About this Document (version 1.1; 9th May 2013)
The objective of this document is to capture and catalog industry technical papers that reflect good practice or the application of notable techniques where Schlumberger software was used. All papers referenced in this document have been published between 2006 and 2012, with a priority given to more recent papers (2010 onwards). Authors include Schlumberger employees and customers.
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I. INTEGRATION, OPENNESS & STANDARDIZATION

Production Performance Monitoring Workflow (SPE 103757)

M. Stundner, SPE, and G. Nunez, SPE, Schlumberger

Abstract

The availability of accurate production volumes, at the well level and throughout the production network, is fundamental to the workflows that target the optimization of the economic potential of the reservoir. Without an accurate understanding of production volumes, the company’s field development and operational decisions may not support the maximum economic value of the reservoir and can undermine the accuracy of the reserves estimates.

With current Digital Oilfield technology it is possible to measure production volumes at the well level and at intermediate outlets of the production facilities. However, for many fields this isn’t a cost effective solution. Building non-parametric (Artificial Intelligence) production rate models based on pressure and temperature measurements has proven to be a valid and cost effective solution.

Several processes are necessary to measure and validate oil production at the well level as follows:

- Virtual Rate Measurement (VRM): ensuring accuracy of the volumes at the well level.
- Back Allocation: focussing on accuracy of the volumes at outlets of the facilities. To minimize the error in the volumetric measurements at both ends of the production network, both processes should be reconciled.
- The reconciliation procedure allows the comparison of the data coming from two different sources. By using this procedure, engineers can detect discrepancies that affect future decisions.

The sum of all these processes working together in a workflow is defined as “Production Performance Monitoring” (PPM).

The objective of this paper is to provide recommendations on how the PPM process should be properly implemented as an automated workflow to improve well productivity as well as to standardize process and data management. To fulfill this objective, the paper will address the following topics: brief introduction of current work practice, processes and workflows descriptions, technology available, real time environment, automated workflow application recommendation and potential benefits.
Optimizing the Production System Using Real-Time Measurements: A Piece of the Digital Oilfield Puzzle (SPE 110525)

Robert B. Thompson and Valli Shanmugam, Aethon; Shekhar Sinha, Natalie Collins, Suhas Bodwadkar, Marc Pearcy, and Stan Herl, Schlumberger

Abstract

The oil industry is investing millions of dollars in the infrastructure of digital oilfields in an effort to increase efficiency and recovery. An important part of the puzzle, transferring data from the wellsite to the office in real-time, is very much solved. However, this data is largely used to monitor the status of wells and equipment, and in most cases, the life cycle of the data ends there. A key part of the puzzle is to utilize the real-time data to optimize the production system, from the wellbore to the reservoir where most of the value lies. With the current infrastructure and technology we can get real-time data up to every second. The challenge is to extract the right information from that data at the right time to impact the way fields are managed.

This paper discusses the workflows utilized in identifying production optimization and enhancement opportunities from large amounts of streaming data flowing from a number of wells. Case studies are presented for mature waterfloods in four different fields with over 60 wells. The economic impact of surveillance is quantified through electrical costs, efficiency in fluid movement, and enhanced reservoir deliverability. The real-time data analysis for the entire field revealed opportunities to increase the production in the short-term, as well as the necessity to adjust the long-term exploitation strategy.

The methods and examples in this paper show the value of applying digital oilfield technologies in one of the most cost sensitive environments in our industry. Observations based on a large number of wells during a 2-year period show that over 50% of the wells can benefit from some form of optimization, resulting in a substantial increase in production.
Improved Production and Process Optimization Through People, Technology, and Process (SPE 110655)

Jan Richard Sagli, Statoil ASA; Hans Eric Klumpen and Gustavo Nunez, Schlumberger; and Frank Nielsen, Statoil

Abstract

A joint venture Production & Process Optimization project between Statoil and Schlumberger is targeting two distinct areas:

- Improved reservoir management to optimize the reservoir performance over the life of the field.
- Production optimization of the intelligent wells, production network and process facilities on a day-to-day basis. This is achieved through development of tools, methodologies and workflows.

In order to support the change management process, a prototyping process has been developed for surveillance workflow development and deployment. The dynamic prototyping process allows a bottom-up development of workflows starting from data conditioning and reconciliation up to optimization and control. These different automation modes for provided workflows go along with deriving information and ultimately knowledge from production process data in order to improve decision making processes.

A demonstration project will concentrate primarily on the Water Alternate Gas (WAG) cycle optimization process, which has been specified together with the asset team, and will describe how the workflow supports production optimization.

The solutions are successively tested together with the Snorre B asset. Results from the demonstrator, change management issues and the concept of full integration of all decision making loops into a workflow framework will be presented in the paper. During the testing not only the application of the software solution was evaluated as well the impact on the organization and how changes in proposed work processes improved the inter domain collaboration within the team.

The project has demonstrated successfully that three key areas have to be addressed simultaneous:

- Change Management procedures in order to introduce the developed workflows and software tools as early as possible
- Necessary software tools for providing a workflow oriented framework for production optimization
- Prototyping workflows and implementation through demonstration and pilot projects as well as permanent facilitators working with asset teams
WITSML Changing the Face of Real-Time (SPE 112016)

N.R. Deeks, Schlumberger, and T. Halland, StatoilHydro

Abstract

WITSML is a key enabler in an increasing number of real-time workflows. This is particularly true for integrated operations within the growing numbers of onshore operations centers. Two years ago WITSML was a technology known by few and actively used by even less. Now the SIG steering the standard has grown to 51 companies.

The starting point for most companies in using WITSML is to bring depth data into their asset databases. For many this has become the norm. Early adopters like Statoil are broadening their use into a wider range of wellsite operations. Within asset teams a standard data delivery mechanism allows integration of new tools and workflows, letting Geologists and Engineers make use of real-time data within their familiar desktop applications. It also enables centrally managed data delivery services letting them focus on their areas of expertise, not data gathering.

New technology and processes in these areas are helping operators make the next big step from real-time remote monitoring to real-time remote control.

For growing numbers it is now not enough to receive a visual representation of the data. They expect data to be delivered in real-time via a standard format.

WITSML also brings operators the opportunity to standardize data delivery workflows, to clarify contractual requirements to providers and to establish and measure realistic data delivery KPIs.

Within Schlumberger WITSML enabled workflows are well established, answer products for drilling optimization and interpretation utilize the standard via a unified WITSML client. This reduces software development cycle time and simplifies data gathering.

WITSML is becoming established, bringing proven advantages to real-time workflows. Continued uptake of the standard will enhance the competitive advantage of service companies and the operators utilizing it. WITSML is here to stay and should be supported more widely within the industry.
Measuring Development and Adoption of New Oilfield Systems Using Technologies with Real-Time Capability (SPE 112023)

Daan Veeningen, SPE, Sanjay Kanvinde, SPE, Guillaume Coffin, SPE, and Olisa Udezue, Schlumberger

Abstract

If a brand-new oilfield product or service becomes widely used in less than a decade, that’s fast. The fact is that the petroleum industry is one of the most conservative when it comes to adopting new technology. This paper proposes and describes the use of a capability adoption index to benchmark and measure the development and adoption level of oilfield systems with real-time capability.

The capability adoption index is a tool for measuring and managing the advance of real-time technology in the industry. The application tracks incremental change and provides a roadmap for technology development and adoption. There are three main reasons for deploying systems with real-time capability. First is the growing shortage of skilled professionals. Second is the need to operate in harsh or environmentally sensitive regions, where monitoring and controlling operations from a distance can improve safety and limit the environmental footprint. The third driver is that systems that feed back data in real time may increase production by allowing operators to respond quickly to changing conditions in the well.

The 10-level index provides a bigger picture of the maturity of real-time technologies within the global market. The different levels of technology adoption are illustrated both for geographic areas and for different services. The roadmap towards autonomous automation provides more efficiency and profits for the operating company. For service companies, the ability to drill, test, operate, and control wells with real-time capability helps maintain the quality of service delivery. It creates more efficiency for people and systems.

In the industry’s journey toward autonomous automation, the significance of the index is a measurement allowing companies to look back at their progress, manage change, and plan the road ahead.
From Data Monitoring to Performance Monitoring (SPE 112221)

Michael Stundner and Gustavo Nunez, Schlumberger, and Frank Møller Nielsen, StatoilHydro

Abstract

The availability of accurate performance information throughout the production system is fundamental to optimization of the economic potential of the reservoir. Without this understanding, a company’s field development and operational decisions may not permit the maximization of economic value and may undermine the accuracy of the reserves estimates.

Present digital oilfield technology gives the production engineers all the data needed to monitor process parameters and fluid production, under the assumption that deviation from any target would be detected with just monitoring the data collected. Then, any “good” decision for improvement or optimization would be taken based on this data. However, the answer to questions such as “how good is the decision?” or “how does the production engineer know that it is operating at the best performance possible?” is not easy, because a reference for comparison is needed.

Performance efficiency can be defined as the ratio between theoretical result from a model or test results and the actual results achieved. A Production Performance System (PPS) based on workflows can be implemented to calculate key performance indicators comparing the actual performance versus targets, models, or base case and identifying performance deviation on time in order to avoid undesired lost production. PPS includes an events management and knowledge base system that allows not only detecting events but also identifying possible reasons for them based on historic data and artificial intelligent models.

Our objective is to provide recommendations on how a PPS should be implemented to improve well productivity as well as standardize process and data management. To fulfill this objective, the paper will address the following topics: brief introduction of previous work, processes and workflows descriptions, technology available, real-time environment, automated workflow application recommendations, and potential benefits.
Production Data Standards: The PRODML Business Case and Evolution (SPE 112259)

Dave Shipley, Chevron; Ben Weltevrede, Shell International E&P B.V.; Alan Doniger, SPE, Energistics; Hans Eric Klumpen, SPE, Schlumberger; and Laurence Ormerod, SPE, Weatherford International

Abstract

PRODML™ is a set of production data standards, initiated by 13 upstream oil and service companies with the industry standards body Energistics (then POSC) in 2005. In November 2006, PRODML Version 1.0 was released. The focus was on production optimization processes which could produce results implementable within a day. The domain was from perforations through to start of processing on the surface. The objective was to enable plug and play integration of current upstream applications while supporting a variety of optimization processes.

In 2007, the PRODML community, now expanded to 23 companies, worked on extensions addressing production reporting, the use of a common “flow network model”, and into “smart wells”.

This paper, authored by experienced members of the PRODML community, explains the evolution from a concept to “do something about production data” into a well-defined series of interoperable services, with a defined future path.

A practical approach to the implementation of an integrated production optimization “analytic environment” will then be described, illustrated by a richly detailed and broad-based real life case study as deployed by Chevron.

The strategy that current members have set for the next three years will be outlined. This covers expansion of the “footprint” of PRODML, (reflecting the need for a clear understanding of business drivers for end-users and for developers), functionality (supporting above all a focus on “usability” – ensuring that PRODML expands while remaining accessible and quick to pick up for new developers), support, and governance.
Enabling an Intelligent Energy Strategy Through Industrialization of IT (SPE 127754)

Craig Hill, Schlumberger

Abstract

In the industry today IT has become “business critical” in wells and field operations, moving beyond the traditional back office role. As a result, there are significant implications for the IT organization, where rig site and producing-asset interaction, both in terms of people and technology, has been infrequent, ad hoc or confined to the witnessing and delivery of data. It is now critical to align the strategies and plans of IT and Operations both at HQ and local level, to achieve the efficiency, performance, and technology objectives set. Key focus areas are

- Staffing—Assign experienced staff to real-time-related IT management.
- Process—Define clear processes for all “touch points” between IT and Operations.
- Infrastructure—Design, build, and operate a highly resilient infrastructure from end to end.
- Service Quality—Benchmark, measure performance, and plan to continually improve.

This paper describes a “model real-time framework” and the standards defined for compliance by target geographical areas over a 12-month period. The aggressive targets were achieved through a high level of HQ support, key personnel moves, and monthly reviews tracking progress against action plans.

With the application of a well-structured program, support and confidence was gained across the company, united through the understanding of the clear business benefits brought about by advances in IT. Complacency in the existing level of infrastructure resiliency was apparent and compelling arguments to justify investment were required and provided.
An Integrated Framework for SAGD Real-Time Optimization (SPE 128426)

Mahyar Mohajer, Carlos Damas, Alexander Jose Berbin Silva, and Andreas Al-Kinani, SPE, Schlumberger

Abstract

Developing an automated framework for real-time optimization (RTO) of the Steam Assisted Gravity Drainage (SAGD) process has significant potential because of the large number of parameters that must be monitored at a high frequency. However, the industry has not yet adopted a standard RTO framework for SAGD because of the intrinsic complexity of the process, the large number of parameters that must be monitored, harsh operating conditions, the lack of integration between various data acquisition systems, and the complex criteria required to optimize SAGD performance.

In this paper, a real-time monitoring workflow for SAGD is proposed that streams field data from multiple sources, including fiber optic distributed temperature sensing (DTS) directly into an engineering desktop application that has artificial intelligence (AI) and data mining capabilities. This system is used to derive advanced criteria to make decisions in a timely manner to improve the performance of the SAGD process.

It also demonstrates how subcool calculations can be effectively performed along the length of the horizontal well in real time and how the results are used to improve SAGD operation. Observations are compared “live” against simulated predictions from a multisegmented wellbore model that is fully coupled to a thermal/compositional reservoir simulator.
Streamlined Production Workflows and Integrated Data Management: A Leap Forward in Managing CSG Assets (SPE 133831)

Shripad Biniwale, Rajesh Trivedi, Georg Zangl, SPE, Schlumberger; Chris White, Scott Delaney, James Blair, SPE, Origin Energy

Abstract

A case study of the Spring Gully coal seam gas (CSG) field illustrates how an integrated production data management and analysis system has consolidated scattered data sources into a unified repository to provide easy access for reporting and analysis. Automated surveillance workflows with notification and alarm capabilities have simplified production performance tracking and enabled proactive decision making. Current analysis techniques and expert knowledge have been captured in predefined templates and workflows to identify trend violations, flagging the issues and optimizing production.

The new system has provided a foundation layer for managing the production and deliverability of thousands of wells now and in the future, helping to translate data into information. Enabling timely decision making through the use of accurate, validated data and automated workflows has helped engineers focus on problem solving and analysis. The streamlined process will continue to help the operator’s CSG teams improve the efficiency and productivity of all their assets.
Abstract

After intense collaboration among operators, service companies, and software vendors (all members of an Energistics Special Interest Group (SIG)) Version 1.0 of the RESQML data exchange standard has been released. Prototypes implemented by both vendors and operators have been tested and have proved the efficiency of the concepts.

RESQML has been designed to support:
- Interaction with real-time production and drilling domains;
- Transfer of giga-cell reservoir simulation models, which are currently in use in some areas of the world, and with static reservoir models, which may be significantly larger;
- Loss-less data transfer for complex grids, especially for non-standard connectivity;
- Retention of the geologic and geophysical metada-data associated with 3D grids;
- Data exchange for flexible and iterative multi-vendor subsurface workflows- across geology, geophysics and engineering.

A demonstration will illustrate how different components of a shared earth model can be exchanged between major commercial applications. Additionally, based on the Alwyn North Field dataset, a typical validation loop involving operator in-house and vendor applications will be demonstrated. The objective is to transfer in-house interpretation results (e.g., horizons and faults) as RESQML features to diverse structural, stratigraphic, and reservoir vendor applications, then re-import the RESQML features (modelled horizon and faults, reservoir grid geometry) obtained by these applications into the in-house application to ensure, at each step, an overall consistency with the original interpretation.
Integrating All Available Data To Improve Production in the Marcellus Shale (SPE 144321)

Efe Ejofodomi, Jason Baihly, Raj Malpani, and Raphael Altman; Schlumberger; Terry Huchton, David Welch, and Jerry Zieche, Marquette Exploration

Abstract

Shale gas exploitation has dominated the E&P landscape in North America for nearly a decade. There is a great deal of competition for shale acreage in the US, and leasing occurs rapidly once a new shale play is discovered. It can cover tens of thousands of acres and are often selected based on limited data, mainly vintage paper logs, mud logs, and access, cost, and availability considerations. Rarely are core, seismic or modern log data available to the operator. Capturing data in exploratory vertical wells is crucial, but comprehensive integration of the data to optimize horizontal well design is often overlooked.

This paper discusses one operator’s approach to fully integrate data captured in the Marcellus Shale in order to optimize horizontal well performance. Based upon insight from the study, the operator wanted to make more informed asset management decisions, improve economics, and look for future investment opportunities. Data were captured from vertical offset exploratory wells and an initial horizontal pilot well. The data that were acquired and incorporated into the study included field-wide seismic and data, as well as mineralogical, geomechanical, well plan, drilling, completion, microseismic, and production data from the aforementioned wells.

A comprehensive study was performed incorporating the data to optimize the design of a horizontal well in the Marcellus Shale. This study was performed to get the operator up the learning curve in a short time period rather than by trial and error on wells. The first step in the study involved constructing a field-wide 3D static geologic model using the data captured above to determine the best petrophysical and structural areas to drill new wells. A reservoir model was then constructed with existing production, fracture, and microseismic data as well as the geologic model. The reservoir model was then used to forecast various production scenarios, including lateral length, number of stages, and perforation cluster spacing. Various fracture models were also included in the analysis to determine height growth and complexity.

The results of these geologic, reservoir, and fracturing models were used to optimize the design of a second horizontal well drilled in the area of interest. The production increase between the first and second horizontal well was analyzed on a percentage basis. Lastly, recommendations were made for further well design enhancements based upon the study findings and the results of the second horizontal well.
Improved Performance in Real-Time Operational Support Processes via Application Process Workflow Optimization Techniques in Russia (SPE 149345)

Sheldon Rawlins, Todd Giasson, Zim Okafor, Anton Bokarev, and Pavel Moroz, Schlumberger

Abstract

The emergence of real-time enabled support centers has significantly improved the level of service delivery that is received by the operator companies that are drilling across the numerous oil fields in Russia. These support centers are multidisciplinary in approach and are focused on supporting measurement-while-drilling, logging-while-drilling, and directional drilling services and executing work flows without incurrence of nonproductive time. Many challenges, ranging from ensuring connectivity in remote areas to client acceptance of the role of support centers in their internal decision-making processes, have been successfully overcome. Key to this success was the implementation of work flows that optimize drilling processes in the holistic well construction cycle with incorporation of geomechanics and that support the optimal geological well placement based upon petrophysical analysis and interpretation.

These process work flows were synthesized to capitalize on the strong petrotechnical expertise and synergies existing within the collaborative environment of the support center. To further improve on the performance of such support centers, an engineering study was conducted in 2010 to assess further possibilities for improving service quality. Several areas of opportunity were identified, one of which included the incorporation of Lean and Six Sigma techniques to quantify the effect of modifications on these work processes. It was critical in this assessment to ensure that these process work flows seamlessly integrated into the work flows of the internal and external stakeholders that are beneficiaries of the support centers.

This paper discusses the results from the initial generations of these process work flows and the way forward for the continued process work flow integration, using a support center that was developed in Russia as an example. The application of these work flows has brought demonstrable financial and service-quality benefits to both operators and service companies, and the broader applications in its consistent execution have presented a critical step change in Russian environment drilling performance.
Enhancing Production, Reservoir Monitoring, and Joint Venture Development Decisions with a Production Data Center Solution (SPE 149641)

Mark Allen, Tullow Oil; David M Smith, Schlumberger

Abstract

Tullow Oil is an independent E&P company with a portfolio of operated and non-operated assets predominantly located across sub-Saharan Africa. The Production and Reservoir Engineering team in Cape Town monitors non-operated production and evaluates Joint Venture (JV) development opportunities for these assets. In 2010 the team initiated a data consolidation project, the objectives of which were to quality control the incoming production data, provide engineering and management teams with easier access to current reservoir and field performance parameters, and reduce engineers' time spent on raw data manipulation. A Production Data Center (PDC) solution would improve the accuracy of data and information in reservoir and production models, thereby improving decision making and asset management.

The PDC solution, successfully implemented in February 2011, automates production data gathering from the JV daily and monthly production reports, assists with data validation, provides a standard data terminology and structure across the portfolio, and links with the corporate finance and reserves systems.
Integrating WITSML, PRODML, and RESQML Standards for Cross-Domain Workflows (SPE 150057)

William McKenzie, Chevron; Francis Morandini and Philippe Verney, Total; Laurent Deny, Paradigm; Jean-Francois Rainaud, IFP; Rob Eastick, Computer Modelling Group; Gary Masters, Energistics; and David Mack Endres, Schlumberger

Abstract

The WITSML™, PRODML™, and RESQML™ standards for data and Web services have achieved early success in providing the “information plumbing” to enable the digital oil field in their domains (drilling and completions, production operations, and reservoir management, respectively). As the adoption of these standards accelerates, it has become clear that a simple way is needed to combine information objects from these standards for cross-functional workflows. This paper examines a proposal for an EnergyML Package file format that can be transported over standard protocols such as HTTP and FTP with emphasis on the following features. The file format can be consumed without special parsing by all major programming languages. It provides relationship files that can identify and link individual data objects according to the role they play in a workflow. All objects can reference common metadata, such as geographic coordinate systems, a common property dictionary, and Dublin Core® attributes.
Transforming IT To Sustain And Support Real-Time Operations Globally (SPE 150095)

Joel Patterson, Sebastien Lehnerr, Terry Mead, Kevin Goy, Brad Schmid, and Robin Harris, Schlumberger

Abstract

In 2009, Schlumberger implemented a technology-driven strategy to make real-time operations globally sustainable within 3 years. The 3-year plan included the alignment of opportunities for business segments with the drivers of client businesses, and the creation of robust information technology (IT) operations, scaled for global, 24/7 support of real-time programs.

Schlumberger’s business strategy for real-time operations combines market insight with technology, and includes investments in initiatives for performance assurance, improved service quality, and delivery of certain value-added workflows. Organizational alignment and accountability for real-time operations within the business segments required clearly defined responsibilities for headquarters, support functions, and field operations teams.

Over the past 24 months, the company has implemented several key elements of the strategy on a global scale, including a real-time IT readiness program, wellsite connectivity, operation support center standardization, real-time data delivery platforms, proactive 24/7 monitoring, and a service management model. Integration of people, processes, and technology has been key. Driven by strong commitment from executive management, these initiatives have provided the robust foundation required to make the intelligent energy vision sustainable.
Efficient Use Of High Frequency Data Through Production Data Management System Implementation (SPE 150214)

A. Creemer, SPE, Corridor Resources Inc., R.W. Holy, SPE, F. Fuehrer, SPE, M. Mohajer, SPE, Schlumberger

Abstract

The McCully Field (New Brunswick, Canada) is highly instrumented and generates a massive quantity of high-frequency data stored in a data historian. Data time range and frequency of interest had to be manually retrieved through spreadsheet macros for analysis, plotting, and gas allocation. As the production history grew, the amount of data generated was overwhelming and unconsolidated, making the task of manual data handling and visualization both difficult and time consuming.

The implementation of a production data management system resulted in a fully automated, end-to-end workflow that acquires five-minute data from the Supervisory Control and Data Acquisition (SCADA) system into the operating database; performs accurate allocation of gas, condensate and water volumes; as well as creates and distributes daily production summaries to a custom email list in a matter of minutes.

