One Plant, One System

Benefits of Integrating Process and Power Automation

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Abstract

This paper discusses how a single integrated system architecture benefits plant operators, engineers, and managers. By taking a one plant, one system approach, end users of process and power automation systems can realize the benefits of an integrated system including increased energy efficiency, improved operator effectiveness, increased plant availability, reduced maintenance costs, and lower lifecycle costs. The architecture is based on Industrial Ethernet standards such as IEC 61850 and Profinet as well as fieldbus technologies. Emphasis is placed on connecting the substation automation system with the process control system via IEC 61850.

The energy efficiency gains from integration are discussed in a power generation use case. In this use case energy efficiency is realized with integrated variable frequency drives, improved visibility into power consumption, and energy efficiency through faster plant start-up times.

Substation visibility is becoming more critical in modern plants and facilities. IEC 61850 can be leveraged to provide substation visibility in a cost effective way. The substation standard as well as other open fieldbus standards can be used to create a plantwide asset management strategy. End user benefits are discussed for integrated electrical asset management. Condition based monitoring examples include Low Voltage (LV) motor starters via Profibus and Profinet while protective relays are integrated with IEC 61850.

Benefits of integration help not just the process engineer but the power engineer as well. A discussion of Disturbance Recording (DR) integration is made. An integrated system allows for remote access to the DRs and automated analysis of the recordings. Faster analysis of plant disturbances means faster problem resolution and root cause analysis which equates to increased plant up-time.

Several actual implementations of the one plant – one system architecture are discussed. The first case is capital expenditure (CAPEX) savings where cost avoidance is achieved in a substation wiring project. Next, a power management success story from a major oil and gas company, Petrobras, is discussed. In this case, Petrobras utilized integrated process and power automation to lower CAPEX, operational expenditure (OPEX), and explore future energy saving opportunities. In a third case, the one plant – one system approach allows E.ON, a Swedish power company, the ability to perform remote control of hydropower plants from its dispatch center in a cost-effective way. Lastly, a success story from Boliden's Aitek open pit Copper and Zinc mine is discussed. With integrated electrical, process, and maintenance systems, Boliden is able to operate and maintain the mining site from a single control room.

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Introduction

Substation SCADA systems and plant process control systems have been separated for years. Each system runs in its own island of operation with limited or no interfacing between each other. Trend setting modern plants are integrating the two systems together to realize both capital and operational expenditure savings.

This paper discusses the merging of the Supervisory Control and Data Acquisition (SCADA) with the Distributed Control System (DCS). SCADA is for applications with a large amount of I/O. Often the I/O is scattered with Remote Terminal Units (RTUs). The RTUs are similar to Programmable Logic Controllers (PLCs) as they do the control locally. The RTUs communicate back to the SCADA via telephone lines, Global System for Mobile Communications (GSM), etc. As a result, the bandwidth is low. SCADAs are often used to control substations. A DCS has controllers that take on specific functions for a particular plant area. The controllers communicate together over high speed Ethernet to form a distributed control system. Historians, asset management, and other high level applications gather and analyze data from the controllers. Distributed Control Systems are often used to operate process control plants.

From this point forward, integrating the SCADA with the DCS will be called Electrical Integration.

What is Electrical Integration?

Electrical Integration is the integration of process automation and power automation into one system. Process automation (DCS) and power automation (SCADA) is usually done in two separate systems for a given industrial site. Process automation is done by the plant DCS and can be divided into process instrumentation (for control and measuring of the process parameters) and process electrification (for monitoring and control of process actuators and rotating machinery). This is the core of traditional DCS. Power automation, however, is a new area for those favoring traditional automation. It is the monitoring and control of the power distribution of a plant, usually done by its own system. It can be substation automation for protection, monitoring, and control of the substation equipment, or more advanced power distribution control with power management [1]. The lines between the process and power worlds are becoming blurred.

Who are the users of Electrical Integration?

The users of Electrical Integration include power plants where the power is generated and process plants where the power is consumed. The area in between the power and process plants is called power transmission and distribution. Although Electrical Integration can be applied to transmission and distribution, it is not an area for consideration in this paper.

Objectives of Electrical Integration

Different industries have different objectives. Power plants want to optimize their generating capacity. Approximately 7 to 15% of the energy generated by a power plant never leaves the “fence” of the utility plant. This power is consumed by the use of plant auxiliary systems for anti-pollution and by an increase in cooling water pumping needs to control thermal discharge issues [2]. To optimize their generating capacity, power plants need to reduce their auxiliary system’s energy consumption.

Oil and gas facilities need to maximize production by keeping the production processes running especially at refineries and offshore platforms. Therefore, load shedding during power interruptions is very important. Pulp and paper mills and metals and mining facilities use a great deal of energy. They treat electricity as a raw material cost so peak shaving is important to these industry segments.

Traditional approach

Integrating process and power automation systems is not a new concept. Leading companies have been delivering this type of integration for over 20 years. See Figure 1. This traditional method of Electrical Integration has limitations, however. On the substation side, there are too many standards and no one standard has become dominant in the marketplace. There are two separate systems. Typically a DCS is used for process automation, while a SCADA is used for power automation. The cost to engineer the power system is high when multiple vendors supply equipment that uses different communications protocols. The lifecycle costs of a system with a hodgepodge set of communication links are also very high. Integration of the two systems requires custom, device specific solutions on a project by project basis. These device specific solutions often equate to extensive hard-wiring, low bandwidth serial buses, and complex software gateways. Often overlooked, this integration methodology causes critical electrical asset health information to be lost. Organizational barriers typically exist among process and power departments creating an operational separation in the plant's work flows. These same barriers can also be found within automation and power system suppliers. A new approach is needed to overcome these barriers [1].

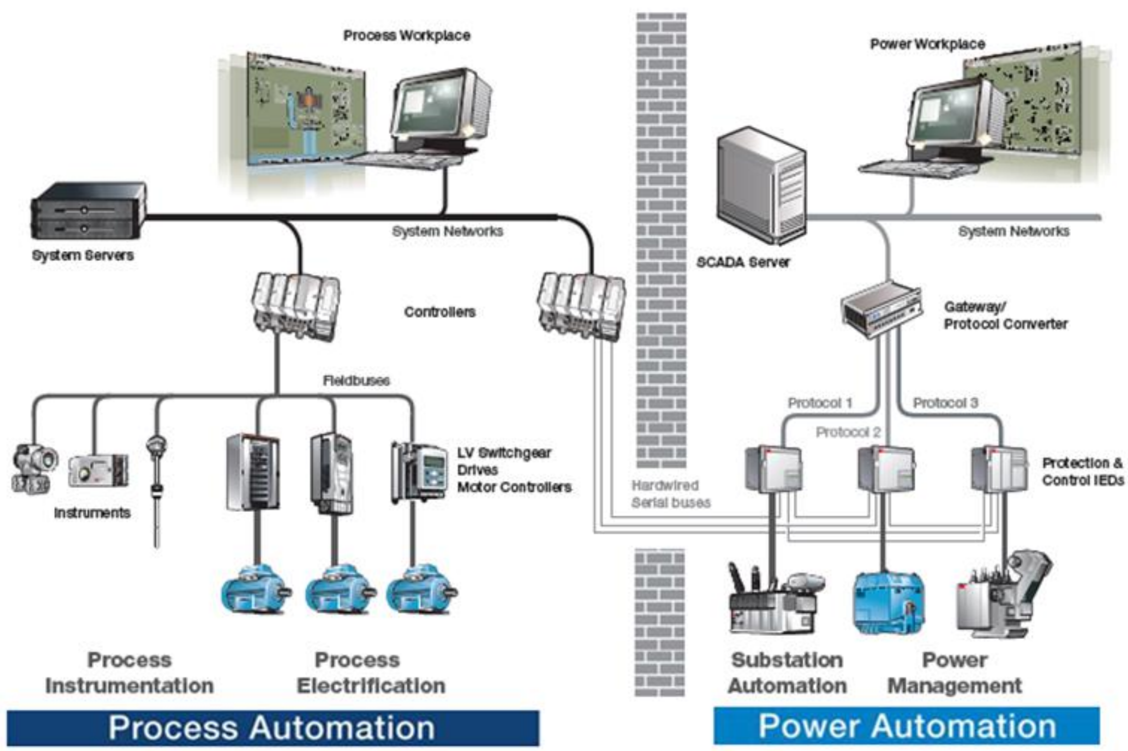

Figure 1 – Traditional approach to Electrical Integration

Full plant integration

The integrated architecture is used to overcome the barriers of traditional Electrical Integration solutions and offer full plant integration. Full plant integration is accomplished by taking advantage of open standards from both the process control and power industry worlds. See Figure 2. A common system architecture is provided for both process and power automation. A true integration platform is needed to seamlessly combine the electrical control system, process control system, plantwide data historians, and maintenance equipment health information. This enables personnel to make informed decisions on energy management, lifecycle management, and up-time on a plant-by-plant, process-by-process, or global basis, as user needs dictate. The platform is used as a common engineering and production interface for process control, electrical, and safety systems.

With full plant integration, there is one integrated system for both process and power automation. This common system architecture allows the same hardware and software components to be used within the single system. For example, the same DCS controller can be used for process applications, such as PID loops, or for power management functions such as load shedding. Common software and hardware leads to common engineering for all application areas of the plant. Operations can now be integrated for both process and power operators. Plantwide information management can provide access to all plant data from a single database. Finally, a common asset management strategy can be deployed for both process and power assets.

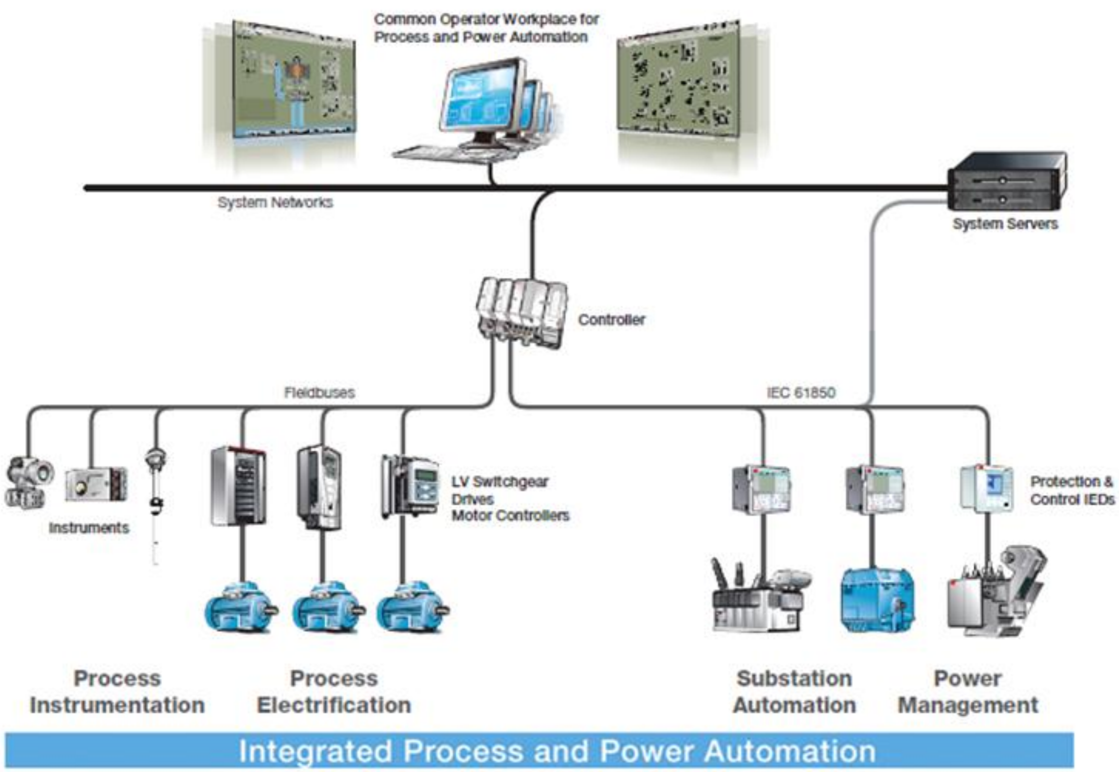

Figure 2 – Modern approach to Electrical Integration

Open industrial communications standards

There is a variety of industrial communications standards for the process and power industries. To enable the integrated architecture, open industrial standards must be implemented. For power automation, the only global standard for substation automation available today is IEC 61850. For process automation, there is a variety of choices including Foundation Fieldbus, HART, Wireless HART and Profibus. The Low Voltage (LV) process electrification area includes Profibus, Profinet, ModBus, and Modbus TCP. Of these choices, Profinet and Modbus TCP are Ethernet based. The current trend is to have a common Ethernet backbone for all process and power automation devices in a plant. Also, using Ethernet makes integration easier.

