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The Benefits of Installing Remote IO to a Two Stage Oil Free Screw Compressor Package in an Upstream Oil and Gas Application

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Abstract
A two stage oil free screw compressor package was recently delivered to a major blue chip oil and gas giant for use on one of their oil platforms located in the North Atlantic. During initial design it became clear that the amount of instrumentation required on the package would be substantial. As a result of this an elegant solution was required that would move non-critical inputs and outs (IO) from the control panel to the package itself.

This paper first describes the problems caused by the substantial amount of instrumentation required on the package. This description includes how the instrumentation is classed as critical and non-critical and what signals must still be sent over a hard wire and why. As the final location of the package is in an extremely hazardous environment, a highly corrosive marine environment, and the compressor itself is compressing highly combustible hydrocarbon gas, the protection methods employed by the instruments to prevent explosion is then discussed. The same protection methods must also be employed by the control systems IO that have been moved from the safe area to the hazardous area and this is all detailed within the paper.

The multiple communications networks that allow the remote IO system to send its values to the package control system and then onto the client's distributed control system are also discussed and how redundancy is built into this network. The paper concludes with how the changes made to this package have resulted in cost savings to the order of tens of thousands of Dollars.

Keywords: Instrumentation, Control, PLC, Remote IO,

INTRODUCTION

This paper concerns the design of the Howden low pressure compressor package being supplied for the Hebron Topsides project, off-shore Canada. This compressor package consists of two oil-free screw compressors; associated process piping, exchangers and vessels; lube oil system; main drive motor; gearbox; seal system and safe area Unit Control Panel (UCP). Under normal operating conditions, the compressors are configured to operate and maintain a set point suction pressure.

The instrumentation deployed, both in terms of quantity and level of specification, led to the delivery of the most instrumented package in Howden Process Compressors history. All of these instruments measured values had to be sent back to the package control system located in a control room in a remote location. A safe, reliable and easy to install method of sending these values back to the control system was required in order to reduce the cabling cost to the end user.

HAZARDOUS AREA

The compressor package is designed for use in a Zone 2 IIB T3 hazardous area according to IEC 60079-10-1, the unit control panel is designed for use in a safe area. The IEC 60079 series of standards is the international standard on the subject of potentially explosive environments caused by gases and dust. The regulations deal with how to classify areas into different zones (0, 1 and 2 for gas) depending on their likelihood of an explosion with regards to the plant and process, the substance involved and the various temperatures (ambient and minimum ignition for example). They then go on to specify different protection methods (Ex ratings) to protect against explosion within the different zones. The end user has classified the zone as a zone 2 environment which is a place in which an explosive atmosphere consisting of a mixture with air of flammable substances in the form of gas, vapour or mist is not likely to occur in normal operation but, if it does occur, will persist for a short period only [1]. Zone 2 is the least onerous of the hazardous area classifications with Zone 1meaning a potentially explosive situation more likely to occur and for a longer period and Zone 0 more serious still. Certain protection methods utilised on electrical and instrumentation, and on some mechanical equipment, can only be used in the particular Zones. For example Ex n, non-sparking apparatus, protection methods can only be deployed in Zone 2 areas but Ex ia, intrinsically safe apparatus, protected equipment can be used in Zones 0, 1 and 2. The unit control panel is designed for use in a safe area.

CONTROL SYSTEM ARCHITECTURE

There are three locations for starting and stopping the package: from the package HMI (Human Machine Interface), the control panel HMI and from the client's Process Control System (PCS). This allows the operator to initiate compressor pre-start or compressor start and stop sequences via the HMI buttons or from the client's control system. By using the Local/Remote selector switch mounted on the UCP the operator selects between Local HMI control and Remote client's control system control. The Local/Remote selector switch status is sent to the client's PCS. Additionally, maintenance functions can be selected from the HMI which enable the operation of the low voltage motors; oil heaters and stroke valves as required during plant maintenance checks.

An Allen-Bradley ControlLogix series PLC and two FactoryTalk View powered Hazardous Area HMI are supplied with the control panel to provide automatic package control and operator interface, and to provide a communication interface point with the client's Integrated Control and Safety System (ICSS). The client had two separate control systems that required an interface with the Howden UCP: the client's PCS controlled non-critical applications (indication and alarm functions) whereas the client's ICSS controlled the critical trip functions. Also within the Howden UCP a Bently Nevada 3500 Machine Condition Monitoring (MCM) system monitors the package main drive motor, gearbox and compressor temperature and vibration parameters and initiates a trip of the package if any of these parameters exceed the shutdown limits. The machine monitoring system values, alarms and trips are all transmitted to the PLC over an industrial Ethernet link using the Modbus protocol for display on the HMI and re-transmission to the platform ICSS. A simplified control system architecture schematic (reduced from nine sheets to one) showing how the package instrumentation signals are fed from the package to their end destination is shown in Figure 1.