The implementation of an automated approach was driven by five main objectives:
- automate production data acquisition
- optimize field production through real-time well surveillance
- increase data processing speed (reduce time spent on data handling, preparation, cleansing and reporting)
- take advantage of existing high-frequency database
- improve communications regarding well performance between office and field operations

After a successful implementation, data acquisition time has been reduced from a manual 30 minutes to an automated 5 minutes each day. Daily production reports, instead of only being accessible through the server, are now automatically emailed to a distribution list within the company. Real-time well surveillance is now possible from the main office and not only through the SCADA system in the field, which provides the engineering group with a better understanding of individual well performance and also allows any production disruptions to be identified early and resolved efficiently. Finally, the consolidated database is now integrated with engineering analysis tools for further use of information, which ultimately increases the effectiveness of the technical team.
A WITSML Enabled Workflow for Integrating Offset Well Drilling Risks and Events into Well Planning and Execution (SPE 150382)

N. R. Deeks, SPE, Y. I. Arevalo, SPE, and A.J. Fernandes, SPE, Schlumberger

Abstract

In recent years, our ability to record and share information about risks and events affecting rig operations has improved significantly. An important enabler in this has been the development, and broad adoption, of the risk object within the WITSML standard. However, the ability to effectively share data on a broader scale between wells, fields, and blocks has been a challenge. This is particularly important during the planning phase of a well, when access to all available offset risk information is crucial for a successful safe well design.

This workflow, developed within a drilling engineering center, aims to better address this challenge through an integrated 3D approach, using functionality already available on the drilling engineer’s desktop. The introduction of a WITSML-based workflow enables efficient and complete data transfer of risk and event data between different users and software applications with the result that the right data is available to the right people, at the right time.

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Drilling risks and events are defined throughout the planning and execution of a well, for example, during surveillance operations within an operations support center or at the rig. Although risk data is generated in predominantly well-centric software, a WITSML server is used to aggregate the data and populate a regional, 3D master risk project. In this project, intelligent filtering and 3D visualization tools are used to target offset data relevant to the current operation. Relevant risks are integrated into a 3D evaluation of the proposed well design, incorporating the geological model of the current prospect. As the well is drilled, the 3D evaluation is used to alert the rig and remote support teams of potential issues ahead of the bit.

This approach streamlines the evaluation of risks in the planning stage of wells and enables more effective collaboration between the drilling and geological and geophysical team during execution.
II. MODELING & OPTIMIZATION

Optimization of Riser Design and Drill Centers With a Coupled Reservoir and Facility-Network Model for Deepwater Agbami (SPE 90976)

G.M. Narahara, SPE, and J.A. Holbrook, Chevron Corp., and M. Shippen, SPE, and A. Erkal, Schlumberger Information Solutions

Abstract

The use of multiple wells connected at a subsea manifold provides the opportunity to reduce the number of risers and capital expense. The problem is the proper modeling of the reservoir well flow coupled with the combined flow into the facility network (i.e., manifolds, flowlines, and risers), which is necessary to prevent underdesign, resulting in flow-rate bottlenecks, or overdesign, resulting in extra expenditures. This paper presents a tool and methodology for better modeling of the well-to-riser flow and the optimization of riser count and configuration.

Although reservoir models coupled with facility networks is not new, software enhancements provided the capability of including operation logic that could duplicate operations in the field. The reservoir model coupled with the facility network provided more reasonable and accurate modeling of multiphase rates and pressures as wells were combined into a single riser.

To optimize the riser count, operation logic was applied to maximize rate in the riser at all times against the erosional-velocity limit. This in turn prevented overdesigning by placing more risers than needed to obtain the field-facility capacities.

The use of the coupled model and operation logic allowed the optimization of the riser count for any particular reservoir model. The optimum riser count was then determined for 3 earth (geologic) models.
From Reservoir Through Process, From Today to Tomorrow—The Integrated Asset Model (SPE 99469)

A. Howell, Schlumberger Information Solutions; M. Szatny, Aspen Technology Inc.; and R. Torrens, Schlumberger Information Solutions

Abstract

Simulation technology from reservoir through process facility has advanced so much, that field development strategies can be developed within a new systematic workflow, using existing applications from many E&P departments. Detailed production data from many sources can be used within simulation models to give a good representation of future field wide behavior. In this paper a fictional case study of a reservoir that has been producing for some 12 years will be examined. The wells are all producing into a sub-sea manifold and then tied back via a 60km flow line and riser system. The reservoir is in severe decline with field production well below the original design capacity of the production system and surface facilities. Hence, further development options are being investigated for this asset. A new, nearby, reservoir has been discovered. A reservoir simulation model has been constructed for the new discovery. This second reservoir is a gas condensate system, much smaller than the existing reservoir and located 90 kms to the east. The current development plan shows six wells drilled and brought into production over an 18 month period. Reservoir 2 is a marginal development, the viability of producing this reservoir will depend on quantification of the reservoir uncertainty and finding a cost effective development strategy with existing processing facilities. The Business Development Team has suggested a number of possible options for developing this new reservoir; Option 1 involves tying in the new reservoir to the existing sub-sea infrastructure. Option 2 is to install a complete new flow line from the sub-sea template of the new reservoir and run this directly to the existing platform. But how do these options effect reservoir management and surface facilities performance? Evaluation is achieved by constructing an integrated asset model of the entire field, allowing the reservoir through facilities interaction to be evaluated in detail.
Integrated Optimization of Field Development, Planning, and Operation (SPE 102557)

B. Güyagüler, SPE, Chevron, and K. Ghorayeb, SPE, Schlumberger

Abstract

Field management (FM) is the simulation workflow through which predictive scenarios are carried out to assist in field development plans, surface facility design/de-bottlenecking, uncertainty/sensitivity analysis and instantaneous/lifetime revenue optimization from a hydrocarbon field. This involves, among others, the usage of reservoir simulators, surface-network simulators, process-modeling simulators, and economics packages.

We present a comprehensive, portable, flexible, and extensible FM framework completely decoupled from surface and subsurface simulators. The framework has a clearly defined interface for simulators and external FM algorithms. Any black-box simulator or algorithm may become a part of the system by simply adhering to the FM interface, which is discussed in this paper.

The FM framework capabilities are demonstrated on several examples involving diversified production strategies and multiple surface/subsurface simulators. One real field case that requires advance/complicated development logic is also presented.
A New Approach to Gas Lift Optimization Using an Integrated Asset Model (IPTC 11594)

Fernando Gutierrez, Aron Hallquist, Mack Shippen and Kashif Rashid, Schlumberger

Abstract

One of the most common methods of increasing production in oil fields is through the continuous injection of lift gas into the tubing. The injected gas reduces the bottomhole pressure, thereby allowing more oil to flow into the well. The optimal amount of lift gas to inject into individual wells depends on a number of factors including inflow performance, tubing and surface hydraulics. Additionally, careful consideration must be given to operating constraints including cost, handling capacities, compression requirements and the availability of lift gas.

In traditional gas lift optimization projects, a gathering network model is used to calculate the optimal amount of lift gas to inject into each well based on static boundary conditions at the reservoir and processing facility. However, as reservoir conditions change over time, lift gas requirements will change as will operating constraints. The design of the processing facilities will need to accommodate these changes while taking into account the power requirements for compression and treatment processes. By including the reservoir and processing components in an integrated model together with the gathering network, static boundary conditions become dynamic, enabling a true system-wide optimization that greatly enhances field planning strategies in the area of reservoir management.

A case study is presented that illustrates how this concept is applied to an oil field during the conceptual design stage for life of field forecasting.
A Fieldwide Integrated Production Model and Asset Management System for the Mumbai High Field (OTC 18678)

S.K. Moitra and Subhash Chand, Oil & Natural Gas Corp.; Santanu Barua, Deji Adenusi, and Vikas Agrawal, Schlumberger Data & Consulting Services

Abstract

To increase the profitability and field production an Integrated Asset Modeling project was initiated. A high fidelity, fieldwide, Integrated Production Model (IPM), was developed for Oil and Natural Gas Corporation's (ONGC) giant offshore field of Mumbai High. The network based IPM enables superior engineering analysis and more efficient decisionmaking compared to classical single branch and nodal analysis approaches. This is done by capturing, in the model, the effect of all the network interactions that occur in the production network.

Such a model helps to quickly identify and accurately quantify bottlenecks and other opportunities to improve production. Production improvements can be made by making daily or weekly operational changes as in gas-lift-allocation, surface backpressures, pipeline lineup etc as flow conditions change in the field. The IPM model would also assist in reliably evaluating field operational and re-development plans, and thus expedite the engineering decision processes.

The project-plan also called for an Integrated Asset Model (IAM) by integrating the IPM to reservoir simulation models and to a suite of fit-for-purpose optimization tools. The IAM model will then enable model based field-wide future development projection studies and planning scenario studies over time. Network based optimization such as network-gaslift optimization can be easily done to find the optimum operation set points that maximize production without violating user defined operational and capacity constraints. The model will eventually evolve into an online IAM. Here the On-Line utilities will effortlessly update data from the application historian to the IAM with the latest or requested data set. The historian stores recurrent data from field-wide SCADA-DCS systems and other sources. This paper describes the development of the IPM for ONGC's giant offshore Mumbai High field and the technical and project management challenges faced. The IPM includes the production, water-injection, gas-lift supply and transportation networks. The integrated model also includes simplified models of processing facilities at each process complex. Work to extend the IPM to an IAM is ongoing. Factors that were found to be critical to the success of the project are identified and discussed in this paper. This will provide a better understanding and appreciation of the complex project implementation issues and challenges that need to be resolved.
Online Integrated Asset Models With Map-Based Visualization (SPE 106914)

Michael J. Weber and Alison Bondurant Vergari, BP, and Mack Shippen, Schlumberger Information Solutions

Abstract

BP North America Gas has completed the first stage of a ground-breaking R&D field trial in Arkoma, involving use of online integrated asset models and map-based visualization tools. This application called MAPS (Maximizing Asset Performance System) enables operators and engineers to geographically navigate and explore real-time operating data and model results across a large field, gaining new insights and interrelationships needed to optimize field and production performance.

In Arkoma and other assets, optimizing wells and facilities to achieve maximum performance requires sifting through volumes of data for hundreds of producing gas wells. MAPS is a new innovative means to geographically view and playback real-time data visually, enabling operators and engineers to navigate, explore, and discover information about the field and production. Through use of MAPS, online integrated asset models and real-time map-based visualization are now available to operations and engineering personnel from virtually any location, enabling better and faster identification of operating issues and opportunities for further action.

Integrity management issues are being addressed through use of MAPS and online models which are capable of providing insight and visibility into thousand miles of pipeline in terms of monitoring corrosion and erosion factors, as well as managing water, chemical usage or various location-based HSSE metrics. The MAPS tool is not limited to well or pipeline performance, but capable of locating and tracking field personnel and mobile equipment for managing field activities such as maintenance, drilling, equipment surveillance, or emergency evacuation. What began as a concept has now expanded into a robust visualization and modeling application which is expected to grow across other BP assets as part of FIELD OF THE FUTURE roadmap.
Integration of Production and Process Facility Models in a Single Simulation Tool (SPE 109260)

Fernando L. Morales and Juan Cruz Velázquez, Schlumberger, and Aarón Garrido Hernandez, PEMEX

Abstract

Traditionally in the upstream business, operational decisions are made separately at the reservoir, production and surface facility levels, using only their respective knowledge, experience and engineering tools without limited coordination between them, sometimes bypassing important considerations from other components of the overall production system, outside of their specific domain. For example, a common practice in the oil industry is to generate a production forecast derived from a reservoir-based model, without taking into account surface facility constraints that could lead to unrealistic approximations. Restrictions in compression power or pump capacity, for example, could impose significant limitations over the well and surface network performance that could impact long term field management plans if they are not properly identified and solved.

PEMEX E&P San Manuel complex produces in excess of 276 mmscf/d and 13,100 BOPD from 10 fields (mostly gas and condensates, but also oil fields) through 69 wells using 6 process facilities and its corresponding pipeline network. Built more than 25 years ago, this PEMEX E&P facility, originally designed for much higher gas and liquid rates than the current ones, faced several slug and counter-pressure problems arising from over- and under-capacity of in its current surface infrastructure. This work describes how a team of reservoir, production and process engineers, developed and implemented a data, simulation and analysis workflow to identify the well-network-process system’s major bottle necks and made recommendations of several low cost optimization alternatives to overcome them. The project’s results of implemented recommendations increased production in excess of 2,000 BOPD, with no additional investment, and reduced the asset’s operational cost by more than USD$ 600,000 USD a year. This simulation tool also proved to be very valuable for early identification of well optimization opportunities, strategic planning and informed decision making, considering the size of the full well-surface facility system.
Developing a Holistic Global Approach to Asset Management (SPE 109963)

Benito Cabrera, Daniel Musri, and Carlos Selva, Petrobras, and Carlos Lardone, Schlumberger

Abstract

The oil and gas industry has made great strides in the individual applications of the intelligent oil field technologies. However, the “big prize”—the integration of the individual pieces into a comprehensive solution that transforms work processes to achieve step-change efficiencies in development and operations—has been more elusive.

This paper chronicles the work and resulting methodologies of the international unit of an oil company as it implements an open platform asset management solution in a newly producing field, and adapts and transforms related processes to develop a template for re-use in assets anywhere in the world to anticipate and pre-empt problems—essentially realizing the promise of the intelligent oil field.

This holistic approach begins at the static model and includes reservoir simulation, surface facilities, processing plants, through economics, thereby making available the comprehensive technical picture to all geoscience and engineering professionals, and providing the basis for sounder economic decisions.

The development of this methodology is possible because of the ability to exploit these factors:

- A relatively new field coming online, with limited production problems, provides a solid starting ground on which to develop the methodology.
- Implementation of the most current asset management solution, based on an open platform that will allow the integration of other technology for the full spectrum of upstream applications, from static model through economics, provides the right technology.
- A commitment from the operator to not simply implement the solution, but to dedicate the resources to assess and analyze the workflow and processes, and combine the expertise of the operator, service company and consultants to develop methodologies that can be applied globally, to any operations.
Abstract

Today's hydrocarbon environment requires depth of knowledge and expertise combined with technology innovation and integration across the various disciplines involved in the Reservoir Management cycles going from exploration to production, in order to increase production, reserves and improve operational efficiency. An integrated approach including People, Process and Technology is necessary to break the barriers between the various reservoir management cycles - operations - production optimization and field management, and to improve the maturity of information to knowledge. Engineering processes related to each reservoir management cycle need to be accelerated by the implementation of automated/interactive workflows, integrating various levels of field data frequency with petrotechnical processes, that can help in operational efficiency, leaving more time for a more proactive engineering analysis of problems and solutions. A successful workflow approach ensures that the hydrocarbon's decline curve is mitigated with higher ultimate recovery. Also, the integration of data with numerical and analytical reservoir and well models, through workflows, helps to bring more efficiency in the field planning cycle in order to establish proper Enhanced Oil Recovery (EOR) or in-fill drilling plans to increase recovery factors.

The purpose of this paper is to show how workflow oriented solutions, within the context of the Digital Oilfield, have helped increase production, ultimate recovery factors and operational efficiency in various types of operational environments, and i.e. water flooding, Water Alternating Gas (WAG) and gas lifted fields.

The challenges facing the industry today are presented in the introduction, with an overview of the reservoir management cycles and why an evolution is necessary using workflow solutions. The next section presents the journey to improved reservoir management, introducing the concepts of workflow automation, integrated asset modeling and simplified asset modeling using proxy models. The section also presents the required changes to management disciplines to ensure successful deployment of workflow solutions. Finally, the paper presents three case studies where the concepts defined were successfully implemented in real asset situations.
Production Enhancement for Khafji Field Using Advanced Optimization Techniques (SPE 120664)

M.A. Al-Khaldi and E.O. Ghoniem, Al-Khafji Joint Operations, and A.A. Jama, Schlumberger

Abstract

The gas lift, by limited capacity of 25 MMSCF/D, was introduced for Khafji field in 1988 which could successfully sustain target rate until mid of 2004. Artificial Lift is part of the long term production sustainability solutions for Khafji Field necessitated by the increase of field water cut and depletion of reservoirs. In order to make up for production decline in Khafji Field and to sustain the field target rate and defer large investments associated with exploration and drilling new wells as well as commissioning new facility expansions, Production Optimization and de-bottlenecking of the existing production system was found to be the best cost effective solution. For that purpose, general optimization and gas lift allocation models have been built and applied for Khafji field as presented by Ghoniem et al\textsuperscript{1, 2}.

This paper is an extension to the previous papers for Khafji Field cited above. The optimization approach presented in this paper is based on a field-wide production planning solution, which is achieved by combining steady-state multiphase network simulation with a nonlinear, multivariate optimization technique called Genetic Algorithm (GA) through a newly developed and commercially available optimization application called Avocet Gas Lift Optimizer\textsuperscript{TM}.

The present work therefore represents the introduction of a new optimization platform for Khafji crude production and its results with a particular focus to:

- Building a comprehensive network model for Khafji Field (including wells and production facilities).
- Demonstrating production gain by the use of advanced optimization techniques (e.g., GA) to sustain field quota.
- Optimally distributing limited gas lift availability to Khafji Field to enhance production, while taking into multiple well and field constraints.
Energy Balance in Steam Injection Projects Integrating Surface-Reservoir Systems (SPE 121489)

E. Valbuena, J.L. Bashbush, and A. Rincon, Schlumberger

Abstract

Steam injection projects consume considerable amounts of energy to generate steam. Understanding where the heat goes at various times and places during the process provides the means to improve the performance of a project. Enhancements can be achieved integrating an energy balance analysis from the steam generator through the injection network, the reservoir, the producing network and the journey of the produced fluids to the separator.

This investigation presents a workflow to analyze the integration of surface and reservoir systems for a Steam Assisted Gravity Drainage (SAGD) project, to properly estimate energy transfers in the various components of the system thus providing information to improve project planning and enhance both the oil recovery and the economics of the project.

The elements considered in the systems were: boiler, heat exchanger, steam trap, steam injection and well networks, reservoir heat usage, heat losses to the over- and under-burden, production wells and surface networks. Parameters such as completion schemes, artificial lift and boiler-wellhead distances were also analyzed.

Results show that surface-reservoir integration, using reservoir and network simulators, is a powerful tool to estimate heat losses in steam injection projects, helping to understand and successfully optimize their performance. The integration allowed the detection of steam quality variations at injection wells at various times during the process as a function of injectivity changes. Adequately insulated production wells under certain circumstances could produce under natural flow for some FAJA types of reservoirs. However, artificial lift methods had to be incorporated into other completion schemes to compensate for high heat losses and their correspondent increased oil viscosities that imposed higher pressure drawdowns in the production and surface gathering networks.

The SAGD processes analyzed were energy efficient in spite of retaining in the reservoir less than a third of the energy from the steam. In all the scenarios, oil production was considerably greater than the fuel consumed to generate steam.

The paper shows how the analysis of steam injection processes integrating surface, well and subsurface mechanisms allows the identification of critical components of heat losses to optimize the design and operations to maximize oil recovery and reduce energy consumption.
Abstract

The reduction of greenhouse gas emissions in order to decelerate the global warming process could be achieved through the emerging process of geological CO\textsubscript{2} storage. Also in terms of Enhanced Oil Recovery (EOR) the injection of CO\textsubscript{2} as a pure component or as part of a mixture has proved to increase the productivity of oil and gas reservoirs.

Optimization techniques have been applied independently to the reservoir and surface models, leading to non-optimal solutions due to the non-dynamic integration between models. A recent trend of the industry is the integration of subsurface and surface simulators to have a better representation of the fluid production/injection, taking into account the constantly changing interaction between systems.

The integrated approach has been used to integrate multiple reservoirs with common and advanced surface facilities to properly model the fluid flow behavior of the asset. Different injection variables, facilities, well completion, number of wells have been included in the analysis and numerical reservoir simulation models have been integrated with a network. As CO\textsubscript{2} is captured, it is transported and re-injected to neighbor reservoirs, as an enhancement process for productivity or for storage purpose.

After proving the feasibility of facilities for CO\textsubscript{2} injection as EOR process or storage, the integrated approach has shown a more comprehensive solution that could be used for the design and further optimization of this type of projects. Analysis of reservoir properties as permeability, temperature, etc. is also taken into account in order to assess the viability of the CO\textsubscript{2} optimal injection and storage strategy, while minimizing cost. Finally, integrated asset modeling also shows the flexibility to represent different types of settings such as CO\textsubscript{2} source (reservoir and/or fossil fuel power plants), types of reservoirs and network scenarios.
Coupling a Reservoir Simulator With a Network Model to Evaluate the Implementation of Smart Wells on the Moporo Field in Venezuela (SPE 122421)

A. Alvarez, E. Guerra, A. Gammiero, C. Velasquez, J. Perdomo, and R. Hernandez, PDVSA, and N. Rodriguez and M. Infante, Schlumberger

Abstract

Pursuing new alternatives to develop and produce sands B1 and B4 together, belonging to the reservoir VLG-3729 of Moporo Field located in western Venezuela, different exploitation schemes were evaluated, where intelligent completions have been highlighted. A pilot well with inflow control valves (ICVs) was proposed with the goal of maximizing the well oil production, avoiding cross-flow, minimizing operational risks and well interventions(coil-tubing operations), leading to better reservoir management.

To evaluate the intelligent completion technology, an Integrated Asset Model (IAM) was implemented. This model was divided in two sections: the first section involves the reservoir model using a reservoir simulator, which includes the representation of the ICVs through the multi-segment wells option; the second section represents the fluid flow in the well and pipelines from the couple point to the sink including the artificial lift system (Electrical Submersible Pump, ESP) through a network simulator. Both sections were coupled taking an intermediate point between the ESP and ICVs as a coupled node.

The differences using a stand alone model and a coupled model were analyzed. Given that in both models the main constraints are handled in different ways, the calculated liquid production trend is different for each model. The stand alone model is constrained by maximum liquid rate and minimum bottom hole pressure (BHP), while the BHP constraints on the coupled model is calculated dynamically by the production system. In this case, the stand alone reservoir model leads to an optimistic production profile. These results show the advantage in the use of an IAM, taking into account the network constraints to obtain more accurate results.

To evaluate the performance of the smart well, several sensitivities to the coupled model were made, changing the opening valves position at the beginning of the forecast. An increment in the cumulative oil production was observed when the cross flow between sands were not allowed.
Implementation of Integrated Network Optimization Model for the Mumbai High Field—Crucial to Field-Wide Optimization (SPE 123799)

Anand Kumar Jha, Santanu Barua, Vikas Agrawal, Gunja Agarwal, and Ravi Kumar, Schlumberger, and S.K. Moitra and G.S. Negi, ONGC, India

Abstract

The giant ONGC Mumbai-High offshore field produces about 250,000 bopd (60% water-cut) from 700+ wells through 110+ unmanned production platforms. The production platforms are connected by subsea flow lines to 6 processing platforms where the oil, water and gas are separated. More than 80% of the wells in the field are on gas-lift.

This paper discusses an integrated-network-modeling-and-optimization approach to overcome known drawbacks of single well gas-lift optimization. The new higher fidelity model captured the interactions between wells, flow-lines and platforms, field-wide. Using this approach, previously hidden opportunities for significant production improvement were identified. The model indicated a possibility of significant production increase (2 to 4%) and production efficiency improvement (significant reduction in lift gas requirement), which could be achieved by better allocation of lift gas and repair and redesign of the sub-optimal gas-lift wells. The latest available field implementation results are also presented.

Currently, in the absence of full-loop control-automation of the gas-injection rates/pressures, logistical challenges made it impractical to simultaneously implement the calculated optimum settings field-wide. The network interactions are highest at the production-platform level between adjacent wells and connecting shared flow-lines. So, from practical implementation considerations, optimum gas-injection rates were calculated and simultaneously implemented at the production-platform level, one (or a group of few connected) production platform at a time, with little or no compromise on the quality of the solution or on the validity of the approach.