What is the IEC 61850 standard?

Fifty years ago, substations were equipped with big heavy transformers and circuit breakers. Today, substations are still equipped with big heavy transformers and circuit breakers but operate more efficiently than the ones of the past. Fifty years from now, substations will likely still be equipped with big heavy transformers and circuit breakers and perhaps operate more efficiently than today. The difference between today and fifty years ago is how electrical devices communicate with each other. In the past, minimal amounts of information were communicated via hard-wired signals. Today, hard-wiring is still used in some cases, but both serial and Ethernet has moved into the picture enabling more data to be communicated efficiently. Ethernet's bandwidth is pushing out serial communications. As a global standard, IEC 61850 has made its debut into industry. IEC 61850 is a global communication standard for power distribution and substation automation. Often people consider it a European standard, but it is a global standard common for both IEC and ANSI. IEC 61850 features a flexible and open architecture for MV and HV devices. It is implemented on Ethernet but it is not tied to Ethernet. It is often referred to as future-proof, as the standard will be able to follow changes in communication technologies [3]. Details can be found in the Appendix section titled, "What is IEC 61850".

What is Profinet?

There is a misconception of the Profinet standard. Profinet is not Profibus over Ethernet. Profibus is an open fieldbus standard that utilizes RS485 serial communications. Profinet is an Industrial Ethernet standard that enables devices to communicate with each other from the plant floor to the MES level. Profinet can coexist on the same Ethernet backbone with other industrial Ethernet protocols and IT systems. With the use of a "proxy" from an interface module, however, legacy Profibus networks can be integrated onto an Ethernet network [4]. In a survey taken at the October 5, 2011 PTO General Assembly, diagnostics and asset management of equipment plus IT integration were among the top important functions of Profinet. Asset management will become an important part of Electrical Integration.

Similar to the IEC 61850 standard, Profinet communicates at layers 1 and 2 of the ISO/OSI stack. Profinet is used in process automation as well as discrete factory automation and motion control. Profibus is often used as a communications means for LV equipment. The Profinet standard offers Application profiles. An Application Profile is an add-on that provides an application-specific function [5]. The profiles must be approved by the PI organization to ensure interoperability. For example, Profinet IO is used for communication of field devices and PLCs and DCS controllers in real-time. The field device may be a LV drive, LV switch gear, or a smart temperature transmitter.

Often Modbus or Modbus TCP is used for electrical equipment control. Contrary to Profinet and IEC 61850, Modbus TCP uses the whole TCP/IP stack which reduces speed and determinism. Since layers 1 and 2 are primarily used by Profinet and IEC 61850, they are faster protocols than Modbus. Modbus TCP uses a client/server relationship so it requires more communication (half duplex). Modbus TCP has a limited message size compared to Profinet. Also, Modbus cannot be used for motion control because it is too slow. The trend in industry is to move away from Profibus and Modbus and more towards Profinet and IEC 61850, since they both can deliver an increased amount of asset health information more quickly from field devices including drives and switch gear.

Benefits of Electrical Integration

Reduce investment costs

Traditional integration methods require a SCADA and a DCS. By using one system instead of two and using standardized Ethernet-base solutions, design and construction investment costs will be reduced. Electrical Integration eliminates duplicate equipment such as servers, workplaces, network switches, HMIs, and other IT devices, thereby lowering the system's footprint size. Installation and commissioning costs are reduced with integration by eliminating the need for complex software gateways and protocol converters as well as the tedious engineering of these components. Wiring is reduced by using Ethernet-based solutions of IEC 61850 instead of hardwiring. Project execution and commissioning time are shortened by using standardized solutions during project execution, for example, protection logic in the IEDs, control logic in the controllers, libraries, and faceplates to interface all devices from process and power. A real world use case is discussed in the Demonstrated Cost Savings section.

Plant substation visibility with cost effective asset management

Critical plant equipment health, especially electrical assets, can be difficult to monitor in a cost effective way. As a result, electrical asset health is often neglected and overlooked until a plant disturbance forces maintenance and repairs to be done. The integrated architecture leverages open Ethernet standards such as IEC 61850 and Profinet to monitor the health of vital equipment plantwide. Visualization of the entire chain of assets that comprise a particular plant function from protective relays in the plant substation down to the temperature transmitters can be easily be viewed and monitored with an integrated power and process approach. See Figure 3. Although the IEC 61850 standard does not specify asset management, it does make the asset health data available to end users.

The importance of plant substation visibility is critical in monitoring the functionality and operations of electrical systems. Often critical functions like bus transfer events will occur without an operator's knowledge. PLCs without HMI consoles are often used to control the plant substation functions. This lack of visibility can cause safety and operational issues. Some facilities still rely on workers to perform manual field observations such as transformer temperatures and power meter readings. This method is a costly and unreliable way of obtaining critical substation information and it can be eliminated with Electrical Integration. The IEC 61850 standard, when implemented in an integrated system, provides cost effective plant substation visibility.

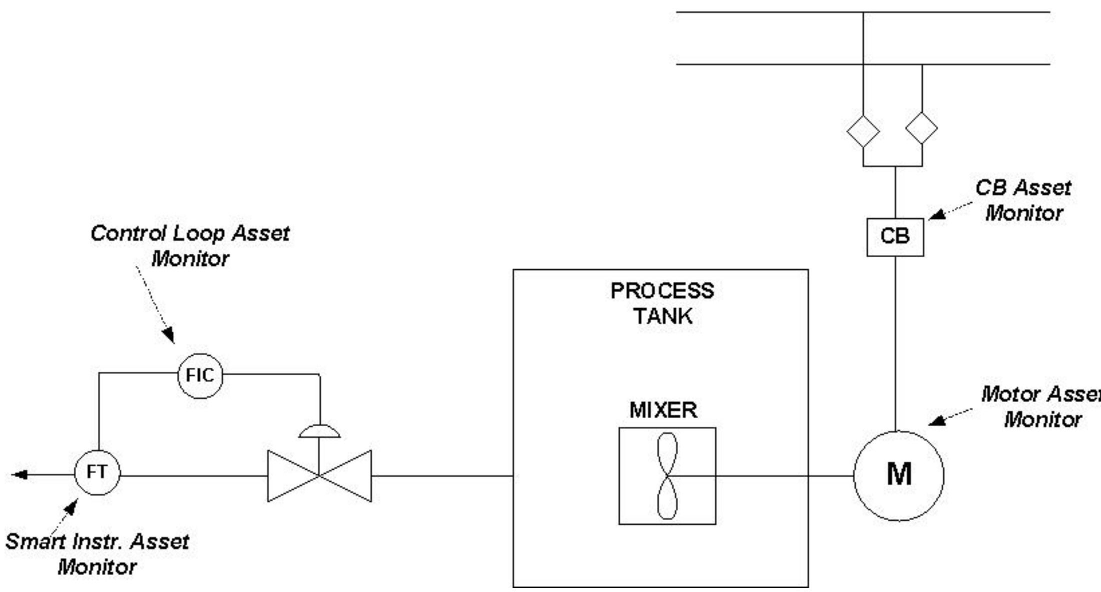

Figure 3 – Health of the entire chain of assets of a plant function.

Plantwide asset management strategy

Asset management is the ability to maintain the health and usage of products and systems throughout their entire lifecycle. Asset management can mean a number of different things to people. With respect to utility plants and production facilities, asset management involves substation equipment health, motor health, power and energy management, instrumentation health, process optimization and so on. Asset management strategies are implemented to minimize down-time and unscheduled shut-downs, improve Overall Equipment Effectiveness (OEE), enable predictive maintenance strategies, maximize the effectiveness of maintenance activities, and capture and use workforce knowledge. OEE is defined as follows [6]:

OEE = Availability * Performance * Quality

Availability = **Unplanned Downtime (Actual Uptime/ Total Time Available)**

Performance = Speed (Actual Speed/ Ideal Speed)

Quality = Valuable Operating Time (# Good Products/ # Products Produced)

Figure 4 illustrates the opportunity for asset management. It is a graph of Throughput versus Time. The BEP or Break Even Point is the dividing line between profit and loss. Any production above BEP is a profit while anything below is a loss. Ideally, the Operating Target and the Design Limit could be equal, but performance will be constrained by asset life, safety, and other considerations. Figure 4 highlights a typical scenario: While the plant is in Start-up mode, operators will try to quickly ramp up to the

Operating Target. During this phase, there may be a small process upset that causes production to slow down. After operators get it back up to speed, a plant upset occurs, and production slows down to a partial shut-down. After the problem is fixed, production is ramped back up to speed, but then a more serious problem occurs. Now the plant is in full shut-down.

Our goals of asset management are to keep the assets available for production, prevent plant upsets, and run assets closer to design limits. By optimizing plant asset availability, one can reliably produce more at a lower cost. Availability will be reduced due to planned or unplanned down-time, set up times, part changing, or improper maintenance. This results in lost capacity and is a barrier to achieving the breakeven point.

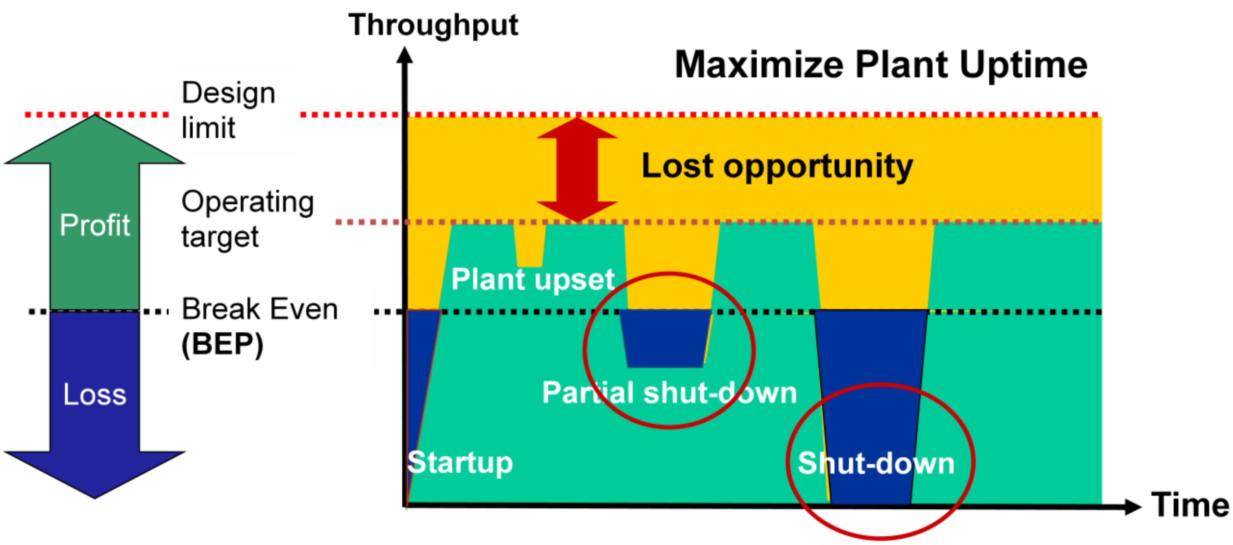

Figure 4 – Opportunity for asset management

Types of maintenance

There are four strategies used in most plants for maintenance. Each has an important role to play.

