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Reservoir Surveillance, Production Optimisation and Smart Workflows for Smart Fields—A Guide for Developing and Implementing Reservoir Management Philosophies and Operating Guidelines in Next Generation Fields

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Abstract

Many oil and gas companies are joining the wave of forward looking operators implementing intelligent well and smart field technologies to improve their ability to optimise production, minimize expenses, and improve reserve recovery. Much has been written about the application of these technologies and steps to successful installation of the hardware. But the real value of intelligent wells and smart field systems come from the ongoing exploitation of the new technology in day to day operations. This paper compares the methods of reservoir surveillance and production optimisation in the "old world" to those of the next generation intelligent fields. Successful exploitation of the new technologies requires an understanding of information flow, control and automation capabilities, knowledge management, interpersonal communications, and decision processes to develop performance indicators, workflows, philosophies and protocols suitable for the fields of the future.

Three core elements are explored in the intelligent field workflow: the reservoir management philosophy, the production surveillance capabilities, and the operating guidelines. The requisite components of these elements are reviewed in the context of intelligent field capabilities. The concept of intelligent well and intelligent field optimization is explored examining the most recent developments in proxy modeling and feed-forward control technologies applied to well and reservoir management.

The value of these new optimisation tools will come not just from fine tuning of steady state conditions, but more likely from being able to react quickly to changes in operating conditions, whether reservoir, well or facilities related, to find optimum production solutions in near real time.

The concepts discussed in this paper are applicable to all intelligent well and smart field applications, particularly to those planning to implement "real-time" reservoir optimisation strategies. The information presented will provide a roadmap for the development of these strategies and protocols in the context of the smart field environment.

Introduction

In 1997, the first successful completion incorporating permanently installed, downhole pressure and temperature measurements integrated with remotely controlled, high fidelity flow control valves was installed in a well in the Norwegian sector of the North Sea. This landmark event marked the genesis of the intelligent well era. The use of intelligent well technology has "crossed the technology adoption chasm" in many regions over the past decade as oil and gas producers have increasingly incorporated the technology in field developments to capture the benefit of enhanced reservoir management that intelligent well technology delivers.

The accelerated adoption of intelligent well technology has been catalysed by two key factors: first, demonstrable and statistically significant improvements in reliability of the equipment and second, the offering of increasing capabilities and functionality of the equipment while holding costs steady. The first is a result of reliability driven engineering, improved manufacturing and quality control, and the accumulation of in-well experience as an increasing number of systems have been installed. The second is a result of innovation by the intelligent well suppliers driven by competition and the realization of a viable intelligent well market, and the demands of the users, who have experienced the benefits of the early generation, simpler systems and have realized the potential for greater value benefit from systems with enhanced functionality.

Concurrent with the advent of intelligent well technology is the escalating growth in field and process sensor technology, real-time communication bandwidth, computing power, decentralized control capabilities, data storage capacity and visualization capabilities being applied to the upstream oil and gas industry. Together, these elements form the foundation of intelligent field technology. Yet implementation of the technologies alone will not deliver the true value of the intelligent field. Processes and workflows, combined with a knowledgeable workforce are required to extract the value promised by intelligent wells and intelligent fields. Old concepts of reservoir surveillance and production optimization must be updated in the context of the capabilities of intelligent wells and intelligent fields.

Much has been written recently about the implementation of real-time optimization technology, integrated asset models, and the structure of the *process* of asset management (Cabrera et al., 2007; Szatny, 2007; Sagli et al., 2007), but the development of the underlying precepts of reservoir management, and the translation of these to operating guidelines in the context of intelligent wells and intelligent fields, has not been extensively explored.

Reservoir Surveillance and Production Optimization: a Historical Perspective

The fundamentals of petroleum reservoir management haven't changed in the past 50 years, however, in the era of the intelligent field, it often seems as if we are spending more time managing the data and the process than we spend managing the efficient extraction of hydrocarbons from the reservoir. Wiggens and Startzman (1990) defined petroleum reservoir management as "the application of state-of-the-art technology to a known reservoir system within a given management environment." Satter (1990) elaborated by stating that the purpose of reservoir management is "to maximize profits from a reservoir by optimizing recovery while minimizing capital investments and operating expenses."