To date, actual optimization implementation changes in 14 of the 110+ platforms (160 of the 700+ wells) indicated immediate production increase of over 2000 bopd and significant reduction in lift gas requirement. Based on these early indications, it is envisaged that the field-wide oil production gain can possibly be as high as 6%.

Additionally, this paper discusses the challenges and recommended approaches with regards to sustainable model maintenance, solution implementation and workflow. Status of control automation and on-line modeling plans (planned for implementation in future) are also discussed.
Optimization of Stimulation Treatments in Naturally Fractured Carbonate Formations Through Effective Diversion and Real-Time Analysis (SPE 126136)

Francois Cantaloube, SPE, Rae Spickett, SPE, and Kaveh Yekta, SPE, Schlumberger, and Mark Anderson, Suncor

Abstract

Long horizontal open holes and naturally fractured reservoirs have always presented a challenge to the industry for successful matrix treatment operations. This is particularly true in western Canada where the reservoirs are competent carbonate formations completed open hole over a length of 2,000 m with a bottomhole static temperature of 110°C. These naturally fractured formations exhibit substantial and unpredictable permeability variations over the length of the interval. During treatment, all or part of the acid may thief to a high-permeability interval leaving the rest of the wellbore poorly stimulated. The industry has developed a range of products and techniques to divert the stimulation treatments from these thief zones in an attempt to improve wellbore coverage and reservoir drainage. However, the placement of these diverting techniques and the evaluation in situ and in real time of their effectiveness were yet to be accomplished.

An innovative technique, developed in Western Canada, combines state of the art viscoelastic acid diversion with fiber optic technology for accurate downhole fluid placement and optimum diversion effectiveness. This is a unique system consisting of live downhole temperature and pressure measurements transmitted to surface through fiber optic telemetry installed in the coiled tubing (CT). Real-time analysis of distributed temperature survey (DTS) and single-point downhole measurement of temperature and pressure, along with petrophysical data, provide an in-situ visualization of the dominant thief zones. The analysis of this information allows for on-the-fly adjustment to the diversion placement schedule matching current downhole conditions.

This technique provides a unique way to ensure the entire pay zone is fully and homogeneously stimulated, optimizing the reservoir contact and delivering the full well potential. The technique was systematically applied to all newly drilled wells in the Suncor Panther field in the western Canadian Rocky Mountain foothills. The comparison of gas production over the entire field for 16 new wells illustrates that results have substantially improved since the introduction of this innovative technique.
Investigation of Gas Well Liquid Loading With A Transient Multiphase Flow Model (SPE 128470)

Rahel Yusuf, SPE, SPT Group; Kees Veeken, SPE, Shell; and Bin Hu, SPE, SPT Group

Abstract

Liquid loading in gas wells occurs when the gas flow rate falls below a critical value due to reservoir depletion where the accompanying liquids can not be lifted up to surface. Since liquid loading has a detrimental impact on production, deliquification methods need to be employed in order to recover the production. To choose the right deliquification measures and achieve a timely deployment, it is therefore important to predict the onset of liquid loading in advance. Traditionally, the Turner correlation has been used for this purpose. However, latest published data from deviated large diameter offshore wells show that the Turner correlation can underpredict the critical gas rate by 20-200%. The operators can be misled by this prediction and are often not well prepared for tackling the liquid loading as they may think the problem is still some years away.

Liquid loading is a transient phenomenon in nature and thus needs to be described by a dynamic multiphase flow model. In the present study, instead of modifying or improving the Turner correlation, a comprehensive dynamic multiphase flow model is used to predict the onset of liquid loading. Totally fourteen offshore gas wells were simulated using the dynamic model. The predicted critical gas flow rates are validated against field data and the predictions lie within the ±20 % error margin. The effect of condensate gas ratio (CGR) on liquid loading is also investigated. The simulations show that it is possible for low CGR wells that the critical gas flow rate can decrease with the increasing CGR. This is also in line with the field observations.

This study brings forth the importance of transient multiphase flow modeling and opens new frontiers for dynamic simulation of gas well deliquification, which shall set up guidelines from dynamic point of view for implementing the right deliquification measures so that more production can be recovered when loading has happened.
Gulf of Suez Continuous Gas Lift Real-Time Optimization Strategy (SPE 128533)

Yasser A. Abdallah, Nabil S. Gaber, Emad Eldin A. Saad, SPE, Elsayed A. Bedair, Gulf of Suez Petroleum Company (GUPCO), R. E. Soegiyono, SPE, Schlumberger

Abstract

The application of continuous-flow gas lift systems have been operating for over 40 years in Gulf of Suez Petroleum Company (GUPCO) offshore Gulf of Suez. Like any artificial lift method, it is to improve the productivity whilst ensuring the most effective use of the existing reserves. Continuous gas lift operations is favorable for these fields because of the flexibility in its production rates, ability to handle corrosive fluids, suitable for high temperature and high gas oil ratio wells, and compatibility with sand production. Some other real challenges facing the Gulf of Suez assets management besides keeping up production and maximizing reserves from mature fields are the ageing production facilities, and limited testing and data acquisition infrastructure. As more and more wells are completed with gas lift, the task of gas lift monitoring becomes more time consuming.

An important part of the gas lift optimization process is the effective gathering of live field data in order to establish the performance of the field and its individual well. A source of this information so far is a bunch of well files placed in the field and or head quarter offices. Because of inadequate infrastructure for an optimization and monitoring schedule, it is required to initiate a system with today’s real-time data acquisition and data transmission technology, which provide an opportunity to implement the real-time production optimization effectively and remotely by means of satellite and web interface.

A pilot platform was selected to prove the concept of real-time production optimization. It is located in El-Morgan offshore field, approximately 160 miles in the south Gulf of Suez. The field consists of four (4) major platform complexes and 17 satellite platforms with over 80 current producers and around 50 injectors. Despite on-going operational difficulties and complexities, waterflood operations in this field indicate a successful exploitation of potential reserves. The field’s cumulative production to date is 51% of its predicated Stock Tank Oil Initially in Place (STOIIP). Manual data gathering exercise is being implemented as a remedial solution to validate definitive benefits from the gas lift optimization process. The pilot began with a feasibility study for most reliable, safe and secured data acquisition and data transmission deployment to overcome the daily struggle of gathering sufficient, current and reliable data, and to better understand the field production potential. The strategy is further defined into several steps from efficiently monitor well behavior on a well by well basis, achieve full monitoring coverage for the field, provide quick response to well down-time, provide thorough review and analysis on well performance, hence give more time to gas lift engineers to look for other optimization opportunities around the field.
Comparisons of Various Algorithms for Gas-lift Optimization in a Coupled Surface Network and Reservoir Simulation (SPE 130912)

Pierre Samier, SPE, Total SA

Abstract

Gas lift is used for gas-liquid two phase producers to boost the production. Increasing gas liquid ratio GLR reduces the average fluid mixture density in the well connections and therefore reduces the hydrostatic pressure drop and hence reducing the bottomhole pressure resulting in a higher production rate or a longer individual well production period. This technique is also used for deep offshore fields injecting the gas at the toe of the FPSO risers located at the seafloor.

But as the lift gas supply is increased further, friction pressure losses in the tubing or the riser become more important and the production rate peaks then starts to decrease. Also high gas flowrates may induce corrosion problems, and the total amount of available gas-lift is limited. Therefore an optimal gas-lift rate exists for a maximum production rate or more generally a maximum production profit.

Various gas lift optimization algorithms have been proposed in literature for optimizing gas-lift to individual wells or within a group of wells, very few are suitable for long-term reservoir development studies with gas-lift injection within a network (FPSO riser toe for example).

Commercial simulators such as Eclipse, VIP, Nexus, … provide internal optimization tool which are convenient for gas-lift at wells connections. Optimizing gas-lift within a network with additional gas rate inside flowlines or risers becomes much more complicated since the THP limits of all the other wells in the network are affected. Each time a lift gas increment is added or substracted, the whole network must be rebalanced with the appropriate lift gas rate in order to recomputed the change in the field oil production rate. The paper reviews some of the optimization methods available in commercial coupled surface network and reservoir simulators such as Resolve -Gap-Eclipse, Nexus, Avocet, …

Several optimization algorithms linked to a surface facility model coupled to an open reservoir simulator prototype have been also applied (Ensemble based method, Steepest-Descent, Gauss-Newton, BFGS, ...) and compared to previous commercial software solutions.

Results of the comparisons are presented on a surface network model coupled to a reservoir simulator where the objective is to optimize the gas-lift allocations at riser toes.

One of the test cases based on a modified SPE 9 comparative test is fully documented and allows the readers to compare results with their own optimization algorithm.
Real Time Production Surveillance and Optimization Solution Implementation in an Offshore Brownfield in Malaysia (SPE 133515)


Abstract

Gas lift optimization and design has traditionally used single-string analysis to perform optimization. This required time consuming exercises and lengthy processes that never achieved the global reach of field constraints management. In a dynamic brown field where field interruptions and process upsets are common, response time is a key performance indicator. These challenges were effectively overcame by introducing a Real Time Production Surveillance and Optimization system capable to perform dual string gas lift optimization field-wide and in real-time.

The implementation was the first Real Time Production Surveillance and Optimization system in the country. The system links up real-time operational data historian system and corporate production information management system (PIMS) and is coupled with the Well-Network suite of simulation tools to provide an integrated suite of production surveillance, diagnostic and optimization application modules that increase the efficiency of daily oil and gas operations activities.

The goal of this paper is to underscore the advantages and benefits that can be drawn from the utilization of Real Time Production Surveillance and Optimization System during the operational phase of production optimization process.
Dynamic Well Clean-up Flow Simulation for Field Start-up Planning in the Pyrenees Development, Offshore Western Australia (SPE 133838)

C. Chung, SPE, D. Marian, and R. Napalowski, SPE, BHP Billiton Petroleum, and J. Thomson, SPE, Schlumberger

Abstract

The Pyrenees development, operated by BHP Billiton, comprises the concurrent development of three oil and gas fields: Ravensworth, Crosby and Stickle. The fields are located in production licenses WA-42-L and WA-43-L, offshore Western Australia, in the Exmouth Sub-basin. Seventeen subsea wells, including 13 horizontal producers, 3 vertical water disposal wells and 1 gas injection well have been constructed to date. The project is presently on production with first oil achieved during February 2010.

Due to the normally pressured reservoir conditions, reliable kick-off and clean-up of the long horizontal development wells to the FPSO was heavily dependent upon gas lift. As a result of uncertainty of gas compression availability at field start-up, detailed contingency plans were developed to reduce the reliance on gas lift during field start-up. Identification of feasible contingencies required a thorough understanding of the dynamic flow behaviour of the wells and flowlines during the start-up process.

This paper summarises how a commercial transient multiphase flow simulator was utilised to model well kick-off and clean-up for a number of cases with and without gas lift against initial flowline contents of seawater, diesel or gas. The approach employed to modelling the lateral well sections completed with inflow control devices (ICDs) allowed for an accurate representation of initial and residual drilling mud volumes, annular flow and the impact of the ICDs on the inflow profile.

The primary objective of the dynamic simulation was to identify the requirement for invoking contingency options and to confirm the feasibility of the various options in ensuring a reliable and successful well kick-off without gas lift. A comprehensive analysis of the results contributed to a thorough understanding of the dynamic flow behaviour of the clean-up process. Secondary objectives of the simulation included an estimate of the reservoir drilling fluid (RDF), diesel and flowline contents return rates and volumes to the test separator and an estimate of the time required for each well to clean-up. Conclusions from this work were crucial to contingency planning and proved to be invaluable in successfully executing and optimising well clean-up operations, the field start-up planning and the production ramp-up.
Gas Lift Optimization Under Facilities Constraints (SPE 136977)


Abstract

Gas lift optimization is often used to enhance production of mature oilfields consisting of multiple reservoirs. For efficiency, several of those reservoirs often share the same surface processing facilities. In such context, we wish to find the optimal allocation of gas lift over an entire network of wells and pipelines, while accounting for the constraints imposed by the reservoir operating conditions.

In this study, we describe a novel, cost-effective approach to perform such optimizations involving non-smooth models and subject to expensive constraints that might be simulation-based and as costly to compute as the objective function. After classifying all constraints depending on their computational cost, points not satisfying simple linear constraints are feasibilized before evaluating expensive constraints. A sequential lexicographic ordering is applied in which the linear constraints take precedence over nonlinear constraints and inexpensive nonlinear constraints take precedence over expensive ones, which in turn take precedence over objective function values. Two oilfield-production optimization examples serve to demonstrate that the performance of the proposed method is much faster than the traditional ones.
The Bakken Shale is one of the largest, unconventional crude oil plays in the United States covering as much as 25,000 sq miles in the Williston Basin. The formation underlies portions North Dakota and Montana and is found at depths ranging from 9000ft to 10,500ft. Reserve estimates vary but the United States Geological Survey (USGS) has calculated risked undiscovered resources of up to 4.3 billion barrels of recoverable oil and bbl/cu ft equivalent using current technology. At this time the field is being developed with single, dual and triple-leg horizontal wells with laterals extending 4500ft to 9500ft into the formation.

However, drilling activity in the area has fluctuated as a result of changing oil prices. Accordingly, reducing overall operation costs is essential to the economic feasibility of each drilling project. Because of the significant impact on drilling costs, the correct selection and utilization of drilling equipment including bits, drilling fluids, hydraulics and downhole tools is paramount. To optimize operations, a holistic approach was adopted to create a drilling “road map” utilizing several application software systems. These software tools enable engineers to envision the specific drilling environment and tool/BHA interaction before the bit goes in the hole.

A recent Bakken project included expert drill bit selection, rock mechanics analysis, shock studies, drilling fluids and hydraulics optimization. The directional well plan was optimized with wellbore simulation software. In order to circumvent deficient options prior to and during actual drilling operations, multiple scenarios are simulated using a collection of detailed geological and offset drilling information. These results were studied, analyzed and assessed as the optimum drilling solution prior to submitting them to the operator. Finally, the service provider monitored and implemented the recommended engineered solutions.

The initial results were encouraging: Drilling days on Well 1 were reduced by 30% which represents a cost savings of $572,000USD while achieving the drilling target and delivering a high-quality wellbore. Building on this initial success, second and third wells confirmed the value of holistic optimization saving the operator 13 days ($676,000USD) and 16 days ($832,000USD) of rig time respectively.
Simulation of Two-Phase Flow in Carbon Dioxide Injection Wells (SPE 144847)

Lawrence J. Pekot, SPE, Pierre Petit, Yasmin Adushita, SPE, Stephanie Saunier, Schlumberger; and Rohan De Silva, SPE, National Grid Carbon

Abstract

To model a variety of potential operating conditions in pure carbon dioxide (CO₂) injection wells we performed a multi-phase transient well flow simulation study. A thermal reservoir simulator was also used to estimate the extent of reservoir cooling and the variation of injectivity index to be expected from injection of cold CO₂.

Depleted gas reservoirs are potentially attractive targets for CO₂ but their low pore pressure results in low bottomhole injection pressure and potentially two-phase flow regime in the wellbore. Other authors have noted the possible implications of this condition; however, none have addressed the issue using transient flow simulation.

A vertical wellbore model was built in a multi-phase transient flow simulator, assuming representative Southern North Sea conditions. To investigate wellbore profiles of pressure, temperature and CO₂ liquid hold-up, parametric as well as thermal reservoir simulations were performed. The latter simulations integrated the bottomhole conditions observed in the wellbore model.

Results show that pure CO₂ injected at the wellhead may vaporize or condense as it travels down the tubing, experiencing continuous changes in pressure and temperature as dictated by its change in enthalpy. However, sudden vaporization or condensation is not predicted by the simulator. Two-phase flow cases resulted in stable injection conditions. Well injectivity index varied significantly with injection fluid temperature and pressure, but the extent of reservoir cooling away from the wellbore was limited. This suggests that onerous processing to avoid a two-phase flow regime in CO₂ injection wells, such as pre-injection heating or downhole choking may not be necessary at the injection start-up into a depleted gas reservoir.
Gas Field Production System Optimization using Coupled Reservoir - Network Simulator and Optimization Framework (SPE 150770)

M.M. Nwakile, TU Clausthal Germany; R. Schulze-Riegert, SPT Group Hamburg; and M.D. Trick, SPT Group Calgary

Abstract

Optimization of oil and gas field production systems poses a great challenge to field development due to complex and multiple interactions between various operational design parameters. Conventional analytical methods are capable of finding local optima. They are less applicable for efficiently generating alternative design scenarios in a multi-objective context.

This paper presents an integrated workflow using a simulator coupled to an optimization framework. It is used to investigate the impact of design parameters while considering the physics of the reservoir, wells, and surface facilities. Experimental design methods are used to investigate parameter sensitivities and interactions. Optimization methods are used to find optimal design parameter combinations which improve key performance indicators of the production network system.

The proposed approach is applied to a representative gas production system and is shown to be capable of finding optimal combinations of pipe sizes and compressor power. The method offers a significant advantage over existing conventional techniques.
Modelling System Failures of Electric Submersible Pumps in Sand Producing Wells (SPE 151011)

T.C. Kalu-Ulu, SPE, Schlumberger; J.A. Andrawus, SPE, Robert Gordon University UK; and I.P.S. George, SPE, NAOC

Abstract

Electrical Submersible Pumps (ESPs) are used to boost production in hydrocarbon and enhance investment recovery in the oil and gas industry is affected by solid particles. Sanding reduces the integrity and reliability of ESPs with enormous consequences. Better knowledge of the performance of Electric Submersible pumps in sand producing well through system failure modelling ensures effective planning and good operational philosophy. Life-failure-data were collated and analysed in this paper using Weibull Distribution to determine the shape ($\beta$) and the scale ($\eta$) parameters of ESP system components. The system failure mode analysis carried out highlighted the failure patterns of ESPs. Mechanical based failure components displayed constant failure pattern while electrical based failure components displayed decreasing failure pattern.

A simple Reliability Block Diagram is designed to model the system failure. This is simulated to ascertain the reliability, availability and maintainability of ESPs in sand prone wells.
Innovative Intelligent Technologies used for Production Optimization and Infrastructure Integrity Surveillance (SPE 150131)

Ian Roberts, Alexander Albert, Layla El Hares and Marcus Rossi, Schlumberger

Abstract

In the oil & gas industry sporadic studies are developed to analyse the flow conditions and operations procedures through the life of the field. The objective of those studies is to understand the environment, boundary conditions and properties changes along the fluid journey. For characterization of the production behavior, engineers use model-based multiphase flow simulation via various applications available on the market.

A constant understanding of the fluid flow conditions is valuable for the decision process on the execution of operational procedures. A robust flow assurance strategy is dependent on the level of awareness of the real production conditions prior to a fluid flow interruption event. Fiber optics distributed sensor system has been recently used mainly for integrity monitoring purposes; the proposed methodology unlocks the additional values for interfacing disciplines as flow assurance by the provided simultaneous distributed measurements of temperature, strain, and vibration.

The model-based multiphase flow simulations represent flowlines and production networks and as output of those simulations operating profiles are used to evaluate the risk of solids precipitation and deposition along the flow path. A regular update of simulation models by real-time data from field sensor results in a more reliable representation of the production system operating profile that can support the flow assurance strategy by the detection, monitoring, and location of events.

This paper proposes the use of real-time data acquisition from an optical-fiber distributed sensor for the assurance of fluid flow along the production system. It outlines a methodology to perform flow assurance automated surveillance based on multiphase flow simulation models constantly fed with real-time field measurements to estimate fluid flow conditions throughout the system to avoid potential problems, such as flow restrictions due to solids deposition.
A Field Wide Surface Network Modeling and De-bottlenecking of Production Network for Nine Fields of GNPOC (SPE 150555)

Aditya Kumar, SPE, Schlumberger, Omer Mohamed Omer, GNPOC, Abu Bakr Ahmed Sulaiman, GNPOC

Abstract

Greater Nile Petroleum Operating Company (GNPOC) is facing challenges to sustain their production, which has been declining at the rate of 15% (approximate) annually. Major part of production is sustained by drilling infill wells re-completion. Pipeline network plays important role in delivering the production from wellhead to Field Processing Facility (FPF). Bottlenecks in pipeline can cause rise in wellhead pressure, which can have impact on production substantially. To identify these bottlenecks and reduce backpressure effect on network GNPOC initiated a project for de-bottlenecking of production pipeline network nine fields. A high fidelity Surface Network Model was developed for all field of GNPOC, which have more than 400 producing wells.

This surface network model will help to quickly identify and accurately quantify bottleneck and other opportunity to reduce backpressure on the system and improve production. This model will also help in further field development, pipeline tie-in / lineup, best nearby Oil Gathering Manifold (OGM) to tie-in new wells etc. The approach of building model is kept simple, robust and scalable. Scalable model will helps GNPOC to add-in well model and integrated this production model to reservoir simulator, facility model and real time data easily and quickly. The model would also assist in evaluating field operation and development plan and expedite the engineering decision process. The identified bottleneck has been ranked in order or priority (which needed immediate attention).

A totally new approach was adopted in the study in terms of the location, training and technology transfer in Sudan. The project engineer worked in close association with operation engineers from field and office. Also actual work has been partially carried out in field as well as office. This approach has given more opportunity to field operation engineers to interact with current modeling tool and technology and increase confidence level.

This paper describes the development of the surface network model for nine fields of GNPOC, technical & project management challenges faced and the way ahead. The model includes the production and transportation networks. This paper also includes major de-bottleneck areas in the production network of GPNOC and How to make effective use of this model for engineering analysis.
Abstract

The application of horizontal well drilling and multi-stage fracturing has become a norm in the industry to develop unconventional resources from ultra-tight formations. A complex fracture network generated in the presence of stress isotropy and pre-existing natural fractures immensely extends reservoir contact and improves hydrocarbon production.

A semi-analytical method is presented in this paper to simulate the production from such complex fracture network. This method combines an analytical reservoir solution with a numerical solution on discretized fracture panels. The mathematics are briefly introduced. A number of case studies are presented, from a simple planar fracture to a real field example from the Barnett shale. Production behaviour and the key flow regimes are discussed.

With its simplicity, yet capturing the physics of the transient production performance, this approach provides an accessible tool for people from multiple disciplines in unconventional resource development to rapidly evaluate treated-well productivity and stimulation effectiveness.


Abstract

Assessing the waterflood, monitoring the fluids front, and enhancing sweep with the uncertainty of multiple geological realisations, data quality, and measurement presents an ongoing challenge. Defining sweet spots and optimal candidate well locations in a well-developed large field presents an additional challenge for reservoir management. A case study is presented that highlights the approach to this cycle of time-lapse monitoring, acquisition, analysis and planning in delivery of an optimal field development strategy using multi-constrained optimisation combined with fast semi-analytical and numerical simulators.

The multi-constrained optimiser is used in conjunction with different semi-analytical and simulation tools (streamlines, traditional simulators, and new high-powered simulation tools able to manage huge, multi-million-cell-field models) and rapidly predicts optimal well placement locations with inclusion of anti-collision in the presence of the reservoir uncertainties. The case study evaluates proposed field development strategies using the automated multivariable optimisation of well locations, trajectories, completion locations, and flow rates in the presence of existing wells and production history, geological parameters and reservoir engineering constraints, subsurface uncertainty, capex and opex costs, risk tolerance, and drilling sequence.

