

OPERATIONAL PERFORMANCE EXCELLENCE THROUGH PRODUCTION OPTIMIZATION IN THE UPSTREAM INDUSTRY

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Abstract

With a large number of oil and gas fields becoming mature, the Upstream industry is facing a new challenge: how to increase, or at least stabilize, production while maintaining available reserves at their present level. As a matter of fact, unstable production in multiphase production systems and pipelines can cause serious and troublesome operational problems for downstream receiving production facilities.

In the last ten years a big R&D effort has been spent aiming to address this issue, mainly through improvement in production management. Important advancements in technologies have resulted in a number of innovative methodologies, solutions and applications which proved to be able to successfully assist upstream production players in their quest for Operational Performance Excellence. To reach this goal, the crucial factor has resulted to be the capability to master and blend very diverse sophisticated technologies such Advanced Process Control, Production Optimization, Operations & Maintenance and Information Management Systems with the overall goal to enhance production efficiency and profitability.

The present paper aims to provide a brief overview of selected technologies and applications. Due to the limited space we will focus on process control techniques aiming at increase production efficiency and throughput by means of an optimized management of the control elements based on real-time process data and – possibly – model-based predictions. In the second part of the paper some reference projects will be briefly presented.

1. INTRODUCTION AND OVERVIEW

A typical Oil and Gas production system consists of one or more reservoirs, a production gathering system (wells/flowlines/pipelines), processing and export facilities, associated instrumentation, and a control system with ad-hoc configured control logic. Its dynamical behavior depends on the combined state of all its components as well as how it is operated, through a proper selection of actions on the different control elements (choke/valve openings, compressor and pump settings) at every instance of time [1].

The quest for Operational Performance Excellence and its related rewards can be actually translated into the pursuit of those control settings able to maximize production profitability.

Because of the inherently time-variant nature of production units, these control settings must be continuously assessed against the real-time plant conditions and adjusted in order to fulfill the scope. This is achieved by continuously collecting real-time process data, which must be automatically stored and analyzed in order to distill real-time information on equipment conditions and production status. On their turn these information are finally used for implementing conscious and forward-looking control actions. Ultimate results are improved production profitability due to:

- increased production
- reduced operations cost
- improved availability

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- improved HES - Health, Environment and Safety

Reaping the huge potential benefits produced by Operational Performance Excellence is much more than just a matter of implementing a few mathematical equations. It is more a matter of preparing, operating and maintaining a comprehensive framework where a proper blend of technologies and expertise work in synergy to achieve the desired result.

The natural foundation for such an endeavor is a modern, highly performing control system, which will take care of the integration of process measurements (real-time and historical), integration of alarm and events (real-time and historical), integration with Computerized Maintenance Management System (CMMS), custom applications, etc.

If the control system is the crucial element allowing proper and safe production, a number of technologies and best practices are nowadays available to produce in a profitable and cost-effective way. It is possible to group existing technologies in the following 3 broad areas:

1. Process Information Management System (PIMS)
2. Operation Support and Maintenance Systems
3. Production Optimization;

In the following some short hints about the first two groups of technologies will be given, while the third category will be the main subject of the paper.

1.1 Process Information Management System (PIMS)

As seen, any possible strategy for improving production processes must be based on accurate and reliable real-time information about how the production infrastructure is actually working. This simple notion explains the big emphasis that must be given to data collection, processing and storage and by a suitable computer infrastructure.

Usually data flows from each single field device to control rooms and/or management offices, either through local area networks, or – recently – by means of wireless technologies [2].

Typically the problem of data storage and consolidation is efficiently solved through the use of a modern Process Information Management System (PIMS), able to:

- Interface the various control and basic monitoring systems to gather process data, with sampling times of a second or less.
- Integrate all significant values and store them in large, efficient relational databases that permit sophisticated off-line analyses.
- Validate and reconcile process-critical measurements and calculations.
- Organize and deliver essential data and information in convenient formats and reports.

Based on this sound and reliable infrastructure, a series of applications helps supervise operations, checks the progress of the production plan, manages maintenance and explores any margins for improvement in the production cycle. Eventually, enterprise resource planning (ERP) systems perform business-cycle management, bridging the gap between transactional and manufacturing levels [3]. Applications cover areas like operator support, safety, production, condition and maintenance management. Their implementation is based on modern software architectures and technologies supporting traditional thin clients as well as portal solutions. Required data is retrieved using open standards such as OPC and SQL, allowing applications to be, to a large extent, platform-independent.