- **Reactive maintenance** or **fix on failure** is performed only when an asset fails. As a plant strategy, this approach would be used where there is a low economic cost to failed devices, such as monitoring only devices, or to fix accidental failures.

- **Preventive maintenance** is used for time-based or interval-based scheduled actions. Preventative maintenance is done at a specific time interval whether the device requires it or not. For example, most car owners have their motor oil changed every 3000 miles whether the oil is dirty or not. This is the most common type of maintenance performed at plants.

- **Predictive maintenance** is performed only when the device truly requires maintenance. Condition monitoring of the device is done based on the analysis of real-time and/or historical data to determine the health and performance of a device. This type of maintenance is typically applied to critical plant equipment where a failure would have significant impact on the plant's production. For an automobile analogy, an oil opacity sensor is used to monitor the cleanliness of the motor oil. When the oil's opacity reaches a predefined limit, the driver is notified via dashboard maintenance light.

- **Reliability Centered** or **Proactive** maintenance is the combination of Reactive, Preventative, and Predictive.

Need for plantwide asset management

According to a study done by Shell Global Solutions, the majority of maintenance work is not needed resulting in doing too much unnecessary maintenance. Figure 5 shows 63% of maintenance labor resulted in no action. The top two reasons were false alarms where the maintenance technician found no problem, and the second is routine checks were performed but no adjustments were made. There are some disadvantages of doing time-based or fixed interval preventative maintenance. One key disadvantage is the equipment is now exposed to possible damage [7]. Another is more frequent access to plant equipment is required which can equate to more down-time. Replacing existing parts with new ones opens the door to infant mortality of new parts [7]. There is also failure risk each time a technician performs maintenance on a device. Sometimes, the device is not re-assembled properly causing it to function improperly or fail completely. In general, using predictive maintenance can reduce the amount of unnecessary maintenance activities.

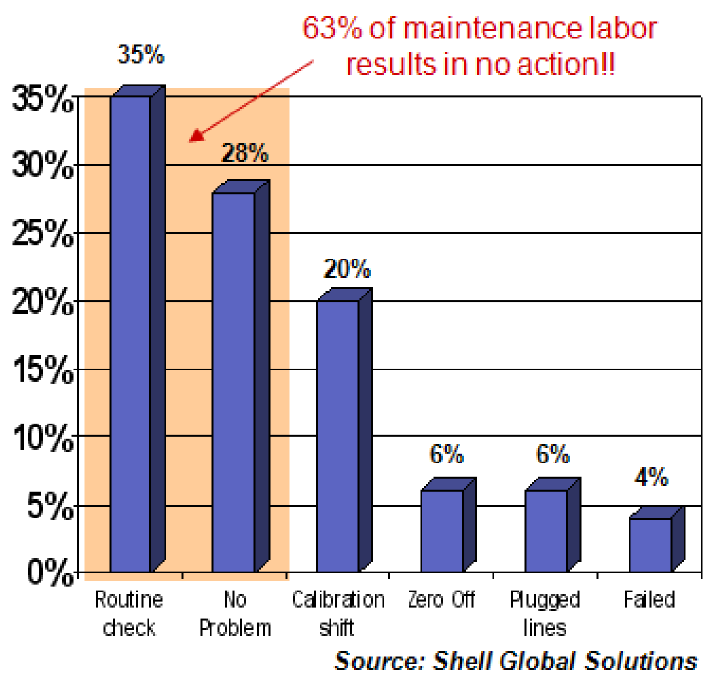

Figure 5 – Maintenance labor categories.

Reliability centered maintenance

The Reliability Services Group of a major process and power company did a survey of maintenance practices of 71 different plants in North America in 2007. The results are plotted as percent of unscheduled maintenance hours each of the 71 plants experience in one year in Figure 6. Note that only less than 5% of the plants have an accurate reliability centered maintenance program. The 71 plants are classified into one of the four types of maintenance. As one can see, there are very few proactive plants. In fact, only 18% of the 71 plants fit into this category. About 20% use predictive maintenance while 34% use preventative maintenance. An amazing 28% of the 71 plants surveyed run to failure. They are letting equipment break first and then go out and do something about it. Billions of dollars in production losses occur each year due to unscheduled down-time.

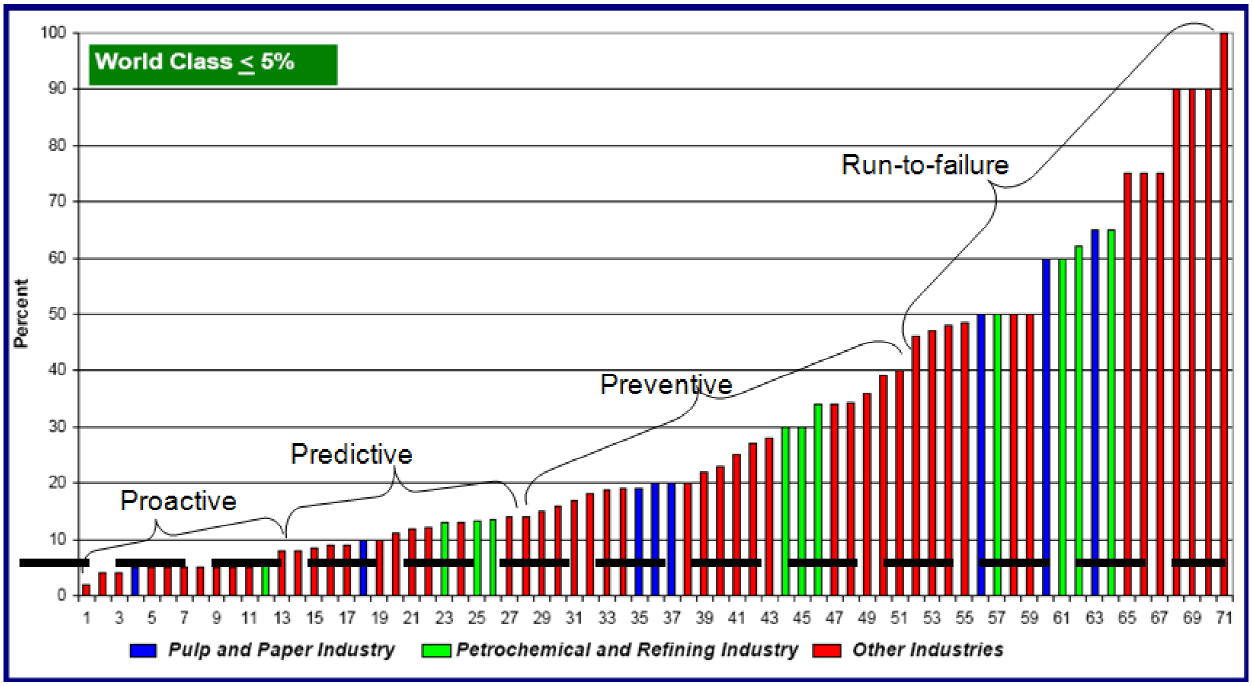

Figure 6 – % of Unscheduled Maintenance Hours each of the 71 plants experience in one year. [SOURCE: World-Class Reliability® Benchmarking, ABB Reliability Services]

Value versus adoption: lack of focus on electrical equipment

Another benefit of Electrical Integration is reduced maintenance costs. According to a survey done by the ARC Advisory group, asset management is typically deployed for smart instruments. See Figure 7. Smart instruments, however, have the lowest return on value from predictive asset management. Electrical equipment maintenance, on the other hand, has high value but low adoption. Adoption rates have been low in these high value items such as electrical equipment health due to the difficulty and high cost in accessing the necessary information. With Electrical Integration, it is now possible to extend asset management into electrical equipment. According to the graph, electrical equipment offers one of the largest opportunities for asset management solutions. With Electrical Integration making it easy to extend asset management into electrical equipment, the electrical equipment bubble in Figure 7 will rise up to high on the adoption scale and provide high return value.

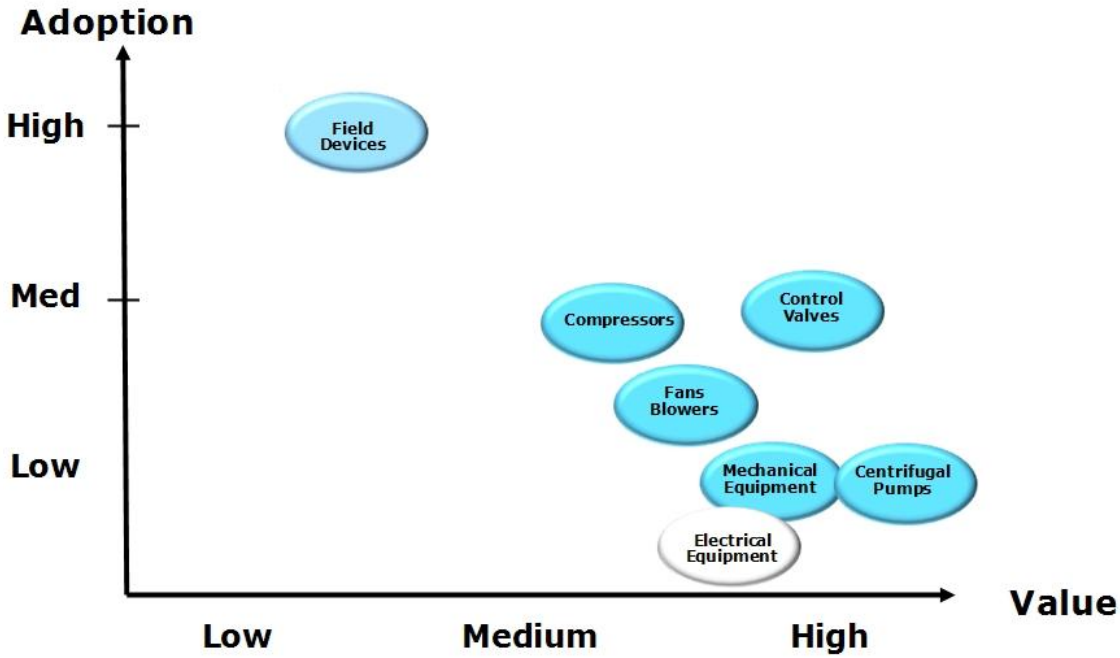

Figure 7 – Adoption rate of plant equipment versus value (Survey completed by ARC Advisory Group). [8]

Vertical versus Horizontal Integration

Integration of data is done vertically and horizontally with Electrical Integration. See Figure 8. Non time-critical data such as alarms and events, circuit breaker status, and disturbance recordings are integrated vertically through an IEC 61850 OPC server. Vertical communication is done with Manufacture Messaging Specification (MMS). Report Control Blocks (RCBs) define the type of information sent from the IED to its clients via the OPC server. RCBs are event triggered and can be buffered within the IED. The events are time stamped by the IED before being sent to the OPC server. If the devices are all time synchronized together, the events can be placed in common SoE (Sequence of Events) list for analysis. This will become critical when discussing the possibility of a single plantwide sequence of events list.

