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Closing the Loop for Improved Oil and Gas Production Management

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Abstract

Well and Facility Operations make operating decisions based on processing huge amounts of data. However, there is a practical limit to the number of optimization moves an operator can make (due to: changing operating constraints, plant disturbances or interactions, fundamental process delays and dynamics, and the remoteness of wells). Automatic Process Control enhances the speed and accuracy with which decisions can be made and is essential for optimization. However, the advantages of automatic process control are often underestimated; hence the discipline is under-staffed and under-utilized.

Process Control also plays a crucial role in plant safety and availability as stable wells or facilities are operated more frequently within the design window. Stable operation results in fewer shutdowns, less breakdown maintenance, less deferment, less flaring, lower operational cost, and sometimes even higher ultimate recovery. The impact of process instabilities on overall well or facility performance are often not recognized; a single trip may wipe out months of optimization benefits.

To achieve the full potential of process control in Oil and Gas Production requires change management; Process Control technology skills need to be used throughout the whole projects lifecycle and integrated with the various processes from field development planning to surveillance and optimization.

This paper will provide the following examples:

1. automatic control of producer wells to prevent coning and/or gas breakthrough,
2. automatic control of injection wells to control water flooding and prevent fracturing,
3. capacity and surge controls for compressor networks,
4. control applications for the suppression of slugs, and,
5. higher level process control applications,

where the application of automated control technology has improved production surveillance, management, and optimization.

The role of Process Control in Exploration and Production

Historical perspective

Most engineers and managers confuse Process Control with Instrumentation; i.e. they think Process Control is only about the video screens in the control room and the associated computers. However, Process Control is the rationale behind the visible systems (instruments and valves) and the strategy about realizing process objectives. Design decisions are made when devising the control strategy; if the level in a vessel is higher than the desired level, the control strategy is either to open the valve of the liquid outlet stream or to throttle a valve in the incoming stream. The right choice will depend on the process itself and the process objectives of the integrated facility (i.e. the consequences of the strategy upstream or downstream of the unit must be considered). Certain control objectives will be conflicting or have different priorities. It is also important to consider the dynamics of the process, the drifts and changes in the underlying equipment and processes, the measurement noise, and the possible disturbances that can occur.

