The use of artificial intelligence and new sensor technology is expected to assist operators in fine tuning power plant operations to accommodate variations in fuel feed-stocks and other plant variable conditions. Advanced controls and sensors have been identified as important supporting technologies in Vision 21. New algorithms utilising state of the art computer hardware and software will be advocated to assure reliable and efficient plant performance as well as low emissions (National Energy Technology Laboratory, 2000).

The intelligent temperature monitoring and control for clean and energy efficiency combustion processes (CLENEF) is a project that involves multidimensional temperature measurements in combustion. This project aims to develop a diagnostic system for temperature tomography of industrial flame combustion processes. The project is run by the Intelligent Manufacturing Systems (IMS), an industry-led, international research and development program. The countries currently involved in IMS include Australia, Canada, the European Union, Japan, Korea, Norway, Switzerland and the USA involving ~400 companies and research institutes (IMS, 2001)

Objectives of the IMF CLENEF programme are:

- development of a diagnostic system that is low in cost, adaptable to withstand harsh environments, and easy to assemble. The system should reduce pollution from coal and natural gas firing: for example for NOx: 10–20%, unburnt carbon-in-ash: 30%, sulphur oxides, ash and arsenic: 19%. A decrease in fuel consumption is also expected, in the order of about 17–20%;
- annual environmental benefits resulting from using the diagnostic system on, for example, 1000 MW coal-fired power plant that consumes about 5,000,000 tonnes of coal per year: decrease in effluent (in tonnes per year): sulphur oxides 250,000 (43,000,000 total in the world); ash (30,000 (5,200,000 total in the world); arsenic 2,500 (430,000 total in the world). Expected direct annual economic benefit is 26.6 MECU (end-users applications in European module) during the following year from project completion. For more details on the companies involved and an analysis of cost and benefit, see IMS, 2001.

The US DOE’s Combustion 2000 Program includes a project on development of an advanced generating plant entitled the Engineering Development of Advanced Coal-Fired Low Emission Boiler System (LEBS). The program combines advanced environmental control technologies capable of achieving emissions of SOx, NOx and particulates significantly below US current New Source Performance Standards (NSPS) with an advanced boiler equipped with improved combustion and heat transfer sub-systems for net plant efficiencies exceeding 40%. Maintaining such performance requirements over a wide load range with load changes at rates of 5% per minute requires the application of advanced sensors and controls to these units. Zadiraka (1996) discussed the development of sensors and control techniques that carry out accurate measurements and control of the individual burner air and fuel flows as they are introduced to the time-temperature-turbulence combustion process in the furnace.

ACORDE is a project funded by the European Commission DG XII within the Brite-Euram III Programme. It consists of an advanced diagnosis methodology that integrates numeral modelling with knowledge-based, expert system data available in a thermoelectric power plant DCS. The main objectives of this project are to (Neves and others, 1999):

- minimise pollutant emissions;
- minimise boiler components degradation;
- maximise efficiency.

A further, secondary objective is to analyse possible deviations of newly accumulated data compared to normal data, so that the system may be used to detect possible anomalies to obtain boiler response in different situations and to use different scenarios for operator training. A prototype version of the ACORDE system was installed in the Sines pulverised coal fired power plant built between 1979 and 1989 and consisting of four units with a total capacity of...
1256 MWe. The plant consumes 106 t/h low heating value coal (27600 kcal/kg) at nominal load and is fitted with 20 low NOx burners. The prototype was installed with the objective of being tested online during operation. Another version of the ACORDE system was produced and coupled to a boiler simulator to provide improved operator training (Neves and others, 1999).

The UK Cleaner Coal Technology Programme includes research and development in the area of I&C within the advanced pulverised fuel section. The programme was established by the UK Department of Trade and Industry (DTI) in April 1999. The objectives of research and development in the I&C area include (DTI, 2001b):

- development of methods for online analysis of coal or coal/renewable energy source mixtures, component wear/replacement strategy for mills;
- improvement of flame monitoring techniques;
- external condition monitoring for a wider range of plant I&C components and integration of whole plant condition monitoring system;
- application of advanced control methodologies.