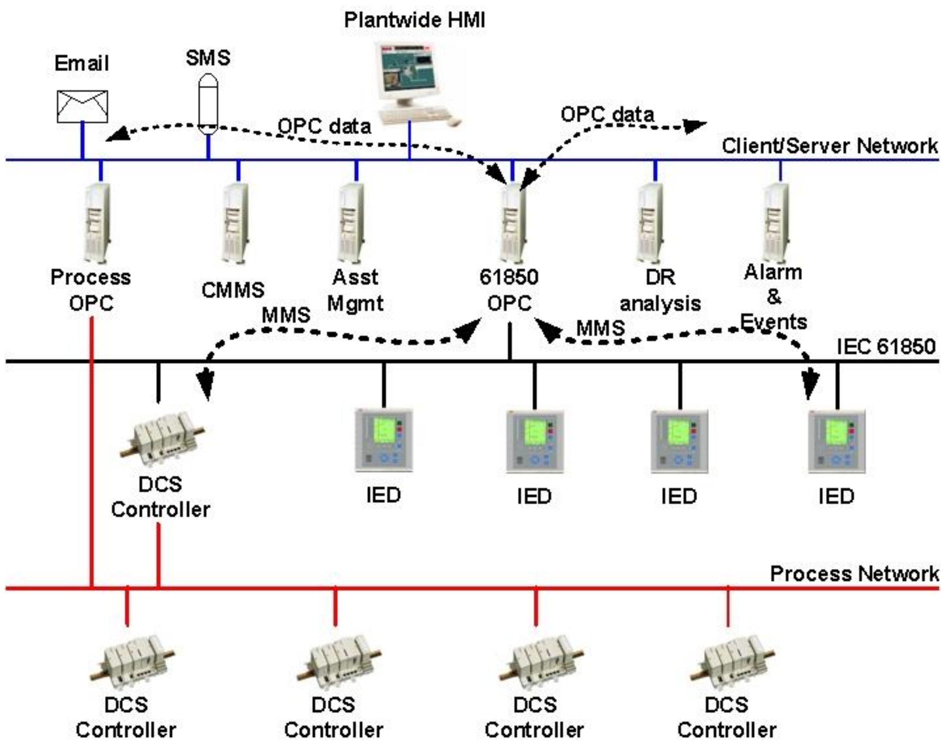

Figure 8 – Vertical Integration of power and process data via MMS.

For fast time-critical communication among electrical devices, Generic Object Oriented Substation Event messaging or GOOSE is used. GOOSE can transmit any type of process data between IEDs. GOOSE is used for fast response actions on the substation bus.

The DCS controller in Figure 9 has dual roles. On one hand, it acts as a process controller on the control network. Here it concerns itself with temperatures and pressures and performs control actions with PID loops as control outputs. It communicates with communication modules for Profinet, Profibus, and other open fieldbus standards as well as traditional IO boards. Its second function is to act as an IED on the substation's IEC 61850 network. The controller is now transformed into an IED and communicates horizontally with the other IEDs in the substation. While on the substation network, the controller reads voltages and currents and performs actions such as fast load shedding with GOOSE in the event of a power glitch. See Goose Messaging in the Appendix for more details.

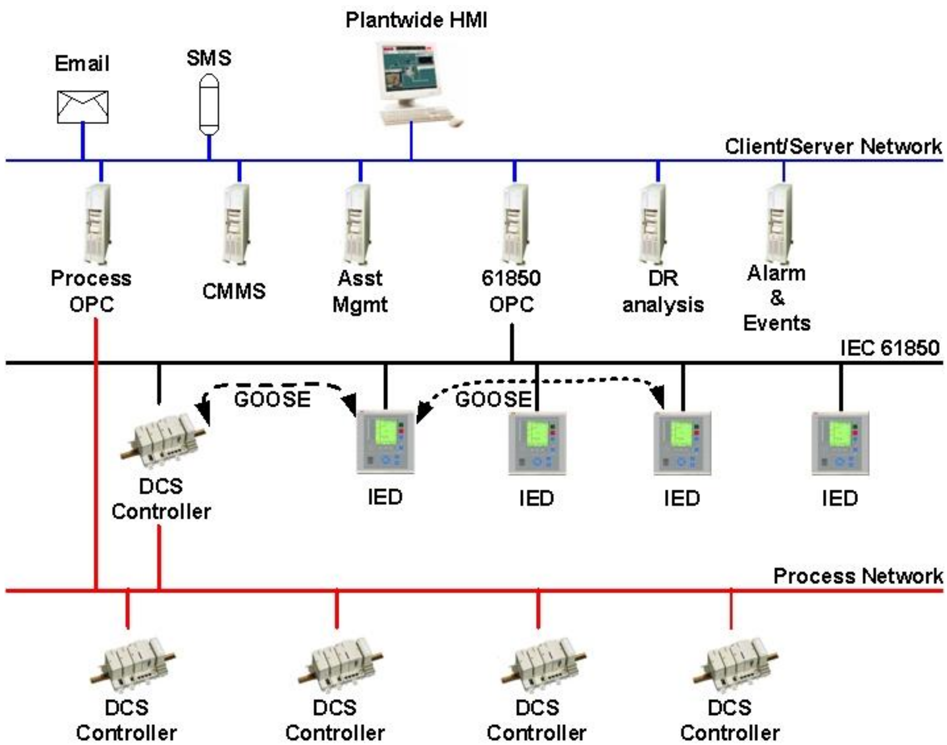

Figure 9 – Horizontal Integration of power and process data via GOOSE.

Asset monitor flow

An asset monitor is a software component that determines the health of an asset from one or more data sources and reports back the device health to the end user. Asset monitors provide detailed information for predictive maintenance and suggested actions. It watches over the health of a device by monitoring both real-time and historical data. It processes the data through an algorithm specified for the device and compares the results to a predetermined set of operational and functional parameters. When a problem is detected, the asset monitor will send out a series of alerts to the appropriate personnel and business systems. For example, the asset monitor will generate an alarm and send it to the plantwide SoE. The alarm can also be routed through a paging system to promptly notify an on-call maintenance engineer. In parallel, the alarm can be sent to an integrated CMMS (Computerized Maintenance Management System) which will automatically open a work order. See Figure 10.

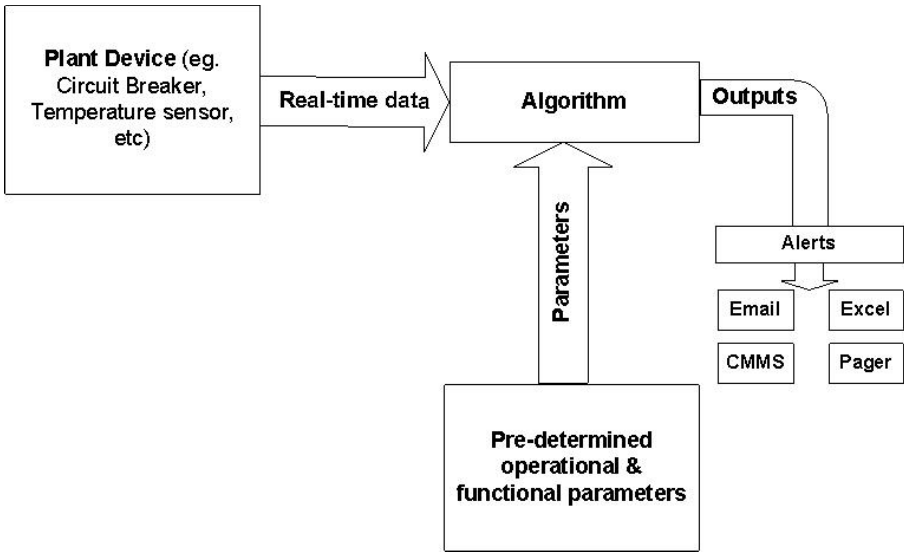

Figure 10 – Asset Monitor flow

CMMS integration

An integrated system allows for a centralized interface point for the back office plant CMMS. As a result, there is only one CMMS interface to maintain. By streamlining maintenance activities through reduced paperwork and administration efforts, maintenance planning is now more efficient with a single source for maintenance analysis. Maintenance planning becomes more efficient. Less time is spent planning, leaving more time for actual maintenance work.

Reduced maintenance costs

An integrated system provides for a consistent asset management strategy regardless if there is concern about the calibration of a smart instrument or predicting the remaining life of a MV circuit breaker. It provides a common user environment for both operations and maintenance departments. Relevant actionable data is provided to the right person including operators, engineers, and maintenance personnel. Problems can be analyzed and diagnosed more quickly and prevent plant down-time.

Single strategy for asset optimization

Asset Optimization is not just for smart field instruments. See Table 1 below. A plantwide asset management system reduces maintenance costs through improved visibility and back office system integration.

Condition based management reduces operational costs and any required down-time can be planned with minimum impact on the production. Collecting and organizing diagnosis and status information with well integrated links to the CMMS provides the maintenance staff with efficient tools to better plan, organize, and follow-up on maintenance activities.

The advantages of using asset monitors include:

- Capturing workforce knowledge of equipment and plant condition

- Gaining knowledge of the root cause of problems
- Enabling predictive maintenance strategies
- Improving Overall Equipment Effectiveness (OEE)
- Minimizing down-time and unscheduled shut-downs
- Early diagnostics to avoid costly repairs
- Reducing of process-critical faults
- Optimization of maintenance costs and schedule
- Predictive instead of preventive (time based) maintenance
- Data for planning of maintenance
- Optimization of process performance

Table 1 – List of plantwide asset monitors

Process	Electrical
Instrumentation	Transformers
Rotating Equipment	LV Circuit Breakers
Vibration	Motor Starters
DCS Controller Health	LV Switchgear
IT Assets	Motors
Heat Exchangers	Drives
Control Loops	Protective Relays
Other Process Plant Equipment	Other Electrical Equipment

Remote access

Electrical device health information is lost with legacy system integration methods. With IEC 61850 and open fieldbus standards, the hidden critical plant electrical equipment health is now revealed. Plants can take advantage of web enabled devices to easily access important information from its assets with centralized remote access to critical plant equipment. This includes circuit breakers in the substation to pressure and temperature transmitters in the process plant. For example, remote HMI web access is available to modern protective relays and MV/LV drives via Ethernet. Other web enabled devices include LV switchgear (Smart MCCs), Profinet devices such as drives, and DCS and PLC controllers. Device Type Managers (DTMs) are used to access data from field devices. DTMs are open standard software drivers that provide remote diagnostics, configuration, and parameterization of smart instruments. Open fieldbus standards such as Profibus support DTMs. For example, a valve positioner DTM provides important valve diagnostic information such as valve signatures. Network switches typically have web access that allows users to view a wealth of information about the health of the switch as well as the network itself.

Condition based monitoring examples and integration benefits

LV motor via Profibus and Profinet

Although IEC 61850 does not address low voltage equipment, the integration of intelligent LV equipment to the DCS is just as important as integrating MV/HV substation equipment. Profibus is often used as a communications means for LV equipment. In the past few years, however, Profinet has started to gain acceptance in LV switchgear communications.

One benefit of integrating intelligent LV switchgear to the DCS includes shorter time to complete repairs. With quicker detection of failures and root cause analysis via integrated asset monitors, technicians will have greater knowledge of the problem and a plan of action before they go into the plant to make the repairs. Integrating the LV maintenance system to the DCS allows all plant teams to be informed and become involved in improving plant performance and up-time. Segregated systems equates to uncoordinated actions and decisions that can result in inefficiencies and lower production.

Twenty-first century LV systems provide continuous condition maintenance information on the health of the plant's LV switchgear. They have asset monitors that provide predictive and proactive condition monitoring. The asset monitors identify what the problem is; where the problem is; the severity of the problem; who should initiate actions (for example, operator, maintenance, and/or engineer); what caused the problem; and most importantly, what specific action is needed to solve the problem.

Unnecessary maintenance is avoided by changing from a scheduled based maintenance approach to consumption based maintenance. Consumption based maintenance focuses on how much the equipment is used and at what power levels. Even if the equipment is used occasionally but at high power consumption, it may need maintenance sooner than if the equipment was used more often but at lower power consumption.

