AADE-10-DF-HO-31

The True Cost of Process Automation

Amber Smith, Tom Geehan, Alan McKee and Mario Zamora, M-I SWACO

This paper was prepared for presentation at the 2010 AADE Fluids Conference and Exhibition held at the Hilton Houston North, Houston, Texas, April 6-7, 2010. This conference was sponsored by the Houston Chapter of the American Association of Drilling Engineers. The information presented in this paper does not reflect any position, claim or endorsement made or implied by the American Association of Drilling Engineers, their officers or members. Questions concerning the content of this paper should be directed to the individuals listed as authors of this work.

Abstract

This paper describes the key elements required for a cost-effective automated process. For illustration, the process of treating and reconditioning of drilling fluids using solids-control equipment is presented. The principles employed, however, are transferrable, regardless of the process. A software management tool also is discussed that not only simulates the process under consideration, but can also identify the key variables that contribute to high efficiency solutions in both operational and financial terms. The software package has been developed to utilize field data and mass-balance calculations in order to model performance to allow for process optimization through the design and automation of key equipment as well as highlighting process dependencies and controlling factors.

The tool allows for easy comparison of financial costs, treatment efficiencies and environmental burdens for a wide range of equipment design specifications and mud processing conditions to ensure delivery of the drilling fluid at optimum specification. It is envisioned that further benefits will be realized when the ever increasing challenges faced by drilling operations as well as the industry in general are considered, such as the deepwater drilling applications off the coast of Norway and South America.

Introduction

In today's oil and gas industry, drilling wells is becoming increasingly more challenging, with drilling nonproductive time (NPT) running at unacceptably high levels.[1] While there are many factors that can be attributed to poor performance, such as formation instability, equipment failure, lack of technological advancement and poor management decisions, it is vital for the industry that lessons are learned and progress made to reduce NPT to acceptable levels.

For an effective automated process, the design, monitoring, control, analysis and optimization all require seamless integration. For example, in the treatment and conditioning of drilling fluids with solids-control equipment, process optimization, through the design and automation of key equipment is being tackled by the development of a Solids-Control Process Simulator (SCPS) software management tool. By utilizing real-time field data that can be automatically monitored and logged, SCPS can be utilized to seamlessly integrate mud processing equipment into overall oil and gas drilling processes.

The many challenges faced by drilling for oil and gas has meant that the progression to automated systems, both for offshore and onshore platforms, has not received the same level of enthusiasm that has been witnessed in some of the other process industries, such as the pharmaceutical and chemical manufacturing industries. The variable nature of the drilling process and the fact that it is an open system, has meant there has been limited interest in platform automation, which in turn has led to it never being fully implemented throughout the industry. Individual countries, such as Norway, have embraced the advancements of new process technologies to enable process automation to become a reality rather than a dream; however, without a growing market, progress has been slow.

Industry Overview

If the oil industry truly wants to reduce costs while increasing production, more automation of well-site processes is required for long-term improvement. This will require investment from the start, with an inevitable steep learning curve in the infancy of each stage of design optimization. Ensuring that those who invest at the onset reap the rewards gained is foremost in the minds of those looking to pioneer automation in this sector. Those who take the plunge can expect to shape this new era of development, from the traditional fully manual phase, to semiautomated phase with supervision, to full automation with external control.

The primary goal of developing the rig of the future is to reduce equipment downtime and personnel requirements while at the same time increasing reliability, safety, regulatory compliance and environmental responsibility. This requires defining operations that optimize equipment usage, comparing costs and efficiencies, whilst enabling root cause failure analysis to be conducted over the whole rig. The success of such a system can be borne out by the fact that data from multiple equipment vendors can be gathered from remote locations, analyzed and used to support decisions that produce positive actionable items.

Key Stages of Process Automation

A system for designing, analyzing and controlling a process through timely quality measurements is the ultimate goal to ensuring continuous improvement.