1.2 Operation Support and Maintenance Systems

Once the data are properly and safely collected, processed and stored, they could (and actually should) be used for supporting Operation and Maintenance practices. Maintenance activities can be facilitated through the use of core functionality available in advanced control systems like the ABB 800xA, as:

- Automatic identification of equipment and systems status and maintenance cases;

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- Automatic work order fill-in, to be forwarded to the CMMS;
- View of maintenance history and maintenance work orders associated with the given equipment.

Furthermore condition monitoring, performance monitoring and planning of maintenance can be assisted by devoted asset management programs able to provide a mechanism for periodic evaluation of the health of the asset. For example in the ABB's Asset Optimizer (AO) environment, software components known as Asset Monitors evaluate available diagnostic information and, if abnormal conditions are detected, provide an intelligent and detailed report on the condition, its probable cause and proposed remedy. Once this information is produced, it is delivered through the 800xA system to a technician who is able to act upon the information. This could be a maintenance worker, a field operator, or remote worker. The fault messages can be distributed through the system or dispatched to individuals via wireless devices such as pagers or cellular phones.

The AO connects to the CMMSs (like SAP, Maximo) for job planning and forwarding of equipment data through a ready-made interface. The system is open and can interface to condition and performance monitoring from other vendors through OPC.

AO significantly reduces costly production interruptions by enabling predictive maintenance. It records the maintenance history of an asset and identifies potential problems to avert unscheduled shutdowns, maximize up-time and operate closer to plant production prognoses. Examples of available Asset Monitors include computer and network monitoring, telecom monitoring, vibration monitoring and protection, valve leakage monitor, compressor monitoring, pump and fan monitoring and many others.

2. PRODUCTION OPTIMIZATION

The main aim of Production Optimization is to improve utilization of the capacity of a production plant to get higher throughput. The idea is to operate the plant, at every instant of time, as near optimum as possible [4]. While this goal is shared with most of the other process industries, optimizing production in the Upstream industry presents some very peculiar aspects. In addition to the production optimization of the downhole, subsea and topside process, one has to consider operational costs, hardware abrasion, reservoir performance, environmental requirements and operational difficulties within each well and/or topside. To further complicate the optimization task, the distinctive challenges change over time. For example reservoir behavior changes as an effect of depletion, shutdown of wells due to slugging, failed sensors and efficiency variations in the topside process system.

Top performances can be therefore guaranteed only resorting to real-time monitoring and control applications. Latest approaches are based on a proper combination of process and flow assurance knowledge, advanced process control technologies, and modern IT technology. For reader's convenience the remaining of this section is structured in three paragraphs: in the first one a detailed description of what can be done to stabilize and increase production is given. In the second the picture is enlarged to include also the monitoring of production performances and identification of potential limitations, while the third one is devoted to the downstream on-shore processing units. For each paragraph a relevant reference case is also shortly described.

2.1 Enhancing O&G Field Control Performances and Operability

Production throughput and regularity are two of the most important key performance indicators in an oil and gas production system. They depend upon several different factors, the most important probably being how flow rate fluctuation are mitigated or smoothed throughout the system, especially when large disturbances enter the processing facilities. Indeed, controlling

the feed disturbance to the separation process is a big challenge for the control and operation of offshore processing facilities and subsea separation units.

A common form of flow disturbance is represented by slug flow in multiphase flowlines [5]. Slug flow is characterized by liquids that flow intermittently in a concentrated mass, called a slug. Slug flow can occur in different scales of time and length depending on the underlying mechanisms for the slug flow formation. Until mid-90's slug flow was considered an "unavoidable evil", typically occurring if the chosen pipe diameter was not in proportion to actual flow rate, but in recent years considerable efforts have been spent searching a way to tame the slug flow using advanced control principles.