Under normal operating conditions, the compressor control system hardware listed above is configured to operate to maintain a set suction pressure across each stage after having first performed the prestart sequence by getting the oil system up to the correct pressure and temperature and the seal system up to the correct pressure. To achieve the desired suction pressures on both stages the compressor control system first measures a process variable which in this case is the suction pressure transmitter located on each of the individual stage suction pipework. Depending on the pressure value measured the control system then has to operate the particular stages recycle control valve.

If the process variable is below the setpoint the recycle valve will open to allow the discharge gas back to the suction pipeline. If the process variable is above the setpoint the recycle valve will close. The opening and closing of this valve is controlled by a PLC proportional, integral and derivative (PID) block whose settings can be adjusted via the HMI.

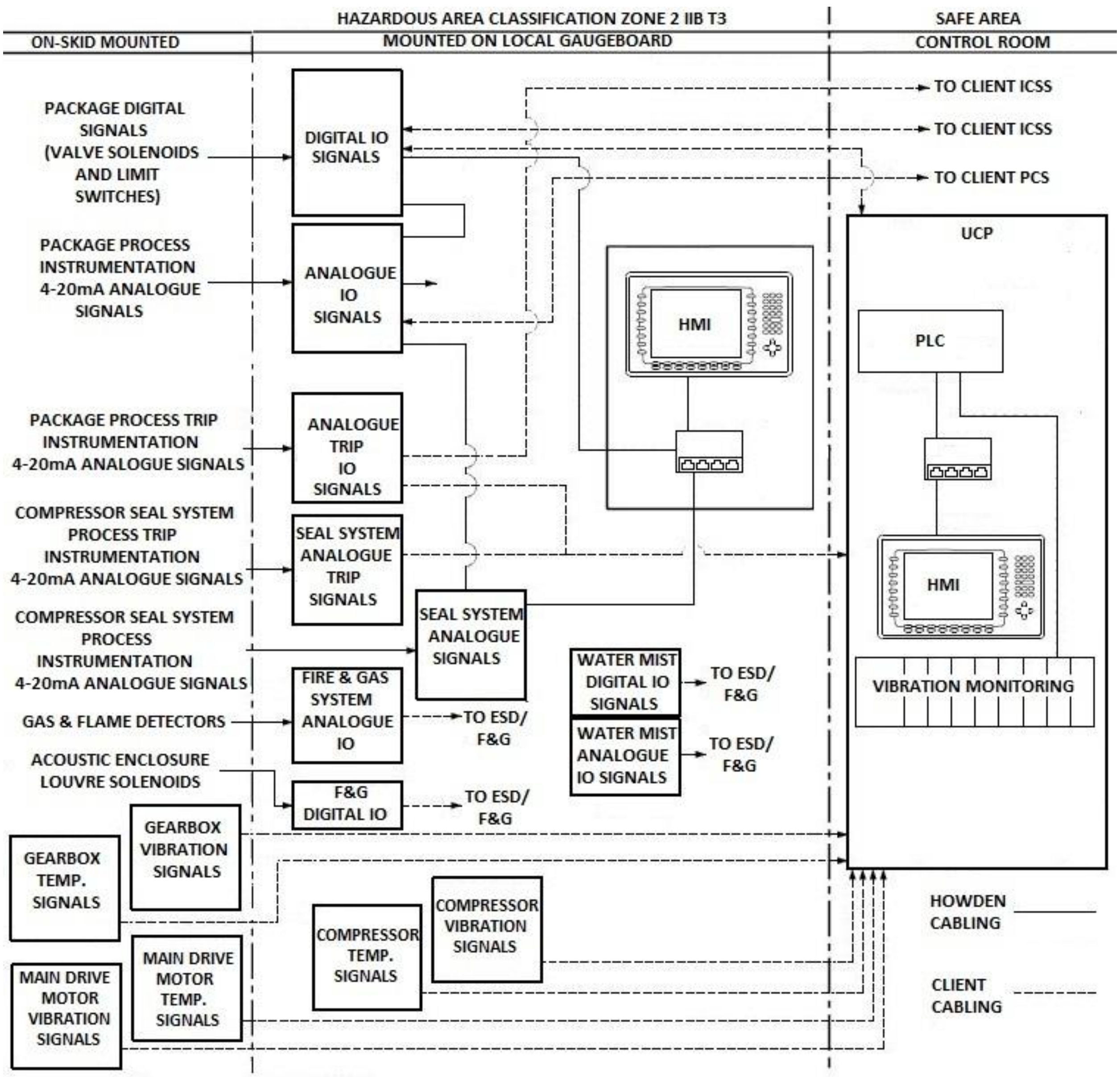

Figure 1: A simplified control system architecture drawing

On the second stage the process variable is taken from the second stage suction pipework and is compared to the setpoint inputted from the HMI. If the process variable is below the setpoint the recycle valve will open to allow the discharge gas back to the suction pipeline. If the process variable is above the setpoint the recycle valve will close. The opening and closing of this valve is again controlled by a PLC PID block whose settings can be adjusted via the HMI.

The re-cycle control valve functions as a trimming valve under PID loop control during compressor running and as an equalising valve during any of the stopping sequences. Each of the recycle valves were fitted with additional solenoids so they could be crashed fully open during a stop, trip or emergency stop sequence to equalise the suction and discharge pipe work and prevent reverse rotation.

The suction pressure set-point along with the PID gains can all be inputted to the PLC via either of the HMI systems supplied with the package. To test the operation of the recycle control valve, the HMI system operator can put the valve into manual mode and manually input a valve position set-point in %. An operator in the field can then visually verify if the valve moved to the desired position before putting the valve back into automatic control.

After the pre-start sequence is complete and the compressor main drive motor has been running for a set period of time, the recycle control valves are released to automatic control. A fifteen second time delay is put in between the enabling the automatic control of the 1st stage and 2nd stage recycle controllers. This is to prevent the controllers hunting during start-up as the system establishes healthy pressures. It is expected that the 2nd stage recycle valve will, to a certain extent, follow the