The key areas involved are:

1. Process measurement
2. Process automation
3. Information management

The task of installing an automated system is not an easy one and just like any other project, key questions have to be addressed. Typically, these questions center around similar themes, regardless of the process:

1. What needs to be automated?
2. How can it be automated?
3. Can it be integrated into an existing/new process?
4. What is a satisfactory verification process?

How these questions are answered depends on the process, what is currently been done manually and what, if any, level of automation already exists. Further consideration is also required on how automation can be integrated seamlessly into the overall process without significant disruption. This requires a high level of communication and cooperation among those involved, from the drilling operators, contractors, equipment vendors and service companies. In instances where the assessment of the key drivers for automation is overlooked, the process can end up as little more than a monitoring exercise, with the delivery of data analysis lacking.

The hardware, software, communications link and equipment operation all require integration, which can often lead to timely and costly solutions. In addition, partly due to lack of experience in the field and partly due to the financial interests of all the parties involved, the best components are often not selected, which can affect the maintenance and costs of the system and ultimately the benefits to the customer. Thus for a totally seamless integrated automation, ideally compatible products should be installed, upgraded and serviced by one company, combining in-house expertise to produce sophisticated analysis and seamless integrated design capabilities. This then leads to a cycle for automation optimization, as highlighted in Figure 1, with integrated information among all processes fed to the expectant downstream production facilities, which in turn will improve their efficiency and reduce downtime.

Above all, a fully automated system needs to be efficient, flexible, safe and critically, user-friendly. Automation leads to predefining process operations, leading to greater standardization and safety.

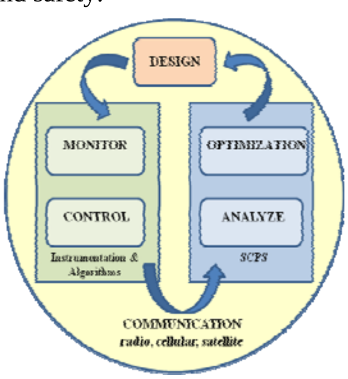

Figure 1 - Cycle for automation optimization, including Solids-Control Process Simulator (SCPS) management tool.

Mud-Mixing Process

Key areas of rig operations where manual control is still paramount are the mud-mixing and solids-control processes. As part of the Wellbore Construction Fluids Domain (WCFD)[2] consisting of four main subsections (Figure 2) the ultimate goal is to deliver a mud with the required specification to allow the drilling process to proceed in a cost effective and timely manner with no wellbore or fluid instabilities that can cause NPT. Thus the major drivers to automate the mud mixing and solids control processes are the safety of personnel and the consistency of the mud properties.

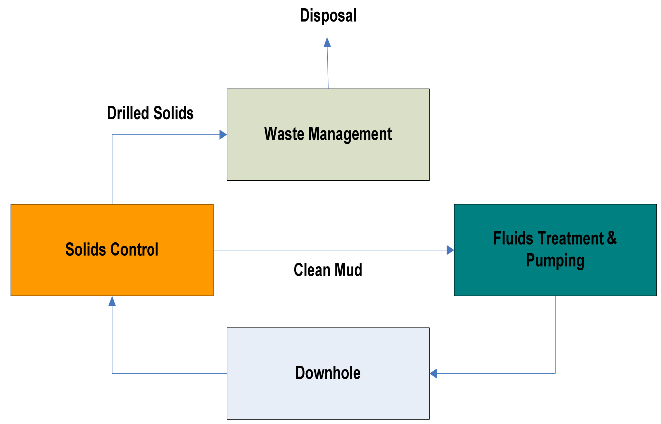

Figure 2 - Schematic of Wellbore Construction Fluids Domain

A traditional mud mixing process, whether it is onshore or offshore, consists simply of tanks, motors, agitators, pumps and pipe work. The equipment is operated manually and the process relies on the knowledge and experience of the personnel involved to maintain the operation and prevent problems leading to downtime. The process itself is labor intensive, with solids and chemicals added manually. Even on a semiautomated system, where some of the operations can be handled automatically by input from a user either in a control room or operator station, the "brain" of the operation is still the knowledge held by key personnel in the control room.