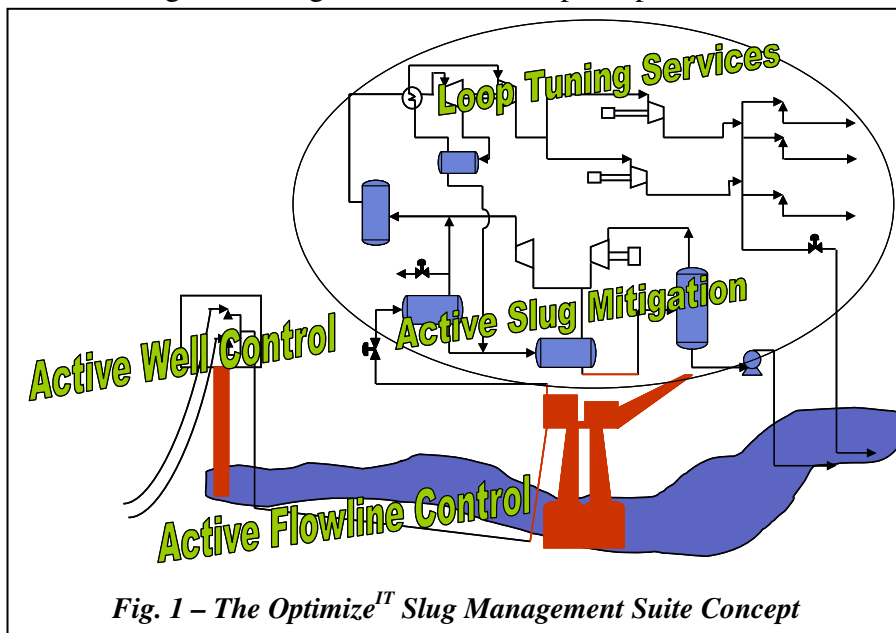


Fig. 1 – The Optimize™ Slug Management Suite Concept

ABB's Optimize™ Slug Management Suite is an integrated suite of products covering all aspects of slug management and suppression, from stabilizing multi-phase flow in wells and production flowlines/risers to mitigating the (remaining) slugs and transients in the downstream surge volumes whilst minimizing the pipeline inlet pressure.

The suite is composed by three main products:

- *Optimize™ Active Well Control.*
Active Well Control stabilizes and optimizes gas lift and naturally flowing wells. Active Well Control prevents flow and pressure surges while maintaining minimal backpressure and maximum production. For gas lift wells it maintains stable production at the optimum lift gas rate.
- *Optimize™ Active Flowline Control.*
Active Flowline Control controls and stabilizes multiphase flow in gathering systems, risers and flow lines. It is currently the only active control solution in the market for stabilization of flow in flowlines and by that removing large terrain-induced slugs. Active Flowline Control prevents flow and pressure surges and smoothes the flow without increasing line backpressure.
- *Optimize™ Active Slug Mitigation.*
Active Slug Mitigation is a coordinated set of dynamic feedback controllers for maximizing the buffer capacity in a separator or

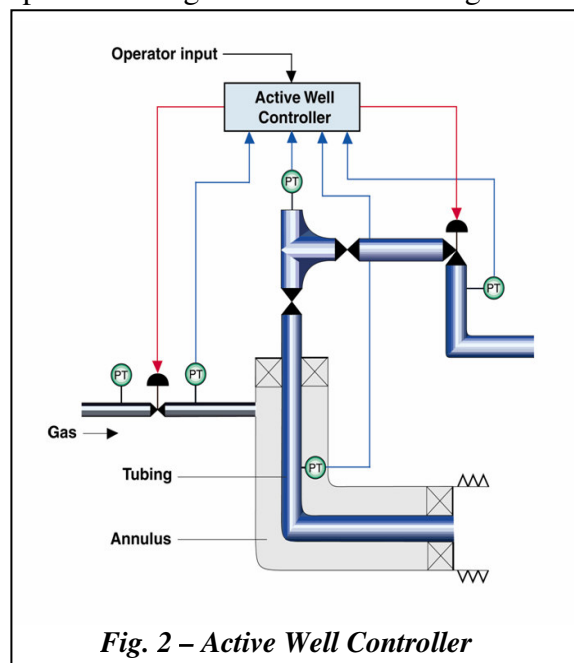


Fig. 2 – Active Well Controller

separator train and mitigating inflow variation caused by slugging or transient operations. It is designed to maximize buffer capacity, avoid overloading the separator (so increasing trip-prevention), help detecting and accomodating slugs, maximize inlet valve opening.

The different products within Slug Management Suite are seamlessly integrated and present clear synergies. For example, Active Flowline Control will stabilize a production pipeline and prevent large, riser-induced slugs from being formed whereas Active Slug Mitigation will mitigate the smaller ones.

Slug management also exploits *Control Loop Tuning Services*, which is a service offered to optimize the tuning of the existing base control layer to improve the slug handling. This is a particularly critical part of the procedures which is often neglected or overlooked. All the production optimization solutions work actually either in synergy or coordinating with base control loops. No fancy software or clever strategy can really unleash its full potential if applied on top of poorly tuned control loops. So taking care of the basic control layer is of paramount importance and can deliver substantial and sometimes even surprising economic returns by itself. Nowadays modern software packages are available which allow computer-aided loop tuning and even loop performance monitoring and appraisal. As an example, the ABB *Optimize^{IT} Loop Performance Manager*, or LPM [6], is a product designed to optimize and properly maintain the base of any process automation system. It permits to drastically reduce the control loop tuning efforts, granting objective and repeatable operations and performances without requiring any new equipment or major capital investment.