position of the 1st stage recycle control valve even though they are controlled independently. As the 1st stage suction pressure falls, the 1st stage recycle valve will open sending less process gas forward, which will impact on the 2nd stage suction pressure causing the 2nd stage recycle valve to open. As the suction pressure increases and the 1st stage recycle valve closes, this will send more gas forward into the 2nd stage suction pipework, causing the 2nd stage recycle valve to close.

The control system deployed on this package had to carry out many different functions. On the gas system there was pressure and temperature control across two different stages, oil pressure and temperature control, seal system pressure and temperature control, drive train monitoring and the inclusion for fire and gas detection equipment. During the initial design phase each of the instruments and valves were segregated into different junction boxes first between analogue and digital signals and then further segregated between critical and non-critical IO. All of these systems coupled with the end user specifications that detail separate instruments for alarm and trip signals and then add in that the package is compressing hydrocarbon gas in a potentially explosive environment means Canadian National and International Hazardous Area regulations must also be applied lead to a package bristling with instrumentation. The design was peer reviewed during a hazards and operability study (HAZOP) with the topsides main contractor and end user who understand their process best. During the HAZOP additional transmitters were included and it became more evident that this package would contain a huge amount of instrumentation.

INSTRUMENTATION

This leads to a compressor package featuring 24 pressure transmitters, 17 differential pressure transmitters, 21 temperature transmitters, 7 level transmitters, 19 flow transmitters, 27 RTDs, 8 accelerometers, 25 vibration probes, 4 Flame and Gas detectors, 7 modulating control valves and 11 solenoids valves. All of the process or machine condition monitoring measurements gathered by this instrumentation must to be sent back to the relevant control system in order for it to control the package efficiently and safely.

Before discussing how this instrumentation is cabled back to the control system it is important to understand the robust nature of the design of the instrumentation systems due to the environment it is deployed in. Instruments, gauges and detectors are provided with stainless steel 316 cases, housings, electronics enclosures and fixings. This protects them from corrosion in the marine environment. The

Degree of Protection of control stations, junction boxes and enclosures are IP 66. This means all enclosures are completely protected against dust and protected against powerful jets of water from all directions [2]. All cabinets and panels have bottom cable entries only to assist in the prevention of water ingress.