For a fully automated process, all equipment and sequences of operation would be controlled by the control system. This would include, for example:

- Transfer of fluid between tanks, whether for circulation or delivery of fluid downhole
- Mud weight maintenance by fully automated monitoring of density and subsequent addition of barite or pre-mix accordingly
- Automated dosing of chemicals, salinity control, sack handling, agitators, pumps and valves would all be included.

The fully integrated system produces a more efficient process that allows for a significant reduction in surface volume requirements and less overfilling of tanks, which results in reduced capital and storage costs as well as a smaller footprint for the mud-mixing process. As there is less fluid, the exposure to hazardous chemicals, dust and fume is also reduced, with less washing down of the areas required to remove these hazards. This has the associated effect of reducing the environmental impact of the process, where discharging overboard is becoming ever more stringent.

Thus the major benefits automation brings to any process are:

1. Optimization and improved performance
2. A more steady, reliable and accurate process
3. Lower operating costs
4. Improved health and safety
5. Workforce optimization – Reduced human errors and manual operation
6. Less training costs and occupational concerns
7. Increased data for decision-making purposes
8. Reduction in environmental concerns

The major disadvantage that automation brings is that the initial investment is not always readily recouped and cost efficiency can be slow to be recognized.

On the Valhall Water-Injection Platform (WIP), [1] extensive field trials were conducted on fully automated mud-mixing systems. The trials concluded that not only were human errors and contact with hazardous chemicals reduced, but that there was the real potential to increase efficiency due to a more reliable and stable process.

Monitoring

Although control is often seen as the most successful component for automation of a process or system, ensuring reliable on-line monitoring is critical, as regardless of how sophisticated a Drilling Control System (DCS) is, the output can only be as relevant as the data input. For wellbore construction fluids, the data often required to be logged are the properties of the fluid required in order to ensure that it is on-spec when it reaches the wellbore. Thus, these monitoring devices have to be able to provide up-to-date information in order to make intelligent decisions. Therefore, great care is required in the choice of such equipment to ensure that all requirements will be met.

Compared to off-line testing, which refers to laboratory based tests, at-line testing requires equipment to be placed next to the production line to provide rapid results by reducing the transfer of samples. For full automation, however, on-line or in-line testing, which are differentiated by how the sensor/analyzer is connected to the process stream, is required. For on-line testing, the testing equipment draws/grabs samples periodically from the production line while for in-line testing probes are placed in constant contact of the production line. Both testing methods provides better control of the process and hence, when combined with providing specific, accurate and precise data from robust apparatus that requires no additional laboratory facilities, the data can be reliably analyzed and integrated into the automation cycle. In addition, the use of on-line processing to prove compliance will reduce manual lab intensive analysis.

Increasingly, as more and more new technologies are being developed, greater capabilities of measurements are being realized. Spectrometric-based technologies are representative of these new developments. For example, sensors made from fiber optics have been developed that can monitor a number of variables, from strain, temperature pressure, vibration and acceleration. Alternatively multiple sensors on a single fiber to enable, for example, a temperature profile to be determined. These technologies are solving complex measurement problems with increasing reliability. Other technologies, such as magnetic resonance analysis (MRA), can provide non-invasive, precise analysis of feed streams requiring little maintenance. Low-field MRA utilizes induction decay data to determine rheological information and component composition while high-field MRA can identify more exacting variations in physical and chemical properties. By utilizing the technologies that have already been proven in other fields, tailoring further development to suit the specific needs of the oil industry has allowed greater advancement in specific monitoring and subsequent automation design.