Additionally a unique feature of LPM, named *Plant-Wide Disturbance Analysis* [7], allows analyzing and categorizing complex disturbances which affect the whole process, up to identifying the most probable root-cause.

2.1.1 Application Example: North Sea Oil Field

The above considerations can be better understood referring to a successful application implemented in 2004-2007 on an offshore processing facility in the North Sea. The processing facility consists of oil, gas and water processing units, and receives multiphase feed flows from both platform wells and tie-in flowlines from satellite fields. Major challenges for operation include various forms of slug flow in wells and flowlines, which causes significant variations in levels, pressures, temperatures and other processing parameter throughout the processing plant. Because of these variations, booster and export pumps are often close to trip, with frequent alarms being generated. Additionally, large flow rate variations are causing levels in gas scrubbers to vary significantly, and high liquid levels in these scrubbers are responsible for a few unplanned shutdowns each year. Due to these, and other, variations in process parameters, production from selected wells and flowlines has to be reduced to keep the inflow disturbances at manageable levels and setpoints has be backed off from optimal values to ensure the process parameters does not exceed safety limits.

To improve capacity utilization and regularity, and to make the subsequent implementation of an optimizing control strategy possible, two key initiatives were taken:

- Ensure that the base control layer is properly tuned, so that poorly tuned controller or interactions between different controller are not inducing or amplifying process oscillation and that the controller are providing the maximum trip protection.
- Reduce or remove slug flow in the pipelines and wells. If slugs cannot be completely removed, the slug control system should ensure that the outflow from each well and flowline does not exceed at any time the capacity of the plant, and thus provide an additional trip protection for the plant.

A tuning campaign revealed that the level controllers in the oil train were too tightly tuned, so that the flow variations entering the inlet separator were not dampened out enough through the

separator train. Better tuning of these controllers resulted in the same trip protection for the separators, but with significantly less flow variations exiting the last separator than what were entering the inlet separator. This in turn led to significantly less variations for the booster and export pumps and therefore fewer alarms and trips. For the gas train, it turned out that the main cause of the problems were interactions between level controllers and minflow protection loops for the condensate pumps. Retuning these controllers resulted in much less level variations and more robust gas train operations.

However, tuning of basic controllers did not solve all the operational problems, and significant variations still remained in the process parameters. Implementing *Optimize^{IT} Active Well Control* at least on the most problematic wells and *Optimize^{IT} Active Flowline Control* on all major tie-in flowlines significantly reduced or removed the slugging and thereby the flow variations entering the offshore processing plant. To handle transient operations such as pigging of flowlines and startup and turn-down of wells, *Optimize^{IT} Active Slug Mitigation* was implemented.

Thanks to these improvements, the plant is now easier to operate and room for optimization has been gained. Operators or an automatic optimization system can now move setpoints closer to their optimal values and the number of unplanned shutdown due to large disturbances that cause plant trips has been reduced. On top of these indirect benefits, slug control solutions directly increased production by themselves. This is partly because wells and flowlines have to be choked back to avoid overloading the plant, but also because the flow through a slugging well or pipeline is generally lower than a corresponding non-slugging pipeline with the same boundary conditions. Because of the many concurrent improvements it is not possible to provide an itemized list of benefit for each of the completed tasks: as a reference it is however possible to state that the Active Flowline Control alone was able to increase production for the given flowline between 2 and 10% with a pay-back time of less than a month.

2.2 Longer Term Production Monitoring and Optimization

In the previous section we have seen how improved control strategies can permit to obtain increased production rates mainly stabilizing process parameters and reducing fluctuations. However more efficient control schemes actually push operation towards more “daring” conditions potentially adding some extra tear & wear factors to field equipment and devices.

In order to avoid that additional maintenance and repair cost (not to mention derived production shut-down periods) could overwhelm the benefits from improved control, overall process conditions must be carefully monitored. To this scope a collection of innovative monitoring tools has been developed and is routinely used in conjunction with production optimization packages, as briefly described below. Often model-based, they differentiate from the Asset Monitors described in section 1.2, because purposely designed for Upstream specific challenges and the related demanding environment (e.g. available/missing sensor). Examples of such ad-hoc tools include software packages like:

- *Optimize^{IT} Well Monitoring System.*

Well Monitoring System is a model-based system for oil, gas and water flow rates estimation for all the individual wells in an oil field. The real-time inference is based on data from available sensors in the wells and flow lines. Well Monitoring System may be used as a software multiphase flow meter, as a reliability tool, and as a production allocation system.