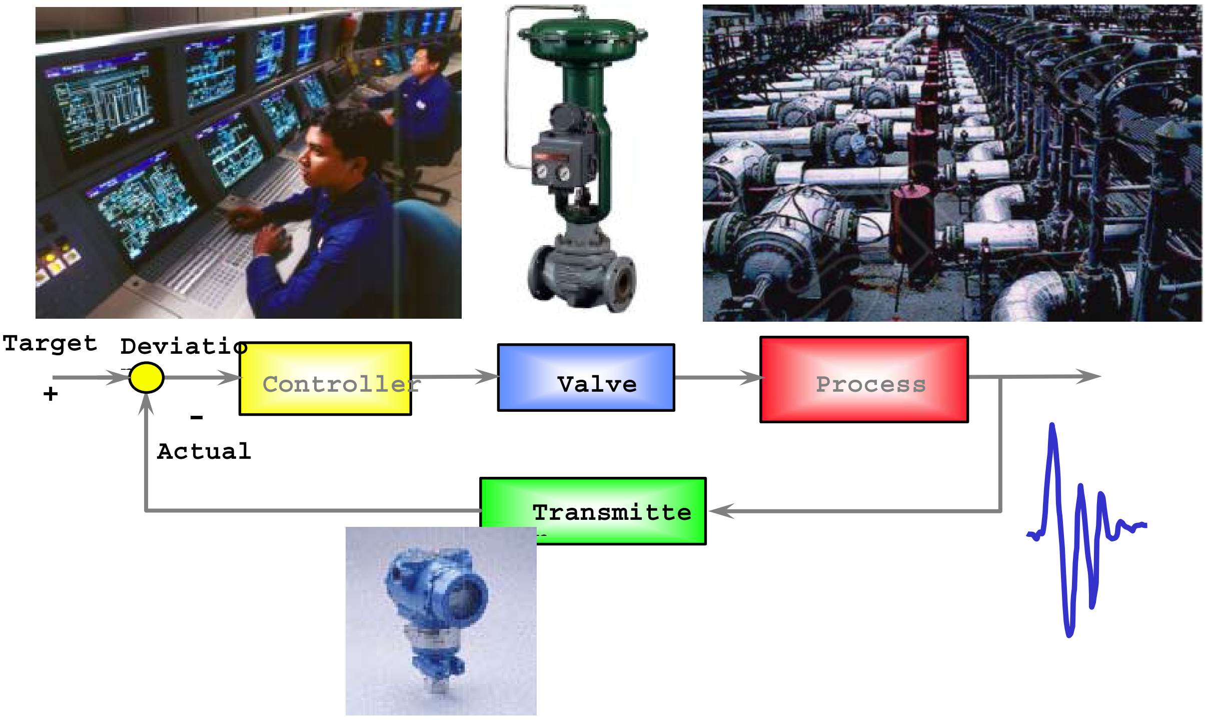

Figure 1: Process Control is the discipline of valve and transmitter placement and controller tactics (algorithm and tuning) based on the process objectives and dynamics.

The complexity of the required Process Control solution depends on the complexity of the well or facility. In the past, facilities were simple and process control did not get much attention. More recently, gas is no longer flared but treated and compressed for export. Hence, modern facilities are more complicated with a greater number of process control loops. Yet the design of the process control has not received much attention; simple Proportional-Integral-Derivative (PID) controllers, which act on the difference between the measured variable and the setpoint (target), are still the most common tools. Operational problems are usually handled by manual operator intervention.

Future perspective: Smart Fields with Process Control

Today, oil and gas demand is increasing. Oil recovery is more difficult and environmental constraints are more demanding. Tremendous efforts are made to develop smart wells and smart fields (for example [13]) with the objective to maximize daily production and maximize the ultimate reservoir recovery at minimum environmental impact. Some of these activities focus largely on the longer term, others on the medium and short term. The human factor of analyzing and interpreting reservoir results and developing short terms production targets on a well-to-well basis will remain important; closing the loop (in the sense of fully automatic control without human intervention) is still a long way off.

Smart Fields or Intelligent Energy initiatives use the “measure, model, decide and control” value loop to improve production and recovery. However, inaccuracies and noise in measured data, inconsistent operation, subsurface uncertainty, unpredictable well or facility performance, and complex dynamics make closing this value loop quite difficult. Process Control and related technologies are an important part of the solution since manual operation is often inefficient, can lead to significant delays and errors, and will result in sub-optimum production. The data quality must improve and the loop must be closed at a shorter time frame (i.e., on a second to 1 minute basis) using base layer control (predominantly PID loops) and Advanced Process Control (APC, multivariable or model predictive controllers) if and when required. Real-Time Optimization (RTO) loops can be applied on top of properly functioning base layer control and APC. Production facilities should run fully automatically to implement effectively the production targets.

Health Safety Security and Environment (HSSE) advantages of improved Process Control

Work in the field usually implies that operators have to travel since gas fields are often in remote locations. Travelling incurs a safety risk (particularly if this means night driving, travel by helicopter, or travel by boat over rough seas). In geographically spread locations (e.g., desert or jungle) driving is one of the major safety risks to staff. Remote and automatic control removes the need to drive between locations and hence avoid these risks.

Timescale	Type of control/optimisation	Examples
Hour to Day or On Demand	Real-Time Optimisation	Calculation of Optimum targets for well production rates and gas lift flows, process pressures, etc.
Minute	Advanced Process Control (model based)	Stabiliser column control minimising condensate losses at tight vapour pressure control taking into account a multiple of process constraints.
Seconds or less	Base layer control	Well control, Separator level control, Slug mitigation, Compressor anti-surge and capacity control. Any constraint control, such as pump minimum flow.

Table 1: Some typical control and optimisation applications

Gas with high H_2S content will be produced as demand for gas increases (some gas fields contain up to 30% of H_2S). Again, remote and automatic control can mitigate the risks. As environmental regulation is becoming more stringent, venting or flaring for example is not acceptable during normal operation. Hence, pressure control by routing excess gas to flare is no longer tolerated. Instead, gas pressure control (a way of mass balance control) has to keep gas demand and gas supply in continuous equilibrium, even if production and demand are several hundreds of kilometers apart. Last but not least, an unstable (or badly controlled) well or production system has a much higher risk of tripping and hence implies a higher safety risk (not to speak of the loss in production).