Figure 11 illustrates a smart MCC layout as part of a seamless integrated architecture. Flow A in the diagram shows the DCS controller monitoring motor status and sending start/stop and rotation commands through fast control signals. Operator actions plus alarm and event data is sent to and from the HMI through the OPC server in Flow B. The Asset Management system monitors time-stamped alarm and events as well as diagnostic data via Flow C. It performs real-time condition monitoring of the motors, switch gear, and also cubicle health via asset monitors. Some examples of available data inputs to the asset monitors are described in Table 2.

Table 2 – Data inputs to LV switchgear asset monitors

Operating Data	Electrical Data	Service Data	Cubicle Data
Motor current	Phase voltages	Motor operating hours	Power losses
TOL (Thermal Overload)	Active Power	Number of starts	Module insertion cycles
Run-time hours	Apparent Power	Number of overload trips	Contact temperature
Remaining cool down-time	PF		

A high level Asset Monitor will cover all four types of maintenance (reactive, preventative, predictive, and proactive). It looks not only simply at the data from the motor but it includes cubicle data to determine overall health of the MCC.

The benefits of an integrated architecture include reducing time to repair, and shifting from a consumption based maintenance program to a predictive and proactive program. With quicker detection of failures via integrated asset monitors, technicians will have the right knowledge of the problem and a plan of action before they go into the plant to make repairs. Integrating the LV maintenance system to the DCS allows all plant teams to be informed and become involved in improving plant performance and up-time. Segregated systems equates to segregated events that result in uncoordinated actions and decisions that equate to inefficiencies and lower production.

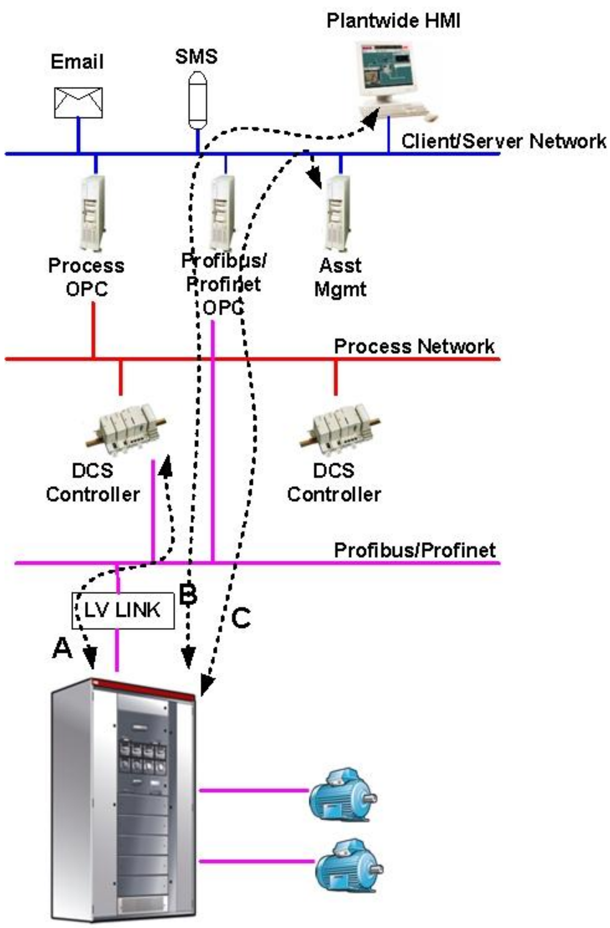

Figure 11 – Three distinct LV data flows. A = Fast control signals. B = Operator actions plus alarm & event data. C = Diagnostic data to Asset Monitors.

Condition based monitoring for protective relays via IEC 61850

Asset management is critical for substation performance. Modern IEDs perform extensive data collection from the substation equipment and power network. They have expanded capabilities that provide real-time circuit breaker, transformer, and motor health information via Condition Based Monitoring (CBM). Through vertical integration, the results of the CBM are analyzed by Asset Monitors in the Asset Optimization system. See Figure 8. The data, however, is often ignored either due to lack of analysis tools, lack of engineers to analyze the data, or simply lack of access to the information [9]. An integrated system reveals this substation information. Having advanced condition monitoring functionality in an integrated asset management server can provide valuable indications for future maintenance activities [9].

Circuit Breakers

An example of integrated electrical asset management is station health. Station health can be broken down into Circuit Breaker (CB) health and Station Battery supervision. An alarm is activated should the battery terminal voltage rise above or falls below preset limits over a period of time.

For circuit breaker health, the relay monitors a variety of parameters and data. For example, the Circuit Breaker Status function monitors the CB's position (open, close, or intermediate). Other parameters are outlined below [10]:

- **Operation Monitoring Time** – CB Operation Monitoring Time is used to determine if a CB has been inactive for an extended period of time. Inactivity is defined as the CB being in the same position for a certain period of time. If the relay determines that the Operation Monitoring Time has been exceeded, then a maintenance alert is generated.
- **Breaker Contact Travel Time** – For this function the IED determines the time to open or close a circuit breaker. Long traveling times indicate the need for maintenance of the circuit breaker mechanism. A maintenance alert will be generated if the breaker contact travel time is exceeded.
- **Operations Cycle Counter** – Some maintenance activities are based on the number of CB operations. Once the operation counter limit is reached, an alert is generated.
- **Spring Charge Indication Time** –The circuit breaker's spring should charge within a certain period of time. If it takes too long, then a maintenance alert is given.
- **Breaker Wear** – Predicting breaker life is important. Each time the breaker is tripped, its life is shortened. The amount it is shortened depends on the current during the trip. The remaining life is calculated from the manufacturer's breaker trip curve.
- **Accumulated Energy –** Accumulated Energy is calculated during the operation of the breaker. If it is off spec, then an alert is generated.
- **Gas Pressure Supervision** – Some breakers (SF_6) use gas to extinguish the arc during operations. Therefore, so the having the correct gas pressure is critical. If the gas pressure is too low, then the breaker goes into a locked state and an alarm is generated.

Network security is always a concern especially when using Ethernet. Sometimes a DoS (Denial of Service) attack can occur. In this situation, the devices on the network are being bombarded with messages. The source of the DoS can be accidental or malicious in intent. Sometimes devices on the network may fail and unintentionally flood the network with messages. Other times, a computer hacker may intentionally create a DoS attack in hopes of disabling network functionality or simply to create chaos. In either case, the devices will then begin to consume too much CPU time while trying to process all of the messages. In the case of a DoS, IEDs with network protection will limit its CPU processing of the flooding messages while still maintaining protection and control of the substation's electrical equipment. Another security concern may be attempts to access a network device by an unauthorized person. In this case, the IED can generate alerts to the appropriate personnel whenever a user's login attempt fails too many times. It can also generate and log an event anytime a user successfully logs into a network device in order to create an audit trail of network activities.

Motors/Transformers

Condition monitoring is typically done for motor and transformer protection. A temperature rise may indicate a critical condition even when the load current is on nominal level. For example, if a motor cooling system is inhibited due to dust or dirt or perhaps a broken cooling fan, the motor's temperature will rise but the load current will remain normal.

Motor protection health and circuit breaker health parameters are very similar. Table 3 shows the IED condition monitoring functions for a motor including trips, counters, and timers. When alarm levels are exceeded, alerts are generated and sent to the appropriate personnel for action as illustrated in Figure 10.

Table 3 – Typical motor protection health parameters.

Trips	Counters	Timers
Short circuit	Motor starts	Motor running hours
Motor acceleration	Emergency restarts	Time between starts
Under voltage	Starter operations	

For transformers, current, power and temperature are the most important CBM data with temperature being the most critical parameter. CBM for transformers is not as clear cut as it is for circuit breaker maintenance. For example, an ambient temperature rise in the transformer should be followed by an increase in the load. If not, then there may be a maintenance issue with the oil. Transformer monitoring is not as straight forward as circuit breaker monitoring. By monitoring the circuit breaker's number of operations, trips, etc. maintenance activities can be scheduled. So, when doing transformer condition monitoring, it is important to capture workforce knowledge of the transformer and configure it into an asset monitor.

In these situations with motors and transformers, the protective relay will report a temperature problem but the overload protection can be automatically adjusted to protect the equipment.

Asset management conclusion

In summary, to maximize a plant's substation visibility, end users should plan their Electrical Integration asset management strategy ahead of time. Often, they want to wait until after commissioning is complete before developing and implementing an asset management strategy. Time becomes critical and the end user wants to concentrate on production first and then maintenance second. The problem with this approach is no one will want to make changes to the power automation system after it is fully in production. The second issue is asset management is critical during the plant start-up so now the critical electrical health information may not be readily available to engineers and operators when they need it the most.

Benefits for the power engineer?

Enable the power engineer

From time to time, the power engineer may need to interlock the DCS from starting/stopping motors. For example, during a plant start-up, the power engineer will want to stagger the starting of inductive loads by monitoring local feeders by interlocking the DCS control of the motors.

In the past, the power engineer could not do so without complex software gateways or hard-wiring signals between the substation system and the DCS when Modbus is used in the substation. Modbus has a master/slave communication scheme. As a result, special logic is required when using Modbus to allow the power engineer to interlock the DCS operator. Moreover, Modbus is very slow. It can take seconds for the operator to see feedback from the relay after initiating a state change. The extra logic will make the communication more complex and therefore, increase lifecycle costs. With traditional Electrical Integration there needs to be a decision on whether control shall be done from DCS or the power distribution system.

In contrast to Modbus, IEC61850's GOOSE messages are multicast so extra logic is not needed to interlock the DCS operator. The power engineer can interlock the DCS operator and the DCS operator will have fast control over the electrical equipment with IEC 61850.

Disturbance recording integration

Disturbance Records (DRs) functionality often needs extra wiring and equipment to trigger and gather the recordings. Today, with the use of Ethernet and the IEC 61850 standard, the disturbance recordings functionality is enhanced and the extra wiring and equipment can be eliminated. For example, when a fault is detected in one relay, a GOOSE message can be used to trigger a recording in other relays. The recordings are triggered with very little delay due to the high speed GOOSE messaging. A comparison and deeper analysis can be made with the additional collected disturbance recordings.

Integration provides easy access to disturbance recordings. Typically, the substation technician has to make a trip to the substation, find the specific IEDs in question, connect a notebook PC to the maintenance port of the IED, and then check for the latest recordings. With Electrical Integration and the DCS, however, DRs are automatically uploaded into a server; old DRs can be automatically deleted in the IED which will eliminate loss of DRs due to IED buffer overloads. Thus, no longer will power engineers have to do manual checks for DRs and manual extractions of the recordings.

With an integrated architecture, technicians are able to remotely access DRs from any operator station. Faster analysis of plant disturbances means faster problem resolution and root cause analysis which equates to increased plant up-time. Most IED suppliers use the standard COMTRADE file format. A few still use a proprietary file format for their DRs. Conversion to the COMTRADE file format must be done, but it usually requires expensive conversion software. A truly integrated system scans the substation bus network's IEDs for the latest DRs. It then sends the DRs via FTP (File Transfer Protocol) through the IEC 61850 OPC server to a specific server's storage point such as the DR Analysis server shown in Figure 12.

In a mining application in Brazil, a substation is 35 km from the Centralized Control Room (CCR). During the start-up phase of the mine, frequent changes to the protective relays were needed. Some of the changes required a reboot of the relay. In order to do so, the engineer would have to get into a truck, drive 35 km to the substation, connect a laptop computer to the front port of the relay, make the changes and execute a reboot. With a remote Web HMI over an Intranet connection, the relay settings were changed and a reboot executed right from an engineering console in the CCR. With Electrical Integration at this mine, the power engineer can eliminate many long trips to the substation.

Disturbance recording asset management

Higher level asset monitors can be used to analyze the DR files as well as the condition monitoring outputs from the circuit breakers and then make recommendations for both electrical and plantwide maintenance.