Prior to the 1980's, reservoir management was based on low-density, episodic production data, rudimentary digital reservoir simulation tools, and sequential work processes. The work processes were organized along functional lines with each discipline "handing-off" its contribution to the management process in "assembly line" fashion. Production data, for the most part, was characterized by 'snap-shot' well tests — usually generated with a frequency of little more than once per month.

In the 1980's, the upstream oil and gas industry increased usage of supervisory control and data acquisition (SCADA) systems, primarily focused on central process plant instrumentation. Basic, remotely transmitted wellhead pressure instrumentation was applied infrequently, and generally reserved for high productivity and offshore wells. Increasing power in centralized computer systems and super-computers enabled more sophisticated reservoir simulators, and the introduction of personal desk-top computers provided rudimentary petroleum engineering analysis tools and production-data-base management systems. Pressure transient analysis still depended on low resolution analog downhole pressure recorders, and well test data was still acquired at a frequency measured on the scale of readings per month.

The 1990's were characterized by the explosion of the information age and the widespread adoption of asset-team organizations and reservoir-management concepts. SCADA systems and DCS systems expanded from the central processing facilities into the field, providing high-frequency wellhead-pressure instrumentation. Multi-phase meters applied to individual wells or clusters of wells provided continuous production data streams, although typically this information was stored at a granularity of one reading per day. Engineering workstations moved more sophisticated reservoir simulators to the petroleum engineers' desktops. More powerful desktop and laptop personal computers combined with improved petroleum engineering analysis applications provided the petroleum engineer with the capability to analyze and optimize well performance with greater ease. Petroleum professionals were organized into asset teams to improve collaboration and effectiveness. (Gringarten, 1998)

Despite these capabilities, the reductions in the petroleum professional workforce through the 1980's and 1990's reduced the focus on continuous reservoir and production surveillance, offsetting the potential gains these tools offered. In many of the world's oilfields, detailed reservoir and well-performance reviews were conducted only at a frequency of once or twice per year.

The last 10 years has witnessed the advent of several new technologies that bring "real-time" asset management closer to reality, including 4D/4C seismic analysis, intelligent well technology, ubiquitous sensors and data communications, massive data storage, faster, more powerful simulators, and collaborative visualization tools. Yet all this digital power has not significantly improved the plight of the petroleum engineer. Fifty to seventy percent of his or her time is spent finding, gathering and managing data. Manipulation, filtering, synchronization, validation and analysis of the data are largely accomplished in a spreadsheet environment. (Deaton and Kloosterman, 2007)

Intelligent Well and Intelligent Field Technology

The objective of any recovery project, whether primary, secondary or tertiary, is the efficient movement of fluids through the reservoir to extract hydrocarbon. Efficiency is measured in terms of the percentage of hydrocarbon recovered and the energy expended to recover it. Intelligent well completions provide a key capability to affect the flow of fluids into and from the reservoir, particularly in reservoirs with complex geology (layering, compartmentalization), in wells with complex architecture (horizontals, multilaterals), or in advanced recovery schemes (secondary, tertiary). As such, intelligent wells form the backbone for the intelligent field.

There are three key elements (figure 1) of intelligent well technology that are essential to realize the full benefit of intelligent field reservoir management:

Flow Monitoring: the ability to generate data about key reservoir parameters such as pressure, temperature, flow and fluid composition, in real time, at frequencies suitable for analysis and understanding about the well and reservoir performance. The data may come from electronic or optical sensors located downhole, in close proximity to the reservoir, acquiring reservoir parameter data, in the ideal implementation, from each zone.

Flow Control: the ability to segment the wellbore into individual flow units or zones, and control the inflow or outflow of fluids in each zone without physical intervention, by the use of downhole interval control valves. These interval control valves may be binary (on-off), multi-position, or infinitely variable, the latter two providing the ability to constrain or choke flow into or from the zone, and thus provide greater ability for control and optimization;

Flow Optimisation: the ability to gather the downhole reservoir parameter data, combine it with other relevant gathering and process production data, store and transmit this data, provide analysis capabilities to generate information and insight about the reservoir performance, make informed decisions to modify the well completion architecture using the downhole flow control, and implement the changes to the settings of the ICV's in a timely manner. Flow optimisation includes the acquisition of data, control and automation capabilities directly associated with the intelligent well hardware, and integrated with the field process control systems such as SCADA or Distributed Control System (DCS).