Our vision for the future for successfully closing the loop in oil and gas production operations is as follows:

1. All base layer control loops are in automatic and the performance is tracked.
2. Advanced process control is installed where justified (including blending, making use of quality estimators, pushing against plants constraints, etc.).
3. RTO is installed where justified. RTO calculates the optimum targets such as separator pressures, gas lift flows, etc, subject to reservoir, wells, and facilities optimization constraints. Use is made of fit for purpose models, including of wells, networks, facilities.
4. Business optimization is used to maximize cash flow, net present value of asset and ultimate recovery. Actual data is used from the base layer control, advanced process control, and real-time optimisation layer for business planning.
5. All real-time data is validated and reconciled. All essential production quantities such as oil and water production are either estimated or measured
6. Models are consistently updated and consistent across real-time, short-term and long-term. (For example actual well production data may be used to update well models but also longer term reservoir models.)

Current situation

Unfortunately, the reality is that often oil and gas production facilities do not meet our vision; many controllers can be found in manual or are badly tuned. A symptomatic problem is overly aggressive level control where the buffer volume of an expensive vessel or tank is hardly used. The flow variations caused by the controller may cascade downstream, resulting in overall unstable plant behaviour. The cause of these stability problems is often not recognized and the operator accepts the fluctuations as normal behaviour. The fluctuations may not be visible in the poor resolution Process Historian data used by the Well Analyst, Programmers and Process Engineers (the sample frequency of the Process Historian may be too long, or a dead band filter may be used so that only large variations are registered).

The remoteness of onshore fields, processing facilities and offshore platforms causes problems when implementing process control. For example, the remoteness of onshore wells may make it difficult to justify automatic choke valves, as utilities and infrastructure at such remote locations are too expensive. Modern technology reduces some costs. However, there have been instances in which oil wells have been fully equipped with remotely adjustable production choke valves for closed loop control, with great success in subsequently achieving increased production and fully justifying the costs. The remoteness and geographical spread of the locations is also a reason why many closed loop Process Control applications are difficult to sustain, in particular when designs did not include measures to increase robustness and reduce maintenance demand. Providing maintenance and support on remote sites is cumbersome and expensive. Remote support is possible these days, but is more demanding with regards to local commitment. With respect to this issue, the development and deployment of robust applications for the surveillance and management of process control loops is deemed of great importance

Oil and gas production flows from wells are inherently multiphase and it is difficult to measure the individual phases accurately and economically. The acquisition of reliable well and facilities multiphase production data is often critical for genuine closed-loop production surveillance and optimization. The liquid production of a well may vary from minimal water to oily water. Furthermore, the gas-oil ratio or water cut or condensate gas ratio of an oil or gas well may vary throughout the life of a well and the surveillance of these ratios is critical to the proper management of production from a reservoir. Yet, multiphase flow measurement for individual wells is difficult to justify and may only provide adequate accuracy if the fluid flow and phases remain within specific ranges. Well testing (lining up single wells in turn to a shared test separator or multiphase meter) is the basic solution to provide accurate information about the production of individual wells. The use of virtual multiphase metering, for example [1], has lead to significant improvements in the availability of production information as continuous well oil, water, and gas production estimates can be generated in real time in between well tests. Virtual metering works by estimating changes in phase flows from changes in the well conditions (pressures, artificial lift parameters, such as lift gas injection rates, and temperatures). Virtual meters make use of either empirical (data driven) models or a combination of physical models and manual "tuning".

Process control problems are addressed typically by backing-off from the true capacity of the wells and production facilities, minimizing dynamic changes such as very slow ramp up times, and/or accepting labour intensive manual interventions. Operational staff find ways to circumvent limitations in control performance by working to lower expectations and by manually taking over the control loop. The resulting performance is sub-optimal. Dedicated process control engineers are needed to highlight control issues and propose and implement solutions. The critical role of Process Control is getting more recognition in Exploration and Production and Process Control Engineers are more regularly consulted. More sophisticated process control technologies are being applied to solve specific oil and gas production problems. Finding or developing these engineers in adequate numbers is a challenge.