All process transmitters are fitted with local LCD indicators to aid the commissioning engineers and operators in fault finding. In addition to the IP rating all process transmitters exposed to the elements are installed into a weatherproof heated enclosure complete with window to the operators can still read the LCD display. All metallurgy of the wetted parts of process instruments, such as control valves, pressure transmitters and differential pressure transmitters match or exceed that of the associated piping classification to prevent corrosion due to dissimilar metals.

All process temperature transmitters RTDs are provided with dual sensing elements within the thermowells so if one of the RTDs fails then the transmitter can use the other. Thermowells have been provided for all temperature measuring devices used in flammable, toxic, or otherwise hazardous, pressurised, or vacuum systems. Thermowells were not required for temperature measurement of machinery bearings, or motor windings where there is no risk to personnel from the process fluid during removal of the measuring element. All thermowells provided in dynamic lines have had wake frequency calculations performed to ensure the stress limits of the thermowell materials and its design are not exceed and will not fail in service.

CABLING

In addition to the high specification instrumentation required on the package the infrastructure taking the instruments signals to and from the package was also of a very high level due to the harsh environment and the nature of the process. There were two main different types of cabling used on the package. One type for digital IO signals and another for the analogue IO signals. The main difference between the two cabling types was the screens. The analogue cabling had a screen wire for every analogue signal whereas the digital cabling only had one overall screen wire as noise or interference affects the digital signals to a lesser extent. In addition to the different types of cable used on the package, all of the home run cables (cables ran from the skid edge to their required destination off-skid) in critical service were also fire resistant. Critical services on a top sides platform include: emergency power generation and distribution systems; UPS and battery charger systems; emergency and escape lighting systems; fire and gas systems; fixed fire fighting and firewater pump systems; emergency shutdown systems; critical instrument signals and alarms; lifesaving systems; safety telecommunications systems and PA/GA; navigation and obstruction signals, helicopter landing and operations systems; and critical platform make-safe systems. Of these systems the screw compressor package included fire and gas systems, fire fighting systems, emergency shutdown signals and critical instrument and alarm signals.

All cables installed on the package and all home run cables were armoured with a tinned annealed copper metal braid and certified for use in a hazardous location. The outer sheath was made from a low smoke zero halogen, flame retardant, UV and ozone resistant, extruded thermosetting compound. This is quite typical for offshore applications as was the cold bend radius testing carried out to ensure the cable would not become brittle and break at extremely low temperatures found in the North Atlantic Ocean. All cabling supplied for the package was suitable for ambient temperatures from -17 to +40 degrees Celsius. The cable outer sheath was grey or blue depending on the hazardous area method of protection applied to the instrument it was connected to. The inner conductor colours were the same for all types of cabling: black as a positive and white as the negative.

All armoured cables were terminated to the instrument and to the junction box with cable glands. All cable glands supplied were nickel-plated bronze with metric threads with earth tags to provide additional equi-potential bonding. All cable glands were suitably rated and certified for use in a hazardous environment and any stopping plugs fitted into unused drilled holes in certified equipment were also suitably certified.

It is important to note for the purposes of this paper that the client specified that all digital communication cables should be treated as a signal cable and given the same protection from damage. This will become relevant during the benefits discussion.

Power and signal wiring systems of different groups were to maintain minimum parallel separation using separate installation methods. For example, all power and signal cable groups were run in separate metal enclosed trays. Further to this all intrinsically safe cabling (blue sheathed cables rather than grey) were run in another separate tray so at times three different 316 marine grade stainless steel trays, with covers, were run: one carrying power to motors, one for signals to flame proof instruments (grey cabling) and one to intrinsically safe instruments (blue cabling). It was by all means a very robust design.

Another design feature of the wiring system was the spare allocation designed into the package to allow for future expansion. All home run multi-conductor cables had to have at least 20% spare capacity which also impacted on the field junction boxes as they then too also had to have the capacity to terminate the additional field instrumentation and the 20% spare capacity of the multi-conductor cables. The same home run multi-conductor cabling also had to be terminated at its off-skid destination which meant a minimum 20% spare allocation in the UCP as well as the junction boxes.

The substantial amount of instrumentation and now the high specification of cabling and cabling methods required meant the cost of cabling these signals back to the safe area control panel or the clients control system would be extremely costly. They were looking for an elegant, and less costly, solution. A decision to terminate the non-critical signals into remote IO terminals was made during the initial design phase to try and reduce the amount of cabling at site. This meant effectively moving the IO terminations from these signals from the PLC located in the safe area control panel out to the package and send the signal back via a communications link. As the cable route distance was 250m from the package to the control panel, a fibre optic physical layer with TCP/IP protocol would be used (client specified) to send the data back.