KOMET 650 is a project sponsored by the German Federal Ministry for Education and Research (now the Federal Ministry for Economics and Technology) for optimising the steam cycle and testing CO2 reduction measures in coal-fired power plants. The project was established by the German Federal Ministry for Economics and Technology (BMWI) in April 1999. The objectives of research and development in the I&C area include (DTI, 2001b):

- process data validation, expert systems and neural networks and monitoring techniques. Computer-based tools such as process data validation, expert systems and neural networks are to be developed or adapted for use in the power industry within the research program of KOMET 650 (BMWI, 1999).

Wetzl and Ottenburger (1996) reported on the I&C system, supplied by Siemens, and efficiency achieved (41%) at the new lignite-fired, Schwartze Pumpe power plant in Germany (2 x 800 MWe). Many recent developments have increased the efficiency of coal-fired power plants, including for example using flue gas that leaves the boiler at 170°C to improve overall plant efficiency. Part of the energy content in the gas is used for preheating the feedwater used for steam generation. Thus less steam has to be extracted from the turbine resulting in a direct increase in power generation. Using advanced and efficient firing technology that meets NOx emission standards alleviates the need to have a dedicated NOx control technology which reduce overall plant efficiency. In addition, flue gas extracted via a cooling tower rather than a stack eliminates the need to reheat the flue gas before dispersion which also helps in increasing overall plant efficiency. All these measures combined with continuous monitoring, open- and closed-loop control function in state-of-the-art I&C technology reduced the lignite required at Schwarze Pumpe to generate one kilowatt hour by one third compared to other plants. When comparing the results of new similar plants with existing facilities that have nearly identical electrical loading Wetzl and Ottenburger (1996) found that particulate emissions were reduced by 98%, sulphur emissions were reduced by 90% and the emissions of NOx dropped by 60%. The authors also reported that the improved plant efficiency and the resulting lower fuel consumption reduced the emission of CO2 by 30%.

According to Wetzl and Ottenburger (1996), an I&C system determines and increases the economic viability of a plant directly as they provide maximum plant efficiency, optimum fuel utilisation, maximum availability, long life-time, and low operational costs. Typical values of components that must be managed reliably in a plant I&C system today, are 200 control loops, 1200 positioning actuators, 1700 analogue measured process values and 10,000 alarms.

The installation of modern, state-of-the art I&C systems in new coal-fired power plants allows such facilities to compete in the market today. These systems contribute towards minimising plant emissions as well maintaining low operational and maintenance costs and achieving the highest possible plant efficiency and availability. Although coal-fired power stations throughout the world use these modern systems, their application in new coal-fired power plants in countries such as Colombia is noteworthy (see INITEC, 2001).

### 10.3 Retrofit/upgrade I&C systems

**Control system upgrades** by replacing vintage control systems with modern digital control systems (DCS) can contribute directly towards improved plant operational performance and identifying fuel saving capacities. New unit control set-up and data acquisition systems are required to upgrade an existing control centre (Freeman and Glegg, 1995). Figure 31 shows a typical I&C system rehabilitation schedule in a coal-fired power plant.

Using advanced DCS systems also impacts operational costs in that the high degree of automation allows the operation of a plant with a smaller number of staff. Maintenance costs are reduced due to the new, more reliable and standardised installed apparatus and system payback is achieved in a relatively short time. However, according to Pierlot and van Rompuy (1997), a control system can have a relatively short lifespan which they estimate at 10–15 years due to the difficulty in obtaining spare parts, such as microchips, in a continually advancing technology. A power plant’s typical lifetime lasts, with periodic overhauls, about 40–50 years. The I&C system retrofit is recommended every 15–20 years to benefit from new hardware and software technologies (Stroick and Chang, 1998).