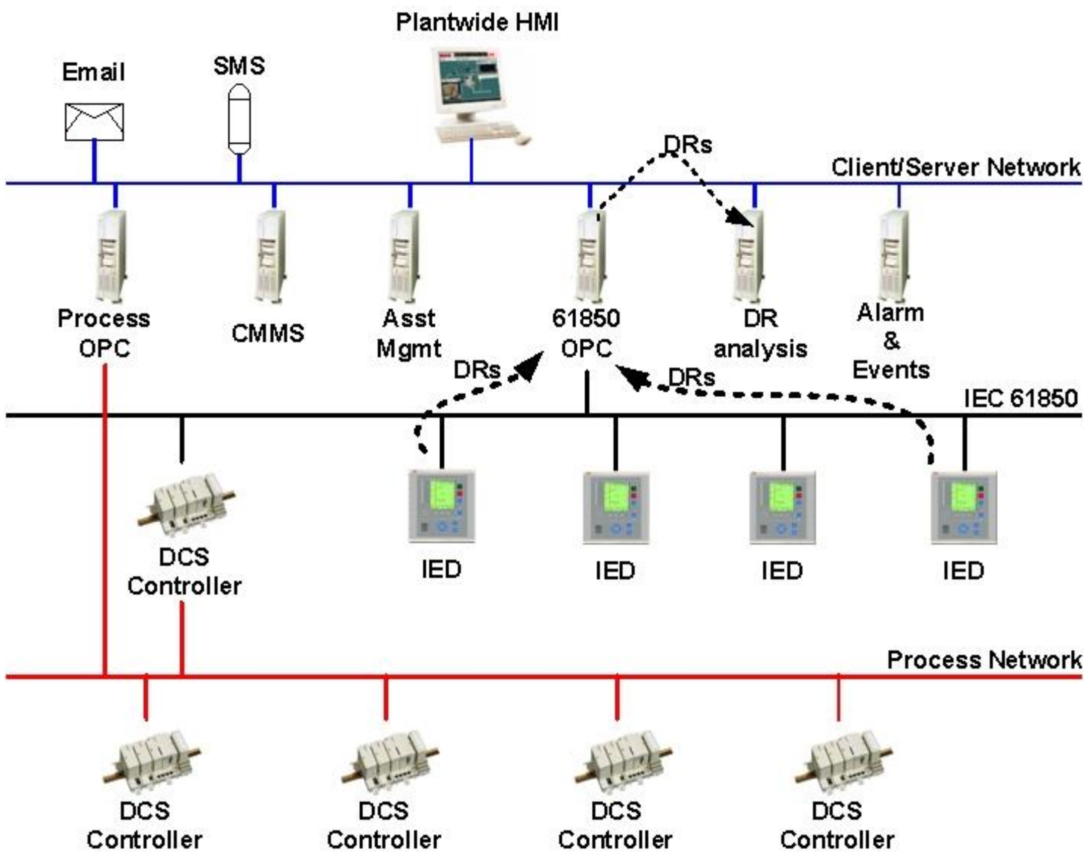

Figure 12 – Disturbance recording flow.

Improve operator effectiveness

Electrical Integration is all about bridging the worlds of power and automation together. By integrating both systems, this also means integrating the operations. Traditionally process and power has been in two separate worlds from both a technical and cultural perspective. A lack of collaboration between operator disciplines and difficulties in sharing relevant information makes operations inefficient. This integration approach eliminates islands of operation.

Modern plants are moving to a CCR approach. Process operators, power engineers, and maintenance personnel work together in a central control room. A common plantwide control system is necessary for the people to collaborate together. No longer will process operations, power engineers, and maintenance perform their work in silos. Petrobras, a state owned Brazilian oil company, has successfully migrated their operations into a CCR at their REPAR refinery.

With one integrated system operators, engineers, and maintenance personnel can view all accessible process and power plant data by with one user interface. The information can be adapted to each specific operators needs. For example, the process operator has access to all relevant process data for instrumentation and process equipment while the power engineer has access to all relevant power information to control the power distribution. With a single plantwide system, troubleshooting plant upsets can be easier and faster. A common plantwide sequence of events (SoE) list is made available by the integrated system. This is possible because IEC 61850 uses Simple Network Time Protocol (SNTP) to synchronize all IEDs on the network. Time-stamped event resolution is 1ms with IEC 61850. No longer will process control and power engineers need to attempt to match up unsynchronized event lists from multiple systems.

Having the same operator interface for process and power group enables better collaboration. A consistent operating philosophy reduces risk of errors. The information that needs to be shared among the groups can easily be shared since all information resides within the same system. A common access point for both process and power data provides faster error analysis. Electrical Integration enables collaboration between departments because it provides access to all relevant plant data for all disciplines.

End user examples using Electrical Integration

Demonstrated cost savings

Integrated process and power automation is all about saving time and money. The strategy can eliminate equipment that might otherwise need to be purchased such as remote panels, IT equipment, and control panels. Less equipment leads to simpler designs and smaller system footprints. It also reduces wiring but increases flexibility for future changes and expansions.

Take for example a substation system that has switchgear with 10 bays. The substation system must be linked with a DCS and a Power Management System (PMS). In general, approximately 70% of the communication signals to the substation's relays are typically hard-wired. See Table 4. In this example, only the wires to and from the IEDs will be considered while the wires among other devices are not included in the calculations. There are 85 wires from the DCS to the substation system, 383 between the PMS and the substation system, and 104 inter-bay signal wires for a total of 572 wires. By using IEC 61850, the wires can be eliminated completely. Each wire has two terminations for a total of 1,144 terminations. Using an average cost of $115 per termination, the termination costs alone could be reduced by $131,560.

Other potential cost savings include less hardware and lower lifecycle costs due to a simpler design. With most of the signals now on the IEC 61850 Ethernet backbone, this gives the flexibility to reconfigure protection and control schemes without re-wiring as future operational needs change and expand. A simpler design takes less time to implement, commission, and maintain.

Table 4 – Number of I/O wires

	To/from IEDs	To/from other devices	TOTAL
Inter-bay substation system signals	104	116	220
DCS	85	47	132
Power mgmt system & other external systems	383	252	635
TOTAL	572	415	987

Petrobras

Petrobras is an energy company that serves in Brazil and abroad with over 100 platforms, 16 refineries, and 6,000 gas stations. Its vision is to be one of the five largest integrated energy companies in the world by the year 2020. Petrobras is investing over 100 Billion USD over the next several years improving and streamlining their infrastructure.

Petrobras is growing its upstream oil and gas business. As the business grows, the need for a standard and a compatible solution to its refining infrastructure is critical. Petrobras must increase its refining capacity to meet the needs of its growing domestic market.

In the past 17 years, Petrobras has had a partnership with leading process and power companies to meet the changing needs of its business. From the first Power Management System (PMS) in 1993 to upgrades and expansions of its refineries in 2011, Petrobras has signed several frame agreements with key suppliers to deliver a standardized solution for power management systems at its refineries.

Petrobras has created a strategy comprised of key components focusing on an automation vision. The components include people, process quality, control and safety, asset health, information, profitability, energy efficiency, and key technologies. One of the key technologies Petrobras has focused upon is integrating process and power automation into a single system.

Within Petrobras' automation vision, lays the IEC 61850 standard as one of the key technologies they have focused upon. Petrobras has adopted the technology to help drive their goal of standardization and unifying process and power control. IEC 61850 is the state-of-the-art global standard for substation automation. It is the fastest substation communication protocol available today. IEC 61850, however, is more than just a communications protocol. The benefits of the IEC 61850 standard include interoperability between protection and control relays or IEDs (Intelligent Electronic Devices) from different brands and vendors. It is an open and flexible standard for user applications. It is often referred to as a "future proof" standard by the choice of Ethernet-based communications, though it is not tied to Ethernet.

REPAR site system description

The REPAR refinery site is very large and is Petrobras' most important refinery. It has several 20MW generators with two additional generators planned for the future bringing the total site power to 70 MW. There are sixteen existing legacy DCS controllers performing power management functions for fourteen conventional substations. Traditional hard-wired Electrical Integration methodology is deployed here. There are a total of twelve substations that use the IEC 61850 standard for power management systems communication. Sixteen modern DCS controllers provide the power management functions for all sixteen substations. There are 470 IEDs that communicate via IEC 61850 and 75,000 I/O tags in the system. The power management applications are viewed and controlled by 56 operator workplaces. The REPAR refinery system is not just power management alone. It also incorporates Profibus, High Speed Ethernet Foundation Fieldbus (HSE FF), Modbus, and IEC 61850, all seamlessly into a single unified system.

Challenges

Even with the new technology to solve their infrastructure issues, Petrobras had to deal with some barriers and challenges. These barriers included executing multiple projects simultaneously, training employees and suppliers on the new technology, and a paradigm shift. Petrobras now has network communications on substation automation systems with critical interlocks.

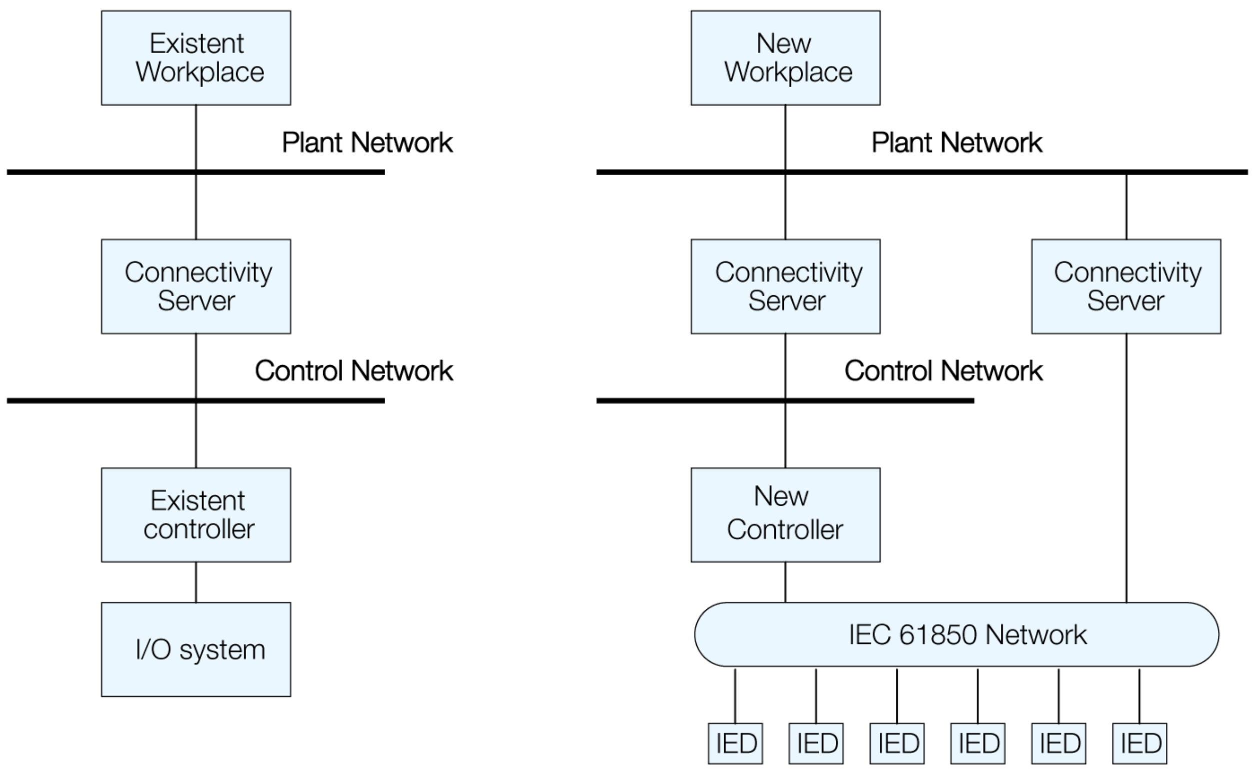

Figure 13 – Petrobras before integrated process and power automation

Benefits of integration with the DCS

Standardization is a key point for Petrobras. They want to avoid having multiple procedures, settings, control logic, control libraries, operational, and maintenance practices often found when multiple systems are used. Integrating the DCS with IEC 61850 brings simplicity to various stages of implementation, through a common work area. Less cabling is required with an integrated system than if multiple systems were used. Replacing hard-wired signals with Ethernet-based solutions, such as IEC 61850 and HSE FF, lowers initial investment costs and provides Petrobras more flexibility in making future changes and system expansions. According to Petrobras, the reuse of engineering data alone with a unified system provided a 30% reduction in engineering labor hours compared to conventional approaches with multiple systems. Petrobras has realized a 25 to 30% reduction in project execution commissioning time with a unified approach. This includes design, engineering, factory testing and on site commissioning. A single toolset for engineering simplifies the engineering and start-up time for the plantwide system. In addition, Petrobras is beginning to realize lower lifecycle costs. Initially, Petrobras has reduced their training costs by 20%.