In addition to the selection of the most suitable type of analyzer for the desired monitoring parameter, attention to the sample conditioning system is also required for a well-designed automated system. Without the sample being representative of the system, there is little use in utilizing the data for control purposes. Thus, a poor design will not only produce poor data, but may result in the wrong action being taken and require considerable maintenance and downtime for an unattended operation. The physical and chemical properties that need to be considered include the following:

- Flow/temperature/pressure – what are the maximum and minimums that the analyzer can handle and what effect will changes in these properties have?
- Phase changes – a challenge for most analyzers and usually not acceptable for most sensor technologies
- Chemical effects – incompatibility with contact materials that can be attacked, such as tubing and valves. For various chemicals present, corrosive, toxic or flammable conditions can exist.
- Loading – excessive loading of the analyzer can, at worst, result in complete failure. Certain particulate sizes may block the equipment.

Also, the following process considerations:

- Response time – how long will it take to obtain actual data from the point of sampling?
- Altered sample – does the sample change during the path to the analyzer, e.g., if depressurization is required before the sample can be analyzed?
- Decontamination – is it necessary to pre-treat the sample before it can be analyzed to remove contaminants/maintain the equipment/ensure health and safety standards?

Central to the overall system design of all these in- and on-line monitors/technologies, is the reliance on computer-based software and networks. Industrial networking, in the fieldbus, not only enables the monitoring process to be conducted in a control room but also decreases installation costs and enables problems to be detected early before they can take effect.

Control

The development in microelectronics, especially semiconductor technology, has enabled process control systems to take advantage of Digital Control Systems (DCS). Field Control Systems (FCS), which represents total information processing to smart field transmitters and actuators is currently being further advanced to allow Open Control Systems (OCS). The basic advantages of utilizing FCS devices is lower installation, wiring and maintenance costs combined with multivariable devices that can be combined and have a greater reliability of data transmission. Progress, such as this, has and will continue to enable not only large platforms to accommodate DCS, but smaller facilities to embrace leading edge automation technology.

These highly integrated rigs with DCS will require a knowledge base that can not only remediate problems as and when they arise but help prevent them in the first place. For this, software, hardware, equipment experience and an overall understanding of all the stages of the drilling process will have to be understood. This is where one of the main problems lies. The control and automation of oil and gas drilling should not be subject to unproven, unmanaged and untested software and instrumentation. Until the economic rewards are shared by all those involved in the optimization of the process, from equipment manufacturers, contractors and operators, the responsibility and ultimate goal of automation on the platform will not be realized fully.

There are greater expectations from new rigs, as they are expected not only to be more efficient than their predecessors but are also expected to operate in more demanding environments, more remote and deeper locations. Unfortunately, these rigs have complex software dependent systems that are often sourced from several manufacturers, who do not have the in-house experience to ensure that their cheaper standard off-the-shelf systems can be integrated harmoniously. Thus, the oil industry must realize that the aforementioned parties must be confident in sharing knowledge to enhance software and systems engineering.

Alarmingly, due in part to lack of suitable personnel and understanding of how these complex DCS operate, many have simply been neglected on offshore and production facilities. Often, with several vendors servicing these systems, software updates can unknowingly introduce bugs into the whole system that sometimes do not get picked up until a critical NPT incident occurs. Even simple procedures, such as software storage, back-ups and up-to-date records of which versions of software have been installed are neglected.

In once such incident,[3] when lightning had destroyed a Programmable Logic Controller (PLC) on a high-specification offshore rig, although there was a new PLC available, there was no backup of the software and until the correct software was identified, it could not be dispatched to the rig. This accounted for unnecessary NPT, due to a lack of basic management practice.

In a recent report,[4] which published the first industry survey on NPT related to Drilling Control System (DCS), found that of the 100 to 150+ million US dollars (USD) lost to NPT, 24 to 45+ million USD was attributed to be as a result of DCS failure on highly automated rigs. In a further report,[5] it was highlighted that a highly automated Gulf of Mexico rig, whose annual NPT cost can be in excess of 120 million USD alone, 24 million USD was attributed to a failure of DCS. In addition, it was found that most major injuries, accounting for 41% of the total, occurred on the rig floor, where 75-95% of all movement of equipment and pipe work is managed by DCS.

As the Drilling Control System is the core interface that drives all the linked processes in the rig, one simple software failure can have a domino effect on the rig and impact on other processes. For example, failure of the mud processing equipment on the rig floor can shut down the drilling of the well and effect downstream production operations.