This optimisation is fast and allows for quick evaluation of multiple strategies to decipher an optimal development plan. Optimisers are a key technology facilitating simulation workflows, since there is no ‘one-approach-fits-all’ when optimising oilfield development. Driven by different objective functions (net present value (NPV), return on investment (ROI), or production totals) the case study highlights the challenges, the best practices, and the advantages of an integrated approach in developing an optimal development plan for a brownfield.
SS FA- Deliquification of an Offshore Oil Well - An Innovative Approach to Overcome Paraffin Plugging (OTC 20900)

S. O'Brien, Champion Technologies; E. Kiihne, Champion Technologies; J. Macias, Champion Technologies; E. Vita, Champion Technologies; J. Gonzalez, Champion Technologies

Abstract

A deliquification technique has historically proven effective for land-based operations. The objective was to deliquify a deepwater dry-tree oil well with minimal impact to normal offshore operational objectives. The deployment of a production chemical to successfully deliquify the oil well involved the study of typical well deliquification techniques for land based operations which were modified to address deepwater, offshore operations regulatory requirements and system objectives. This application also involved flow restrictions due to paraffin depositions in the tubing.

Typical liquid unloading techniques require system analysis, fluid modeling, deployment planning, and implementation. These techniques were applied to the offshore environment with special attention to deployment and implementation phases due to fluid flow-rate limitations associated with offshore production equipment. Modeling tools were used to identify required velocities to successfully unload the liquid hold up and to better understand expected performance.

This paper will discuss the project planning and processes used to successfully deliquify a flow-restricted liquidloaded deepwater oil well. Modeling data, critical flow-rate limitations of the system, and deliquification process planning are included. Results of this application will be discussed in further detail to help understand requirements of offshore chemicals induced deliquification techniques and lessons learned.

The use of a Flow Improver to remediate liquid loading associated with depleting wells offers another solution to offshore facilities. The modeling and identification of wells near the liquid loaded critical rate can prevent well downtime associated with pressure buildup and coil tubing techniques typically applied. This approach can significantly reduce CAPEX costs associated with artificial lift techniques while maintaining offshore operational objectives in regards to pipeline oil quality and water discharge regulatory requirements.
The Importance of Wax-Deposition Measurements in the Simulation and Design of Subsea Pipelines (SPE 115131)

Kamran Akbarzadeh, John Ratulowski, Dmitry Eskin, and Tara Davies, Schlumberger

Abstract

Conventional practices for estimating the amount of deposited wax in pipelines are usually based on predictions made with simulation packages using limited stock-tank-oil (STO) deposition data collected under laminar-flow conditions in bench-scale flow loops. Such practices are conservative and often lead to nonoptimal designs of pipelines and surface facilities. For optimized designs, laboratory-scale deposition measurements made under realistic conditions are required to calibrate flowline models. In this work, a high-pressure deposition cell that operates on the Taylor-Couette (TC) flow principle is used to generate more deposition data with live reservoir fluids under turbulent flow similar to the conditions encountered in many flowlines. The analogy between TC flow and pipe flow is explained, and a scalability flow chart for linking the laboratory-scale deposition data from TC configuration to pipe configuration is presented. Through a case study, the scaled-deposition data are then used to tune a wax-deposition model in the OLGA® simulation package. Next, the tuned model is applied to predict wax deposition under actual production and transportation conditions. The importance of tuning the deposition models with live fluid data under turbulent-flow conditions is also shown by comparing results obtained from conventional dead-oil low-shear data.
Gas-Well Liquid-Loading-Field-Data Analysis and Multiphase-Flow Modeling (SPE 123657)

Kees Veeken, SPE, Shell; Bin Hu, SPE, SPT Group; and Wouter Schiferli, SPE, TNO

Abstract

Gas-well liquid loading occurs when gas production becomes insufficient to lift the associated liquids to surface. When that happens, gas production becomes intermittent and eventually stops. In depleting gas reservoirs, the technical abandonment pressure and ultimate recovery are typically governed by liquid loading. To date, most methods for predicting liquid loading have followed Turner et al. (1969), who describe liquid loading as the point where the liquid droplets suspended in the gas flow start moving downward rather than upward. This paper presents (offshore) liquid-loading field data that exceed the Turner predicted values by an average of 40%, and analyzes the sensitivity of the liquid-loading gas rate for different well parameters. It subsequently presents the results of steady-state and transient multiphase-flow modeling, carried out to identify the influence of the same well parameters. A modified Turner expression is proposed that best fits the liquid-loading field data and broadly agrees with the results of a multiphase-flow model that uses a modified version of the Gray outflow correlation. The results of transient-flow modeling support the flow-loop observation that liquid loading occurs because of liquid-film-flow reversal rather than droplet-flow reversal. The impact of these findings on gas-well deliquefication is explored.
Abstract

Systematic experimental and modeling approaches to designing a safe operating strategy for a 5-km deepwater subsea flowline case study are presented to address unplanned shutdown and restart events for waxy crude production. The measurements confirmed that the fluid behaves like Bingham plastic when it is allowed to become gel at the seabed temperature of 4 deg.C. The cool-down period was modeled using the transient simulator validated by measurements and was predicted to take 21 hours. The restart pressure was then modeled for both stock-tank and at line pressure conditions. These restart pressure requirements were found to be 2,500 psi and 2,100 psi, respectively for stock-tank and at line pressure conditions. Also, the use of inhibitor treatments demonstrated that the fluid would not form gel at the sea bed temperature of 4 deg. C. However, the current shut-in wellhead pressure of 2,500 psi is deemed adequate to restart the lines in the event of unplanned shutdown without the use of chemicals. The presence of a subsea pig-launching pump provides a safety factor for restart in case the line pressure is released to atmospheric conditions. Hence, the operating strategy does not require injection of wax inhibitors at the current state. However, in future when the shut-in wellhead pressure falls below 2,500 psi, the operating strategy is expected to be modified accordingly.
Flow Instability in Deepwater Flowlines and Risers - A Case Study of Subsea Oil Production from Chinguetti Field, Mauritania (SPE 133188)


Abstract

The Chinguetti field located west of the Mauritania coastline has recently experienced a slugging condition in its flowline and riser systems. A study was undertaken in which integrated production system models of Chinguetti wells, flowlines and risers were developed using OLGA® transient multiphase flow simulator. The field is at a water depth of ~800m and was developed with subsea wells, manifolds, 2 flexible flowlines and lazy “S” shaped risers tied back to a permanently moored turret Floating Production Storage Offloading (FPSO) located 6km away from the furthest drill centre. The main objective of the study was to assess slugging and potential methods to improve flow stability in the Chinguetti systems.

An extensive field validation and benchmarking exercise was performed by tuning the models to match field pressures and phase flowrates in the systems. The goal was to validate the models as closely imitating the conditions in the field. However, uncertainties in the field data made it difficult to reach satisfactory results in the benchmarking exercise. Simulations were then performed to examine the impact of various changes in operating conditions on flow instability. These included changes in well routings, gas lift injection rates and location of injection points, riser and wellhead choke openings. The degree of fluctuations in liquid arrival rates and the characteristics of liquid slugs (length and frequency) were used to categorize the severity of flow instabilities for a range of operating conditions.

Results from field implementation of recommended changes in operating conditions indicated improvement in flow stability. The success of this study was found to be dependent not only upon the inputs and assumptions made in the production system models but also on the outcome of the field validation exercises, and the understanding of pertinent governing factors influencing slugging behavior. The study highlights the methodology and analysis used to assess flow instability, outcome of field implementation, challenges faced and solutions proposed to minimize the flow instability of a deepwater oil field development.
Observations of Thermal and Pressure Transients in Carbon Dioxide Wells (SPE 134881)

Lincoln Paterson, SPE, and Jonathan Ennis-King, SPE, CO2CRC, CSIRO, and Sandeep Sharma, SPE, CO2CRC, Schlumberger

Abstract

Carbon dioxide wells are different to oil, gas and water wells because large density changes due to transient thermal effects can decouple surface pressure from downhole pressure. This means, for instance, that wellhead pressure can decline while reservoir pressure is building after shut-in of a production reservoir. Similarly the opposite can occur. This presents challenges for the interpretation of surface measurements.

An ability to forecast wellhead pressure is desirable for the optimum design of surface facilities for both carbon dioxide production and injection. The interpretation of surface measurements is also useful for monitoring carbon dioxide reservoirs as flow rates are more easily measured at the surface, and surface gauges are more easily replaced if a gauge fails.

Here we report on detailed pressure and temperature observations involving a mixture of 77 mole % carbon dioxide, 20 mole % methane and 3 mole % other gas components. The measurements are from two wells, one production and one injection, involving both surface and downhole gauges. These two wells when connected can act as a strong siphon due to thermal effects. Thermal transients are observed to last up to two months before the surface response matches the downhole response. The use of two downhole gauges in the injection well allows measurement noise to be separated from real pressure events. This in turn allows the performance of the downhole gauges to be evaluated.

The results are useful for input into the engineering design of future carbon dioxide facilities and the use of surface pressure for interpreting reservoir behavior.
Use of Wellbore-Reservoir Coupled Dynamic Simulation to Evaluate the Cycling Capability of Liquid-Loaded Gas Wells (SPE 134948)

Bin Hu, SPE, SPT Group; Kees Veeken, SPE, Shell; Rahel Yusuf, SPE; Håvard Holmås, SPT Group

Abstract
The regulated intermittent gas production by automated on/off of the wellhead choke, also called “well cycling”, is often the only short-term option that the offshore operators can practice in order to prolong the well production life once they are loaded up by liquid. The field experiences show that many wells can be cycled for quite a long period, but some other wells may have no cycling capability at all. For the wells that can be cycled, the average production achieved by the cycling also depends on whether and how this process is controlled. These bring in a large uncertainty in predicting the field tail-end production.

This paper is therefore concerned with the numerical modeling and simulation of the regulated well cycling. As the process involves both wellbore and near-wellbore reservoir dynamics, an integrated modeling approach is adopted through coupling a transient well flow model to a near-wellbore reservoir model. The coupled model was successfully used to investigate the cycling potential of a 3-km deep vertical well that produces from a depleted cylindrical reservoir of 100 meters in thickness and 560 meters in radius.

The simulation results confirm that the selected well can be cycled for a long period only if the operator pro-actively starts the cycling before the well is loaded up by liquid. The simulation also shows that the average gas production for the selected well can be at least doubled compared with the meta-stable production rate resulting from leaving the choke permanently open, which confirms the advantage of well cycling.

The major observation in this paper may fundamentally change the offshore gas well operation strategy as that the operators may start well cycling once they foresee liquid loading is soon due to occur in their wells. Besides, the simulation procedure presented can provide advices on how to optimize the timing of the choke on/off operation to maximize the average production.
Well Displacement Hydraulics - A Field Case Study and Simulation Investigation (SPE 137342)

Zheng-gang Xu, SPE, Jaimar Maurera, SPE, SPT Group AS, and Christian Shields, SPE, Marathon Oil Company

Abstract

Post-completion cleanup operations had left a seawater filled well that needed displacing to N2 via coiled tubing in order to achieve the desired underbalanced conditions for perforating. The unloading process is not steady state therefore dynamic simulator describing multiphase flow behaviour is essential to properly design and implement a displacement operation. To achieve a successful displacement a balance needs to be struck between CT run-in-hole speed, gas injection rate and the choice between continuous or intermittent gas injections.

This paper presents a field case study of a well displacement operation that only managed to displace half of the wellbore fluids when gas injection was critically interrupted and then after several days of using much higher nitrogen injection rates of up to 2000scf/min made no further significant progress.

The paper describes the application of numerical transient simulation to model the actual CT displacement in order to investigate the failures that occurred and gain a better understanding of how the displacement should have been performed. The predicted and measured parameters were compared to validate the numerical model. Different scenarios were simulated to optimize the displacement procedure. An effective solution to displacing the remaining half of the wellbore was first positioning the CT deep below the liquid level and then initiating gas injection. In this way, the liquid could was effectively lifted out of the well as slugs.

The primary technical contribution of this paper is the application of dynamic simulation (new technique) to optimize fluid displacement using CT and N2 to lift fluids through the annulus with the added complexity of increasing CT and annular lengths with time. Furthermore, it shows the need to move away from the old “rule of thumb” steady state engineering practices.
Investigations of Flow Behavior Formation in Well-Head Jumpers During Restart with Gas and Liquid (IPTC 14592)

Angelina Coletta, SPT Group Pty; Michael Volk and Emmanuel Delle-Case, The University of Tulsa

Abstract

A very important aspect of offshore operations is the risk associated with flow assurance issues, with hydrates the most prevalent of them. The risk of hydrate formation brings the possibility of hydrate plug formation in the line which usually takes a long time to dissociate. Typically, connecting the wellhead with the manifold, the jumper is usually not insulated and has low spot sections where the water can accumulate - making it one of the most critical locations especially during a restart.

During this investigation a jumper-like facility was operated at atmospheric conditions with oil, gas and water to permit the study of different operating parameters. These parameters provided a better understanding of the water displacement during restart to predict the operating conditions that pose the greatest risk for hydrate formation.

The single phase gas restart experiments showed that initial liquid hold-up had minor impact. Variables impacting displacement were the gas restart velocity, density and viscosity of the fluid. In the two phase gas re-start experiments, water cut played an important role on the liquid removal and the fluid properties (viscosity and density) were found to play a more complex role. Overall, gas re-start at lower velocities promoted less disturbance to the water phase whereas higher velocities pose greater risk due to the considerable mixing involved. During the liquid restart experiments - one jumper volume at the lowest tested velocity removed most of the water from the jumper. Higher liquid restart rates were more effective pushing the water out of the jumper, but lower restart rates promoted more mixing.

Results of this project were compared to a commercially available multiphase transient simulator and found to be a match on the overall flow displacement but not on the final liquid content.
Steady-State Modeling For Raton Basin Low-Pressure Gas Gathering System: Workflow Automation For Rapid Well And Pipeline Analysis (PSIG 1126)

Donald Freeman, Pioneer Natural resources; Maria Vielma, Schlumberger

Abstract

Static models have been used in the last two decades to analyze the hydraulic behavior of gas gathering systems. The driving forces for building these models include the need to increase system awareness and enhance production. Building these systems in any production software and keeping them up to date are processes that require expertise and time; the latter depends on the system complexity. Manual data transfer can delay recognition of problems until changes have adversely impacted production. This paper describes the implementation of a systematic workflow to build the Raton basin gas gathering system model in PIPESIM* and to control and automate the model data transfer and optimization through Microsoft Visual Basic® macros. The results demonstrate how the modeling, combined with an automated interface, became an invaluable tool for updating, optimizing, and simulating scenarios for the gas gathering system.
Downhole Chemical Injection Through Gas Lift: Options and Consequences (SPE 142951)


Abstract

Gas lift is being utilized to enhance production of heavy crude from the Campos field offshore Brazil. Downhole chemical injection is implemented to treat the crude and assist with chemical inhibitor delivery to protect the reservoir fluids in the well tubing from corrosion due to elevated concentrations of hydrogen sulfide (H₂S). Due to the absence of dedicated chemical injection lines in the field, H₂S scavenger is diluted in ethanol and transported with the gas lift, through the gas lift line (GLL), to the well casing. The gas lift and aqueous chemical phase flow together in the inner annulus between the casing and tubing as a multiphase mixture. The mixture is then injected into the well tubing through a gas lift valve (GLV). Field measurements have shown the crude is not always uniformly treated with the chemicals due to unsteady discharge of the chemicals from the casing into the production tubing through the GLV.

Advanced steady state and transient simulations were carried out to analyze the supercritical / multiphase flow in the gas lift system. Moreover, the complex phenomena associated with the hydraulic instability upstream of the GLV, and subsequent irregular injection of the multiphase mixture into the tubing, were well-characterized.

Simulation results are qualitatively accurate and descriptive as they duplicate the phenomena observed in the field. It was found that the dynamic stability of the wellbore was disturbed by either insufficient pressure gradients at the GLV or by localized slugging initiated in the casing. As such, chemical accumulation in the casing and intermittent pressure build-up upstream of the GLV were responsible for the non-uniform injection into the well tubing. The system’s dynamic stability can be restored by either increasing the casing pressure to a level high enough so the GLV tolerates normal variations in the casing pressure or by manipulating the flow pattern in the casing to avoid slug flow. Simulation results proved both techniques to be effective.

Field data and simulation results show that GLL may be substituted for chemical injection lines provided the GLV is designed based on a sound understanding of the system’s hydraulics and a reasonable prediction of the operating pressures on its sides throughout the well life.

Findings from this study provide guidelines for proper flow assurance practice and safe design and operation in artificial gas lift and chemical injection applications.
A Systematic Approach to Evaluate Asphaltene Precipitation during CO2 Injection (SPE 143903)

Wan Nurul Adyani, Wan Ata Wan Daud, Nasir Darman (PETRONAS), Afzal Memon, Ifadat Ali Khan, Abul Jamaluddin* (Schlumberger)

Abstract

With declining oil production, the E&P companies are in search of applying innovative methodologies to improve recovery factors from existing fields. Gas injection is one of the most commonly used enhanced-oil recovery techniques in the oil and gas industry. Here, gas such as carbon dioxide, natural gas, or nitrogen is injected into the reservoir. Gas injection relies on the phase behavior of gas and crude oil mixtures that are strongly dependent on reservoir temperature, pressure and crude oil composition. In addition, water is also injected in alternating manner to alter the wettability of the porous medium, and hence improving the sweep efficiency.

Carbon dioxide in combination with alternating water is usually injected in light to medium oil reservoirs in order to increase the ultimate oil recovery. Available data on carbon dioxide injection indicates that an additional recovery of 7% to 15% can be achieved (put reference here). Also, it has been illustrated in the literature that carbon dioxide may cause asphaltenes to precipitate in contact with oil in the laboratory pressure-volume-temperature equipment or in the reservoirs. The asphaltene precipitation mechanism in the porous medium can have serious consequences of blocking pore throats depending on the size of the asphaltene aggregates, and hence, the permeability.

This paper presents a systematic approach and a workflow process to evaluate carbon dioxide miscibility evaluation criteria along with the propensity of asphaltene precipitation in the reservoir for a field located in South China Sea. In this study, measurements were conducted to define the minimum miscibility pressure and also, asphaltene precipitation locus during carbon dioxide injection process. Consequently, these data were used to develop thermodynamic models.
A Current Mapping and Predicting of Indonesia Flow Assurance Challenges Based on Fluid Physical Characteristics (SPE 144639)

Ardian Nengkoda, Schlumberger; Supranto, Hary Sulisty, Imam Prasetyo, Hendra Amijaya, Gadjah Mada University

Abstract

A domain of “flow assurance” is a key concern in the oil and gas industry, and refers to the need to guarantee the flow of oil or gas from reservoirs to processing facilities in the face of a number of engineering challenges, especially in offshore environment. The Indonesian next future exploration and production predicting to be more to deep water offshore, remote production, floating gas production-supply and will face more difficult fluid impurities to be dealt with such increasing volume of produced water, inorganic/ organic scale, mercury and H2S/ CO2. As preliminary, a comprehensive quick review of production and operational problems across the regions both onshore and offshore and PVT fluid data base have been done. These early information on fluid physical characteristics and chemistry can be beneficial to see the potential of tight emulsion, hydrate problems, inorganic scale precipitation or asphaltene/ wax deposition. It is important for flow assurance perspective, to gather all lesson learnt across the offshore production, where these information can be useful for the next future oil and gas exploration and production strategy. As one case, for example, in one of the offshore field in East Kalimantan and Madura East Java, the emulsions were unusual tight where oil-water are difficult to separate and creating a process up set and in the end, creating such lost of production. However, if we look detail across regional geological basin, the emulsion tendency from formation fluids of offshore Kalimantan ever been identified. Furthermore, in the deepwater environment especially, the produced fluids tend to cool significantly, thereby losing the benefit of heat-induced demulsification and causing waxes to precipitate start from downhole, sub sea, trough the surface facilities. The initial base line study have been performed to pick early flow assurance problems base on quick fluid physical characteristic and chemistry from early stage exploration sampling (DST or MDT/PVT). It involves an “integration work flow” of understanding better the physical fluid characteristics from the reservoir and its journey from pore to process facility and it relations to production flow assurance problems. Other important production chemistry and flow assurance issues from Indonesia oil and gas offshore production that being addressed include: gas hydrate, inorganic scale, emulsion, H2S/ CO2 corrosion, reservoir souring (due to waterflood), asphaltene and wax deposition and mercury corrosion. Finally, as a finding, basic reservoir fluid information can be link to the future production problems and flow assurance study has an important role in maximizing the production and minimizing the facility bottle necking.
Impact of Water Hammer in Deep Sea Water Injection Wells (SPE 146300)

Suk Kyoon Choi, SPE, and Wann-Sheng (Bill) Huang, SPE, Chevron Energy Technology Company

Abstract

Water hammer is a known pressure pulse or surge that may occur by the instant shut-in of a valve in a flow line. Sudden momentum change may create a pressure cyclic pulse that could cause damage to valves, bending parts in tubing, and/or joints. Usually this effect has been well managed in surface facility design; however, it tends to be overlooked in subsurface well design. Additional possible impact by water hammer in subsurface wells could be on the sandface completions. The severe water hammer could cause failure of formation integrity, resulting in sand production. It may also damage the wellbore and downhole completions. Especially for deep sea water injection and/or production operations, water hammer effect needs to be thoroughly investigated and properly managed because it could be more severe due to longer flow line and higher flow rate.

The purpose of this study is to have a comprehensive investigation on water hammer effect for an actual water injection well in Chevron’s deep water project with different design parameters and operating parameters. The design parameters include a) height of vertical riser; b) tubing diameter; c) injectivity index (skin or completion type); d) sandface wellbore length; and e) well deviation. The operational parameters include a) injection rate; b) closing time; and c) injection water temperature. Multiphase transient fluid flow model OLGA is used for the water hammer simulation.

Results of the water hammer parameter study for optimum well design and operating strategy are reported here. It is shown that the impact of water hammer can be significantly mitigated or eliminated at well design stage or by adjusting the operating parameter(s).
Abstract

Most reservoir simulations use vertical flow performance (VFP) tables to represent flow in the tubing, which ignores the flow dynamics in wells and their downstream gathering and transportation networks. On the other hand, most dynamic well-pipeline flow models use pressure-rate equations to describe the inflow/injection from/to the reservoir, which ignores the flow and pressure transients in the near-wellbore regions. Obviously, neither of the two types of modeling can account for the transient reservoir-well/pipeline flow interactions that can be of great importance in many operation scenarios.

To bridge this modeling gap, a joint industry program (JIP) was initiated based on a previous successful investigation [1] on the feasibility to implicitly couple a reservoir model to a dynamic well-pipeline multiphase flow model. The aim of the JIP was to deliver a simulation tool that can fulfill the industry's basic requirements on the modeling of transient flow interactions across the sandface, which should also lay the foundation for its future expansion in functionalities. This paper is intended to summarize the outcomes of the JIP.

First of all, the paper discusses the need for integrated dynamic modeling and reviews earlier efforts on building integrated dynamic reservoir-well/pipeline systems. Secondly the paper describes the details of building the reservoir model and how to couple it to a well-pipeline flow model to assure numerical stability and simulation speed for cases of interest. Thirdly, the paper shows the PVT and fluid handling options the integrated simulation tool can provide. These are identical for the two models in order to keep the consistence of fluid properties particularly when the same fluid flows back-and-forth between the wellbore and the near-wellbore during transients.