An integrated system provides a single strategy for asset management. Maintenance practices are now integrated and optimized at the REPAR refinery for instrumentation, motors, transformers, drives, communication networks, and smart MCC. This gives Petrobras the ability to do remote maintenance of the site from a central maintenance point or to outsource the maintenance.

A unified integration architecture will make the system more reliable with fewer devices, hard-wired signals, and protocols to maintain. A single source for asset management will reduce unscheduled down-time and increase availability via real-time condition-based asset monitoring, diagnostics, and reporting. The DCS integration to the substation bus via IEC 61850 enables greater data reliability and data integrity.

Data integrity has become an important topic when using Ethernet-based architecture solutions. An integrated system provides a single database storage point as well as a common data historian. A time synchronized single point for data storage eliminates duplicate data storage issues. It also provides a single point for end user access. Now all pertinent data can be accessed and studied from a single operator station and a root cause analysis can be completed which will result in more efficient decision making and less operator errors.

Government compliancy is made easier with an integrated system. A common audit trail for the entire plant is possible. In addition, only one system will need to be updated with software security patches. It is easier and cheaper to maintain security on one system than it is to secure multiple systems.

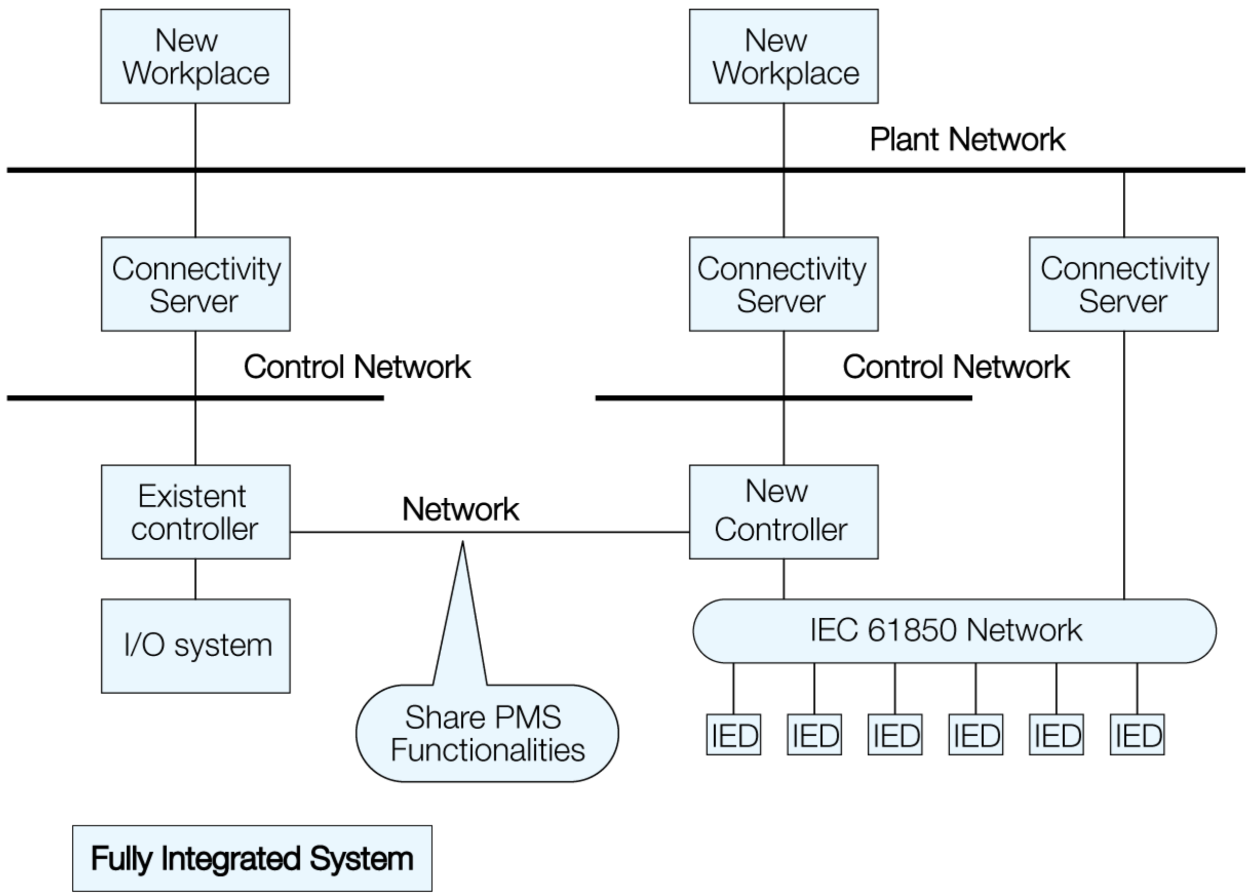

Figure 14 – Petrobras after integrated process and power automation

Lessons learned with IEC 61850 projects

Petrobras has learned valuable lessons regarding procedures and standards when implementing an IEC 61850 based project. The first lesson is breaking down the barriers between the process and power engineers. Both must be put on the same project timetable. Before the project begins, the standards for protection and control configuration must be created. This includes defining the controller libraries for power management and the selection of the IEDs. Interoperability among IED suppliers is part of the IEC 61850 standard but interoperability does not equate to interchangeability. Therefore, a single supplier must be named to be the main automation contractor (MAC) and main electrical contractor (MEC). This will eliminate any finger pointing among multiple vendors.

Other lessons learned involve network topology and communications interfaces. There is a large amount of data available from just a single IED. The information can include thousands of data points including protection and control schemes, both condition and time-based monitoring information, communication channels with other IEDs, disturbance recordings, as well as I/O data, which includes trip signals, voltages, currents, and power readings. With all of this information available from the various electrical devices in the plant, it is important to avoid unnecessary data communications, be mindful of server transfer rates to realize the maximum performance from the networks, and map only the most important data to the end users.

Petrobras has learned to take advantage of the latest network hardware available in the marketplace today. For example, they selected network equipment makers that have created network switches and routers just for IEC 61850 substation environments. Some of the features include prioritization and routing of critical messages ahead of other messages, Enhanced Rapid Spanning Tree Protocol to recover from Ethernet hardware issues, and environmentally hardened network gear that can survive the EMI (electromagnetic interference) bursts common in substations. Just about all of the IEDs available today communicate at 100 Mbps. Petrobras connected the 100 Mbps IEDs using a star topology network and then connected the switches together in a ring topology at 1000 Mbps to get the best network performance. Always do worst case response time and throughput analysis study on each project.

Future plans

Petrobras continues to look for savings and performance improvement opportunities with an integrated architecture. Their goals include obtaining higher process efficiency while using less energy. Plant electrical information is often difficult to access and view. By taking advantage of an integrated architecture, critical power data is more readily available. With this critical data, power usage can be observed, monitored, and studied. It provides better visibility into power consumption and real-time energy usage and costs. It also allows for easier energy audits and benchmarking. More sophisticated IEDs today have built-in asset management capabilities. Petrobras' next steps are to leverage both the condition and time-based maintenance information from the IEDs. Their goal is to do remote maintenance from a central point.

Boliden increases production at their Aitik site

End user requirements

Located in Sweden north of the Arctic Circle is the town of Gallivare. Here at the Aitik site, Boliden has Europe's largest open pit mine with mining and milling operations for primarily Zinc and Copper (the concentrate is transported by railway to Boliden´s smelter Rönnskär in Skellefteå). They are building a new concentrating plant to handle the increase in production as they double the production. They need a single integrated system for all plant operations with a seamless connection to their business system. The integrated system will include process and power automation as well as their own CMMS asset management system.

Solution

The solution is Full Plant Integration to meet the needs of this important mining customer. Since Boliden uses a variety of protection and control IEDs, the global standard IEC 61850 was chosen for the substation equipment. By taking advantage of the IEC 61850 open standard, they were able to integrate third party protection and control IEDs into the DCS. One of the benefits of the IEC 61850 standard is interoperability of devices among different suppliers. This feature makes integrating multivendor devices cost effective compared to traditional communication methods such as Modbus.

A complete portfolio of integrated process control and power automation equipment has been provided to Boliden. The scope includes a DCS based process control system, integrated substation automation system, LV switchgear, HV switchgear, as well as drives.

End user benefits

With an integrated system, Boliden will be able to operate and maintain the concentrator plant from a single control room. Operators will be able to work side by side with maintenance personnel to keep the plant and the production running smoothly. Because the Asset Optimization is fully integrated into the DCS, this will provide a tightly integrated connection to the mine's CMMS. Only one operator station will be needed to access the CMMS and condition monitoring applications. All pertinent information will be available in a single system. Mining personnel will not need to go to multiple systems and aggregate data to determine equipment health. Operators and maintenance personnel will no longer have to work in silos. Boliden will have a standardized solution that will be possible to apply to their other mine sites.

Control and Electrical Integration for E.ON hydropower plant

Owned and operated by E.ON, one of the world's largest power and gas companies, Flåsjö is a 26 MVA hydropower station on the river Ljungan in central Sweden. Originally built in 1974, the plant is one of five that E.ON operates on the 350-kilometer river.

End user requirements

E.ON is currently investing in safety, renewal and productivity improvements in its Swedish power plants. At Flåsjö there was a need to revamp and modernize the existing control system. Design requirements included remote control capability from E.ON's dispatch center, 260 kilometers away in Sundsvall, from where all the company's hydropower plants in Sweden are monitored.

Solution

The solution is based on its Integrated Process and Power Automation architecture that combines the DCS with the substation automation system. The electrical equipment scope contains redundant transformer and generator protection using IEDs. Other IEDs are used for grid line protection. For process control, the DCS solution includes modern controllers with a total of 600 I/O points.

Integration with the substation's electrical equipment was accomplished with IEC 61850, the global communication standard for substation automation. Profibus-DP was used to connect to the remote I/O modules, excitation system, turbine unit and vibration monitoring system. Profibus is an open fieldbus standard with a wide range of applications, including process instrumentation and process electrification.

The Network Manager is used to remotely monitor, control, and optimize energy production at Flåsjö and at all of E.ON's hydropower sites in Sweden. Full plant integration gives E.ON the ability to perform remote control from its dispatch center in a cost-effective way.

End user benefits

End user benefits include a single integrated system with a unified user interface, common toolset, and a standard connection to the remote control center. E.ON now has access to all station data from the dispatch center for remote operations and maintenance.

Problems can be analyzed and solved remotely from the central dispatch center resulting in fewer trips to the hydro dam sites. When a trip is needed, the correct personnel will be sent with the necessary equipment to resolve the issues. The integrated solution proved to be cost effective as the installation time was significantly reduced, taking only six months to complete the entire project. E.ON will continue to save money throughout the lifecycle of the system, as the solution is easier to maintain. By taking advantage of the DCS' integration capabilities, E.ON has created a standard solution for future hydropower plant upgrades.