The benefit of intelligent well technology is realized when production information generated by downhole and field-deployed sensors can be actively and frequently used to make decisions to modify the well zonal completions, thereby optimizing production and manage reservoirs near real-time. To effectively exploit this technology requires work processes, data management and optimization routines that permit frequent adjustment and fine tuning of the intelligent wells (Figure 1).

The Challenge of Time and Space

Management of the hydrocarbon recovery process relates to management of the flow of fluids moving through the reservoir, complicated by phase transformation and interface effects. The parameters which we can directly control are the flow of fluids into the injection wells, and the flow of fluids from the production wells. By controlling these parameters, we can influence the pressure and saturation of the reservoir. Yet optimization of reservoir recovery is not simple, complicated by the significant lag time in observed response when a change is made to the operation of the wells, either at the injection wells or the production wells (Brouwer et al., 2001).

Production optimization can be considered in two contexts, temporal and spatial. In the temporal domain, reservoir management focuses on short term vs. long term objectives, actions and responses. In the spatial domain, the extremes range from the individual (well) zone or completion scale to the full reservoir or field scale. Short-term reservoir management focuses on production performance at the completion or zone level with objectives of maximizing hydrocarbon production and short-term profitability. Long-term reservoir management focuses on maximizing hydrocarbon reserves recovered and Net Present Value for the asset. Rossi et al. (2000) describe these processes as Fast-Loop and Slow-Loop workflow processes. Balancing the decisions of short-term objectives versus long-term objectives is the key to effective reservoir management. Intelligent wells provide the petroleum engineering expert and asset manager with new tools and capabilities to improve performance in both the short term and long term.

Significant benefits can be achieved with the integration of intelligent well capabilities with intelligent field management systems. In particular, having "real-time", localized, pressure, temperature and flow readings, and a controllable valve at each completion interval provides the operator the ability to pro-actively manage the flow of fluids in the reservoir in ways that have been impossible to do in the past.(Harts, 2001; Nyhaven, 2000) Reservoir management can use intelligent well technology to improve the performance of the asset at the following degrees of spatial hierarchy: completion level, well level, pattern level, field region level, reservoir level and asset level (managing multiple assets) (Martinez and Konopczynski, 2002).

Optimization and Control Theory

Global optimization of complex systems such as the intelligent field has been the subject of much study recently. The most pragmatic methods have approached the problem by breaking up the overall system into sub-components and sub-systems, each of which may be optimized independently, or more ambitiously, coupled together in an integrated asset model which seeks to tackle the problem holistically (Nikolaou et al., 2006). The mix of fast loop and slow loop systems, and combination of small scale and large scale spatial entities call for a variety of solutions. From control theory, we know that feed-back control systems are suitable for fast loop systems while feed forward control systems are appropriate for slow loop systems (Figure 2).

Let's look at the problem of optimizing the performance of an intelligent well

Various methods have been proposed to optimize the performance of intelligent wells. The foundations of these methods generally are based on the ability to model the performance of the well, combining reservoir inflow, downhole ICV performance, and production conduit outflow performance, in order to predict the flow performance response to perturbations of reservoir, fluid composition, or equipment setting parameters. The models may be analytical or statistical in nature. Optimisation may be accomplished through analytical methods for simple problems, and a variety of numerical methods, including exhaustive simulation (testing all possible combinations and permutations), linear programming, non-linear programming, and genetic algorithms, for more complex well architectures and problems. (Konopczynski and Ajayi, 2007)

Two types of intelligent well performance optimization can be defined: one, set-point optimization and two, parametric optimization.

Set-point optimization is the ability to determine the appropriate artificial lift settings, surface production choke setting and interval control valves' settings to produce a well at or as close to a specific set of flow conditions (rate, pressure, fluid composition) as possible. Producing a 3 zone well at 3500 bbl/d with zonal contribution of 45%, 20% and 35%, while keeping drawdown pressure below 250 psi is an example of a set-point optimization objective function.

Parametric optimization is the ability to determine the appropriate artificial lift settings, surface production choke settings and interval control valves' settings to maximize (or minimize, as appropriate) a specific production parameter while maintaining other production parameters within defined constraints. Maximizing total oil production from all zones while keeping water cut below 30% is an example of a parametric optimization objective function.