Two application cases based on the resulting model are presented in the paper. One case is about simulation of chemical squeezement hydraulics for refining the operational procedure, and the other case is about quantification of the pressure gradient in the near-wellbore formation for different well bean-up procedures in order to prevent sand production. The two cases demonstrate the advantages of using the coupled wellbore-reservoir transient modeling.
A Flow Assurance Study on Elemental Sulfur Deposition in Sour Gas Wells (SPE 147244)

Ia Tang, Joe Voelker, Chevron Asia South E&P; Cengizhan Keskin, Zhenggang Xu, Bin Hu, SPT Group; Changqing Jia, China National Petroleum Company

Abstract

This paper summarizes a flow assurance study for elemental sulfur deposition in the tubing for the Chuandongbei Gas Project (CDB), a greenfield sour dry gas development project in Sichuan, China. The project is a co-venture of Chevron and China National Petroleum Company (CNPC). The development contains several fields, all containing dry gas with 8-17% H2S, and 8-10% CO2.

Elemental Sulfur (S8) dissolved in the gas may precipitate in both the near-well reservoir region, and tubing, within the pressure and temperature range predicted for gas well flow in the fields. The precipitate may form gas flow restrictions. An offset operator producing gas from the same reservoir interval and having similar composition has reported flow problems attributed to S8. This study focused on the prediction of S8 deposition in the tubing, during both production and shut-in periods.

Numerical transient well pressure and temperature modeling with the OLGA wax deposition module was used to predict precipitation and deposition of S8 in the tubing. Presently, no other S8 deposition model is available. The model estimates the pressure and temperature gradient between the bulk fluid and tubing wall, and molecular diffusion rates through the laminar sub-layer of the fluid velocity profile. An S8 phase equilibrium model calibrated by measured phase behavior from a laboratory synthetic gas having the composition of CDB field measured surface gases was used to generate the S8 phase diagram.

The study indicates that shut-in periods present the greatest S8 deposition risk: suspended sulfur precipitate accumulates at bottomhole during shut-in periods, possibly forming a flow restriction. Mitigation through solvent treatment applied after shut-in periods is therefore planned. S8 deposition on tubing walls during flow periods was found to present relatively low flow assurance risk.

This study also provides operational design recommendations for well start up, sustained flow, and shut-in periods, as well as flow assurance mitigation design.
Breaking the Frontiers for Effective Flow Assurance using Integrated Asset Models (IAM) (SPE 149537)

Charles C Okafor, Schlumberger

Abstract

It’s no common news were pipelines/facility may be oversized or undersized, due to some certain traditional norms or nominal constraints imposed. When considered with the harsh subsea environments and long tie backs which the industry experiences these days, then it is highly important that the design of the production surface network is optimized efficiently. It could save remarkably millions of dollars. All thanks to advanced modelling approaches, where the concept of integrated modelling has shone brightly.

The traditional methods practiced by the flow assurance engineer involves obtaining reservoir simulation production profiles either uncertainty profiles (P10, P50 & P90) to early, mid and late field life for engineering design/debottlenecking of surface networks. These methods rely heavily on the assumption that those profiles which form the basis of design are healthy for providing boundary conditions for the surface network. In most cases the engineer does not contest/ understand how these profiles were obtained from reservoir simulation and what controls the wells were subjected to. As an example, a natural well could have been subjected to a nominal well tubing head pressure control (staying constant) for about three quarter of its life. This is a major limitation or “gap” in the traditional approach; it could lead to wrong design and estimations of the thermo-hydraulic responses.

In this paper we introduce the concept of integrated modelling for the flow assurance engineer and compare it to the traditional approach. We show three case studies. The first shows a real case where the IAM corrected a design for a North Sea gas condensate field saving millions of dollars. The second shows how IAM aids an engineer in sizing a line with known indicators such as (mean slug length, Erosion velocity) and the third uses the integrated model to identify wax, asphaltenes and corrosion possible areas.
A Benchmark and Optimization of Dead Oil Gasification (BHR 2012-A003)

H. Dong, SPT Group; H. Shi, J. Ross, BP; R. Berger, Manatee

Abstract

One of the most serious challenges in deepwater operations occurs when the reservoir pressure drops too low to support production by the normal operation techniques. To overcome the low pressure challenge during a restart, a gasified dead oil stream can be used as a technique for continuously unloading the production risers. The technique needs to be evaluated and optimized by simulating the unloading process in a transient manner. As the first step, the simulation accuracy is evaluated in the paper for the future oil gasification simulations and for optimizing the operation procedures for oil gasification. Simulations of the sequence actually performed in the dead oil gasification field trial were performed and the simulation results were benchmarked with the field data. The gas/oil ratio (GOR), gas rates and gas ramp-up rates with the surface constraints were optimized to obtain the lowest riser base pressure. The results showed using a gasified dead oil stream can successfully unload the production risers before the restart of production wells. The OLGA model with CompTracking matches well with dead oil gasification field data except with slightly larger fluctuations when the system gets close to slugging region as the gas and oil rates decrease. It can capture the gas absorption and breakout during dead oil gasification, showing better results compared with standard OLGA.
Dynamics of CO₂ Transport and Injection Strategies in a Depleted Gas Field (CMTC 151265)

J. Veltin, S.P.C. Belfroid, TNO

Abstract

As Carbon Capture and Storage slowly gets accepted and integrated as a mean for cleaner utilization of fossil fuels, accurate knowledge of the transport of CO₂ through pipelines and into wells becomes crucial. A representative North Sea transport and injection scenario into a depleted gas field is being analysed in this study through numerical simulations of the flow during steady state and dynamic operation. The balance between gravitational and frictional pressure drop is being described in details for this specific case, with a focus on the operability of the transport system. Dynamic simulations during an Emergency Shut Down are being analysed, exhibiting very low temperatures at the wellhead that could require the addition of a heater or of a low temperature tubing.
Experimental Study on Wax Deposition Characteristics of a Waxy Crude Oil Under Single Phase Turbulent Flow Conditions (OTC 22953)

Priyank Dwivedi*, Cem Sarica and Wei Shang, The University of Tulsa, *Currently with Schlumberger Corp.

Abstract

Crude oil, having a paraffin nature, has been studied extensively in the small-scale flow loop at Tulsa University Paraffin Deposition Projects (TUPDP). The effects of turbulence/shear and thermal driving force on wax deposition characteristics were experimentally studied using a waxy crude oil from the Gulf of Mexico. The test matrix consisted of a total of 15 experiments which include 12 short term tests and 3 long term tests. The tests were conducted under different operating conditions with a wide range of Reynolds numbers from 3,700 to 20,500. The shear stress ranged from 5.4 to 53.9 Pa.

It was observed that paraffin deposition is highly dependent on the thermal effective driving force which is the temperature difference between oil bulk and initial inner pipe wall and also on turbulence effects. The deposit thickness obtained using both the pressure drop method and a direct measurement was found to decrease with increasing shear stress and decreasing thermal driving force. The wax content showed a gradual increase with an increase in flow rate. For the short term tests, the deposit mass with no entrained oil seemed to increase and then decrease with an increase in initial shear stress and decrease in effective thermal driving force whereas the total deposit mass was found to decrease with an increase in initial shear stress or decrease in effective thermal driving force.
A Modelling Study of Severe Slugging in Wellbore (SPE 150364)

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Abstract

Developments in extended reach drilling and completion technologies allow to economically access a number of scattered small hydrocarbon pockets and will open up further opportunities for maximizing recovery from these fields. Effective use of these developments requires us to better understand the transient multiphase flow behaviour.

Undulation is associated to horizontal wells with some degrees of deviation from the horizontal. The inclination angle could be a result of a lack of sufficient drilling control or could be designed on purpose, for instance, fish-hook wells, snake wells and undulating wells. A complicated and undulating trajectory may initiate severe slugging at the bottom of a wellbore. In this paper, OLGA, a commercial transient two-fluid multiphase flow simulator, and Cheng’s inflow performance relationship were coupled together to characterize severe slugging. Simulation shows that severe slugging is formed at the bottom of the wellbore and moved up to the surface. Furthermore, it creates pressure pulsation at the bottom of the wellbore that can influence the reservoir performance.
A New Approach to Calculate Pressure Drop for Three-Phase Flow in Pipe (SPE 151537)

Kegang Ling, SPE, University of North Dakota, He Zhang, SPE, Texas A&M University, Guoqing Han, SPE, China University of Petroleum (Beijing), Zheng Shen, SPE

Abstract

Multiphase flow in pipe has been intensively investigated since the onset of oil and gas transportation by pipelines. As flow assurance problems keep arising in recent years, pipeline design solutions are desired for multi-phase flow system. The algorithms have widely guided the design of stream transportation from offshore well head to onshore terminal or platform. Operators would always seek cutting platform number or shut-in producing marginal field whose reserves cannot justify the construction cost. An accurate design of multiphase flow pipeline system is by all means demanded.

Traditional studies focus on gas-oil two-phase flow by deriving empirical or semi-empirical correlations that fit the experimental data. This study investigates a gas–oil–water three-phase pipe flow system. Starting from the momentum and mass conservation equations, force balance, and interaction relationships between different phases, we developed analytical solutions to estimate the pressure drop for stratified flow regime. This general approach can be applied to any gas-oil-water flowing systems. It provides a solid base for nodal analysis, pressure drop calculation for multiphase flow, artificial lift evaluation, etc. to help design and optimize production system. This work can be particularly useful for steady-state distance transportation.
Sizing of Gas-Condensate Pipelines Using Multiphase Dynamic Simulation, Based on Minimum, Medium, and Maximum Flow Rates (SPE 153426)

V. Martinez-Ortiz, SPT Group

Abstract

In this paper a methodology based in multiphase dynamic simulation to size gas-condensate pipelines is presented. This method considers minimum, medium and maximum forecasted field flowrates. Sizing the pipeline considering only the maximum flowrate can result in oversizing the pipeline diameter. An oversized pipeline can cause operational problems when the field’s production declines. The multiphase dynamic simulation allows evaluating the flow stability for minimum and medium forecasted flowrates, where the steady state condition may not be defined.

In this paper, this methodology was applied to size a pipeline in South America’s gas condensate fields. Previously, these pipelines were oversized using only steady-state tools.
Dynamic Simulation Applications to Support Challenging Offshore Operations: A Kitan Field Offshore East Timor Case Study (SPE 156146)

Ryosuke Yokote and Vanni Donagemma, Eni Australia and Juan Carlos Mantecon, SPT Group

Abstract

This paper describes the use of multiphase flow numerical transient simulation to assist a petroleum engineer in making proper critical decisions during supervision of well cleanup operations on a rig, and initial well startup operations on a Floating Production Storage and Offloading facility (FPSO).

Eni JPDA 06-105 operates the Kitan oil field located in the Joint Petroleum Development Area (JPDA) between East Timor and Australia. The Kitan oil field consists of three subsea intelligent wells, subsea flowlines, risers, and one FPSO. The three wells were completed and cleaned up using the rig before the FPSO arrived on location.

The intelligent completions were modeled in detail using commercial dynamic simulation software to establish a sound and safe operating procedure for the well cleanup and well test. The simulation results provided the petroleum engineer on the rig with key operational information, such as the time for the oil to arrive at surface, expected pressure at the down-hole gauges (DHGs) and upstream of the choke manifold, etc. This enhanced the ability of rig site supervisors to anticipate well behavior, enabling a significant risk reduction.

The well models were successfully validated with the data obtained after the well cleanup and well testing campaign was finished. The validated well models were integrated with flowline and riser models to investigate the optimum field startup operations and to overcome constraints in the production system which emerged late in the project. Different topside choke and multi-stage hydraulic down-hole flow control valves (FCVs) opening schedules were tested to predict pressure and temperature at the DHGs, the subsea tree (SST) and the FPSO, as well as the flow rates and oil arrival time at the FPSO.

The dynamic simulation results played an important role in defining a sound and safe operating procedure for the well cleanup and well test, and initial field startup, providing the offshore petroleum engineer with reliable operating guidelines.
Using Dynamic Simulations to Predict and Optimize Cleanup Operation of Horizontal Gas Wells (SPE 158026)

Khairul Azmi, Ogbonna Christopher, Maharon Jadid, PCSB, Rahel Yusuf, SPT Group

Abstract

Cleanup operations of gas wells are conducted when the well is kicked off and tested the first time. During cleanup, the drilling and completion fluids come out of the well along with the produced gas and associated liquids. The phenomena is transient in nature and minimum gas rate and time required for cleanup are key questions to be answered before embarking on the cleanup and subsequent well test operation. The knowledge of minimum gas rate and time required for cleanup can assist the engineer in deciding the well test package and make best use of the available time.

In the current study, transient simulations of cleanup and MRT of three horizontal gas wells are conducted using a commercial multiphase transient simulator. Before the actual cleanup operations, simulations were conducted to estimate the cleanup time and to arrive at optimum breamup procedure to achieve best cleanup for a maximum gas rate constraint of 60 MMscf/D which is dictated by the size of well test package. After the cleanup and MRT operations were conducted, the operational data was used to tune the model. It was observed that the predicted temporal variations of gas rate and gauge temperature and pressure from the tuned model were in very good agreement with the measured values. The tuned model was then used to ascertain the degree of cleanup achieved from the actual cleanup and MRT operations and the model predictions showed that except the last 60 metres from the toe, the wells were completely cleaned of completion fluid. The poor cleanup in the last 60 metres was possibly because of 60 MMscf/D gas rate limit imposed by the size of well test package or resulting from poor contribution from the near-toe area.

The study brings forth the significance of dynamic simulations in predicting and history matching gas well clean up operations and how dynamic simulations can provide an insight into the pressure and flow transients during cleanup. The knowledge gained from dynamic simulations can assist the engineer in deciding the well test package for gas wells to be cleaned up and in quantifying the cleanup achieved from an already conducted cleanup operation.
The Use of a Transient Multiphase Simulator to Predict and Suppress Flow Instabilities in a Horizontal Shale Oil Well (SPE 158500)

H. Lee Norris III, SPT Group

Abstract

Due to its limited drainage radius, the sand face pressure in a hydraulically fractured, horizontal shale oil well will fall rapidly with cumulative production. Once the sand face pressure falls below the bubble point, flow instabilities will increase dramatically. The onset of instability can be predicted using a transient multiphase simulator such as OLGA1, and techniques to minimize instabilities can be quantitatively investigated through simulation. This paper describes flow instabilities in a typical horizontal shale oil well and demonstrates both causes and remedies for fluctuating production rates in the intermediate and latter stages of well life. Through the suppression of production instability, the ultimate recovery of reserves may be significantly increased.
IV. MONITORING & SURVEILLANCE

SPE 100133  2006

Application of Artificial Intelligence in Gas Storage Management (SPE 100133)

G. Zangl, M. Giovannoli, and M. Stundner, SPE, Schlumberger

Abstract

An approach is investigated, to reduce the amount of CPU time needed to execute a numerical full field model in an optimization loop.

To demonstrate the power of this approach, a real life example is presented. Data from a gas storage reservoir have been used to setup a single tank material balance program. Then, a limited number of simulation runs is carried out. These simulation runs are intended to span over the whole range of input parameter variation (app. 25 runs).

In a next step, a Neural Network (NN) model is setup. By training a Neural Network on the so gained simulation outputs, a model, which is able to interpolate between the individual simulation scenarios is created. In this way, a large variety of different scenarios can be represented with a limited amount of model runs.

The trained Neural Network model is used as a proxy function for an optimization routine. The trained Neural Network has been used as fitness function for the Genetic Algorithm to minimize the output parameter, which is in this example the RMS-error of measured and calculated tank pressure. Due to the very low CPU consumption of the Neural Network, a large number of realisations can be calculated in a short amount of time. By this, the absolute minimum of the desired output parameter (in this case the RMS-error) can be evaluated in a few seconds.

The Genetic Algorithm has succeeded to find a minimum, which is located very close to the absolute minimum of all possible solutions.
Automatic Surveillance System for Large Gas Fields with Multifrequency Measurements (SPE 110401)

M. Mota, SPE, O.M. Campos, SPE, H. Escalona, and L.D. Teran, Schlumberger, and G. Sandoval, Pemex

Abstract

This paper presents the results of an automatic surveillance system implemented by PEMEX for one of Mexico’s largest gas fields. Activo Integral Burgos (AIB) is a typical example of large gas field where production declined due to gas-loading backpressure and reduced permeability in the target formation. The fast decline of the gas wells during their first year of production drove a change from reactive into proactive management tactic to monitor the field and to select candidates for workovers. However, the large number of wells in AIB (approximately 2000 active wells) and the fact 95% of data is manually captured made the implementation of automatic surveillance particularly challenging.

We introduced an automatic surveillance solution that synchronizes the data collected daily in more than 200 wells. Conventional production tools, including Nodal modeling, Turner’s equation, Decline Curve Analysis, or Pressure Survey, were individually validated and subsequently implemented as a sequence of automated routines to process the data over the entire field. The data was then analyzed using a self-organizing-map engine to automatically identify wells where fluid loading impedes production. Daily production rates were also computed using nodal models automatically updated with operational data for each well.

The integration of tasks including production data gathering and standardization, monitoring, reporting and alarm functionality, was a key element for the successful and efficient management of gas-loading problems at the field scale. Milestones achieved with this implementation included the automatic identification of problematic wells and a reconciliation of the production rates measured at the gathering stations with rates calculated at the well level.

This surveillance methodology offers new perspectives for the proactive management of wellbore liquid-loading problems in large fields with very limited data stream. The early-stage diagnosis of problems enables the operator to make decisions in record turn-around times and extends the productive life of the wells beyond initial expectations.
Remote Real Time Well Testing - Experience in the Grove Gas Field in the North Sea (SPE 127909)

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Abstract

Accurate well test data acquired throughout an appropriately designed test program is critical to confidently characterize a reservoir. Achieving this requires the right DST string selection or completion and stimulation designs, surface test set up / facilities, and the ability to rapidly handle dynamic changes in flow regimes. Well testing is inherently complex due to the interaction between these various elements. “Successful failures” in well testing is unfortunately not uncommon and results from each element of a test performing as per standards, but losing focus on achieving the ultimate objectives. The remote participation in operations of expertise that designed the test is becoming increasingly important in achieving test objectives, in particular in geologically complex structures, low-deliverability formations, reservoirs with high flow rate wells, or environmentally challenging conditions.

Technological developments have enabled improved monitoring and controlling of advanced well testing equipment often now with multiple data acquisition systems. For increased accuracy in highly dynamic test environments, well tests are also performed using multiphase flow metering alongside separators specifically designed to increase handling and separation efficiencies with separate acquisition systems. Remotely located experts are now able to validate and evaluate data in real-time, 24/7, with flexibility to change acquisition and test programs to ensure that objectives are achieved.

Real-time access and remote connectivity were provided during gas condensate testing of three North Sea wells in the Grove field. This paper describes the value of real-time services where the test program required continuous data quality assurance and rapid real-time evaluation onshore. This paper also demonstrates how real-time collaboration of personnel at multiple sites was crucial in carrying out a successful pressure transient analysis and a complete interpretation, both of which helped achieve the test program objectives within the planned test duration.
Recent Developments in Control and Monitoring of Remote Subsea Fields (SPE 128657)

Bjørn Bringedal, Espen Storkaas, Morten Dalsmo, and Marius Aarset, ABB, and Hans Marius With, SPT Group

Abstract

Two trends in development and operations of offshore oil and gas installations give increased demand for real-time monitoring and control; number & reach of subsea tie-ins and emerging implementation of integrated operations solutions. Within integrated operations, remote operation and collaboration between onshore and offshore are key elements. Sophisticated monitoring and control applications for wells and pipelines have been available from several vendors for some time. However, these applications have generally been stand-alone expert applications connected to a single subsystem, for example, a slug control solution for pipelines located in the plant control system or a virtual flow metering system for wells located in the subsea (control) system. The usage and benefit of these systems have therefore been limited. This paper outlines how monitoring and control applications for gathering networks should be structured in an integrated operations framework, and which benefits this will give for operators.

Structuring of the different applications ensures that data from monitoring applications are easily available for a large group of users while ensuring that closed-loop control applications retains the robustness and security that is required. Furthermore, recent developments of the applications itself, partially made possible by the modern integrated operations system topology with increased data availability, provides additional functionality not only for expert users, but for generalists as well. Finally, synergies between different monitoring and control applications can give additional value to the users.

Control and monitoring for remote subsea field in an integrated operations framework offers benefits such as faster decision making processes, increased production, improved deduction testing, condition monitoring of sensors using a combination of virtual metering and process data.

The paper outlines the status and future development trends for control and monitoring applications for subsea fields, illustrates the value of the technology and gives recommendations for implementation.
Abstract

This paper explains the development and implementation in the Schlumberger artificial lift real-time surveillance center of a workflow to track ESP alarms from their initial identification through their classification to the analysis of their root-cause. The workflow uses a QHSE database with Web access to enable collaboration between the surveillance center and field locations throughout Europe and Africa. Of more than 700 alarms which were substantiated over an 18-month period, over one third were classified as “critical”, i.e. if no actions were taken, an Electric Submersible Pump (ESP) failure could potentially ensue. As such, real-time surveillance was seen to contribute to an increase in ESP run life, firstly, by preventing the ESP from being misoperated and experiencing excessive stress, and secondly, by using the alarm classification as the basis for service quality reviews to promptly identify remedial action items.
Successful Implementation of InterACT (Real Time Data Transmission) in Testing Services To Allow Remote Witnessing of Testing Operations and Multipoint Collaboration (Latif Gas Field - A Success Story) (SPE 142840)

Tofeq Ahmed, Moien Siddiqui, Amjad Hussain, OMV Pakistan Exploration GmbH; Chia Boon Shin, Asif Hussain, Zia Nabi Butt, Rao Nouman, Schlumberger Seaco Inc.

Abstract

Secure monitoring of well site operations via Internet has made a significant impact on how oil and gas companies plan and execute their operations. InterACT is web-based application used to witness and deliver well site data in real time using a reliable Internet hub. InterACT in Testing Services is enjoying a number of advantages which can be summarized as below:

- Allow immediate and better decision making with rapid data interpretation and remote expert support.
- At any time during or after the test, data can be downloaded and imported into E&P software tools for further analysis, and their results and reports can be posted back unto the InterACT hub.
- Reduce costs through optimized cleanups and shorter well tests.
- Reduce travel and logistical costs, as well as HSE exposure.
- Enable remote operations with limited local support.
- Provide data confidentiality with secured login and continuous encrypted transmission.

Data from DART, Vx Multiphase flow meter, events, real time plots and any other data useful for operations can be monitored at bases and offices of E & P companies especially for exploration and remote location wells for expert’s opinion and making timely decisions. Theme of this paper is to demonstrate different steps to design and plan InterACT job on an exploratory well of OMV Pakistan. It also describes successful implementation of InterACT technology which was introduced first time in Pakistan and its advantages for Exploration and Production (E & P) companies.
Use of a Parallel System For Improving Subsea Intelligent Well Control, Monitoring And Reliability (SUT SCADA 10-65)

Gregor Deans and Derek Chaplin, Schlumberger Subsea Surveillance

Abstract

The issue of improving monitoring and control of subsea completions while maintaining high reliability is critical due to accessibility and intervention costs. Hydraulic control of the downhole choke valves in multiple zones can be complex, and the situation is further complicated by the fact that traditionally different companies supply the downhole completion equipment and the tree control system at the wellhead. This can lead to less production data being available, reduced control functionality and valve control logic issues. Additional interfacing requirements also lead to an increase in costs for a project.

This paper details the design approach, application and advantages of a dedicated intelligent well completion (IWC) control system for subsea fields. It also reviews the methodology and issues related to the integration of the control system within an existing field development in the North Sea.

The proposed system has an electrohydraulic control module, provided by Schlumberger, mounted on a subsea production tree, which provides complete control and monitoring of the intelligent well independent from the tree control system. This approach allows the intelligent well subsea control system to be tailored specifically for the completion equipment and well type. It also provides additional protection to the tree control system from control line thermal expansion and the potential of leaks.