Examples of successful Process Control implementation

In this section, examples are used to illustrate the business improvements obtained by successful implementation of process control.

Category: Specific closed loop control applications developed for oil and gas production operations

1. **Automatic control of producer wells to prevent coning and/or gas breakthrough.**

   In thin oil rims, oil production from wells at a too high rate can lead to gas coning. Similarly, in fractured carbonates, oil production higher than the reservoir can make up for by gravity flow will lead to increased GOR (Gas Oil Ratio) or even gas break through. The GOR increase can be gradual or can be fairly fast. This situation can be avoided by suitably throttling back on the well choke valve. However if this is done manually, then it can be done too late, leading to unnecessary and wasteful gas production, or done too much, leading to the well production ceasing and deferment. Finding an optimum position of the choke valve for optimum oil production at minimum GOR is not an easy job and in fact for oil fields with a gas cap it is only possible by automatic feed back control. A simple control method to prevent excessive gas coning has been developed by Shell for use in DCS and has been reported in [9, 10]. In this instance, the wells are started up automatically on lift gas and then switched to coning control via the production choke when coning occurs. This method has been successfully implemented; enhancing the continued production of an oil field and after five years operations has been proved to be operationally sustainable.

   In PDO in Oman a gas breakthrough control algorithm has been developed and successfully been applied on several remotely located unstable wells in fractured GOGD reservoirs. The control application runs in a modern RTU and both the valve and the RTU are solar powered. Some wells that previously could only be operated in stop-cock mode (regularly alternating periods of production with periods where the well is closed-in) now have been converted by closed-loop control to continuous producers at low GOR. Regular flaring that occurred during well gas-out by hitting compressor constraints can now be prevented. Other more continuous producers can now be operated in an optimal low GOR operating point, previously not possible. Reduction of reservoir pressure due to loss of gas to the atmosphere can now be prevented and as such ultimate recovery is increased. Another example of closed loop control with the intention to stabilize a gas-lifted well can be found in [2].

2. **Automatic control of injection wells to control water flooding and prevent fracturing**

   PDO has developed and is implementing automatic control applications for improved water flood operation and flood front management on a growing number of water injector wells. While flow and pressure control of injection wells is common in offshore facilities, the challenge is that the well sites are geographically distributed. The scheme offers flow control of each injector as a basis, but in addition provides controlled protection against exceeding a pre-determined maximum flowing bottom hole pressure (FBHP). Where this FBHP is not directly measured, it is calculated on the basis of surface measurements and well depth. In cases where fracturing needs to be prevented, the set point of a protective pressure controller would be set to a value below the fracture pressure, thus providing an upper limit. In cases where water needs to be injected above fracture pressure, this set point will be higher than the frac-pressure. Controller set points to the individual well flow and pressure controllers can be remotely adjusted on the basis of area/field based water flood optimisation requirements. Compared to manual operation of water injectors equipped with conventional chokes, the advantages can be summarised as:

   - Remote control of injection, without the need for operator intervention

- Elimination of (surface) interaction between wells by flow control
- Elimination of disturbances introduced by other water users (e.g. drilling rigs)
- Continuous down-hole over-pressure protection, without tripping or blowing relief valves
- Enabler for field wide optimisation (loop closing)