Upgrading traditional I&C systems involves carrying out an in depth feasibility study or what is known as a cost benefit upgrade analysis to justify the installation of a modern control system. Factors in such analyses include control equipment prices, cabling/wiring, floor space, control room, operational staff requirements and maintenance requirements (Mendel, 1999). In 1999, Mendel also reported the results of a survey of I&C controls practices in the process industries carried out under the sponsorship of the Electric Power Research Institute (EPRI) (USA). In 1992, EPRI prepared a three volume, in depth report on control system retrofit guidelines. The report presented key phases of control system
retrofits, technical assessment of a digital control system and case studies from utilities focusing on individual retrofit approaches.

Hoffman and Wetzl (1995) report on substantial power plant improvement by I&C upgrading in Germany. The authors reported on the application of a new I&C technology which comprises automation, process control and information as well as design and commissioning and provides:

- central configuration;
- uniform man-machine interface;
- redundancy configuration;
- object-oriented software structure;
- open communication system;
- application of international standards and requirements.

The new I&C system (TELEPERM XP) was retrofitted at the Voerde power plant which consists of 2 x 350 MWe coal-fired units. Input signals, 6000 binary and 2500 analogue, were logged via extension cabinets and six central units and transferred to three monitoring terminals in the central control centre/room. The input level is connected to the processing unit (PU) and the server unit (SU) via the plant bus. Display is achieved via a terminal bus to four operator terminals (OT) with two video displays each. Information is supplied through 53 plant displays, 18 operating point displays and characteristic value displays. Mounting, including cabling and marshalling, of cabinets, bus and terminals was carried out over four weeks. The process control and information uses a system based on expandable, modular and upgrade compatible hardware and software.

Figure 31 A typical I&C system rehabilitation schedule in a coal-fired power plant (Apostol and others, 1996)
concept for operation. It uses standard UNIX and X/Windows operating systems; the interactive graphic retrieval system (INGRES) which is a commercial database system; and Intel and the reduced instruction set chip (RISC) processors (Hoffman and Wetzl, 1995). In RISC, the ‘instruction set’ is the hardware ‘language’ in which the software tells the processor what to do. It was found that reducing the size of the instruction set, that is eliminating certain instructions based upon a careful quantitative analysis and requiring these seldom-used instructions to be emulated in software, can lead to higher performance, for reasons including (Joy, 1995):

- the vacated area of the chip could be used in ways that accelerate the performance of more commonly used instructions, compensating for the inevitably degraded performance of the seldom-used instructions;
- it became easier to optimise the design;
- it allowed microprocessors to use techniques that were restricted to large computers;
- it simplified translation from high-level language in which the programmes were written into the instruction set that the hardware understood, resulting in a more efficient programme.

Hoffman and Wetzl (1995) reported that following initial operation, performance problems were encountered during the activation of plant displays and curves. These were addressed by using new software and sequential optimisation. Extensive analysis functions were used to localise disturbances and faults. The new I&C configuration was built with prospects of extension without rewiring thus permitting a step by step replacement of the old I&C equipment with a modern system.

Jaswal (1998) discussed the installation of a new PC/PLC based control system to Northern Indiana Public Service Company (USA), Schaefer power generating station (units 17 and 18) when the FGD was upgraded to a wet limestone gypsum scrubber. A study, conducted to determine the type of the new control system, showed that PC/PLC based control was the most cost effective option based upon the least installed cost, maintenance and spares cost, training, reliability, availability and flexibility for future modifications. Online modification flexibility was necessary to cope with optimisation of the process and the new FGD plant. The new control system began operation in 1996 for unit 17 and 1997 for unit 18. Both systems are reported to be operating satisfactorily achieving high reliability and availability.