The subsea solution selected by the client aims to reduce the loading and project-specific customisation of the production critical tree control system. This will allow it to be standardised while still providing maximum performance and flexibility for monitoring and control of the well. This approach permits a single supplier, in this case Schlumberger, to manufacture and test the complete intelligent well control and surveillance system from surface to the subsea well prior to delivery and the site integration test (SIT). This reduces the overall project risk and avoids interface issues being detected late in the project phase.
Abstract

In this paper we present a fully integrated pipeline and flowline integrity monitoring system. The system uses optical-fiber distributed sensors to provide simultaneous distributed measurements of temperature, strain, and vibration for the detection, monitoring, and location of events including

- third-party interference (TPI), including multiple simultaneous disturbances
- riser strain, pipeline buckling and upheaval, geohazards, landslides, and ice scour
- Vortex-induced Vibration (VIV)
- flow assurance and distributed temperature monitoring of heated pipelines
- gas and oil leaks
- permafrost protection.

The technology also provides a unique means for tracking the progress of cleaning and instrumented pigs using existing optical telecoms and datacoms cables buried close to pipelines.

The solution provides a unique and proactive approach to pipeline integrity management. It performs analysis of a combination of measurements to provide the pipeline operator with an event-recognition and location capability, in effect providing a hazard warning system and offering the operator the potential to take early action to prevent loss. Through the use of remote, optically powered amplification, an unprecedented range of 100 km is possible without the need for any electronics or therefore remote power in the field. A system can thus monitor 200 km of pipeline when configured to monitor 100 km upstream and downstream from a single location.

As well as detecting conditions and events leading to leaks, this fully integrated system provides a means of detecting and locating small leaks in gas pipelines below the threshold of present online leak-detection systems based on monitoring flow parameters. Other significant benefits include

- potential reductions in the construction costs of new pipelines
- enhancement of the operator’s existing integrity management program
- Potential reductions in surveillance costs and HSE risks.

In addition to onshore pipeline systems, this combination of functionality and range is available for practicable monitoring in a wide range of other applications, such as

- the monitoring of long subsea flowline for flow assurance, leak detection and movements such as ice scour
- flexible riser integrity monitoring
- strain and shape monitoring of offshore riser and umbilical systems
- Facilities perimeter security.

An important element of this system is a bespoke direct-bury optical sensor cable, designed to allow distributed strain measurement and hence enable monitoring of ground movement whilst withstanding the rigors of pipeline environment. The system can also be configured for detection of third-party interference and leaks with the majority of existing buried onshore cables.
Improving ESP Life Time Performance Evaluation by Deploying an ESP Tracking and Inventory Management System (SPE 144562)

N. E. Bougherara; K. Si Ahmed and H. A. Algdamsi, SPE, Schlumberger

Abstract

One of the most popular and efficient artificial lift mechanisms is the electrical submersible pump (ESP). According to recent statistics, there are more than 100,000 ESPs worldwide. With the increasing number of wells equipped with ESPs, operators are making substantial efforts to improve ESP performance and achieve longer runlife. The primary focus has been on tracking ESPs sensors real-time data, along with failures prediction as proactive measures. It is however, still difficult to keep track of historical ESP pull and run jobs, ESP equipments, and benchmark pump runlife. Typically there are no structured datastores for ESP movements. ESP runlife statistics are stored in multiple individual spreadsheets and are resource-intensive to compile.

This paper presents a solution that enables to track within database software ESP operations, equipments movements and failures along with classical production data to enable better ESP lifetime evaluation and equipments management. The solution encompassed ESP operations and equipment tracking within a next-generation production volumes management system. The software and database were expanded to ensure that data was generated through a single point of reference, so that operators could capture and store downhole and surface equipments tracked via serial-number along with operations details and failures. ESP runlife, failure and equipment statistics were also calculated and reported graphically. More accurate ESP lifetime was calculated using well production uptime, installation and pull dates. Using these key statistics, the asset team was able to benchmark equipments and vendors. Each time the team needed to design or redesign an ESP, the solution enabled them to browse current and historical production, ESP operations, and both installed and warehoused equipments data. Used equipments historical installations can be tracked to make informed decisions before any reinstallation in other wells. In addition, the solution allows through reports to track wells with longer pull operations time providing input to improve rig workover planning. In summary, the proper capture, validation, data browsing, and accurate performance evaluation enabled by the pilot solution reduced routine work time, positively impacting the asset team. More time could thus be dedicated to recurrent problems identification, in-depth investigations for remedial actions for underperforming ESP wells.
Obtaining Real-Time Flow Rate, Water Cut, and Reservoir Diagnostics from ESP Gauge Data (SPE 145542)

Lawrence Camilleri, SPE, and Wentao Zhou, SPE, Schlumberger

Abstract

Routine testing of wells with electric submersible pumps (ESPs) is usually conducted monthly to monitor liquid rates, water cut (WC), and gas/oil ratio (GOR). This monthly testing is the most common form of production and reservoir surveillance and is implemented in even the most mature fields where cost control generally takes precedence over reservoir surveillance.

However, this technique has its limitations. The most common limitation is insufficient testing duration to capture a representative sample of reservoir fluids. This testing duration issue is often the case in low-flow rate and deep wells, which require several time-consuming whole or complete liquid holdup periods. Other potential problems include insufficient resolution or repeatability to identify trends in liquid and water-cut rates over short periods of time. To date, the only method for resolving these issues has been to install permanent multiphase meters on each well. Although this method has been implemented in some fields, it is uneconomical for most wells. An analytical method is described for a flow rate calculation that can be implemented in wells produced with ESPs and equipped with downhole gauges and real-time monitoring systems.

These downhole gauges and real-time monitoring system provide continuous real-time virtual flow rate measurements and therefore, both liquid and water-cut trends, which deliver the required resolution and repeatability to support both well performance diagnostics and near-wellbore reservoir analysis. This technique, which has the advantage of being valid for both transient and steady-state conditions, provides instantaneous flow rate data when used with real-time data. Case studies presented will illustrate model calibration and its application to back allocation and transient analysis. Examples are provided to show how the data can be used to rapidly identify changes in productivity index and reservoir pressure across the drainage area; thereby, enabling real-time production optimization.
Permanent Distributed Temperature Sensing (DTS) Technology Applied in Mature Fields - A Forties Field Case Study (SPE 150197)

Craig Costello, SPE, Peter Sordyl, SPE, and Cledwyn Hughes, SPE, Apache North Sea Ltd.; Martin Figueroa, SPE, Emmanuel Balster, SPE, and George Brown, SPE, Schlumberger

Abstract

Permanent distributed temperature sensing (DTS) using fiber-optic technology provides measurements over the complete length of the fiber in the wellbore. The temperature profiles can be monitored at surface in real time, minimizing the need for production logs, preventing deferred production losses, decreasing well interventions, and reducing operating costs. This technology has been applied by Apache North Sea Ltd in the Forties field to monitor and optimize the performance of two wells producing by gas lift in the Delta platform and, at the same time, examine their completion integrity.

To accomplish these objectives, a hybrid fiber-optic electrical cable was installed in two Forties wells, allowing the continuous measurement of temperature and acquisition of pressure data from a downhole gauge located below the deepest gas-injection point. The combined benefit of reducing both the number of well interventions, and thus eliminating the associated QHSE risks, and the operating costs made this well monitoring strategy the appropriate one in this mature field.

The analysis and interpretation of downhole pressure and DTS data provided rapid feedback to the platform production team regarding the status of the well, allowing a better and more informed decision-making process.

In this paper, we outline the deployment of the hybrid DTS system and describe the analysis performed in each of the two wells. Data handling, analysis, and interpretation are described as well as the methodology and workflow for well monitoring and optimization using permanently installed DTS.
Total Asset Surveillance and Management (SPE 150813)

E. Wokoma, G. Okuns, and F.E. Idachaba, Shell Petroleum Development Company of Nigeria; and P. Edghill, A. Pickburn, and O. Ashion, Schlumberger

Abstract

This paper presents the report of a pipeline intruder detection system using the Optical Time Domain Reflectometry (OTDR) based Distributed Vibration Sensor technology (DVS). A 12 km optic fiber cable was buried under a 0.9m thick slab of concrete buried 1.6m deep along an SPDC 18‖ pipeline within the pipeline right of way (ROW). The application of the OTDR was to detect some predefined types of intrusion (walking, digging, driving, etc.) normally associated with vandalism and bunkering activities along the pipeline ROW. The system was able to identify with sufficient signal clarity:

- the footsteps of a man weighing about 80kg walking up to 3m near the buried sensor,
- digging activities at about 3m away from the optic fiber cable,
- a moving herd of cattle crossing the pipeline ROW from 15m to the ROW, the presence of a wheeled 4x4 vehicle 10m away from the buried cable and a 5 ton truck 50m away from the cable was also detected.

The results were displayed on a graphical user interface with different colour codes for each intrusion event or category. The system was found to be able to detect the different possible types of intrusion activities prevalent around pipelines. The concrete slab was found to have minimal effect on the sensitivity of the optic fiber with respect to its ability to detect intrusion activities up to 5m from the optic fiber cable, but for areas without the concrete slab, the system sensitivity much better, hence the received intrusion signal strength was found to be very high. This system can be deployed along our pipeline ROW to provide intrusion detection for SPDC pipelines and provide an early warning system for malicious intents on the pipelines.
Production Monitoring Using Artificial Intelligence (SPE 149594)

G. Olivares, PEMEX, and C. Escalona, SPE, and E. Gimenez, SPE, Schlumberger

Abstract

The Litoral de Tabasco asset, in PEMEX’s southwest marine region, was initially implemented to monitor and estimate the flow rate of naturally flowing wells, using daily operational conditions and well tests with the so-called Gilbert and Ashford and Pierce correlations.

The effectiveness of these correlations has now been reduced as a result of irregularities in operational conditions; lack of consistency in conducting the production well tests; limited availability of measurement and operational issues with mass, conventional, and multiphase flow meters; and ongoing problems with electronics communication, nonavailability of vessels, and high operational costs. If the operational conditions measured during the well tests were wrong, all the properties are suspect and may have affected the correlations developed in determining the estimated volume per well and associated monitoring workflow.

To address this problem, a new workflow using a set of predictive proxy models has been developed that combines artificial intelligence techniques such as neural networks with nodal analysis, and sporadic and high-frequency data to allow engineers to process and understand production behavior from the large amounts of information available, which are gathered according to the system being studied or evaluated.

This workflow enables validation of field well test data, which reduces the uncertainties in well production allocation, increases the accuracy of hydrocarbon accounting from the pumping process to the marine terminal, and implements an early detection system for anomalies that is published on the Internet for sharing with the entire asset management.

Now, when it is not possible to measure well production, the outputs of a proxy model and a nodal analysis are combined with sporadic and real-time data to reconstruct the historical and actual volume on a daily basis.
Innovative Work Scheme: Real Time Analysis During Well Test Operations (SPE 150142)

A. Ferreira; J. Vidal; R. Abi-Ramia; I. Jouti; S. Flores SPE OGX; D. Essenfeld; J. Cañas; F. Rey; G. Landinez, P. Maizeret; G. Villanueva; J. Cabanilla; R. Alves SPE Schlumberger

Abstract

In 2007, a new Independent Brazilian Oil and Gas company acquired 21 exploration offshore blocks, increasing its portfolio up to 29 blocks by March 2009. Ambitious exploration and production goals were set, such as Drilling Commencement by Q3 2009, Minimum Well Drilling Commitments in four Basins by 2010/11, Initial Development in the Campos Basin and First Oil by 2012. The first three initial goals have already been met and the fourth one is well online to be met as expected with the FPSO already in the Brazilian coast.

One of the key elements to reach these objectives is recognized to be the implementation of a focused innovative decision workflow, supported by a real time monitoring process from a cross-disciplinary Operations Support Center (OSC). This paper presents this innovative work scheme, based on a collaborative working environment between the operating and service companies during the well testing operations, with the most advanced monitoring and interpretation tools.

It includes a concrete field case which resulted not only in improved risk identification, prevention and mitigation, but also in operational performance optimization.

This case was a horizontal open hole test of 1080 mts with 90 deg deviation. The real-time collaboration resulted in significant rig time savings, mitigation of unexpected events consequences, and delivery of higher productivity comparing similar wells results in the area.

This innovative decision workflow implemented in Brazil is considered as a high-technological reference model for operating companies, locally in Brazil and others around the world, to achieve success during challenging Well Testing operations.
Pelican Lake Surveillance: Polymer Flooded Heavy Oil Reservoir (WHOC12-413)

A. Valentine; M. Mohajer, Schlumberger; C. Alpaugh, Cenovus Energy

Abstract

Pelican Lake is one of the largest polymer flooded fields in the world, producing about 63,000 barrels of oil per day from the Wabiskaw formation in the Athabasca oil sands region of northern Alberta, Canada. The operational focus of this field, which has been developed with long-reach horizontal wells, is on increasing heavy oil production using infill drilling and advanced oil recovery techniques. The original oil in place is estimated to exceed 6 billion barrels.

Although the majority of fields in this region are successfully produced by steam-assisted gravity drainage, Pelican Lake presents a greater challenge technologically because of the unique characteristics of the reservoir; i.e., average net pay of 9 feet, high permeability, and viscosities ranging from 800 to 80,000 centipoise. The field is being produced by a combination of waterflood and polymer flood programs. As a result of the high number of wells (~2,200), a massive amount of available data, and high level of activities (up to 300 wells drilled per year), data-driven techniques are used by the companies operating in this field to monitor production, choose infill drilling locations, forecast rates, and analyze performance.

In this paper, using public data, we review the development history of the field, including the pay and viscosity of each area of the field, the various well spacings and polymer locations that have been tried, and success to date. We also comment on the effect of the polymer on the mobility ratio. Based on our observations of this public data we demonstrate the viability of conventional Waterflood surveillance techniques, propose additional techniques, and show how they can be used to meet the unique requirements of this field.
A Simulation Framework for Multi-Scenario Production Forecasts in the North Kuwait Jurassic Complex (SPE 127595)

Kassem Ghorayeb, SPE, Schlumberger, Rafi Mohammad Aziz, SPE, Kuwait Oil Company, Rick Penney, SPE, Schlumberger, Qasem Dashti, SPE, Kuwait Oil Company

Abstract

The North Kuwait Jurassic Complex (NKJC) consists of six fields with four potential reservoirs in the Jurassic age naturally fractured carbonate formation. Current understanding of the complex, has led to 12 subdivisions of the area and potentially 48 separate compartments (segments) in the complex. These subdivisions are defined by fault boundaries supported by a combination of variations in fluid composition, initial pressures and free water levels estimated from capillary pressure and log saturation data.

Multi-scenario production forecasts based on integrated full field modeling were needed in the process of building a Field Development Plan (FDP) for the NKJC. An integrated Asset Modeling (IAM) framework is adopted where multiple separate reservoir models (up to 48 models) are coupled through global constraints in order to meet gas delivery targets. The solution uses a black oil delumping technique to obtain compositional wellstreams while running black oil simulation models. The adopted simulation framework provides us with all the benefits of a compositional full field simulation model while topping-up with two advantages i.e. computational speed and flexibility.

We discuss the impact of the IAM solution on the selection of the optimal development scenario given that these fields are in the early stages of production via an early production facility on line in 2008. Coupling of all fields/segments allows optimization over the entire production system rather than optimizing each field individually. This reduces the number of wells required to meet targets at any one time under any reservoir realization, while also staying within the surface network constraints.
Abstract

Production from shale gas reservoirs has formed an increasingly large part of the U.S. natural gas mix in the last few years. More than half of the rigs in onshore U.S. will be drilling horizontal wells with a large majority in shale plays. Within the last year, shale gas plays have dominated the onshore U.S. natural gas drilling activity, with this boom occurring during a time of economic uncertainty. However, skepticism has recently been placed on shale gas production decline trends from consultants and investment firms, where estimated ultimate recoveries (EURs) and the overall economic feasibility of shale gas plays have been brought into question.

EURs of shale gas wells have been forecast in a number of ways within the industry. Some entities have been calculating EURs based on initial production rates (IPs). Others are applying the decline trends established in one basin to a different newer basin with less production history. In other cases, two different operators may use different trend types in wells that are in the same location.

This paper seeks to more accurately assess the decline trends and EURs of these shale plays, if the decline trends are improving, and what returns are required to make a well economically feasible. This study compares the production trends of horizontal wells in the Barnett, Fayetteville, Woodford, Haynesville and Eagle Ford shale plays, analyzing each over time to determine if there have been improvements to production. Where applicable we address the impact that technology has made in this enhanced production. Furthermore, the decline trends of horizontal shale to horizontal tight gas sandstone plays are examined to look for differences and shed some light on potential EURs.

The results of the analysis helped establish which decline trends could be used to determine the EUR of these horizontal shale wells, or if a better methodology may exist. A basic economic analysis to estimate breakeven gas price for an average (P50) horizontal well in each play was performed.
Production Allocation in Multi-Layers Gas Producing Wells Using Temperature Measurements (SPE 139261)

Reda Rabie, SPE, Ahmed Daoud, SPE, El-Sayed El-Tayeb, SPE, Mohamed Abdel Dayem, SPE, Cairo University

Abstract

We present a methodology of allocating gas rate and associated water to each individual layer using temperature measurements and total surface production of gas and water. This paper consists of two parts. In part one; we propose an analytical forward model for wellbore temperature response under two-phase production in a multilayer geometry, using a nodal representation of the well. This model accounts for the formation geothermal gradient, steady-state gas-water flow in the wellbore, friction loss and Joule-Thomson effect in the wellbore, contrast in the thermal and physical properties of gas and water, wellbore heat losses due to unsteady heat conduction in the earth, and the mixing of the fluid streams of contrasting temperature. The second part shows the solution technique used to allocate the gas and water rate for each layer by knowing the temperature measurements inside the wellbore and by using the previously derived forward model for temperature response along with commercial software packages used to estimate the pressure loss required by the temperature forward model.

Two synthetic cases are used to test the validity of the new developed forward model; the first one is account for a well that produces from a single layer, while the second one produces from multilayer well in which the temperature in the wellbore and production rate is known. The developed model is applied to calculate the temperature profile inside the wellbore. The calculated profile is compared with the actual profile. The results showed that the new developed model is valid and reliable.

The practical implementation of the new developed production allocation model is examined on data from two actual gas wells with temperature measurements taken from Production logging tools recorded in these wells. The results showed that the model succeeded to accurately allocate the flow rate of gas and water phase for the multilayer producing wells based only on the temperature measurements inside the wellbore and the total surface rates.
Production Allocation in Multi-Layers Gas Producing Wells Using Temperature Measurements (By Genetic Algorithm) (SPE 139260)

Reda Rabie, SPE, Cairo University/TPS, Ahmed Salah El-Din, SPE, Ahmed Daoud, SPE, Cairo University, Ahmed Ali, SPE, AUC/TPS, Ahmed Nabet, SPE, TPS

Abstract

We present a methodology of allocating gas rate and associated water to each individual layer using temperature measurements and total surface production of gas and water. This paper consists of two parts. In part one; we propose an analytical forward model for wellbore temperature response under two-phase production in a multilayer geometry, using a nodal representation of the well. This model accounts for the formation geothermal gradient, steady-state gas-water flow in the wellbore, friction loss and Joule-Thomson effect in the wellbore, contrast in the thermal and physical properties of gas and water, wellbore heat losses due to unsteady heat conduction in the earth, and the mixing of the fluid streams of contrasting temperature. The second part shows the solution technique used to allocate the gas and water rate for each layer using the genetic algorithm and the constructed software by knowing the temperature measurements inside the wellbore and by using the previously derived forward model for temperature response along with commercial software packages used to estimate the pressure loss required by the temperature forward model.

Two synthetic cases are used to test the validity of the new developed forward model; the first one is account for a well that produces from a single layer, while the second one produces from multilayer well in which the temperature in the wellbore and production rate is known. The developed model is applied to calculate the temperature profile inside the wellbore. The calculated profile is compared with the actual profile. The results showed that the new developed model is valid and reliable.

The practical implementation of the new developed production allocation model is examined on data from two actual gas wells with temperature measurements taken from Production logging tools recorded in these wells. The results showed that the model succeeded to accurately allocate the flow rate of gas and water phase for the multilayer producing wells based only on the temperature measurements inside the wellbore and the total surface rates.
Production Forecasting in Heterogeneous Reservoirs Without Reservoir Simulation (SPE 139696)

A. H. Akram, L. Camilleri and A. Badr, SPE, Schlumberger

Abstract

As an increasing percentage of the world’s production comes from mature fields, there is a growing need for production enhancement techniques that are both rapid and easy to use for the practicing production engineers. For mature waterfloods, the ln(WOR) versus Np plot enables rapid well screening on the basis of incremental recovery factor, where WOR is the producing Water Oil Ratio and Np is the cumulative oil production. Published in-depth information on application of this tool is sparse. Yet, this is often the only tool available to the production engineer for evaluating development options, where a history-matched simulation model has not been maintained.

In this paper, the theoretical basis for the use of the ln(WOR) versus Np is reviewed and studied, and is used to arrive at practical guidelines for interpreting production data. Its applicability as a forecasting tool to single-layered and multilayered clastic, waterflooded reservoirs of varying heterogeneity is demonstrated. Numerical simulation models then predict the behaviour of this plot for a wide range of heterogeneities.

Production data is then analysed to show the applications of the theory for multilayered reservoirs. The ln(WOR) versus Np plots are analysed, and the impact of various factors is observed. The authors also demonstrate that, where applicable, this plot is the preferred decline curve for the following reasons:
- Ln(WOR) versus Np does not require any pressure data; only surface well test production history is required.
- It can be assumed that the ln(WOR) versus Np function is an approximate function of the reservoir only, and is decoupled from the outflow and facility constraints. This is especially useful when comparing artificial lift and drawdown strategies.
- It is a decline curve model that provides a forecast of water cut, which is indispensable on waterflood projects.
A Holistic Approach to Back Allocation of Well Production (SPE 145431)

Leonidas Kappos, SPE, SPT Group, Michael J. Economides, SPE, University of Houston, and Roberto Buscaglia, ENI

Abstract

A continual conundrum for comingled production wells is back allocation, a process by which oil and gas production is apportioned to the contributing wells. The task becomes even more problematic when the wells produce from multiple zones as the production allocation needs to be extended to the individual zones. Simplistic methods (e.g. an even split factor between the wells or a split factor based on the ratio of the permeabilities or the permeability/thickness products of the producing zones, etc.) are bound to lead to erroneous results on the performance of the wells/zooms, and more important, the estimation of the remaining reserves. To date, several investigators have presented their solutions on how to tackle the unwieldy problem of back allocation putting the main weight on satisfying the mass balance and honoring the (down-hole) pressure measurements. In all these efforts, the connection of the reservoir and well with the surface pipeline network is ignored. Downstream of the wellhead choke lies a whole pipe network that takes the production to the separator(s) before routing it to the process facility. Imposing a specific choke opening and separator pressure makes the subsurface system consistent with the pressure constraints and alters the wells’ IPR/VLP operating point, the multiphase flow regime in the wells and the degree to which phenomena such as condensate banking, coning, sand production, etc. appear exacerbated or mitigated.