Figure 2: Hardware for Coning Controls in an equatorial rainforest

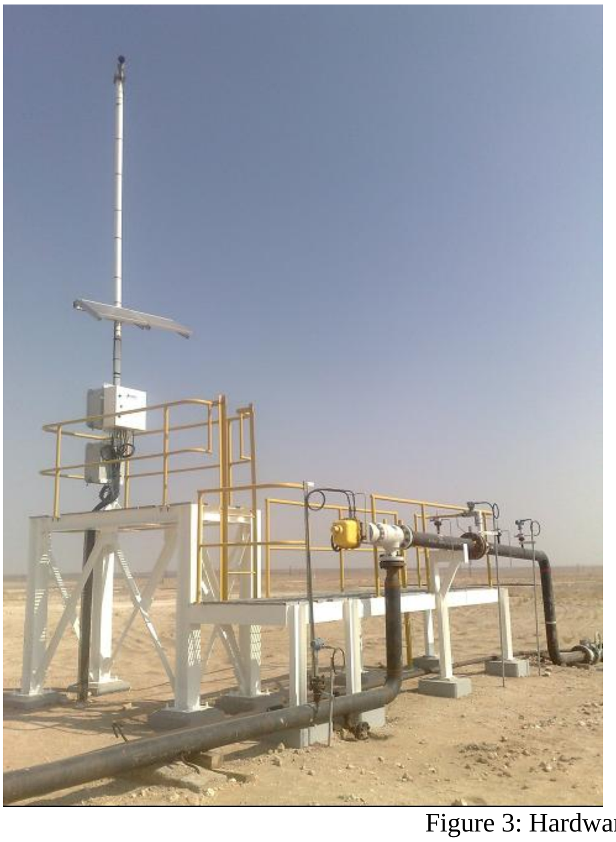

Figure 3: Hardware for control of gas breakthrough in Oman

- Reduction of driven kilometres by operators (HSSE risk reduction)

Depending on the remoteness of the well, the scheme can be implemented in the facility DCS and the valve be powered by instrument air. Alternatively stand-alone solar powered applications are possible where the control algorithm is housed in a modern remote terminal unit (RTU).

3. **Slug (mitigation) Control**
   Severe slugging is a result of liquid falling back by gravity against the upward (multiphase) flow direction in risers. The alternating liquid/gas flow behaviour is detrimental for downstream gas/liquid separation and can hamper overall production capacity. By applying special slug mitigation control algorithms this phenomenon can be strongly reduced. For large ramp-up or pigging induced slugs these either have to be absorbed in large volume slug catcher designs, or constraint control methods have to be applied to avoid overloading of the slug catcher. References [12,18,19].
   Process Control solutions can help mitigate problems with separation of water and condensate in (onshore) pipeline based slug catchers.

Category: Facility control improvement and stabilization, enabling production increase

4. **Controller tuning**
   A controller tuning exercise on an offshore plant in the Far East resulted in an increase in production capacity of 5%. Similar exercises on several onshore production stations in Oman have lifted facility constraints by 10%.
5. **Control structure**
   A review of the process control design of a gas treating plant in Oman, by changing the dew pointing control from acting on a heat exchanger bypass to acting on the Expander Inlet Guide Vane, resulted in an increase in plant capacity of over 5%.
6. **Controller improvement exercise**
   A control improvement exercise of a large produced gas compressor network in Oman has enabled a non-flaring operation without production loss. As all produced gas can now be reinjected the decline in reservoir pressure has been reversed, thus increasing ultimate recovery.

Category: Process Control support in project design

7. **Change in control strategy**
   Decline in reservoir pressure of a gas field in the Far East required adding a compression step. In view of non-conventional circumstances a process control workshop was held. This resulted in a change in control strategy (simpler, and more transparent), compared to the initial design.
8. **Compressor anti-surge control**
   Compressor anti-surge control is often left to dedicated vendors, installing their dedicated control systems. However, Shell has over 30 years of experience in implementing robust anti-surge control schemes in standard DCS systems. This has many advantages, such as the ease of integrating surge control with compressor capacity control to avoid interaction. Including compressor control in the plant DCS also prevents the need for dedicated maintenance requirements and/or contracts.

Category: Higher level or Advanced Process Control applications

9. **Control of a large gas field in the Netherlands**
   The field consisting of several clusters is equipped with fully automatic control, adjusting gas production in line with a continuous load variation from zero to maximum, and switching on and off complete clusters, trains or individual wells as required. This required the use of non-linear control for which model based control was selected.
10. **Advanced process control**
    An APC application increased the recovery of condensate from a gas field in Australia by more than 15%.

Category: Trouble shooting

11. **Improving compressor reliability**
    Compressor reliability is a major issue in EP, with liquid entrained gas being one of the key problems. Apart from ensuring an adequate process design to knockout the liquid from the gas to design specifications, the dynamics of the process are often overlooked. Start-up or upsets can lead to abnormal or overload situations, causing some entrained liquid (e.g. mist flow) entering the compressor. Also slugs can lead to load variations. These conditions need to be identified and should be avoided by automatic constraint control or start-up procedures.