An example of the effects of upgrading the control system in a coal-fired facility is given by Ambos and others (1999). Even though 70% of power generated in France is nuclear-based, Electricité de France (EDF) has engaged in retrofitting the whole analogue control system with a state-of-the-art full DCS at its Le Havre, unit 1250 MW coal-fired plant. The objective of the project was to enhance plant performance by co-ordinating the turbine valve, coal flow and injection and burner angle to respond to power demand, maintain constant pressure and control the excursions of the secondary superheat and reheat temperatures. A Multi Input/Multi Output (MIMO) controller was developed to achieve these objectives. The retrofit programme, accomplished in May 1998, was the result of the following constraints:

- lower emissions profile requirements;
- plant life extension while annual operating hours decrease;
- maximise plant availability;
- improve response to dispatch unit load demand.

Computer Aided Design (CAD) system control tools were used to establish a systematic design procedure for the controller. A closed loop simulation was performed. The resulting, advanced controller was generated in C computing language and loaded onto the DCS. Testing was conducted and implementation of the controller was deemed successful in normal operation as the plant was reconnected to the electrical network (Ambos and others, 1999). Another project involving control system retrofit was carried out at the EDF La Maxe coal-fired plant (2 x 250 MW). For more information on this retrofit plant see Leurette and Pellerej (1999) and Kropp (2001).

Retrofitting existing plants with new air pollutant abatement systems such as low NOx burners can impact the plant control and auxiliary systems. Szczzerbicki (1995) discussed the experience of retrofitting five existing coal-fired plants with low NOx burners. The five units were tangentially-fired. The boilers were two 350 MW drum units and three 750 MW supercritical once-through units. The existing electronic analogue burner management and secondary air control systems were upgraded to microprocessor based, DCS elements for all units. The implementation was performed by the low NOx burner vendor. As part of the burner management system design and installation, a comprehensive review of each unit’s boiler, turbine and generator protective tripping and interlocks was conducted. A study was performed to determine the best method of operator interface for the new burner management and secondary air control systems. In addition, complementary control functions, such as mill temperature control, feeder speed, and furnace windbox damper positioning and biasing were integrated with the burner management system graphics. A combination of touch-screen, keyboard and trackball devices was used across the various units and systems. The new low NOx burner equipment and material design created a number of interferences with both the existing and new plant equipment. In almost all instances, the low NOx burner took precedence over either the existing plant equipment or the new material installation. In the case of new material installations these were modified, adjusted or moved to eliminate the interference. In the case of existing equipment, major interferences were detected with soot-blower steam supply and drain piping, existing wall-blower locations, and economiser recirculation piping. These necessitated the rerouting of high pressure piping which required a piping stress analysis. All interferences were resolved within the outage completion date.

At the beginning of the 1990s units 4 and 5 (330 MW) of the Turceni power plant in Spain ceased operation due to advanced state of degradation. It was decided in the mid-1990s to rehabilitate these units. The units automation system
was considered the most important measure to be taken within the rehabilitation framework programme to avoid pressure circuit stress, decrease the number of trips and increase unit availability. The following were the main objectives of the plant I&C rehabilitation programme:

- to decrease operational costs;
- increase unit availability;
- to ease operation and maintenance activities;
- reduce environmental pollution.

The retrofit I&C system tasks were as follows:

- remote control and monitoring from the control centre;
- automatic operation between 40 and 100% load;
- local monitoring and control of the common/auxiliary systems from separated control rooms;
- automatic control system diagnostic capability.

The new automation system adopted at the Turceni power plant achieved its objectives and continues operation today (Apostol and others, 1996).