- *Optimize^{IT} Hydrate Prediction Tool.*

The main focus with the Hydrate Prediction Tool is to assist the operator in avoiding hydrate formation, which may occur if a subsea gathering system is allowed to cool down too much before necessary hydrate preventive actions are performed. During normal operation, the flowlines are kept heated by the flowing fluid. However, when

production is shut down for some reason, the fluid in the flowlines slowly cools down to the ambient seawater temperature. The longer the shutdown, the higher the risk for forming hydrate plugs. If the shutdown is planned, the flowlines can be protected e.g. by injecting methanol at the inlets to the gathering system for a sufficient period of time before the shutdown. This is normally expensive and is therefore not done continuously. Thus, if an unexpected shutdown occurs, another method for protecting against hydrate formation must be used. This method is typically to depressurize the system unless flow can be started up fairly immediately. This is also very costly and is avoided if possible. However, as the consequences of forming a hydrate plug are potentially much more severe, the flowline is often depressurized much earlier than is actually required. On the other hand, the Hydrate Prediction Tool accurately models the cooldown in the flowline and provides the operator with an accurate estimate for the time available until the system must be depressurized. The operator can therefore avoid any unnecessary and costly depressurization

- *Optimize^{IT} Insight – Erosion Management*

Sand production may be an issue on several fields, particularly on mature ones. But instead of operating the wells after a Maximum Sand Free Rate (MSFR) criterion where sand is not allowed at all, there may be major economical benefits in moving to an Acceptable Sand Rate (ASR) criteria where some sand is allowed. The increased production will normally justify the costs related to the resulting choke erosion. However, with ASR there is a need to monitor and manage the choke (and pipeline) erosion on an individual well basis. *Insight* does exactly this, using advanced erosion models to give production engineers as well as maintenance personnel a tool to optimize production and plan maintenance with regards to erosion. The system can be run in online mode (for monitoring) or offline mode (for analysis of different scenarios), and uses available data from the client production database (such as allocated rates, well tests, choke information, sand rate, sand trap measurements etc.) *Insight* has several models available, and is an extendable framework for managing erosion issues in different components in any part of a production system. See [8] for a case demonstrating how choke erosion was detected by the models. The benefits are increased production, reduced maintenance costs and improved safety.

- *Optimize^{IT} Constraint Monitor*

Maximization of oil production is in principle done by ensuring that the production system is running against some constraints both with respect to reservoir, wells and topside. Examples of constraints include: maximum valve openings, max pressure drops, pump speed, discharge pressure, liquid flow in a manifold or pipe, minimum heater outlet temperature or bottom hole pressure in a well. Because relevant constraints can dynamically change over time both in nature and in values, it is crucial to be able to continuously assess the capability of the system to operate as close as possible to the limits, while monitoring the number and the magnitude of possible violations. The ABB Constraint Monitor is a software tool designed to monitor and document constraints in a typical oil installation. It offers a method for getting a quick overview of the utilization of the production capacity and the satisfaction of all constraints imposed on the operation of the production system. Their measured value is scaled (normalized), so that all the constraints may be easily compared and classified into different constraint groups. Typical classifications could be based on reason (safety, quality, environment, optimization), or on topology (reservoir, wells, oil processing, water processing, gas processing).

2.2.1 Application Example: the Bonga Oil Field

As an example of the benefits derived from the application of model-based monitoring solutions, we will refer to the Bonga oil field. Bonga has been the first deepwater project for the Shell Nigeria Exploration and Production Company Limited (SNEPCO) and for Nigeria as a country. Bonga lies 120 km south-west of the Niger Delta, in water more than 1,000m deep. Recoverable reserves have been put at 600 million barrels (bbl) of oil. The field is completed with subsea wells and water injection wells. Waterflood injection on the Bonga field is accomplished via a network of subsea flowlines and 15 subsea injection wells. Maximizing water injection volume is an important economic objective for Bonga. Water injection is used to maintain the reservoir pressure and thereby maximize oil production. The water injection flowrate to each well is limited by the fracture pressure of the overlying shale layer. Fracture of overlying shale could significantly reduce oil recovery from the damaged reservoir. Hence, it is important to accurately control the reservoir injection pressure such that volume of injected water is maximized without excessive risk of damaging the overlying shales. Since there are no downhole pressure gauges in the injection wells, the downhole injection pressure must be estimated from other measured variables.