Our work addresses the contribution of the surface network in defining the well and zone production. More precisely, the pressure constraints stemming from the surface pipe system in conjunction with the total measured production play a pivotal role in determining the wells’ production in the initial steps of back allocation. Furthermore, once the well production is derived, the back-allocated production is based on the identification of the individual zone’s IPR. The latter is generated from a number of techniques such as multi-layered testing but most commonly from short production periods when solely a specific zone is producing (a common operating practice for e.g. well test purposes, high water cut mitigation effort, well workovers, etc.). The form of the IPR used becomes generic and has a particular form which incorporates the effect of the zone permeability, skin, the fluid viscosity, etc and, hence, no additional well test interpretation is necessary. Our method employs minimal information of the production system: total (comingled) production rate and choke pressure measurements. An optimizer is employed to identify the choke opening that brings about the recorded pressures. Critical parts in the developed method are the selection of the pipe pressure drop correlation as well as the PVT characterization of the fluid (for multiphase flow). A field example is given and prediction results generated by the developed back allocation algorithm are compared against field measurements. The proposed technique is a holistic approach as it engulfs all three domains of upstream production (surface network, well and reservoir) and provides a reliable input for the remaining reserves.

Even more important, a definitive description of the system and the individual contributions and back-allocation may lead to multi-well, multi-zonal optimization for overall improvement of the system performance.
Novel Method of Production Back-Allocation Using Geochemical Fingerprinting (SPE 160812)

Xavier Nouvelle, Schlumberger, Katherine Rojas, Schlumberger, Artur Stankiewicz, Schlumberger

Abstract

Geochemical fingerprinting using gas chromatography techniques is a proven alternative or additional tool to traditional approaches for the production back-allocation such as metering or production logging tools. It can be applied in various scenarios, from commingled reservoirs in a single well to allocation of multiple wells or entire fields produced via the same evacuation system. The approach is fast, cost-effective and does not require interruption of production, thus enabling frequent monitoring of production. The method is based on detailed comparison of fluid compositions obtained from gas chromatography of representative samples acquired from the point of interest (single reservoir, well, etc.), called further the ‘end-member’ and the ‘commingled fluid’ to be allocated. Production allocation using a geochemical fingerprinting approach has been successfully used across the globe with specific traction in North America, the North Sea region and the Middle East.

Our method is based on analysis of ratios of heights of neighboring chromatographic peaks (compounds) rather than the single peak heights or areas that all the chromatograms have in common. Such approach reduces inconsistencies between light and heavy hydrocarbons due to some problems of reproducibility during the sampling or during the analysis. It also allows us to tackle issues related to the changes in compositions of end-members during production. In addition, the resolution manages the non-linearity of the equations derived from the physics of the mixtures. The non-Gaussian distribution of the errors is taken into account to comply with the maximum likelihood. Thus, a solid theoretical framework is established to avoid current issues encountered when peak ratios are utilized. Benefits of this method include firstly, a complete management of the uncertainties on the proportions of end-members and on each individual peak ratio employed. In addition to minimization of ‘calibration’ lab mixtures, elimination of manual peak selection (sometimes subjective). Finally, with this methodology employed heir in there is theoretically, no limitation on the number of end-members.

In this paper we demonstrate our approach applied successfully on a series of case studies including biodegraded oils and ‘annoyingly’ similar fluids. We demonstrate that our approach can be successfully and cost-effectively applied to allow for more reliable reservoir/field management.
Using Down-Hole Control Valves to Sustain Oil Production from the First Maximum Reservoir Contact, Multilateral and Smart Well in Ghawar Field: Case Study (IPTC 11630)

S.M. Mubarak, T.R. Pham, and S.S. Shamrani, SPE, Saudi Aramco, and M. Shafiq, SPE, Schlumberger

Abstract

This paper describes a case-study detailing planning, completion, testing, and production of the first Maximum Reservoir Contact (MRC), Multilateral (ML) and Smart Completion (SC) deployment in Ghawar Field.

The well was drilled and completed as a proof of concept. It was completed as a trilateral and was equipped with a SC that encompasses surface remotely controlled hydraulic tubing retrievable advanced system coupled with pressure and temperature monitoring system.

The SC provides isolation and down hole control of commingled production from the laterals. Using the variable positions flow control valve, the well was managed to improve and sustain oil production by eliminating water production. Monitoring the rate and the flowing pressure in real time allowed producing the well optimally.

The appraisal and acceptance loop of the completion has been closed by having this well completed, put on production and tested. Approval of the concept was achieved when the anticipated benefits were realized by monitoring the actual performance of the well.

Leveraged knowledge from this pilot has provided an insight into SC capabilities and implementation. Moreover, it has set the stage for other developments within Saudi Aramco.
Analyzing Underperformance of Tortuous Horizontal Wells: Validation With Field Data (SPE 102678)

M. Kerem, SPE, Shell E&P B.V.; M. Proot, Shell GSI B.V.; and P. Oudeman, SPE, Shell E&P B.V

Abstract

This paper presents the results of a project that was initiated to analyze the inflow performance and inflow distribution of one smart and two problematic conventional, long, and tortuous horizontal wells in Brunei.

Following a detailed hydraulic analysis of these wells, a good match with field measurements was obtained. Simulation results show that the problems in the conventional wells were not as severe as those interpreted from the measurements of distributed temperature sensing systems (DTSs). It is also demonstrated that the compartmentalized completion with inflow control valves (ICVs) in the smart well has added value, because the well would not be producing from over half of the reservoir section without the smart completion.
Remote Optimization Improves Drilling Performance in US Land (SPE 128614)

Nathan Estep, Barry Parsons, Rod Middleton, and Ahsan Alvi, SPE, Schlumberger

Abstract

An Operation Support Center (OSC) was established in Colorado, USA to support clients drilling in the Pinedale Anticline in Wyoming as well as other operators throughout the onshore drilling market of the continental US. In the Pinedale Anticline region, operators plan to drill several hundred wells per year. The time to drill and complete a typical well stood at thirty-five days through 2007, and a target was set to reduce this to fifteen days. Achieving this target would result in a savings of approximately 2190 combined rig days a year thus saving the operator over $100 mm.

A strategy with 2 main elements was developed: a powered rotary steerable service for vertical drilling and remote optimization via the OSC. This approach allowed for no rotary steerable operations personnel to be based at the wellsites during drilling. The new OSC centric processes and procedures developed increased efficiency and allowed fast deployment across a fleet of rigs. The process included a rig-up crew that moved from rig to rig for BHA pick up or lay down.

The remote operations team then monitored operations and began analysis to optimize performance. Using offset data and mean-specific-energy (MSE) techniques, drilling performance targets were set for each depth interval. OSC based drilling engineers alerted the rig when penetration rates were compromised by adverse drilling dynamics, or when input energy needed to be reduced to preserve bit life and minimize trips. The remote team also generated a daily report for each well that continuously compared penetration rates with expected performance targets and captured best practices. This process was used to communicate across the entire drilling organization.

This method of challenging the target was complimented by the operator’s ongoing optimization initiatives and resulted in an increased average ROP of 36% through February 2009. Average time to drill and complete these wells was substantially reduced from the original benchmark; with average drilling and completion time standing at seventeen days. This reduction in days has the potential of saving the operator an average of $900 k per well.
Increasing Drilling Efficiencies Through Improved Collaboration and Analysis of Real-Time and Historical Drilling Data (SPE 128722)

Catheryn Staveley, SPE, and Paul Thow, SPE, Schlumberger

Abstract

Spears and Associates (2009) estimated spending on drilling and completions at over USD 250 billion in 2008. With rig costs estimated to consume 37% or USD 92.5 billion of that spending, every effort to reduce drilling time has a direct impact on our bottom line. Estimates of non-productive time (NPT) ran from 15–40% or USD 14–37 billion, depending on well type and operator. The causes were varied and included technical and non-technical challenges such as wellbore stability, stuck pipe, weather, logistics, etc. Obviously any effort made to reduce NPT will tremendously impact bottom line spending.

Given that causes of drilling inefficiencies are often known and predictable, why do we struggle to improve our results? The challenge is often one of fundamental knowledge management, which includes: difficulty in using historical data, lack of access to relevant data, and the inability to effectively correlate multiple wells in a single view.

Imagine how much more efficient the drilling process would be if you could plan future wells based on nearby offset wells populated with important drilling knowledge from a living drilling knowledge base. The knowledge base would contain all surface drilling parameter data, BHAs, bit records, MWD/LWD data, drilling events, lessons learned, best practices, etc., associated with each well. Data from new wells added to the knowledge base in real time make it more robust, allowing for tracking of position with respect to the shared earth model and updating of the model while drilling. All pertinent data could be displayed side-by-side, allowing correlation of multiple wells by formation, depth or time, in one, two, or three dimensions. Comparison of multiple wells in a single view facilitates better well planning through anticipation of problems and mitigation of risks. This comparative ability leads to an increase in drilling efficiency and a decrease in rig time, which can result in reduced spending.

This paper illustrates techniques for improving collaboration and analysis of real-time and historical drilling data, increasing the cost effectiveness of drilling efforts, and presents a case study highlighting the achievable benefits.
Intelligent Completions and Horizontal Wells Increase Production and Reduce Free-Gas and Water in Mature Fields (SPE 139404)

J. C. Rodriguez, Schlumberger; A. R. Figueroa, Pemex

Abstract

The maturity of the giant fields has resulted in a large number of complex operational and reservoir management problems. The reservoirs pressure has substantially dropped as a natural outcome of the accelerate production rhythm sustained by the field during the productive life. The gas-oil contact and oil-water contact have reached the production intervals in many wells. Horizontal wells have proved to be a valid alternative to drain narrow oil columns in this naturally fractured reservoir. To be able to recover the reserves at sufficiently high rates, new ideas and state of the art technologies need to be implemented to innovate the production process, particularly well completions, to maintain the oil production plateau.

In the mature fields the objective is to maximize production rates to effectively drain the reserves, while minimizing intervention costs. Intelligent wells will be used to increase productivities and recoveries in a less expensive manner, and to significantly reduce the production of free gas and water.

The proposed innovative completion system consists of remotely actuated flow control systems with permanent downhole gauges to permanently monitor the production variables and take actions in real time. This alternative is significantly more effective than the traditional procedure, consisting of selective completions that require expensive subsea interventions to close one zone to open the next one.

In this work, the applicability of multi-purpose intelligent completions for highly productive oil reservoirs has been evaluated from both, the productivity and the operational standpoints. Mandrels will be fitted with intelligent gas lift valves that can be operated from the surface, using downhole gauges for reservoir and production surveillance. Design criteria will be discussed in detail to verify that every productivity case is fully optimized.
Realistic Well Planning with Dynamic Well Control Modelling (OMC 2011-092)

B. T. Anfinsen, G. Weisz, SPT Group

Abstract

Well control planning is a necessary requirement in any well design. Recent year's increased emphasis on drilling wells in deepwater or HPHT conditions require a more detailed planning with regards to kick tolerance, pressure loads and surface flowrates. The consequences and risks associated with drilling operations have recently been emphasized by severe well control incidents around the world. The narrow margins associated with these well types require more accuracy in the calculations than have previously been achieved with more basic models. Advanced dynamic multiphase models will give a more realistic picture of the pressure development during a well control event by accounting for the dissolution of the influx in oil based drilling fluids or dispersion and migration of the influx in water based drilling fluids.
Real-Time Drilling Parameter Optimization System Increases ROP by Predicting/Managing Bit Wear (SPE 142880)

Yashodhan Gidh, Hani Ibrahim, Arifin Purwanto, Smith Bits, A Schlumberger Company

Abstract

Tool manufacturers have made significant progress improving downhole drilling technologies, but little effort has focused on optimizing the drilling process. The set-it-and-forget-it approach and inherent inefficiencies of the automatic driller are inadequate for keeping bit parameters matched to lithology and wellbore conditions. The industry requires a new methodology to help rig-site personnel make informed drilling parameter decisions based on real-time offset data analysis that increases operating efficiency to reduce drilling costs.

To solve the problem, the service provider launched an artificial neural network (ANN) drilling parameter optimization system (DBOS OnTime) which provides rig-site personnel real-time information to ensure maximum run length from all bits and downhole tools at the highest possible penetration rates (ROP). Benefits of the new system include extended tool life, fewer trips and the ability to manage the bit’s dull condition.

The objective is to replace the human factor of applying operating parameters such as weight on bit (WOB) and RPM with the intelligent ANN “learned experience.” By using the ANN based software system, operating parameters can be selected based on the documented physical rock characteristics (offset log data) of the formations being penetrated and then fine tuned for the bit’s specific cutting structure and wear rate. By following the real-time ANN recommendations, changes can be implemented to increase overall penetration rates (ROP) while maximizing bit life by managing the dull condition.
Drilling Automation: An Automatic Trajectory Control System (SPE 143899)

Dimitrios Pirovolou, Clinton D. Chapman, Minh Chau, Hector Arismendi, Mbagba Ahorukomeye, Juan Penaranda, Schlumberger

Abstract

In the last decade, the oil and gas industry has witnessed the emergence of rotary steerable systems (RSS) that led to certain achievements that were not possible with conventional mud motors. Rotary steerable systems enable faster drilling, smoother wellbores, and extended-reach drilling (ERD).

Still, a drilling assembly built around an RSS tool is sensitive to factors such as bit type, operating parameters, type of drilling fluid, lithology, and borehole diameter. Therefore, it is not always optimal for a human operator (typically a directional driller) to select and issue the right commands to the drilling tool at the right time. This situation becomes even more challenging when those decisions have to be made in a matter of minutes.

Steering the well accurately is paramount to geo-steering, optimal well placement in the reservoir, and anti-collision.

This paper discusses a new system that monitors all real-time data that is available, “learns” the steering behavior of the drilling assembly, and uses the acquired information to create more accurate projections for the directional driller. The system recommends the optimal command to direct the drilling tool according to plan.

This tool is currently being used by a number of field locations as an advisor. The next version of the system, being field tested, autonomously issues downlink commands directly to the RSS tool, making it an automatic trajectory controller. The concept is very similar to the autopilots used in commercial airplanes today.

The anticipated value from this technology is better service quality and higher performance that can be delivered predictably and consistently.

Preliminary results look very encouraging. During the evaluation period, the system has accumulated approximately 5,000 running hours, corresponding to approximately 72 runs. These tests are in various hole sizes and well profiles, using different RSS tools.
Artificial Neural Network Drilling Parameter Optimization System Improves ROP by Predicting/Managing Bit Wear (SPE 149801)

Yashodhan Gidh, Arifin Purwanto, Hani Ibrahim, Smith Bits, a Schlumberger Company

Abstract

Tool manufacturers have made significant progress improving downhole drilling technologies, but little effort has focused on optimizing the drilling process. The set-it-and-forget-it approach and inherent inefficiencies of the automatic driller are inadequate for keeping bit parameters matched to lithology and wellbore conditions. The industry requires a new methodology to help rig-site personnel make informed drilling parameter decisions based on real-time offset data analysis that increases operating efficiency to reduce drilling costs.

To solve the problem an artificial neural network (ANN) drilling parameter optimization system was developed to provide rig-site personnel real-time information to ensure maximum run length from all bits and downhole tools at the highest possible ROP. Benefits of the new system include extended tool life, fewer trips and the ability to manage the bits dull condition.

The objective is to replace the human factor of applying operating parameters such as WOB and RPM with the intelligent ANN learned experience. Using the ANN software system, operating parameters can be selected based on the documented physical rock characteristics (offset log data) of formations being penetrated and then fine tuned for the bits specific cutting structure and wear rate. By following the real-time ANN recommendations, changes can be implemented to increase overall ROP while maximizing bit life by managing the dull condition.

The overall project results were positive and proved successful in all the trails carried out after this field trial. This paper will address the methodology of the new approach and highlight the importance of planning and implementing the drilling parameters in realtime.
Real-Time Drilling Engineering: Hydraulics and T&D Modeling for Predictive Interpretation While Drilling (SPE 150069)

Ricardo Borjas, SPE, and Leopoldo Martinez, SPE, Schlumberger; and Carlos Perez and Reginaldo Rodriguez, PEMEX

Abstract

In the early stages of real-time data transmission from the rigsite, real-time monitoring engineers focused on viewing data as it was presented on the rigsite. While this setup was ideal for service quality and event mitigation, it fell short of providing predictions of wellbore condition. As remote real-time monitoring matures in its use of “while drilling” data, remote engineers need to identify issues before they affect drilling operations and are evident to rigsite personnel.

Using a combination of data analysis, engineering models, algorithms for data reduction, historic behavior, and experience, a remote monitoring engineer is able to see the data in the context of the drilling environment and to identify developing incidents.

However, as data volume increases, remote engineers must focus their analysis on the tools by which they can have the biggest impact and effectiveness. Real-time hydraulics and torque and drag (T&D) analysis are such tools, and by using engineering models, engineers can judge the condition of a wellbore before it impacts operations.

Two examples show how effective monitoring of “while drilling” models of hydraulics and T&D identified events, allowing them to be prevented before they were evident on the rigsite and caused nonproductive time.
Real Time Factory Drilling in Mexico: A New Approach to Well Construction in Mature Fields (SPE 150470)

Pablo A. Codesal, Luis Salgado, SPE, Schlumberger

Abstract

In today’s economic environment, oil and gas companies are continuously challenged by a combination of maturing fields (yielding less while requiring more attention), coupled with increasing human resource scarcity. This situation is creating higher costs per barrel and changing economic viabilities for development projects around the world. One way to improve economics is to introduce new efficiency gains that reduce nonproductive time (NPT), reduce well construction times, and, therefore, minimize costs.

The Factory Drilling* approach for field development has demonstrated significant benefits when applied to a well-known field that has consistent well programs and reduced uncertainties. This new way of conducting drilling operations is enabled by real-time data, seamless integration of services, application of suitable technology specific to mature fields, remote operations, multi-tasking of personnel, and fit-for-project rigs. The concept has been successfully piloted in Mexico, on the above-mentioned field, and deployed in twelve land rigs simultaneously during 2009 and 2010.

This paper describes what was done, how it was done and summarizes key results. Since then, other projects have implemented the same model (with some variations) in other parts of the world.
VII. ENHANCED OIL RECOVERY

Waterflood optimization using data-driven and model-driven approaches

M. Mohajer, A. Valentine, and L. Murphy, Schlumberger

Abstract

This project was initiated to develop a workflow for performance review of a waterflooded field and evaluation of opportunities for improving production. The workflow started with a review of the limited geological data available and the application of a series of analyses on the selected field to review its performance. The data utilized within the workflow was Canadian public data. Analysis of pay and formation tops data, along with a wider look at surrounding wells indicated that this field most likely represents a channel. In addition, there is a possibility of faulting impacting field performance. A series of waterflood analysis techniques were applied; pressure/GOR analysis, voidage replacement ratio calculations, conformance plots, water movement, streamlines and pattern analysis, drainage radius, heterogeneity index, water control diagnostics and hall plots. The generated performance plots show that water production exceeds water injection, indicating an influx of water from other formations with high permeability. The use of grid and bubble maps further reinforces this evidence by indicating that the areas with highest cumulative water production do not correspond to the areas with highest cumulative water injection.
A Workflow for Selection of Stimulation Candidates in the Deep Basin

A. Valentine, M. Mohajer, and L. Murphy, Schlumberger

Abstract

The Deep Basin gas play in Western Canada has been recognized since 1975 as an immense gas resource, the size of which has still not been determined. It is located on the eastern flank of the Rocky Mountain Foothills. The tight, abnormally pressured pools of North-Eastern British Columbia and West-Central Alberta have been shown to respond favorably to refracturing and other types of stimulation. This may represent a very large underexploited resource.

This paper presents a workflow for identifying candidates for refracturing and other forms of stimulation. From the public Canadian data store, we extracted and reviewed the results of 576 previous treatments from several pools within the Deep Basin. Self-organizing maps were used to analyse the pre- and post-treatment performance and characteristics of each well. This enabled us to identify the pre-treatment criteria which would produce the highest likelihood of success.

To test this hypothesis, we selected a sample of wells, all of which had recent treatments, and hid the performance data from the date of each stimulation treatment onward. We applied the previously identified criteria and selected those wells likely to have a successful outcome. Decline analysis was performed to predict the production rates with and without the stimulation. The actual results were revealed and analyzed for validation of the workflow. To evaluate the financial impact, economic analyses were completed ensuring the validity of the selection criteria.

This validated workflow has the potential to be applied to this gas play or other reservoirs. It can be used to:

- Make quicker candidate selection decisions
- Maximize the probability of increased production
- Optimize well treatment investments
Numerical Simulation of an EOR Process of Toe to Heel Air Injection (THAI) - Finding the Best Well Pattern (SPE 129215)

Jose Rojas, SPE, Jorge Ruiz, SPE, and Jaime Vargas, SPE, Schlumberger

Abstract

This paper offers an innovative method to test various scenarios for toe-to-heel air injection wells, to meet the demands for new technology and methods using in-situ combustion coupled with steam injection. It presents research conducted over the last few years on the numerical simulation of the toe-to-heel air injection enhanced heavy oil recovery process. Reservoir simulations were used to evaluate multiple variables and scenarios, leveraging the integrated workflow capabilities of software while maximizing the effective time for performance analysis.

Included are discussions of the workflow process, a description of base model details, well array testing results (i.e., four patterns combining horizontal and vertical wells), a comparison of injection air rate in the toe-to-heel air injection process versus a conventional in-situ combustion method, and sensitivities in oxygen concentration and injection rate, which led to increased recovery through the application of toe-to-heel air injection technology.

The effects of heterogeneities on the development of the toe-to-heel air injection process are also examined, along with multisegmented well model benefits demonstrated in the reservoir simulation software tool (ECLIPSE). Additionally, coke deposition during combustion was simulated, showing that toe-to-heel air injection does not affect the fluid flow dynamics process.

Based on our research study, this analysis of the best scenario for toe-to-heel air injection well placement efficiently produces nonconventional hydrocarbon accumulations by delivering increased process control on the combustion front.
Importance of Using Pressure Data While History Matching a Waterflooding Process (SPE 132347)

R.G. Barroeta, SPE, SPT Group; L.G. Thompson, SPE, University of Tulsa

Abstract

In order to demonstrate the importance of using observed pressure data for history matching an early-stage waterflooding process, a novel workflow for experimental design, assisted history matching and probabilistic analysis, was applied to analyze laboratory displacement test measurements. In order to achieve matches between experimental and model data, an evolutionary global optimization technique was used and three different strategies were investigated: matching pressure data only, matching production data only and matching both pressure and production data. For the purpose of generating model displacement data, a one dimensional, two-phase simulator was run.

Tornado plots on the matched data reflect that calculated model pressure values appear to be more sensitive to changes in the dynamic calibration parameters (uncertainty parameters) than calculated cumulative fluid values. This implies that use of the pressure drop information enhances the ease with which acceptable history matches can be obtained. Additionally, the results obtained while history matching pressure only were better than those from matching volumetric data only. The results were validated by crosschecking the probabilistic forecasting with real postmortem observed values and by comparing calibrated uncertainty parameters with core petrophysical properties (laboratory analysis).
Integrated Sand-Production Management in a Heterogeneous and Multilayer Mature Field with Water Injection (SPE 139378)


Abstract

Casabe Field since the beginning of primary stage presented sand production problem because the producers are opened with different multilayer and heterogeneous unconsolidated sandstone. Additionally in the first stage of waterflooding project the use of gravel pack was implemented to control sand production, but it generated a large fall down in production due to the mechanical damage, which caused re-pressurization in certain area and drop down injection rate. At the end oil recovery was too low and sweep efficiency very poor.