In April 2001, Frank presented the current and future needs for I&C in power generation. The author showed the benefits achieved, at the unit 9 of Kingston coal-fired power plant, with combustion optimisation and upgrading the plant I&C system (see Figures 32 and 33). He also discussed the effects of improved efficiency and reduced emissions on the example plant fuel cost, and cost of total installed fossil capacity in the USA, additional capacity generation as well as the additional benefit of reducing CO₂ emission and waste by-product (see Figure 34). Frank (2001) discussed generation plant challenges such as reduced staffing, pressure to improve

![Figure 32](image1.png)  **Figure 32** Kingston units 9 and 5-8 control system retrofit benefits: reduced heat rate (Frank, 2001)

![Figure 33](image2.png)  **Figure 33** Kingston unit 9 loss-on-ignition (LOI) improvement (Frank, 2001)
Experience

profitability, push to reduce emissions and new emissions regulations. He concluded that the future needs of power generation are:

- individual burner tuning and active control capability;
- improved combustion measurements (for NH₃, CO, NOx and other emissions and flame quality);
- real-time cost-of-generation data linked with economic and environmental dispatch;
- improved ‘plug-and-use’ software;
- adaptive control modes for changing market demands.


10.4 Dedicated plant performance enhancement systems

Since the mid 1990s, data collected in the I&C data acquisition systems or real-time data are being used to create models, simulations, as well as ‘intelligent’ computer-based products. The drive behind the use of these advanced systems is to achieve greater understanding of what occurs within the boiler and enhance the performance of the plant. For example, Figure 35 shows typical combustion as a function

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**Figure 34 Overview of benefits, in monetary terms, of upgrading I&C system at a typical 500 MWe coal-fired unit** (Frank, 2001)

- A 1% improvement in EFFICIENCY yields $390,000 savings in fuel costs.
- For the entire US installed fossil capacity, this yields $409,439,000.
- Additional benefits include 1% REDUCTION in greenhouse gases and solid wastes.
- A 1% increase in availability equals an additional 32,850 MWh/year for the 500 MW plant ($1,971,000 in additional sales@60 $/MWh)
- At a retail price of 60 $/MWh, this yields a $1,461,825 increase in gross profit for this plant at 15.5 $/MWh production costs.
- This equals an additional 5000 MW of capacity for total US installed fossil power plants.

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<table>
<thead>
<tr>
<th>Fuel costs</th>
<th>$39 million/y @ 9,500 BTU/kWh, $1.25/million BTUs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Non fuel O&amp;M costs</td>
<td>$5.85 million/y (10-20% of total costs)</td>
</tr>
</tbody>
</table>

**Total Fuel + O&M Budget** $44.85 million for ‘Average 500 MW unit’

- A 1% improvement in efficiency yields $390,000 savings in fuel costs.
- For the entire US installed fossil capacity, this yields $409,439,000.
- Additional benefits include 1% REDUCTION in greenhouse gases and solid wastes.
- A 1% increase in availability equals an additional 32,850 MWh/y for the 500 MW plant ($1,971,000 in additional sales@60 $/MWh).
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- This equals an additional 5000 MW of capacity for total US installed fossil power plants.
of excess O₂ and optimised combustion with reduced O₂ that can be achieved with the use of boiler optimisation software.

Muñoz and others (1993) discussed the development of a prototype automated diagnostic system, based on neural networks and mathematical techniques, that detects anomalies in the boiler combustion process by processing images of the flame. The prototype was used successfully at the Meirama, 550 MW coal-fired power plant in Spain.

In the beginning plants used open-loop optimisation software in an ‘advisory’ mode. In this mode, recommendations are provided by the software but decision making is undertaken by the plant operator. With the increasing use of, and confidence in such systems, closed-loop operation became progressively more accepted where the software determines new set points, communicates them to the control devices and reconfigures the control system based on the software models continuously (Swanekamp, 2000a).

Process optimisation results in less particulate matter, NOx, SO₂ and CO₂ emissions due to improved combustion and greater efficiency. Opacity, for example, has been shown to reduce by 15–30% by managing the trade-off between excess air flow (O₂) and boiler efficiency. Other demonstrated benefits include improved loss on ignition (LOI) levels, heat rate enhancements of up to 1.5% and more consistent steam-temperature control (McFarland, 2001).