Both set-point optimization and parametric optimization are applicable to injection wells, production wells, and dumpflood wells.

On the larger scale, optimization of the recovery process in an entire reservoir requires a different approach. The optimization capability of a feed forward control system requires the ability to accurately model the response of the system to a perturbation of a controllable parameter. (Figure 3) When faced with multiple controllable parameters and an objective function covering decades into the future, exhaustive modeling using physics based models to determine an optimum solution in "real time" becomes impossible. For this reason, the use of proxy models for both subsystems and for total systems has been suggested as a solution to the requirements for fast modeling capability. In the early time frame of operating the asset, the full physics model is used to train the proxy model. As historical experience is gained and responses to perturbations are captured in the production data, this information is used to retrain and tune the proxy models. The speed of the optimization can be improved by limiting the time frame of examination and using a moving horizon approach. (Nikolaou, Cullick and Saputelli, 2006)

Intelligent Field Workflow

The Real Time Optimization Technical Interest Group have defined the three cornerstones critical for implementing any new technology, and defined how they apply to the adoption of real time asset optimization. (Mochizuki et al., 2004) Of People, Process and Technology, thus far we have examined the technology. But how we implement and utilize the technology is determined by the process or workflow we set out, and this must be considered in the context of the capabilities and limitations of intelligent well and intelligent field technology.

The development of the workflow is often based on historical methods, "that's the way we've always done it", or is developed to fit the technology infrastructure, organizational hierarchy, people competency, or any combination thereof. What is often lacking is a clear, common understanding of the objectives of the workflow, what parameters can be controlled, and who gets to make the decisions affecting the process. Farid et al. (2007) describe the structure of engineering workflows for production surveillance and optimization, but just as important as the structure of the workflow, the rules and protocols which provide the "modus operandi" of the workflow process need to be defined.

These rules and protocols must be developed through the definition of the Reservoir Management Philosophy, the Production Surveillance Capabilities, and the Operating Guidelines (Figure 4).

Reservoir Management Philosophy

The reservoir management philosophy (RMP) is a set of principles and concepts which provide guidance for developing and operating a reservoir asset to maximize economic return. The RMP is based on sound reservoir engineering concepts, and a framework of good fiscal and economic models which accurately describe the business environment under which the asset operates. Inherent in the quality of the reservoir engineering judgment is an understanding of uncertainties and parameter sensitivities, based on modeling, analogs, or discipline specific wisdom.

The RMP considers the entire life-cycle of the reservoir, from appraisal, through development, primary, secondary, and tertiary recovery phases to abandonment. It defines the expectations for the asset in consideration of the development plan, and as such is a framework for maximizing the recovery. Table 1 lays out many of the reservoir attributes that must be considered in the development of the RMP, and the associated parameters which affect the development plan and management philosophies. One method of defining the development plan and assessing which attributes and parameters are most critical to optimizing the recovery has been described as the Reservoir Technical Limit process (Smalley et al. 2007). The Reservoir Technical Limit process strives to determine the maximum recovery potential of an oil field and identify and prioritize specific activities that will help increase recovery.

The RMP considers the entire value chain structure affecting the asset, from reservoir to market. The reservoir management philosophy is influenced and constrained by the social-political concerns, that is, regulatory compliance, a demonstration of the highest standard of stewardship of the resources, and health, safety and environment considerations. In our energy hungry society, with replacement of hydrocarbon reserves becoming more difficult, it is becoming both socially and economically imperative to examine every avenue toward maximizing the ultimate hydrocarbon recovery.

The RMP seeks to define the objective functions upon which the optimization of the asset is based, but it also attempts to address the priorities and trade-offs when different objectives are in conflict with one another.