Software

As software is often already built-in to the hardware, it can often be overlooked as a means to provide advanced diagnostics for on-board troubleshooting of the equipment/monitoring device. By providing closely integrated, custom-built and configured software to operate the equipment on drilling rigs, tight management of such a system is required. Rig personnel have to be trained to ensure that they have the knowledge and ability to update and reinstall software on all the equipment on the rig, just as you would expect that all equipment should be able to be repaired on site.

Once installed, the software should be frequently reviewed and updated to ensure that is operating as it should and that any potential problems are identified and resolved before they become real on-line issues, which could lead to NPT.

Control Room

With a better overview of the whole system from the control room, operators can anticipate problems and prevent accidents rather than having to react to them. Operation rooms, especially if located remotely from the site, should have the ability to access self-cleaning ATEX-approved closed circuit television (CCTV) stations, with user-friendly screens that have the capability to jump from one operation to another, ideally by the touch of a screen. The software should not only display data but be capable of providing acquisition, logging, storage, distribution and remote control of equipment. Providers of such systems are already available,[6] where small-scale sensor packages to full-scale drilling control can be managed without additional equipment to interface between various types of equipment.

Joystick-operated robotic motion control (RBC) is also allowing large equipment and pipe work to be moved more safely, with minimum personnel required.

Testing and Costs

Time-to-market goals can often be hampered by automation software testing and the movement to testing offshore. Field trial and testing on-site should be reduced to a minimum to cut down on interruptions and the added cost of testing offshore. Simulations in the lab and onshore should be encouraged to develop and rectify potential problems and train personnel that will be in charge of the operation once live.

Software testing is an attempt to actually "break" the software, by trying to find all the bugs that are inherent in the software before the customer does. This involves designing and running tests, identifying problems and reporting back to management for further development. It should not be done at the end of the process before the equipment/product is ready to go to the customer. Once satisfied with the reliability of the software, installment and testing of monitoring devices, reducing lag times, integrating easy-to-use menu screens and multiple languages native to the existing hardware and combining the communication to the platforms capabilities are all required as part of the testing procedure.

Testing can be outsourced to third parties who have more experience in particular fields. However, there are pitfalls that need to be considered when outsourcing:

- Poor communications with the outsourced company, whether this be miscommunication of expectations or unresponsiveness caused by language and cultural barriers.
- Insufficient skill base, lack of knowledge in the software being tested
- Product vendor problems
- Improper intellectual property protection

Often an unexpected increase in cost and time are possible and just as in any effort, without proper coordinated management and planning, effective automation testing can be deemed a failure, with reluctance from the customer to reinvest. Thus before any organization expends time and resources in the specification and development of an automation process, it is vital that it should directly benefit the customer.

The overall cost of the development very much depends on where in the phase of the project the related costs are incurred. These costs can be categorized generally into four major sections:[7]

1. Prevention costs – these consist of costs related to preventing errors, whether it is the product or the software. For example, staff training, early prototypes/bench-scale equipment, clarity of specification
2. Appraisal costs – all the costs spent on testing, improving the design
3. Internal failure costs – fixing problems before they are released on the market
4. External failure costs – defect and error costs once the product is in the marketplace. Usually these are expensive, time dependent costs, with subsequent intangible costs also likely, such as poor customer satisfaction and loss in future sales.

Analysis and Optimization

Analysis of the data, which is often overlooked in the early stages of automation, should be incorporated from the start. Identifying the purpose the data is to be used for is crucial in determining what is to be analyzed. This ranges from comparison against historical trends, pattern match, failure analysis, modeling for future development to full statistical process control.

The data will then allow correlation of actual field measurements to design performances and enable weaknesses in processes to be identified and improvements made. The data alone provides permanent records, which are becoming ever more desirable in today's industry, as more and more regulatory bodies require proof of compliance, such as meeting EPA emission control requirements.