Model-based plant optimisation using trends shown in historical data from operational instrumentation is discussed by Allan and others (2001). Many such knowledge-based computer systems are used today to optimise the combustion process including heat rate and steam temperature control and/or reduce NOx emissions and carbon-in-ash from baseline conditions (Rodríguez, 2000; Soud, 1999; Klinger-Rheinhold and others, 1995).

Since the mid-1990s dedicated software systems targeting NOx, SO₂, or particulate matter emissions and enhancing the performance of specific techniques such as soot-blowing have been developed. A brief discussion of technologies developed to reduce NOx emissions and improve the process of soot-blowing in coal-fired power plants follows.

### 10.4.1 NOx reduction

NOx emissions are closely linked to the combustion process and are a natural candidate for optimisation. The NOx reduction software receives the data on various control parameters of a coal-fired power plant such as coal-flows, excess oxygen, burner tilt and load as inputs and predicts the resultant NOx emissions, carbon-in-ash levels and other parameters as outputs. Models are created that use data either from the plant control system (DCS) or a set of real-time plant operating period data. The system can be used either in open-loop (that is advisory mode) or closed-loop mode which involves automatically changing plant settings.

The application of an advanced model-based NOx control scheme, as with other control schemes, involves the following (Lyet and others, 1997):

- **Building a model** where the advanced control algorithm utilises mathematical process modelling that can be obtained by:
  1. a model can be built from ‘first principles’, using the knowledge of the basic physics of the process (conservation of mass, momentum, energy, etc);
  2. the model can be fitted to a purely empirical mathematical form using only experimental input and output data (statistical approach).

A neural-net based model can be trained using experimental input and output data. A hybrid approach is also possible where certain unknown parameters of the first principal model are empirically fitted. It is then necessary to test directly on the plant either to calibrate or empirically fit the model. This process is known as **system identification**.

- **Design a controller**: using the model following system identification, the control algorithm is designed analytically to obtain the required response and add robustness to modelling errors. The result of this design process is a set of plant specific parameter values which
are used in the control algorithm calculations. Computer aided design tools are used to help automate the design procedure. Although this involves a high level of computation, current high-end, personal computers (PCs) are capable of performing the task.

- **Control implementation:** the control algorithm is installed and integrated with the plant control system. The algorithm can run directly on the plant DCS or in a stand-alone controller unit.

Several intelligent modelling systems continue to be developed in order to achieve maximum combustion efficiency. Commercial application of some of these systems show efficiency improvement ranging between 0.1% and 2.0%. This reflects a reduction in all emissions from a plant including particulate matter, NOx, SO2, CO, CO2 and trace elements, as well as lowering the costs of operation. Reported reduction in NOx emission averages between 10% and 25% without entailing excessive cost and whilst maintaining carbon-in-ash/loss on ignition at an acceptable level.

Several utility coal-fired power plants are currently using such systems successfully. It is expected that the use of these systems will increase firstly to achieve plant operation closer to required regulatory limits at reduced compliance costs and secondly to achieve maximum plant efficiency and hence profitability. Numerous software products are available on the market today aiming to minimise NOx emissions in coal-fired power plant. Data available prior to 1999 are included in Soud (1999). For more recent information see Labbe and Thorpe (1999); Copado and Rodriguez (2000); Cowder and others (2000); James and others (2000); McCafferty, 2000; Moreno (2000); Noblett and others (2000); Romero and others (2000) and many others (see IEA Coal Research, 2001b).

### 10.4.2 Intelligent soot blower control

Soot blowing plays an important part in efficient power plant operation. Removal of fireside soot deposit is a task usually achieved with high pressure and high temperature steam. Multiple sootblowers are continuously used according to predefined sequences and fixed schedules. The frequent operation of sootblowers wastes steam, increases blower maintenance costs and aggravates tube erosion. Infrequent soot blowing results in the accumulation of too much soot, leading to decreased efficiency, and can result in high stack opacity when a fouling area is being blown. Cheng and others (1999) discuss the design and implementation of an automated, intelligent, soot blowing advisory system at the South California Edison, Mohave, 2 x 800 MW, tangential coal-slurry, super-critical units.