Conclusion

Leading process and power engineering companies have global installations of integrated process and power automation projects across many industries including oil and gas, power generation, metals and mining, chemical, and pulp and paper. Other projects are underway in all parts of the world including North America, South America, Canada, Europe, Africa, Asia, Australia, and the Mideast. These sites will benefit from the open standards of Electrical Integration through reduced investment costs and operational expenditures. With the Electrical Integration architecture, all devices communicate back to the main control system using their individual open protocols. Electrical Integration bridges two worlds: The process group and the electrical group now work together as they share a common system. An integrated system provides a unified way to maintain the entire plant.

Appendix

What is IEC 61850 [1]

IEC 61850 is a global communication standard for power distribution and substation automation. Often people consider it a European standard, but it is a global standard common for both IEC and ANSI. IEC 61850 features a flexible and open architecture for MV and HV devices. It is implemented on Ethernet but it is not tied to Ethernet. It is often referred to as future-proof, as the standard will be able to follow changes in communication technologies [3]. IEC 61850 does not specify substation protection and control functionality instead it specifies how substation electrical equipment exposes their information and then communicates the information to other components.

Ethernet provides fast, reliable, and secure communications. Using a standardized model and communication language, the standard provides interoperability among electrical devices. Now end users can select equipment from a variety of suppliers and know that the equipment will operate and communicate together without having to create custom interfaces. IEC 61850 has a standard data modeling and naming convention. It has self-describing devices, virtualized modeling of logical devices, and a common language to configure devices. Various functions are modeled with logical nodes. Logical nodes contain data for a specific function. The IEC 61850 standard allows application engineers the ability to add multiple nodes within a physical device.

Benefits of IEC 61850 [1]

Ethernet versus hard-wire: Who is faster?

If there were two hard-wired IEDs and an identical pair of IEDs communicating GOOSE over Ethernet, which pair of IEDs will communicate faster? In many cases, GOOSE messages are faster than hard-wired signals among IEDs because the hard-wired signal must go through an output contact on the sending relay and then again on an input contact on the receiving relay. IEC 61850 is the fastest substation automation communication standard currently available in the marketplace.

Network traffic is a concern when critical signals need to be sent to other IEDs. Many network switches have the ability to prioritize GOOSE telegrams; this way the critical information passes ahead of other network traffic.

Ethernet versus hard-wire: Who is more reliable?

Connectivity among IEDs is automatically supervised by GOOSE. GOOSE sends out a quality byte with each telegram. If the quality is bad or poor, the application can notify operators of a problem in the network. Each GOOSE message is repeated continuously until the data set values change. Each GOOSE message has a counter as well. The recipient of the GOOSE message can compare the counter value to the last one to see if it has missed a message and then take appropriate action. Or if the repeating message is not received in a certain period of time, then the recipient can take action. In either case, the connectivity failure will be detected. In the case of hard-wired IEDs, detecting a break in the signal wiring may not be possible.

GOOSE messages

GOOSE messaging is a peer-to-peer broadcast message, while MMS is a client server communication to the system level. GOOSE messages are continuously broadcast at a specific time interval to ensure reception of the data. The frequency of the broadcasts slows with each interval until a maximum time period is reached in order to better manage network bandwidth. The GOOSE message will continue to be broadcast at the maximum time period until a value in the message's dataset changes. At this point, the message will be broadcast at a high frequency and then gradually slow down until the maximum time period is reached unless a value within the dataset changes.

Using Ethernet requires highly reliable network equipment. Commonly available network devices, however, will not hold up very well in the harsh environment of substations. Substations experience EMI surges as well as a wide range of temperature changes. The IEC 61850-3 standard outlines requirements for EMI and environmental conditions. There are several leading suppliers of network devices who see these implementation problems as an opportunity. Today, network equipment is available that will operate reliably in the electrically harsh environments of substations.

Security continues to be a concern and a high priority for suppliers and end users of computer equipment. GOOSE messages are sent at layer 2 of the ISO/OSI seven layer model. As a result, GOOSE messages cannot be transmitted through routers or firewalls. Hackers outside the firewall will have a difficult if not impossible time in sending rogue GOOSE messages. The North American Electric Reliability Council (NERC) and Critical Infrastructure Protection (CIP) have requirements for network equipment used in substations. Key suppliers of IT assets are designing and building network equipment that complies with these standards. Even with the high security that GOOSE messaging provides, improving and upgrading security measures will be a continual effort for both suppliers and end users of IEC 61850.

Energy efficiency with integrated VFDs [1]

Power plant auxiliary system power usage is on the rise. In fact, 7 to 15% of generated power is used by the power plant's auxiliary systems [2]. This number is increasing due to the addition of anti-pollution systems and an increase in cooling water pumping needs to control thermal discharge issues. Today, modern plants are still using direct connect motors with throttling valves to control flow. By replacing them with integrated variable frequency drives (VFDs), the expected energy savings is substantial. Figure 15 shows a chart of percent power required versus percent flow. According to the chart, when operating a direct connect motor at 50% flow, the power required is 68% of what it would be at maximum flow. When using a VFD, the power consumed is only 22% of maximum power. This equates to 67% less power consumed when using a VFD versus a direct connect motor.

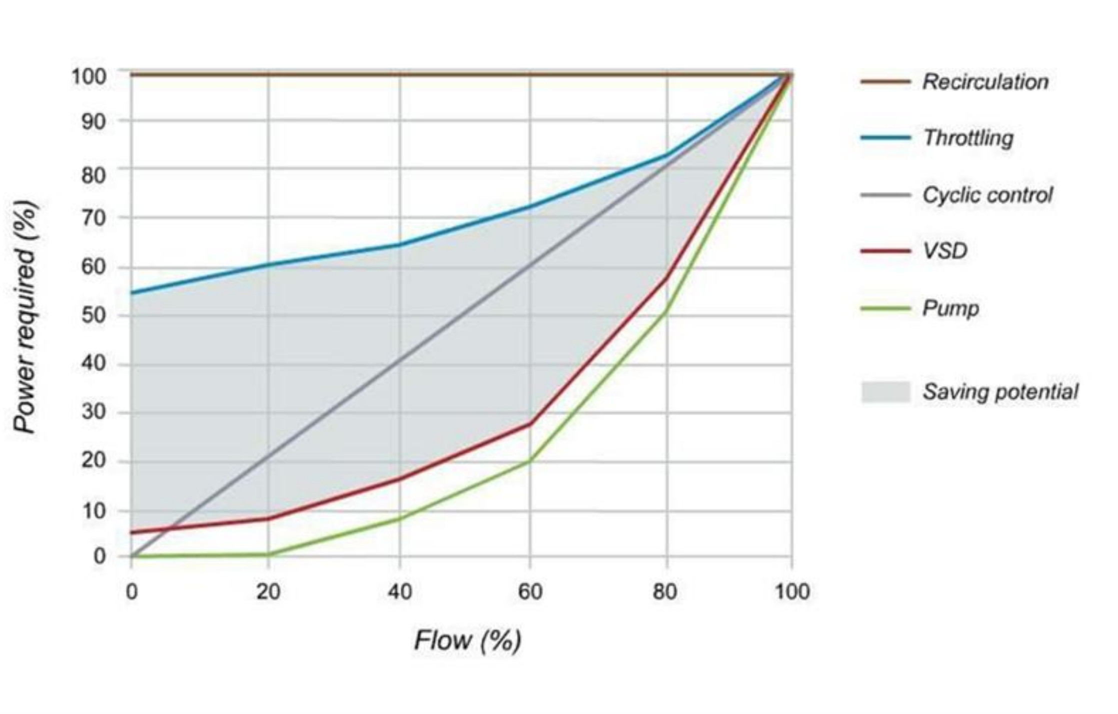

Figure 15 – Percent power required versus percent flow

Energy efficiency through improved visibility into power consumption [1]

Plant electrical information is often difficult to access and view. By taking advantage of an integrated architecture, critical power data is more readily available. With this critical data, power usage can be observed, monitored, and studied. It provides better visibility into power consumption and real-time energy usage and costs. It also allows for easier energy audits and benchmarking.

An integrated system enables operators to understand and easily access power usage. New energy savings opportunities can be explored, while existing energy reduction programs can be enhanced. An integrated system provides a centralized historical data source. Now energy consumption can be tracked plant-wide from one database. For example, an increase in power consumption by a unit or an area can indicate equipment malfunction and wear. Without visibility into power consumption, the problem may go unnoticed which could result in unexpected downtime plus a preventable increase in energy usage.

Another advantage to an integrated system is immediate visibility of a power event such as bus transfer, load sheds, or trips from any operator station. The status of critical electrical equipment can be seen, alerting operators to potential system problems. Information can be provided via alarm and events lists as well as email and text messaging notifications. Work orders can automatically be opened to a CMMS. Whether it is an electrical glitch, process control problem, or a failing IT asset, plant operators will have complete visibility and control of the situation.

Energy efficiency through faster plant startup times [1]

A large amount of energy is spent when starting up a plant. The more quickly and efficiently a plant is started, the more energy is saved. For example, a power plant can achieve faster start-up times by replacing the mechanical overspeed bolt trip system with a turbine protection system integrated with the DCS. After every shutdown, the power plant must test the turbine's trip system. A mechanical overspeed bolt trip system test requires the turbine shaft to spin at 110% synchronous speed. The turbine must first be warmed up for a few hours on-line in order for the shaft to be thermally prepared to operate at 110% of synchronous speed. When the turbine protection system is integrated with the DCS, it is possible to perform the overspeed trip test at nearly any turbine shaft speed by simply initiating a trip through the two-out-of-three trip manifold. In addition, functional testing can be performed at any time, on-line or off-line, by watching the solenoids activate without actually tripping the turbine. No time is spent thermally conditioning the turbine for trip testing; thus, startup times are lower compared to a mechanical overspeed bolt trip system. Removing the need for an overspeed trip bolt decreases startup time and increases the life of the turbine, as operating above the shaft design speed prematurely ages the turbine.

An integrated system allows for enhanced energy savings applications such as rotor stress prediction for steam turbines. The controller-based rotor stress application is now possible since all of the required inputs are available from the integrated system. Data from the various integrated components such as vibration, turbine position, and thermal couple inputs, in conjunction with process data, simplifies the design of the application. The rotor stress application produces turbine thermal stress information. If the turbine is started improperly, the shaft can warp. Typically, it takes nine to twelve weeks to straighten a warped turbine shaft. The goal of the application is to keep stress on the turbine shaft to a minimum while providing operators with safe acceleration and loading rates. With this information, operators can start the turbine more quickly. The faster the turbine is started, the more startup energy is saved, and more revenue is realized from the generation of power.

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Keywords

AM – Asset Monitor

ANSI – American National Standards Institute

AO – Asset Optimization

BEP – Break Even Point

CB – Circuit Breaker

CBM – Condition Based Monitoring

CCR – Centralized Control Room

CIP – Critical Infrastructure Protection

CMMS – Computerized Maintenance Management System

DCS – Distributed Control System

DoS – Denial of Service

DR – Disturbance Recording

EMI – Electromagnetic Interference

FTP – File Transfer Protocol

GOOSE – Generic Object Oriented Substation Event

HART – Highway Addressable Remote Transducer Protocol

HV – High Voltage

IEC 61850 – International Electrotechnical Commission's substation automation standard

IED – Intelligent Electrical Device

LS – Load Shedding

LV – Low Voltage

OPC – OLE for Process Control standard for soft interface over Ethernet

MMS – Manufacture Messaging Specification

MV – Medium Voltage

NERC - North American Electric Reliability Council

PID – Proportional Integral Derivative Control Algorithm

RTU – Remote Terminal Unit

SA – Substation Automation

SCADA - Supervisory Control and Data Acquisition

SF_6 – Sulfur Hexafluoride

SG – Switch Gear

SLD – Single Line Diagram

SNTP – Simple Network Time Protocol

SoE – Sequence of Events

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