Given the description of what the Reservoir Management Philosophy addresses, we can define specific elements that should be included in the document defining the RMP. Requisite elements of the RMP are:

- Development and re-development plans: including well types, architecture, functionality, numbers, placement
- Fluid Management Tactics: including production schedules, injection schedules, voidage replacement
- Surveillance and data management requirements
- Constraints, boundary requirements: Pressure, flow rates, fluid composition, cut-offs

In addition, business parameters and operating rules are also defined in the RMP, including:

- Key performance indicators: Recovery efficiency, net present value, return on capital employed, HSE statistics, etc.
- Objective functions: Oil production, effluent production
- Facilities constraints: volumes, pressures, temperatures, time between overhaul, preventative maintenance
- Boundary conditions: start-up conditions, end of life conditions, maximum allowable rates
- Reporting requirements: business, regulatory, contractual (partner), production accounting, HSE, reservoir management
- Description of how the flow of fluids in and out of the reservoir should be managed
- Reaction to unplanned events: facility upsets, gathering system problems, loss of injection facilities, etc. – what takes priority, how will the fluid management be re-distributed when disruption occurs?

Production Surveillance Capabilities

The Reservoir Management Philosophy drives the functionality and specification of the equipment used in the field development plan, and in the intelligent field, this is most relevant to the field deployed sensors, data acquisition systems, data management systems, analysis systems and visualization. The sensors and data acquisition systems are the nervous system of the intelligent field, and while more information is usually better than less, to avoid paying for capabilities not needed, and to prevent data overload, some key questions must be asked when defining the requirements.

- What information is required?
- Who needs to see it?
- How often?
- How does information flow?
- Where is it stored?
- How is it used?

These considerations play an important role in the design of the intelligent field work process, and drive the structure of the real time data infrastructure. Get it wrong, and the aspirations for the intelligent field are put at risk.

Operating Guidelines

The Operating guidelines are a set of recommendations, rules and policies based on the Reservoir Management Philosophy which provides guidance for asset operating procedures and decision processes, including optimization processes. The operating guidelines as discussed here are focused on those procedures and protocols affecting the reservoir management and production optimization, and do not address equipment or facilities technical operating procedures, or HSE requirements. Key elements to address in the Operating Guidelines are those associated with:

- Steady-state operation: defines the well operating guidelines for production and injection, including injection schedules, production rates, temperature and pressure constraints, maximum pressures to avoid fracturing, drawdown balancing guidelines, effluent cut guidelines, minimum critical rates for flow stability, maximum rates for erosion, sand-control considerations, field fluid distribution share, production and injection testing schedules, fluid sampling requirements, flow assurance, scale - paraffin, emulsions, hydrate formation , etc.
- Transient operation: defines the well operating guidelines when changes need to be made, including guidelines for rate of change in well pressures, temperatures and flow-rates (particularly in wells with sand control issues, or high temperature wells), bean-up procedures, how fluid production/injection should be re-apportioned in the event of an upset or loss of capacity, etc., for start-up or shut-down, planned or unplanned, local or field wide
    - Start-up: cold, hot
    - Shut-down: planned, unplanned
    - Perturbations to injection/production schedules

Understanding the reservoir management philosophy and the operating guidelines can form the backdrop to the "real-time" optimization process, and define how the operating staff, petroleum engineers and management use the tools from the intelligent field to maximize the value from the asset. The objectives, constraints and decision processes are vital to developing autonomous control logic for the next generation intelligent field.
Factors that must be considered in the Operating Guidelines include:

- Health and Safety,

- Functionality, capabilities and limitations of equipment
- Data and analysis tools available
- Training and capabilities of staff
- Communication and command protocols
- Decision making processes and lines of authority

Fine Tuning Steady State vs. Reacting to Significant Changes in Operating Conditions

Although the industry talks about reservoir optimisation in real time, most of the time the asset is performing with a steady state or pseudo-steady state behavior. There is likely to be little value in fine tuning the interval control valves in the intelligent wells every 15 minutes; once a week or once a month may be sufficient to realize most of the benefit of the optimisation workflow. However, transient behavior will likely be the situation where rapid identification and optimization capabilities will have their biggest payout. This is particularly true for acute or sudden situations, such as the need to shut down a separator, a flow line, an injection pump, or a well. The real time optimization capability will allow the operator to respond quickly to the changing situation, and establish the new optimum set points for the wells and facilities to maximize value within operating constraints and Reservoir Management Philosophy rules.