Schlessing (1999) reported on optimisation of soot blower operation in Grosskraftwerk Mannheim AG (GKM), coal-fired, Boiler 18. Problems encountered at the plant included:
- high noise (>100 dBA);
- high heat loss;
- stress-induced cracks in the soot blowers;
- erosion of heating surfaces.

A soot blowing programme was devised on a shift basis of approximately seven to eight hours and the soot blowing operation was maintained at high pressure resulting in lower noise levels due to reduced steam mass flow in the soot blower, reduced stress cycle resulting in less material damage, fast operability following boiler start-up, lower heat and water losses and finally increased availability.

Following the benefits achieved with manual modification in Boiler 18, GKM decided to carry out a procedure to determine the data for an upgraded soot blower programme and its conversion to I&C parameters in Boiler 19. The procedure began by establishing the fouling criteria for boiler heating surfaces in order to decide the sequence of these plant criteria to actuate soot blower operation. The investigation resulted in establishing that with increased fouling, the tolerance ranges of the target values for parameters, such as secondary air temperature, feedwater heating and reheat injection, are exceeded. Soot blowing optimisation was thus based on the following conclusions and functions:
- high flue gas temperature downstream of the economiser indicates extreme fouling in the steam generator;
- low waterwall outlet enthalpy and high HP superheater injection mass flow indicates that the waterwall region is fouled;
- low waterwall outlet enthalpy reflects high flue gas temperature downstream of the economiser but if HP and reheat injection values are less than the target then the economiser requires cleaning;
- where the reheat injection mass flow exceeds the target value, the total heating surface on the flue gas side upstream of the reheat region is considered fouled. It is assumed that the reheat extraction steam quantity for consuming units, such as feedwater heating, gypsum drying, NH3 evaporator, is maintained at design value;
- if a noticeable fouling of the super heater surfaces is detected, that is the injection mass flows are low despite a correct operating mode and normal flue gas temperature, the soot blowers are to be activated;
- if cleaning results remain unsatisfactory the remaining soot blower levels are activated after an intermediate scanning of the effects achieved at that stage.

The fully automated soot blower optimisation logic programme has been in operation at GKM’s Boiler 19 since 1998 and due to its success GKM made the decision to apply the same logic programme at Boiler 18 (Schlessing, 1999).

Thompson and others (2000) reported on the development of a software to monitor boiler fouling and to provide advanced warning to plant operator when a fouling episode is imminent. The software uses a combination of combustion diagnostic techniques and convective section heat adsorption analysis to identify boiler operating conditions where ash deposition rates may be high and conducive to triggering a fouling episode. The software was implemented at the Wabamun, tangentially coal-fired unit 4 (300 MW) commissioned in 1967 and the Sundance power station units 1 and 2 in the USA.
The current trend in coal-fired power generation consists of increasing existing plant availability and reliability and reducing power generation and fuel costs. Another area of main concern is maintaining emission of pollutants below the limits imposed by national, regional and international legislation. The most economic method to achieve all these objectives is combustion optimisation that results in efficiency improvements.

Power plant instrumentation and control (I&C) systems play a vital role in coal-fired power generation and can directly impact plant performance. Advanced control systems are installed in power stations, to reduce operational and maintenance costs and emissions, as well as replace outmoded and increasingly hard-to-service systems.

All I&C devices can be included in one of the following categories:

- sensors (including signal conversion equipment);
- controllers (including associated control logic and operator interface stations);
- actuation devices (including positioners).