Like most complex processes, drilling for oil and gas consists of several interlinked, yet unique sub-processes, with the bottleneck in the whole system being the flow of useful, easy-to-read, real-time oilfield data that allows the engineer to make effective decisions in a timely manner. Often aggregating data from the surface equipment, which is usually provided by multiple service companies, is still a manual process on the rig floor and furthermore, does not allow sufficient insight into the dynamics of the platform and the impact on field operations. Dependence on spreadsheets to track production and trying to interface the results with equipment performance renders proper evaluation, management and mitigation of equipment downtime almost impossible. Thus underperforming or critical conditions are often picked up long after production rates have been affected.

Solids-Control Process Simulator

In order to provide analysis of the extensive quantity of Solids-Control Equipment (SCE) data that has been collected over many years, in a form that can assist control of these processes, a software package entitled Solids-Control Process Simulator (SCPS) was developed. The SCPS structure, or basic loop (Figure 3) includes the complete mud treatment system, where cuttings are continuously added to the mud from the well, mud passes through the solids-control equipment and raw materials are added to the active pit before the mud is redelivered to the wellbore in one continuous loop.

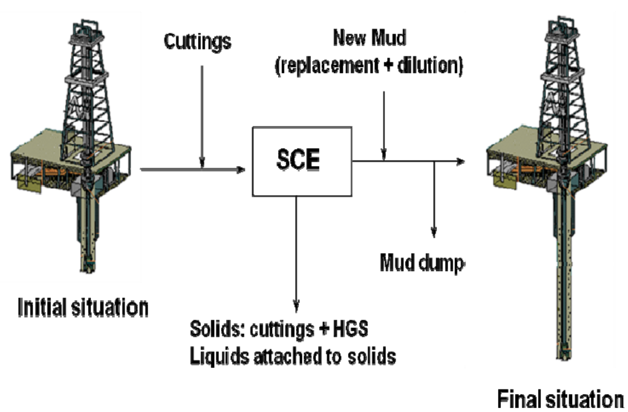

Figure 3 - Basic loop for a mud system.

In simple terms, SCPS takes into account equipment parameters and mud properties to simulate material consumption and waste volume generated based on:

- Well configuration
- SCE configuration
- Mud specification

The SCPS software has a database based on empirical models for a wide range of equipment design specifications and mud processing conditions to ensure delivery of the drilling fluid at optimum specification. With empirical models for every type of SCE, from shale shakers, hydrocyclones and centrifuges as well as unique coefficients developed for specific makes and models of equipment, predictive modeling of the process can be achieved.

For each piece of equipment, modifications to the models can be made to improve results, such as a new turbulence factor for the centrifuge model. However, the empirical nature of the software program does also highlight its weakness, which is inherent with most software packages, in that the software program does require updating from time to time as further understanding of the unique properties of the equipment is made. This process is made less onerous however by the validation facility built into SCPS that allows a comparison between the predicted values with actual field examples/data that already exist.

As shown in the configuration input screen (Figure 4) the complete mud treatment system can be easily built up with a series of drop-down menus for equipment selection and the option of adding equipment in series or parallel to replicate exactly the configuration on the platform.

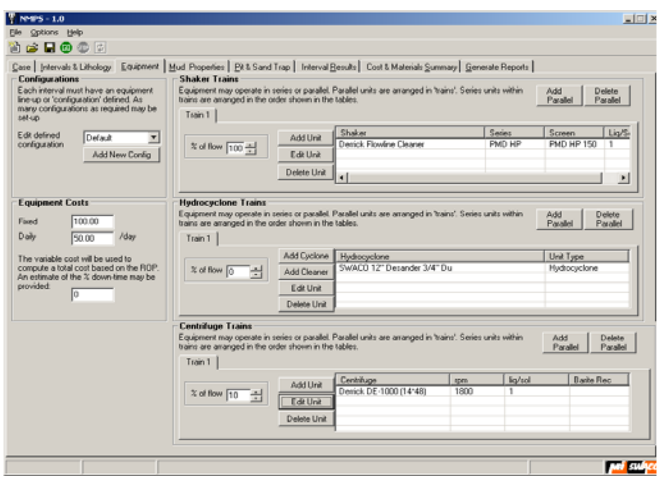

Figure 4 - SCPS SCE configuration screen.