Category: Use of Process Control Technology for Surveillance, Optimization and Overall Field Management

12. **Base technology for closed-loop real time production surveillance and optimization**
    In references [1,5,6,7] the Production Universe data driven modelling system for real-time virtual metering and real-time optimization is described. The Production Universe technology is developed from identification techniques applied to the specific oil and gas production environment. Production Universe handles processing of real-time data. The application of Production Universe allows real-time surveillance and management of well performance, and is significant in the oil and gas industry as the work makes clear the following:
    (i) The importance of process control for the basic stable operation of wells and their artificial lift systems, for example automatic lift gas injection control, and automatic well ramp back on gas demand changes. Slugging wells, wells with significantly increasing gas, wells with drifting lift gas injection rates and wells which are unstably operated due to overall demand changes are all made clear to the entire production operations team both in the field and in the office.
    (ii) The importance of process control for the single and multi-rate testing of the wells. During single or multi-rate testing using multiphase meters or test separators, or testing by difference using production separator meters, the stable response of the separator or multiphase metering system to well oil, gas and water rate changes is critical to well characterization. Poor tuning of well test facilities control loops, including the multiphase metering systems with compact separators, is often the major factor that produces incorrect test results and forces long well test durations.
    (iii) The importance of process stability as production is optimized. The optimizer of [1] consistently makes recommendations for the wells to be adjusted to maximize production. The oil, water and gas production rates are continuously pushed against the various facilities constraints (for example, maximum water handling capacity). This requires the underlying process control systems to be suitably tuned, as process trips, poor pump on-off sequencing controls, liquid carry over or equipment damage will negate significant optimization gains.
13. **Operational optimization of oil and gas production**
    Other examples of operational optimization of oil and gas production include, for example [14,15]. See also the surveys [16,17].
14. **Optimization of field recovery**
    Closed-loop control technology and concepts have also been applied for high-level optimization of the ultimate recovery of a field. See [8]. This is particularly valuable at the development stage of a project. Recent work has also attempted to extend these concepts to real-time production environments, see for example [11].

The business case

HSSE is the most important factor for plant operations followed by plant reliability. In fact both HSSE performance and plant reliability go hand in hand. Good functioning process control is essential to achieve this. Overwhelming support for this statement is given in [3], [4]. Reference is made to a study by Solomon Associates on over 100 Olefin plants, stating that approximately 70 % of reliability issues were process (control) induced and only 30 % mechanically induced. It is unlikely that this picture would be very different for oil and gas production sites. Traditionally plant reliability is sought in maintenance programs. However, this overlooks the contribution of good functioning process control. Yet the cost of maintaining a good functioning process control layer (in particularly base layer control) is almost nothing compared to the gains. Monitoring and Diagnostic tools (for offline as well as for on line analyses) are standard and cheap tools.

Improved production management starts with having good metering and baselayer control over the production at the lowest level. Management is not effective if management targets cannot easily be implemented, when targets are not well followed or when management uses inaccurate data. Therefore a functioning production metering and control baselayer is essential to make the more advanced control work. For example, lift gas injection rates that are manually adjusted frequently result in over injection or well quitting as a result of fluctuation of lift gas pressure. Separators trip when wells start to slug due to poorly tuned level or pressure control loops. Compressors trip when confronted with sudden changes in gas demand or supply as a result of badly designed gas pressure control and/or poor tuning.
It may be argued that setpoint adjustments are not required on day-to-day basis because conditions in the reservoir will not change that fast. However, at the surface the operational conditions may rapidly change, for example due to lift gas compressor trips causing a gas handling constraint. Day and night variations in temperature have a significant influence on fluid flow properties and on the maximum power of a compressor gas turbine drive. The GOR of wells can change fast with the well production, in particularly with coning wells and stop-cocking wells. The generation of slugs will have a direct impact on the operation of the processing facilities. A change in gas demand will require adjusting the gas production in seconds to hours, depending on the buffer capacity (or line packing capacity) of the specific system. Problems in the purification of produced water may pose immediate constraints on water disposal or injection capacity, necessitating a reduction of

production typically within a few hours. For production stations without much excess capacity there will regularly be a number of wells that will require adjustment each day in order to cope with the facility constraints. These adjustments may be subject to Real-Time Optimisation, in order to operate at the next best optimum.