For this, a novel technology, named WRIPS (Waterflood Reservoir Injection Pressure System) was developed and is in execution since 2004 [9]. The WRIPS algorithm is used to:

- Estimate downhole injection pressure based on the model and available measurements
- Estimate injection pressure uncertainty as a function of available measurements
- Calculate an injection pressure target as a function of system conditions
- Calculate injection rates for wells where the Venturi has failed
- Calculate the most probable pressures and flowrates based on model, measurements, and sensor accuracies (data reconciliation)
- Set conditioned alarm flags

WRIPS is implemented on standard PCs as a redundant system with two servers. It is a

low-cost option: its total cost (software, hardware, commissioning and maintenance) is negligible compared to the one of bottom hole sensors in all injection wells. An additional

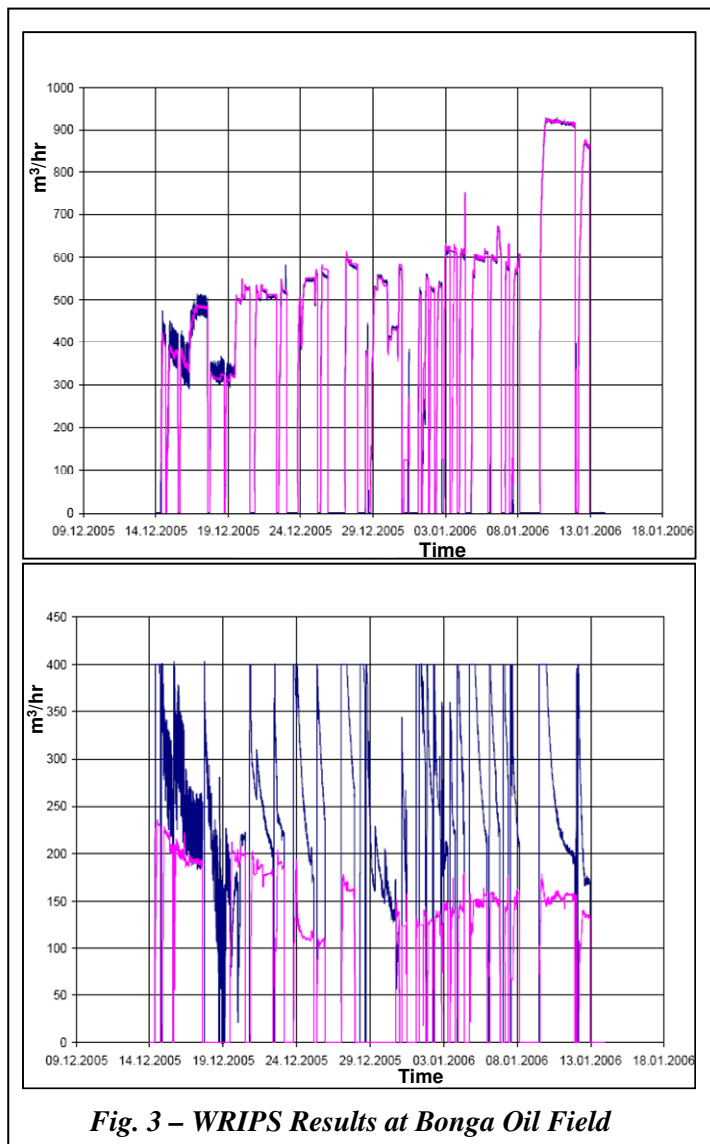


Fig. 3 – WRIPS Results at Bonga Oil Field

advantage is represented by its inherent reliability: compared to conventional downhole sensors, which often fail and are too expensive to replace. WRIPS uses all available sensors for its estimates and will proceed undisturbed of failing sensors as long as the system is solvable. Figure 3 highlights some results from the Bonga application: the trend in the upper part of the figure compare the total flow measured at topside (in blue) with the sum of all the wells contributions as predicted by WRIPS (in magenta): it is possible to note the excellent agreement between the two trends. In the lower chart we can appreciate the capability of WRIPS to detect the failure of a physical sensor and to provide a reliable replacement without adding any actual hardware component.

The main benefits for the customers have been:

- Avoided damage to the shale layer: monitoring of the injection pressure and its uncertainty ensures that shale fracture pressure is never exceeded. No injection is allowed into the Bonga reservoir without WRIPS in operation, due to the expected major economic loss if the maximum allowable bottom hole injection pressure is exceeded.
- Optimized water injection: WRIPS calculates a target pressure for each well. The operator can optimize the production by keeping the injection pressure at the target pressure. Operating at maximum allowable injection pressure has been given large focus on Bonga and WRIPS has been used a lot for this.
- High accuracy of the downhole pressure: WRIPS uses all available sensor data and a model to calculate the pressure. A downhole sensor would have higher accuracy, but it might fail or drift. In a big field like Bonga some downhole sensors would most likely fail and a data validation system like WRIPS would have been needed anyway.
- High accuracy in the estimated injection rates: this enables higher accuracy for volume balance calculations (i. e. better reservoir model).