A visual overview of the process configured, as shown in Figure 5, then allows for confirmation of the correct design in one simply step.

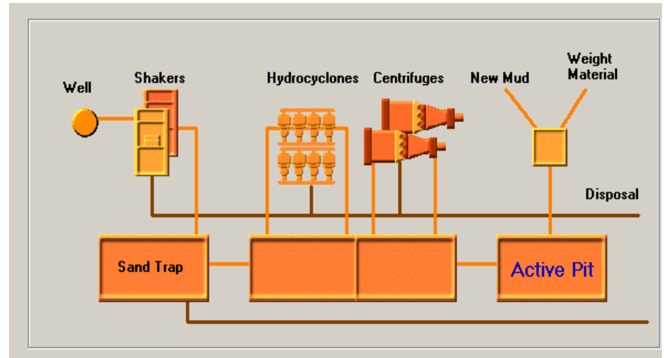

Figure 5 - SCPS visual overview of configured process.

The output screens on SCPS, as shown in Figure 6 and Figure 7, plots real-time data and includes information on the active pit properties, mud disposal, material consumption and solid removal efficiencies. Thus, SCPS not only demonstrates mud-cost reduction and waste minimization for different equipment configurations, it can also collect SCE data and run simulations to evaluate the efficiency of various SCE installations. With easy-to-use menu screens, data can be readily accessed and saved in readily sharable documents, such as spreadsheets.

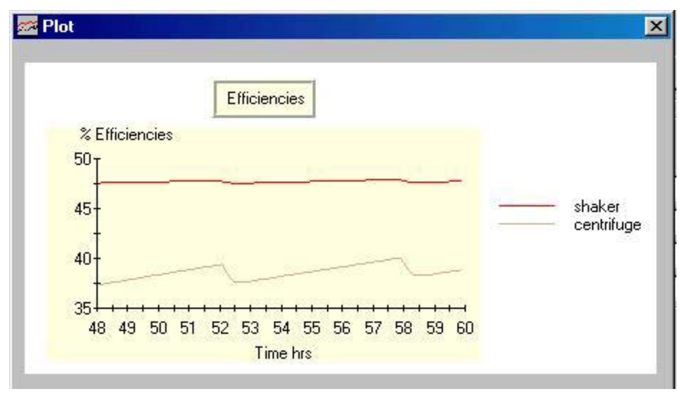

Figure 6 - Sample plot of shaker and centrifuge efficiency real-time data.

During the actual SCE operation, the monitoring devices[2] take the necessary readings, such as volume, density, percentage of Low-Gravity Solids (%LGS) of the active pit and then feeds this data to the SCPS simulator, which in turn analyses these properties by checking them against predetermined values and calculating the corrective action by providing options for adjustment of the mud and/or equipment. The SCPS has two kinds of settings to achieve this, either alarm settings or targets/objectives set by the user, (Figure 7) with corrections performed on the controllable properties if drifting occurs from the set points and limits.

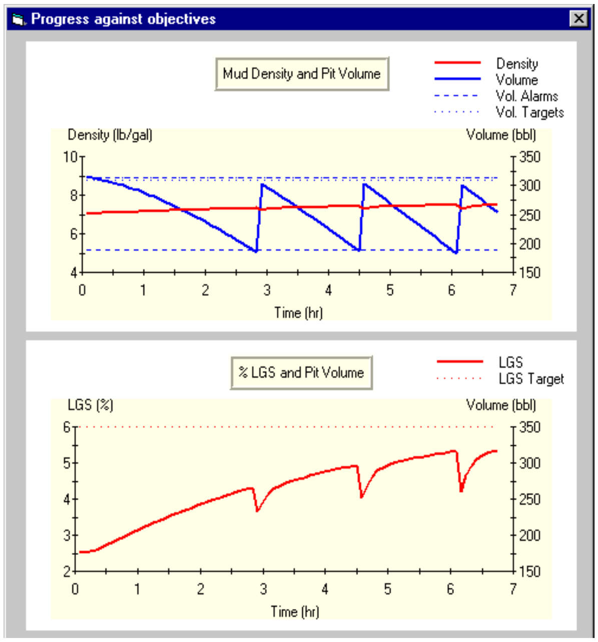

Figure 7 - Examples of real-time corrective action plots for a mud system; correcting mud density, %LGS and pit volume.