Structural challenges in Project Design

During the various stages of a project the various discipline specialists from the customer and/or from the contractor bring in their comments and contributions. The Process Engineer usually provides the Process Control strategy of the plant or facilities, identifying the main control loops and also providing the main input to the Process Control Narrative. The Control and Automation Engineer normally provides the control loop details and implementation details. As the Control and Automation Engineer is mainly automation system (DCS, Safeguarding System) and not process oriented, there usually is a gap in understanding between the Process Engineer and the C&A Engineer. Important operational aspects such as start-up and abnormal operation are normally forgotton from the design scope. Furthermore, the Process Engineer and the C&A Engineer may not fully appreciate the operation or the dynamics of the wells. The resulting oil and gas production process design is such that neither the integrated well and process controllability nor the operability has been fully addressed. As the project moves on, hardware design changes will be more and more challenged in view of schedule and cost impact. Instead the tendency is to prefer to bank on problems to be fixed later by changes in instrumentation and controls. Too often the question of operability or 'how to control an uncontrollable process" is thereby not asked. When the project actually moves to the implementation stage, the process control narrative has to be interpreted by the DCS Implementation Engineer, who knows all about the DCS capabilities, but generally lacks an understanding of the wells or the facilities and the process and production objectives. He may also be the person to commission the control system and assist with the hand over to Operations.
With all the best intentions and quality procedures in place, it is understandable why many process and production control loops end up dysfunctional in manual mode, either by inadequate design or by not being properly commissioned. Other factors causing an increasing challenge to properly integrated production and process control are:

- The production process objectives being insufficiently translated into a functional control strategy, caused by e.g. a copy/paste approach from other projects.
- Lack of evaluation and checking of the dynamic aspects of the design.
- The FAT (Factory Acceptance Test) has only or mainly concentrated on the DCS system aspects and has not or has insufficiently checked the functional requirements of the control applications.
- Designs applying Package Unit concepts have insufficiently addressed the control interface issues.
- Opportunities for production optimization are seldom addressed.

The lack of project input from a professional experienced Process Control Engineer with sufficient understanding of the oil and gas production process, including its dynamic aspects, is key issue to resolving process control problems. Traditionally the Process Control discipline is not represented in oil and gas facilities design and engineering projects. As projects are becoming more complex this is becoming an increasing challenge. Recruiting and training of sufficient experienced process control staff (something contractors are also struggling with) will be the next challenge.

Focus areas for closing the loop

Awareness:

- The first step is "awareness". Most operators and plant managers are not aware of the state of their process control loops. Unstable behaviour is perceived as normal. Operators have got used to making regular manual corrections over many years. They simply do not know any better. However, plant managers should not accept that controllers are in manual, or when in automatic lead to oscillatory behaviour. If proper tuning (based on identification of the process dynamics) does not lead to satisfactorily plant behaviour, then clearly the control strategy needs to be changed, which can mean a software change but may also mean a hardware change (instrument or valve).

Process control engineer involvement:

- A process control engineer should preferably be part of the local organization, being responsible for the proper functioning of the process control loops, ensuring a stable and well-regulated plant. He should apply a strict and systematic tuning methodology as well as make use of modern monitoring and diagnostic tools. For remote facilities such as offshore platforms remote monitoring capabilities should be a standard feature. The same process control engineer may also provide the required process control input into local projects. This person should maintain good contacts with Operations, Process Engineering and Instrument (C&A) Engineers. For well automation he/she should also liaise with Well Analysts, Petroleum Technologists and Reservoir Engineers.
- Project Engineering Procedures should include formal involvement by a Process Control Engineer of the appropriate authority level by signing off relevant documents such as Process Control Narrative, Process Flow

Diagrams (PFDs) and Piping and Instrumentation Diagrams (P&ID). The project documentation should include the control philosophy (relevant in the earlier conceptual stages of a project). It is during the conceptual design phase that process control can have the biggest impact, notably by ensuring a process design with good controllability and operability. Further process control involvement and signing off is required during functional testing of the control implementation in the factory (FAT) and during commissioning and start-up.