The I&C chain begins with sensors that carry measured values to controllers where a control strategy is activated based on the received values and the response moves to final actuating control elements. This loop repeats over and over during plant operation through a complex and multi-level communications schemes. ‘Smart’ devices, including sensors and actuators, continue to be developed in order to simplify and improve the control process. These advanced digital sensors that accurately measure and report key temperatures and flow rates can provide information that would result in higher efficiency and lower emissions for power plants. The information they provide on the state of the transmitter and the validity of the signal (for example whether the transmitter is faulty or suffering from calibration drift) would allow timely maintenance and hence continued optimum performance. The capabilities and low cost of digital signal processors is expected to result in many more of these sensors being used in the future compared to the numbers of mainly analogue systems currently utilised in many coal-fired power plants today.

Until recently, two distinct platforms were usually used in coal-fired power plant control. The distributed control system (DCS) which is designed to replace panel board controllers and recorders and handles large amounts of inputs/outputs (I/O) for continuous process control and the programmable logic controller (PLC) which was developed to replace hardwired relays and mechanical timers. The PLC performs efficient high speed and discrete control. Today, the distinction between the two plant control platforms is becoming less apparent as vendors introduce DCS with embedded PLC and unified DCS/PLC systems. Such systems can offer the features of both control platforms in one integrated package. However, it may be beneficial to keep the protection function of the PLC independent of the DCS. With the increasing power and reduced cost of personal computers (PC), these are expected to become a further platform for future development and growth. Use of proprietary DCS and PLC will become increasingly limited due to the end users’ demand for open architecture, interoperable DCS/PLC and PC based control and data acquisition.

Advanced, digital I&C systems are being installed from new and retrofitted in existing coal-fired power plants throughout the world. These systems enable:

- faster plant start-up and shutdown by programming plant control sequences;
- higher availability by detecting and indicating the causes of impending malfunctions;
- greater thermal efficiency by moving variable set points closer to the operating limits;
- reduced emissions by controlling the combustion process and downstream emission control technologies;
- lower maintenance costs by replacing pneumatic, electromechanical or electronic/analogue devices;
- decrease operational costs by reducing staff requirements.

There are several further developments that are currently being investigated which can accelerate the uptake of advanced I&C systems in coal-fired power plant. For example development of smaller and more robust I&C products that can reduce installation and maintenance costs and introducing advanced software to manage and extract information from the I&C system. Also, developing predictive or anticipatory diagnostic software to detect malfunctions and recommend actions to reduce unplanned plant outages.

New coal-fired power plants are in general built with a modern, advanced DCS/PLC. Control system upgrading by replacing vintage control systems with modern digital systems can contribute directly towards improved plant operational performance, identify fuel saving capacities and hence increase profitability. A large number of coal-fired plants have been retrofitted with the advanced digital system in many developed countries. It is of interest to report the use of these modern techniques in coal-fired power plants in other countries such as Colombia, Philippines, India, China and Zimbabwe.

Cost estimates and benefits analyses of upgrading vintage I&C systems vary greatly from one plant to another. However they all show that upgrading I&C system is cost-effective and amortisation can be achieved within two to five years due to higher efficiency and availability of plant as well as reduced maintenance costs and extended intervals between inspections. A further benefit is optimisation of personnel deployment. However, in a highly automated coal-fired power plant, attracting and retaining experienced and competent I&C staff is recommended.

11 Conclusions

Instrumentation and control in coal-fired power plant
The array of information technology (IT) products available today to power producers is vast. Adopting all products simultaneously is impractical and costly. There are also many different protocols, standards, operating systems and other incompatible aspects of IT products between suppliers. Interoperability between instruments, DCS and PLC, is vital for the successful upgrading, or application from new, of a modern I&C system. However, there seems to be a great deal of confusion with regards to the various standards for the different I&C networks available on the market today. Until a network, or more likely, a few networks become universally accepted within the I&C industry and with the end users, conflicting standards and incompatibility will continue to cause confusion. Interchangeability is another factor that is becoming increasingly important due to the rapid development in computer hardware and software technologies. New software management systems are coming onto the market to link the many disparate applications throughout a power plant to communicate and integrate successfully. Convergence of the two main control platforms, the DCS and PLC, is helping to ease the challenges of plant control system integration.
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