Finding the Value of the Intelligent Field

The business impact of the intelligent field has been an area of speculation in the industry, but most agree that the benefits include increased hydrocarbon reserve recovery, increased and accelerated production, reduced capital expenditure for asset development, reduced operating costs, reduced development risk and uncertainty, and reduced HSE exposure (van den Berg, 2007). Estimates are that intelligent wells and intelligent fields could impact ultimate recovery by an increase of 8%, increase production by 10%, and according to BP, in the long term add 1 billion barrels of additional recovery (Reddick, 2007).

Perhaps the most mature application of intelligent well and intelligent field technology is in the Snorre B project in the North Sea, where 10 of 13 wells are intelligent wells equipped with downhole monitoring and flow control devices, typically controlling 3 to 4 zones. (Kulkarni, et al. 2007) The Snorre field is a highly compartmentalized and layered reservoir, with a geologic structure dictating the use of long horizontal producers with commingled production from several reservoir zones. The recovery mechanism is based on a water-alternating-gas injection strategy. All injectors are intelligent wells, and while the original development plan had about 50% of producers completed as intelligent wells, experience thus far has led the operator to prescribe intelligent completions on all future development wells in the Snorre B development. Intelligent well data and control allows reservoir management on a layer and compartment basis. Reservoir management is primarily based on voidage replacement. Simple trending of the downhole pressure and temperature parameters has not been informative enough upon which to base reservoir management decisions, and more advanced analysis for zone flow allocation is needed. Currently, this analysis is still spreadsheet driven. Monitoring of the downhole parameters, particularly temperature has been useful to identify events such as gas breakthrough, and to respond quickly. The results thus far have demonstrated increased production and a better understanding of reservoir drainage.

Conclusions

With the increasing utilization of intelligent well technology in the development of our hydrocarbon reserves, new methods for reservoir surveillance and optimisation are required. The integration of models for the reservoir, wells, gathering systems, processing systems and export lines is only one part of the intelligent field challenge. It is important for us to consider not only the intelligent field process and workflow, but the reservoir management philosophy, rules and protocols on which the process and workflow are based, and ensure that that these elements are developed in the context of the functionality and capabilities of the intelligent wells.

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Reservoir Attribute	Influencing Parameter
Compartmentalization	• Fault Blocks • Multiple Layers • Stratigraphic
Heterogeneity	• Permeability Contrasts • Fluid Saturation/Relative Permeability • Dual porosity
Multiple Reservoirs	• Marginal reservoirs • Gas Zones • Fluid Contacts
Recovery Mechanism	• Depletion • Aquifer • Waterflood • Tertiary
Recovery Efficiency	• Pore Scale Displacement Efficiency • Drainage Efficiency • Sweep Efficiency • Cut-Offs Efficiency – End of field life
Total Reserves	• Pore Volumes • Net to Gross • Gross Reservoir Rock Volume • Saturations • Cut-offs • Irreducible Saturations
Fluid Type	• Gas • Oil • Water • Solvent • Other Effluent
Pressure Contrasts	• Fluid Density • Hydraulics • Pore Pressure • Capillary Pressures • Stratigraphic • Compartmental

Table 1 – Reservoir Attributes and Influencing Parameters to be considered in the Reservoir Management Philosophy