- Advice from a process control engineer is required in the conceptualization and development of new generation "smart" fields (with new equipment or new process line-ups), specifically addressing the dynamics and the controllability of the new concepts (if necessary supported by dynamic simulation). The control engineer may advise on a properly structured infrastructure to support the data acquisition, automation, and control and optimization requirements of the integrated design.

Standardization and sharing of best practices:

- Many typical process control solutions need to be standardized. Although many of these typicals are indicated on P&ID's, the detailed functionality and implementation is often different and "re-invented" for every application. This often leads to inefficiencies in project implementation and malfunctions during start-up. Standardization down to detailed implementation level is therefore highly desirable. The danger of copying these standards in the wrong process situation is a danger that has to be recognized. Therefore the need for a process control engineer during project design as recommended above cannot be neglected.

Use of dynamic simulation during project design:

- Simulation tools are very good and enable rigorous modelling of whole plants and facilities at relatively low costs. This opens the possibility to verify design controllability and control strategies in an early stage of the project and to later verify the control configuration in the control system. The control system verification is done by linking the simulation models to the emulated ("stimulated") control configuration. The overall concept follows a parallel development of the actual production system. Depending on the complexity of the overall project this parallel running simulation project enables to test the design at various stages from design through commissioning, finally resulting in a flawless start-up.

Look for opportunities of advanced process control and real time optimization.

- In the Downstream sector (refineries, liquefied natural gas plants, chemical plants) the application of Advanced Process Control and (to a lesser extent) Real-Time Optimization has resulted in large benefits, globally in the order of a few billion dollars. The Upstream sector is lagging far behind with the application of advanced process control and real-time optimization. Contributing factors to this are: oil and gas production operations deal with a very different set of challenges, ranging from extremely large uncertainty in its well and reservoir production, its inherently fluctuating multiphase flows, and its remote and inaccessible locations and equipment (including sub sea and subsurface equipment). However, while there have been some successes in selected areas, the possibilities are vast compared to the actual optimized base. As has been highlighted throughout this article, there remain clear challenges to achieve fully efficient operation of the oil and gas production systems, in particular as these are becoming increasingly complex. Benefits though may translate immediately into higher production instead of into improved margin, as is the case with Downstream. Therefore benefits may be very high if the APC application is capable of pushing any capacity constraints, as discussed previously. Professional process control engineers with a clear understanding of the oil and gas production process may be able to identify these opportunities.

Conclusion

We have made a case that process control technology not only deserves more attention in oil and gas production operations, but also that it is essential for properly managing and optimizing the production process.

The first priority is to understand fully the basic dynamics of the process and closing the loop at baselayer level is essential as a first line of defence in production process safety and stability, prior to closing any higher level value loops as part of optimizing the production process (including capacity planning) Automatic and properly designed and tuned process control loops will maintain well and processing plant operation within safe limits, thus avoiding shutdowns. A fully functioning process control design will also be able to deal with well variations and operational upsets, minimizing their impact and minimizing the need for error prone operator intervention. Plant availability will increase, breakdown maintenance will reduce and unscheduled deferment will be minimized.

In other words: optimising production starts with sustaining stable production and this can only be achieved by "closing the loop" from the lowest level upward, starting at the baselayer control level (shortest time domain), establishing a stable and controllable plant. Only when this is accomplished higher level loops can be made effective and may be closed, optimizing the operation of the facilities up to the reservoir for maximum ultimate recovery.

To achieve all this may require a paradigm shift, the extent of which may differ per operating company. The authors believe that without dedicated professional process control engineers familiar with the oil and gas production process, there will never be sufficient attention for process control in this sector of the business and consequently its potential will not be fully realized. A focused recruitment and training program should therefore be in place. Projects should spend adequate attention to process control starting in the conceptual design phase. The operability of the integrated production system, including well management aspects should be addressed upfront. Formal reviews and selective testing by dynamic simulation is required, in particularly for more complex or integrated production facilities. The implications this may have on the site and/or project organization and staffing should be followed through. Process Control also has an important role to play with Smart Fields (Intelligent Energy) initiatives, in particularly when "closing the loop". The benefits of process control, when properly applied, will outweigh the costs by far.

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