SCPS is also an ideal tool for training purposes by providing an actual visual display of the consequence of not maintaining equipment efficiency as well as the interrelationships that exist between the operation of the equipment and subsequent properties of the mud.

Thus, in summary, SCPS can optimize the parameters of equipment to minimize mud processing cost and waste generated by improving SCE efficiency and equipment configuration for new and existing installations and rigs.

Conclusions

Just as in other industries, the oil and gas industry is recognizing the benefits of introducing automated processes into the whole drilling process, with simple step-by-step improvements allowing the whole automated infrastructure to be incorporated with minimal disruption to ensure an ever more efficient and cost-effective process.

For a totally seamless integrated automation process, compatible products should be installed, upgraded and serviced by one company, combining in-house expertise to produce sophisticated analysis and seamless integrated design capabilities. This then further leads to a cycle for automation optimization, with full integration between all processes, including the expectant downstream production facilities, which will improve their efficiency and so reduce downtime of the whole process chain.

A realistic goal for the mud mixing process, as for all the surface equipment on the platform, including solids control, is to provide data monitoring to the same level of capability and maturity currently deployed for downhole production. This will then enable local, remote and external control of the whole process to optimize efficiency, reduce energy consumption, waste generation and process costs, based on equipment performance and data analysis. This is achieved through the development of SCPS, to ensure that today's new highly automated rigs operate efficiently and safely. Until this is addressed and adopted throughout the industry, the true benefits of automation will not be realized and mistakes will continue, leaving NPT to run at unacceptable levels.

Acknowledgments

The authors thank the management of M-I SWACO for permission to publish this paper. A special thanks to M-I SWACO Applied Engineering in developing the Solids-Control Process Simulator tool.

Nomenclature

DCS = *Drilling Control System*
FCS = *Field Control System*
HGS = *High Gravity Solids*
LGS = *Low Gravity Solids*
NPT = *Non-Productive Time*
OCS = *Open Control System*
SCPS = *Solids-Control Process Simulator*

References

1. Gunnerod J., Serra S., Palacios-Ticas, M. and Kvarne O. "Highly Automated Drilling Fluids System Improves HSE and Efficiency, Reduces Personnel Needs." *Drilling Contractor* (January/February 2009) 73-77.
2. Geehan, T. and Zamora M. "Automation of Well-Construction Fluids Domain." SPE 128903, IADC/SPE Drilling Conference, New Orleans, 2-4 February 2010.
3. McAfee, T. and Keenan R. "Reducing Rig Software Risk." *Hart's E&P* (May 2008).
4. Lowry, C. "The State of NPT on High-Specification Offshore Rigs." Athens Group. Whitepaper available from www.athensgroup.com (May 12, 2009). 5. Shafer, D. "Rig Safety and Reliability Incidents Caused by Software: How They Could Have Been Prevented." SPE 120584, SPE Americas E&P Environmental and Safety Conference, San Antonio, Texas, 23-25 March 2009.
6. Aker Solutions. "Drilling Control and Monitoring Systems (brochure)." Available at: http://www.akersolutions.com/NR/rdonlyres/65BEFA6C-36EB-4520-8662-1ECC38CCD51A/19123/Drillingcontrolandmonitoringsystems.pdf (2009).
7. LogiGear Corporation. "Offshore Software Test Automation: A Strategic Approach to Cost and Speed Effectiveness." Whitepaper available from: www.logigear.com (2006).