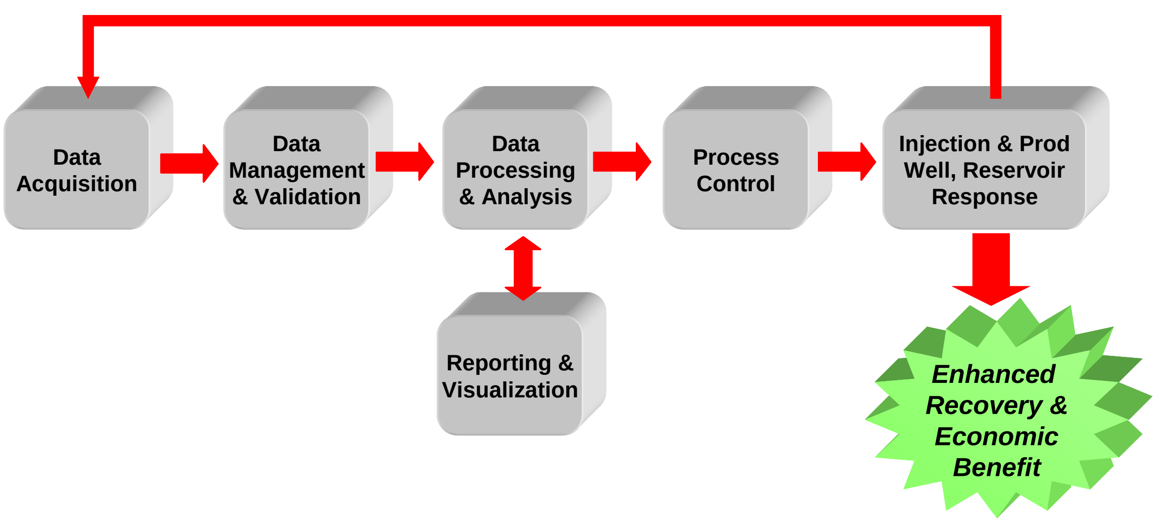

Figure 1 – The Basic Workflow for Asset Managment

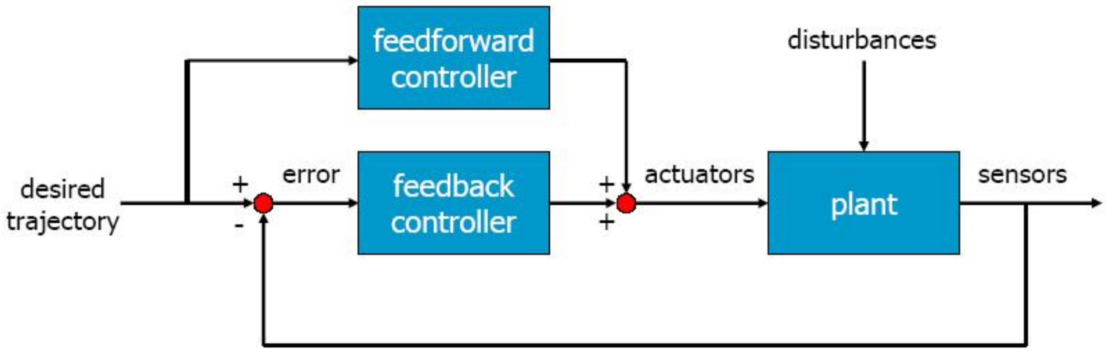

Figure 2 – Feedback and Feed Forward Control

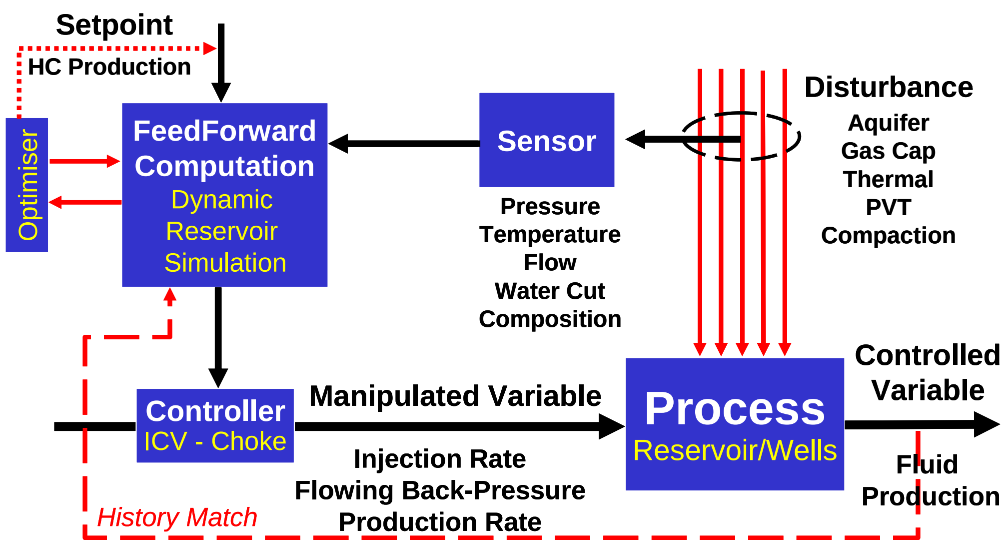

Figure 3 – An example of feed forward control in the context of Reservoir Management

Figure 4 – The Relationship betweek Reservoir Management Philosophy, Production Surveillance and Operating Guidelines