2.3 Downstream Processing Facilities

Including downstream processing facilities into the Production Optimization picture allows fully exploiting and maximizing the benefits that advanced technologies may bring in the O&G business. The objective of advanced control projects is to improve the performance of product quality control and throughput, while adhering to operating constraints. This is typically done with two technologies, Model Predictive Control to drive the process closer to operating targets and Inferential Measurement to increase the frequency of product quality feedback information. ABB provides these capabilities in two packages (see [10] for more detailed descriptions):

- *Optimize^{IT} Predict & Control*
Optimize IT Predict & Control is a multivariable, model predictive control (MPC) software technology package. Predict & Control (P&C) is typically implemented at the supervisory level to manipulate setpoints of multiple control loops in order to drive multiple process output variables to their targets and enforce operating constraints.
- *Optimize^{IT} Inferential Modeling Platform*
OptimizeIT Inferential Modeling Platform (IMP) is a software package for offline development and online implementation of empirical models for advanced process control applications. OptimizeIT Inferential Modeling Platform allows development of empirical models featuring different modeling techniques.

2.3.1 Application Example: The StatoilHydro Sture Terminal at the Coast of Norway

The Sture Terminal receives crude and condensate in a 115 km pipeline from the Oseberg field center, stores the unstable crude in caverns, stabilizes the crude in the processing facilities, stores stabilized crude and loads ships for transportation of crude.

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The resulting recovered LPG is split between a pipeline to Mongstad and storage caverns for transport by ship. The resulting recovered naphtha is split between the Mongstad pipeline and the stabilized crude storage caverns.

An APC system composed of Optimize^{IT} P&C and Optimize^{IT} IMP has been running since early 2005. The objective of the system is supporting Sture operations in maximizing the LPG processing- and recovery capacities. There are 10 key process parameters (pressure, temperature, flow, duty controller set-points) continuously manipulated by the system in order to continuously maintain the system within 9 chosen operating constraints, and 5 LPG, naphta, and stabilized crude quality constraints while seeking to process a target crude feed rate and maximizing the recovery of LPG. The APC system have been reported by StatoilHydro to improve the bottom line for Sture by providing a more consistent handling of feed changes and process disturbances as well as operating closer to constraints.