Previously mentioned in the text is the zone classification, Zone 2 IIB T3, of the area the package is deployed within. As the package contains many instruments and control equipment a few protection concepts were employed in order to prevent a catastrophe. Firstly, all of the process instruments such as the pressure, level and temperature instruments were all certified Ex d. The lubrication oil pumps and the oil heater were also certified Ex d. A flameproof enclosure (Ex d) is defined as an enclosure in which the parts which can ignite an explosive gas atmosphere are placed and which can withstand the pressure developed during an internal explosion of an explosive mixture, and which prevents the transmission of the explosion to the explosive gas atmosphere surrounding the enclosure [3]. Ex d rated equipment can be placed in Zones 1 and 2 only.

The machine condition monitoring instruments were certified Ex ia. Intrinsically safe protection type (Ex ia) is defined as a type of protection based on the restriction of electrical energy within the apparatus and of interconnecting wiring exposed to the potentially explosive atmosphere to a level below that which can cause ignition by either sparking or heating effects [4].

The Allen-Bradley Flex IO modules installed within the junction boxes on the package were certified Ex n, which means they contained non-incentive and or normally no sparking circuits [5].

COMMUNICATIONS

An extensive communication network is installed within the UCP to allow all the information to get to where it needs to go. Firstly, a Device Level Ring (DLR) was designed for the entire package network comprising of the three PLC racks; the HMI and the two fibre optic media convertors in the safe area UCP. These were linked in the same ring to two other fibre media convertors; the package HMI and the four Flex IO nodes installed on the package. The DLR was chosen so that if any one port on any one of the pieces of kit failed then the entire system could still communicate with each other (the network changes from a ring to a bus topology) [6].

A redundant communication connection between the PLC and the clients PCS is installed. This comprised of two RS485 physical connections transmitting information between the PLC and the PCS using Modbus RTU protocol. The RS485 standard is a key component in transferring digital information between control system terminals [7]. Again, if one of the communications links between the PLC and the DCS was removed or damaged, the remaining link will continue to operate. The DCS is configured as the Master, whereby it schedules the messages backwards and forwards between the two nodes, and the PLC is the Slave.

RESULTS AND CONCLUSIONS

When calculating the cost benefits to the end user the hardware costs of the Flex IO modules must be accounted for. This comprised of FLEX power modules, Ethernet communications modules, analogue input modules, analogue output modules, digital input modules, digital output modules, module DIN rail mounts and fibre media convertors. All of this hardware was split across four junction boxes on the package. The hardware costs for the remote IO system was $15,500. As the cable for this project was sourced in North America and for the ease of comparison all prices will be given in USD. An armoured Ethernet cable was used to communicate between the four junction boxes but a fibre optic cable was required to communicate with the UCP. 250m of this fibre optic cable cost $4,375 (courtesy of Ken O'Brien, Source Energy Atlantic Inc.) so we have a combined total hardware costs of $19,875 for the remote IO system.

Figure 2: The compressor package on test with the author shown for scale reference

The above replaced 2 x 24 pair cable for the conventional process analogue instruments, 1 x 24 pair cable for the package digital signals and a further 2 x 24 pair analogue instrumentation cable for the seal system analogues. A 250m run of the 24 pair cable is $8750, and the remote IO system replaced five of these cables therefore the total amount of hardware replaced is $43,750. To conclude, by taking the Flex IO hardware and fibre cabling costs from the replaced copper cabling costs, a saving of $23,875 on the hardware alone and the end user is still left with a safe, robust and easy to install method of sending the instrumentation values back to the control system.

What has not been taken into account is the installation time required, or the installation materials required, for the installation teams in Korea who are building the platform and responsible for installing the cables running from the package to the control room. This would lead to an even larger saving but requiring subtracted from this saving would be the time taken to install the fibre cable, the time taken to install the armoured Ethernet cable on skid by Howden, and the time taken by the author to first design the system. Perhaps what counts but cannot be counted is the customer asking to reduce cabling costs and installation time and an elegant solution being delivered.

Future work will see the removal of process transmitter package wiring altogether for non-critical applications in the oil and gas or harsh environment applications with the advent of wireless pressure and temperature transmitters. The design of these packages are client specification driven so until wireless transmitters are specified then they will not be installed and as blue chip oil and gas companies are quite conservative at adopting new technologies the author does not expect to see them specified for another ten years yet.

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