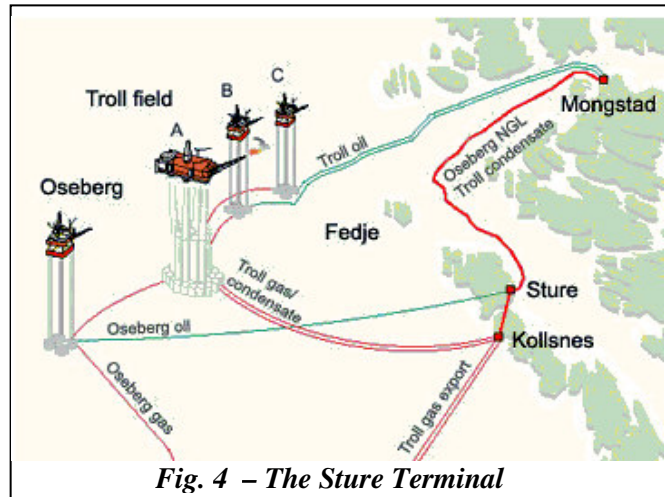


Fig. 4 – The Sture Terminal

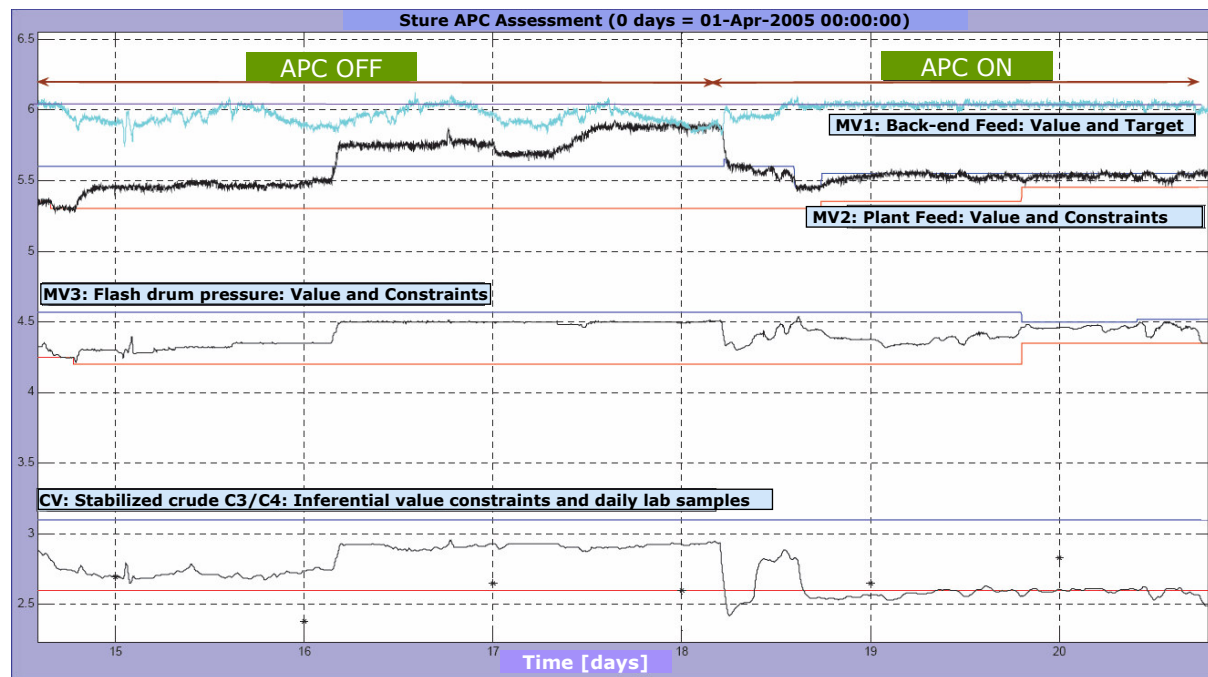


Fig. 5 – APC-induced Benefits at Sture Terminal

3. CONCLUSIONS

A significant number of optimization strategies for the Upstream industry are nowadays available. Many of them are field-proven and can boast a track of record of substantial benefit achieved. Covering the whole path from the wells down to the on-shore processing facilities requires a proper blend of software infra-structure, powerful mathematical and control toolkits, process and automation expertise and know-how for wise implementation and maintenance and – last but not least – a considerable amount of common sense.

In this work a few examples of such implementations together with the associated benefits have been given. The overall lesson learnt is that there is plenty of room for improving processing conditions and regularity, enabling increased production, improved quality and reduced emissions. Fig. 6 shows schematically the several contributions that the different technologies may bring to overall production profitability. It follows that no Operational

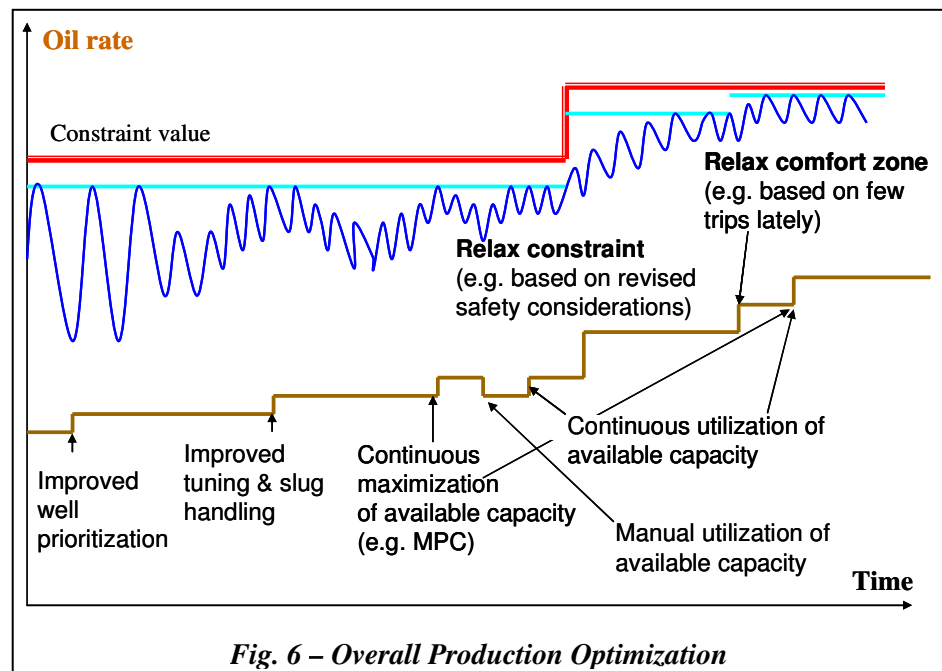


Fig. 6 – Overall Production Optimization

Performance Excellence can be achieved omitting to include the key contribution coming from Production Optimization practices.

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