In the current stage, at first, the sand production was facing by excluding intervals that could produce sand based on geomechanics study made and reduction in PI, but at the end we allow the sand production to increase oil production. Now being conducted an integrated management of sand production by implementing open intervals with high penetration and high density, patterns balance, water injection definition by layer through selective string installed in injector wells, optimization of fluid levels based on pressure drop, real-time sand monitoring, implementation of PCP as artificial lift system, sand fill removal optimization by coiled tubing (using clean fluid and nitrogen), displacement of flow lines and adequacy of surface facilities to better manage produced sand.

It is necessary to learn and live with sand production to increase oil production and profitability in unconsolidated conventional wells instead of looking to avoid it, the solution is to handle in an efficient and economical way.
Ensemble-Based Water Flooding Optimization Applied to Mature Fields (SPE 142621)

O. Pajonk, R. Schulze-Riegert, M. Krosche, SPT Group, H. Mustafa, M. Nwakile Clausthal University of Technology

Abstract

Water flooding schemes introduced as part of redevelopment projects in mature fields are more often built on smart completions with multiple control valves (ICVs) in wells to be drilled. Decision processes for the implementation and operation of ICVs is supported by reservoir simulations to investigate the upside potential of technical production rates. The robustness of any presented solution is difficult to prove and requires workflows which integrate alternative geological scenarios for capturing uncertainties.

In this work the employment of smart well technologies is modeled to investigate the potential for increasing oil recovery over the life time of a reservoir. Challenges exist on different levels. The number of control variables increases significantly as the number of wells, perforation sections per well and injection time intervals with varying injection constraints increases. Uncertainties related to different geological modeling concepts are taken into account for verifying the robustness of any optimized production scenario.

The starting point for this paper is an ensemble of history matched simulation models. Ensemble-based production optimization including stochastic methods is applied for the optimization of water injection scenarios by individually adjusting ICVs. A novel concept for a time dependent target function is introduced. This reduces the number of control parameters adjusted at a time by focusing on incremental contributions to economic indicators.

The workflow is applied to a complex reservoir model with production history. The optimization process is successfully improving economic indicators over the life time of the reservoir including a full risk evaluation based on alternative geological realizations.
Field Development and Water Flood Management in Complex Clastic Field in Oman - Case Study (SPE 145663)

A. Al-Harrasi, Y. Rathore, J. Kumar, A. Maharbi, S. Shukaili, H. Al-Subhi and M. Al-Salhi, Petroleum Development Oman

Abstract

X-field located in the west Central Oman is in a mature stage of development from the Permian Gharif formation reservoirs. These stacked reservoirs have been historically produced commingled since 1984 with natural depletion until 1998. Since then the field is under water flood. Produced water is mainly re-injected and gas is used for gas lift and the rest is liquefied and exported.

The need for effective pressure maintenance was recognised only when the field pressure depleted under primary development and GOR increased. The FDP proposes peripheral injection in the NW due to better sand connectivity and pattern injection in areas of low sand connectivity. The artificial lift mechanisms are a mix of ESP and Gas lifted wells.

Water flood management is highly challenging in this complex and heterogeneous reservoir. Water front conformance causes challenges with impact on vertical and horizontal efficiencies. The reservoir sands that are not supported by water injection have issues with wax and scale deposition in the producers. The field separation facilities are constrained by gas handling design capacity. Future challenges are expected with well and flow line integrity issue due to the gaining facilities.

Despite all challenges, the water flood is actively supporting production in most areas. Surveillance is the key to managing this complex waterflood. Additional drilling is used for further development with well and reservoir management practices to target by-passed oil, improve water flood efficiency and increase oil production. The surface and sub surface integrated system optimization is helping stabilize the system and delivering improved oil production and gas export with ongoing implementation of new artificial lift strategy.

This paper documents a case history of waterflood management in X-field and the challenges that have to be overcome.
A New Method for Dynamic Calculation of Pattern Allocation Factors in Waterflood Monitoring (SPE 153802)

Ehsan Saadatpoor, SPE, The University of Texas at Austin, Hossein Karami, SPE, Schlumberger, and Moudi Fahad Al-Ajmi, SPE, Kuwait Oil Company

Abstract

Successful operation of a waterflood requires the ability to make informed decisions based on pattern voidage replacement ratio (VRR), watercut, and water production rate. These performance measures are calculated from actual performance data using predefined allocation factors. In a pattern, there are several producers, each contributing to the total pattern production. The percentage of total volume produced from each producer is called the allocation factor.

Waterflood performance is commonly monitored and studied using static allocation factors. The monitoring workflow uses the injection and production data from a database, and pattern allocation factors are assigned to production wells as static values based on geometry of waterflood patterns. In fact, the pattern allocation factors are set as a fraction of the area of a circle exposed to that pattern; hence they are constant. The allocation factors will not represent the real physics involved if they are determined based merely on geometry of patterns. Some important parameters, such as water injection rates of patterns, have a major effect on allocation factors. Based on specific assumptions, we have developed equations to define a new allocation factor for production wells.

The dynamic method proposed in this paper includes several parameters that affect patterns—including well radius, distance between wells, and injection rates—and leads to more realistic waterflood monitoring and more efficient decision making with no extra cost or time needed for data gathering or model development and simulation. The effect of using new allocation factors was studied on actual field data, and results verified the possible improvement in performance if dynamic allocation factors are used.
Abstract

An integrated asset modeling (IAM) approach has been implemented for the Alpine Field and eight associated satellite fields on the Western Alaskan North Slope (WNS) to maximize asset value and recovery. The IAM approach enables the investigation of reservoir and facilities management options under existing and future operating constraints. Oil, gas and water production from these fields are processed at the Alpine Central Facility (ACF). A number of local constraints exist for the asset, such as the requirement that all associated gas be used for facilities power generation, gas lift or re-injection. All produced water must be re-injected and, for pipeline integrity reasons, must be segregated from imported make-up sea water used for injection. Additionally, surface gas and water handling capacity is limited at the ACF. To further complicate matters, gas injected for EOR purposes is enriched such that it is miscible or near-miscible at reservoir conditions. These conditions create a unique and changing relationship between the oil, gas and water production, gas lift, miscible water alternating gas (MWAG) injection, lean gas injection, facilities constraints and injection availability.

The scope of the current IAM project has been multi-fold. Optimization of oil production across all WNS fields requires the placement of injection fluids be simultaneously optimized. The optimization procedure begins by allocation of oil production targets based on current operating conditions, the potentials of the wells in each field to deliver fluids, and total gas lift availability. Excess gas compression capacity is utilized for gas lift and is allocated via an incremental gas-oil ratio sort on the production wells. Given the constraints on water injection noted above, optimization of injection fluids begins by determining pump requirements for produced water and the optimal field or injection manifold placement of the produced water. Following this, optimized placement of the miscible injectant (MI) and lean gas injectant (LGI) is determined based on a dynamic MWAG scheduling methodology developed to maximize oil recovery and ensure the number of gas injection wells have sufficient capacity to inject the required volume of gas in each reservoir. The volumetric split of gas into MI and LGI streams falls out directly from the specification of a target minimum miscibility pressure (MMP) constraint for the MI and the volume of condensates driven off the top of the condensate stabilizer column at the process facility. Finally, the volume of the make-up fluid (sea water) is determined based on the minimum of the remaining pump capacity or potential of the remaining wells to inject the water and allocated to each field based on a fractional oil voidage replacement scheme. Maximizing production across multiple fields necessarily requires that the best player (well) plays, regardless of the field to which it belongs. This requirement relates to both instantaneous production as would be considered under a gas lift optimization scenario as well as the longer term MWAG performance and recovery of each individual well pattern across all the fields.

The IAM technology utilized for managing the WNS fields consists of full-field compositional reservoir simulation models for each reservoir integrated with a pipeline surface network model and a process facility model. Spreadsheet based allocation routines and advanced mathematical coupling algorithms complete the IAM model enabling not only the prediction of the assets' performance under the aforementioned constraints, capacities
and operating conditions, but to optimize overall performance and analyze the impact of decisions. To the authors’ knowledge, this is the first time integrated asset modeling has been applied to bring the entire production stream including reservoir, wellbore, surface network and process simulation together for planning and managing MWAG injection to optimize recovery from an existing development.
Real-Time Evaluation of Pressure Transients: Advances in Dynamic Reservoir Monitoring (SPE 123115)

C. Contreras, SPE, S. Bodwadkar, SPE, and A. Kosmala, SPE, Schlumberger

Abstract

Reservoir engineers operating in mature fields across the world struggle to get necessary reservoir data to make their exploitation plans more realistic. Pressure transients are the most effective way to understand the dynamic behavior of the reservoir. Loss of production and cost of acquiring data versus the benefits has always been a classical management dilemma. With the advent of digital oilfield technology, the pressure and hence the deterioration in well deliverability can be continuously and cost effectively monitored. This paper illustrates how real-time data can be used to make decisions on when to invest in pressure transient tests, and when a test is run, how to minimize the downtime. The case studies presented here are for wells on electrical submersible pumps in various types of reservoirs across Latin America.

The paper briefly discusses the three pillars of digital oilfield; technology, processes and people and how they work together to achieve continuous reservoir and production optimization. Reservoir analysis for wells on electrical submersible pumps (ESP) is challenging due to the restrictions imposed by the downhole equipment. Our work presented here focuses on developing workflows and interpretation techniques for this unique environment.

Having sensors downhole provides operators with an opportunity to get pressure drawdown and buildup data when the ESP starts and stops. For the wells we monitor, 10% of these unscheduled events provided much coveted reservoir information without having to stop the production intentionally. For the scheduled pressure transient events, the data acquisition rates were actively changed to ensure sufficient high quality data. Also, the length of the test was decided in real time to make sure that the test was long enough to meet the objectives but not too long to increase the cost without additional benefits. Thus with real-time technology we were able to overcome the shortcomings of traditional well testing and address the concerns of both engineers and the management. Case studies are presented where production enhancement opportunities were uncovered as a result of scheduled and unscheduled events on wells producing with ESPs. The results show that more than 70% of wells can benefit from stimulation, potentially increasing production up to 300%. To make proactive decisions and act on the recommendations generated from these production enhancement opportunities is still a challenge that needs to be addressed.

For fields with large numbers of ESP wells, a time snap of reservoir properties could be periodically obtained to track changes in pressure, skin and permeability for real time optimization.
Integration of Well-Test Pressure Data Into Heterogeneous Geological Reservoir Models (SPE 124055)

Gaoming Li, SPE, and Mei Han, SPE, University of Tulsa; Raj Banerjee, SPE, Schlumberger; and Albert C. Reynolds, SPE, University of Tulsa

Abstract

This paper presents the application of the ensemble Kalman filter (EnKF) method to the integration of well test data into heterogeneous reservoir models generated from geological and geophysical data. EnKF does not require computing the gradient of an objective function, and hence can be applied easily with any reservoir simulator, and more importantly, is far more efficient than a gradient-based history matching procedure when the forward model is represented by a reservoir simulator. In the procedure for integrating pressure transient data considered here, the static geological/geophysical data are assumed to be encapsulated in a multivariate probability density function characterized by a prior mean and covariance for the joint distribution of the porosity and permeability fields. As the prior mean of the property fields obtained from the core and log data can sometimes be erroneous, a partially doubly stochastic model is applied to account for the uncertainty of the prior mean. In the double stochastic model, a correction to the prior mean is adjusted together with the heterogeneous field during history matching. The method is tested with synthetic heterogeneous single-layer and two-layer reservoirs. Excellent data matches are obtained with EnKF in a small fraction of the time that would be required for a gradient-based history-matching process and the observed data fall within the uncertainty bounds of the ensemble data predictions. In the layered reservoir case, the uncertainty in rock property fields is further reduced by integration of production log data (layer flow rates). We show that problems of statistical inconsistency and poor data matches that are sometimes encountered when matching production data with EnKF do not occur when matching pressure data with the EnKF implementation used here. This undoubtedly occurs because the dynamical system (reservoir simulator equations) is much more nearly linear for the single-phase flow problems considered here than for multiphase flow cases.
Wireline Formation Testing-Networking a Globally Distributed Team for Optimal Reservoir Characterization (SPE 128661)

Peter Weinheber, Adriaan Gisolf, and Vladislav Achourov, SPE, Schlumberger Oilfield Services

Abstract

Accurate characterization of fluid and pressure regimes within a reservoir is a crucial part of the overall reservoir description process. In many offshore exploration and appraisal wells this task is performed using data acquired with wireline formation testers (WFT). Significant planning and simulation is required to properly design a WFT program. This is especially true when the anticipated environment is different from that normally encountered in the local region. Collaboration with a wider group of experts is required. Secondly, an iterative approach to the acquisition of WFT data is required, in which the results of the previous step determine the next step.

This paper describes the process for WFT data acquisition within a major service company. We focus on two key aspects. First is the networked collaboration of domain experts around the world who are used as a resource for any given situation. Communication tools, sharing models, and networking options are discussed. Secondly, we examine the processes for real-time interactive communication with the wellsite and relevant stakeholders. Data transmission, real-time integration into reservoir models, and tools for operational interface are discussed.

Finally we show field examples of these processes in use. In one example we document the gathering of best practices for sampling heavy oil in West Africa (heavy oil is a relatively rare occurrence in this region and sampling required the input of expertise from other regions). In a second example, we show the use of collaborative tools to optimize data acquisition for accurate reservoir characterization in the case of an exploratory well that encountered fluids very different from predrill expectations. And finally we show an example of using Interval Pressure Transient Testing (IPTT) and Vertical Interference Testing (VIT) data to economically pre-empt the acquisition of expensive DST data.
Well and Reservoir Management Project at Salym Petroleum Development (SPE 128834)

Andrew Mabian, Yakov Volokitin, Natalia Beliakova, Jean-Mark Genkin, Ad Hagelaars, Mike Pickles, Joe Diamond Salym Petroleum Development

Abstract

Salym Petroleum Development (SPD) has embarked on an ambitious Oil Field Management Improvement Program with as key objectives to:

- Optimise Production (2.5% additional production through reduction of Locked-in-Potential and better reservoir pressure maintenance; unscheduled deferment less than 1% through reduction of ESP trips).
- Increase Ultimate Recovery (Increase RF by 1%; platform for future EOR project; robust basis for infill drilling).
- Reduce OPEX (increase ESP mean time between failure; contain chemical consumption costs; in field staff journeys reduced by 10% /annum; less than 3 non-critical loss of integrity incidents per year).

The goal of this paper is to present SPD’s approach to Oil Field Management in the context of a West-Siberian water flood. Oil Field Management is based on the Value Loop (Figure.1) where data is acquired from physical assets (reservoir, wells, facilities) and subsequently incorporated into models that drive the optimization of these same physical assets. The value loop has different cycling times ranging from seconds to decades (Figure.2). Traditionally, the shortest value loop is called Real Time Optimization (“RTO”) with a time span measured in seconds, minutes and hours, followed by Well and Reservoir Management (“WRM”) with a time span measured in weeks, months or years, and finally Hydrocarbon Development Planning (“HDP”) with a time span measured in years, if not decades.
**Well Testing in Tight Gas Reservoir: Today's Challenge and Future's Opportunity (SPE 129032)**

*Piyush Pankaj and Vikash Kumar, Schlumberger*

**Abstract**

With the increase in demand and rapidly diminishing resources in conventional reservoirs, economically producing gas from unconventional reservoirs e.g. tight gas reservoir is a great challenge today. The character and distribution of tight gas reservoirs are not yet well understood. Low quality reservoirs are often seen as involving higher costs and risk than high-medium quality reservoirs. There is no formal definition for “Tight Gas”. Law and Curtis (2002) defined low-permeability (tight) reservoirs as those with permeabilities less than 0.1 mD. The best definition of tight gas reservoir is “reservoirs that cannot be produced at economic flow rates or economic volumes of natural gas are unrecoverable, unless the well is stimulated by a large hydraulic fracture treatment or produced by use of a horizontal wellbore or multilateral wellbores.”

Unlike conventional reservoirs, which are small in volume but easy to develop, unconventional reservoirs are large in volume but difficult to develop. Improved technology and adequate gas price is the key to their development. Gas production from a tight-gas well will be low on a per-well basis compared with gas production from conventional reservoirs. A lot of wells have to be drilled to get most of the gas out of the ground in tight gas reservoirs.

Testing a tight gas reservoir is a big challenge today but in coming future more and more numbers of wells are expected in tight gas reservoirs. If we want to grab a piece of this upcoming opportunity, we will have to accept the challenge today. More data and more engineering manpower are required to understand and design a well test in tight gas reservoir than a well test in good permeability conventional reservoirs.

In this paper, a possible way to test a tight gas reservoir using hydraulic fracturing will be discussed. Since hydraulic fracturing is one of the most successful ways of producing a tight gas reservoir economically so far, an idea of integrating hydraulic fracturing job with well testing job as a complete package for testing tight gas reservoirs, especially in the exploratory phase, will be discussed.
Implementation of Surface Operating Conditions in Subsurface Reservoir Simulation Model by using Eclipse Simulator - A Case Study of Mari Gas Field (A Success Story), Pakistan (SPE 142844)

Muhammad Shahid, Basit Altaf, Muhammad Zubair Tanvir, Aftab Ali Memon, Mari Gas Co. Ltd.

Abstract

Subject paper discusses the success story of Gas Reservoir Simulation Model having more than 85 wells spread over the reservoir area within Gas-Water Contact (GWC) around 200,000 acres, built in Eclipse™ Simulator. The gas field has production history of over 40 years. The pipeline network of different sizes around 250 Km managing the whole system and successfully deliver the committed volume to different customers. Production Forecast cases need to be run which cater the network impact by implementation of surface operating conditions with subsurface Reservoir Simulation Modeling.

Operator proposed the consultant to build Network with-in the Eclipse™ Simulator by using Network module. For this purpose, two types of lift tables i.e., VFP and Horizontal flow table for each well to CMF had been designed. The production forecast may run with different compression cases. This helps the operator to determine the recovery factor with different operating conditions by using Eclipse Simulation model. Operator also builds itself in-house pipeline network model in Pipesim software. In this paper Authors would discuss, inhouse working, 3rd party studies and than compare all the studies to check the level of accuracy.
Advanced Reservoir Management of Greater Burgan Field (SPE 148198)

Jeen Su, SPE, Farida M. Ali, Kuwait Oil Company, Jaime A. Orjuela, and Sorin Gheorghiu, Schlumberger

Abstract

The Greater Burgan field is the largest sandstone reservoir system in the world, and its complexity requires the state of art technology for a sound reservoir management practice. This paper will discuss our methodology to maximize the production plateau length of Burgan field using parallel reservoir simulation, waterflood efficiency algorithm, streamline visualization, and ensemble-based optimization method.

With a reservoir dimension longer than 48 km, parallel reservoir simulation becomes necessary for an integrated Burgan field study. Through history matching of 60-year production data, we quantified billions of barrels vertical fluid migration between major reservoir units, and fluid migration is a major concern in making reservoir management decisions. To optimize future development plans, an economic analysis package was developed to evaluate various operating scenarios, and Net Present Value (NPV) is used as an objective function. The scalability data of parallel reservoir simulation are discussed.

The waterflood efficiency algorithm was based in injection efficiency or remaining oil recovery, and the input could come from finite-difference simulation, streamline simulation, and field surveillance data. The algorithm utilized the injector-producer connectivity relationship realized from streamline analysis, and it calculated the amount of water injection for each injector in order to achieve maximum sweep efficiency.

The alternative method to optimize the waterflood is based on the ensemble method in which hundreds of simulation models with different operating settings are automatically submitted to run. Results of all models are gathered and analyzed by co-variance. A better setting will be proposed for each model and the next batch of simulation is then launched. At the end, all models will converge to an optimized operating setting.
Integration of Surface and Reservoir Modeling for Steam Assisted Gravity Drainage on the Bare Field in Eastern Venezuela (SPE 152667)

R. Ruiz, J. Nuñez, A. Martinez, A. Alvarez PDVSA Intevep

Abstract

The efficient and economic recovery of heavy oil and bitumen is a mayor technical challenge due to their high viscosity. In the Orinoco Oil Belt, due to the high viscosity, different thicknesses and heterogeneities found, thermal recovery processes have demonstrated to be the best alternative for the enhancement and acceleration of heavy oil recovery. Bare Field, with an average API gravity of 10°, is among the fields of the Orinoco Oil Belt where thermal recovery has been applied through the implementation of Cyclic Steam Injection in horizontal wells, with substantial productivity increase. This led to the introduction of the first SAGD (Steam Assisted Gravity Drainage) pilot project on the Orinoco Oil Belt, on the Bare Field, this pilot test is in operation from 2009, and the recovery factor of the area affected by the steam is estimated to increase from 14 to 60%.

The location and design of these SAGD wells was accomplished using independents models for reservoir, well and surface, creating a production scenario without taking into account the interaction between models. A dynamic coupling of the reservoir simulation model with the well and surface models allows the consideration of more realistic boundary conditions. In this sense, an integrated model was developed in the present work, allowing the dynamic evaluation of the entire system helping to understand the energy consumption along the system to improve the recovery method performance.

To develop this model, a dynamic thermal reservoir model was created from an existing static model of the reservoir. Once the reservoir model was able to reproduce the flow rates, pressure and temperature with acceptable accuracy compared to the real history data, the next step was the elaboration of well models. The reservoir and well models were coupled in one model to evaluate the advantages of use integrated models for the evaluation of the energetic efficiency of SAGD projects.
IX. ASSET / FIELD MANAGEMENT

Breaking the Barriers-The Integrated Asset Model (SPE 112223)

Øystein Tesaker, Alf Midtbø Øverland, and Dag Arnesen, StatoilHydro; Georg Zangl, Andreas Al-Kinani, Richard Torrens, William Bailey, Benoît Couët, Radek Pecher, and Nelson Rodriquez, Schlumberger

Abstract

The objective of this paper is to highlight the necessary steps for the successful use of integrated asset modeling. It presents the full workflow for optimizing production and injection cycle times with the help of a simplified reservoir model (SRM) through the set up of an integrated asset model (IAM) to validate the SRM results and control the actual production performance.

A discussion of the theory of the IAM as well as the steps to set up a SRM and IAM are presented in this paper. The steps are described in context of an actual field operation. A WAG cycle optimization workflow for the Snorre field has been created to demonstrate the advantages of using the SRM and IAM technology. The optimization process is performed using a SRM able to run a simulation run in a matter of minutes and hence being suitable for sensitivity analysis and optimization. The optimized WAG injection and production cycle is then carried forward to an IAM in order to accurately determine the well performance and the reservoir production. The IAM couples the modeling results from reservoir and well model with the surface facility network and process plant model. The coupling and integration allows investigating the impact of changes in one model to all the other models and hence also handles the proper propagation of constraints throughout the system.
Integrated Field Development—Improved Field Planning and Operation Optimization (IPTC 14010)

Feroney Serbini, Low Kok Wee, Lee Hin Wong, and Nicolas Gomez, Schlumberger

Abstract

Field development, operation optimization, production system de-bottlenecking, reservoir management and field re-development involve studies and analyses from multidiscipline engineers and experts that require effective communication of the impact of the results from one discipline to another. Through an integrated subsurface-to-surface-to-economic modeling technology, the team members are able to model all components of the production system simultaneously and evaluate potential development scenarios, thus resulting in optimal decisions. The Integrated Asset Modelling technology integrates reservoirs, wells, surface infrastructure, and process facilities as well as the asset’s operating parameters, financial metrics, and economic conditions into a single production management environment.

This paper presents a case study of an Integrated Asset model for a brown field re-development study project. The field has been producing over 25 years and is going through a field re-development plan with the implementation of Immiscible Water Alternate Gas scheme (iWAG). One of the primary aims of the project is to improve recovery factor through the debottlenecking of the surface system and EOR implementation of Immiscible Water Alternate Gas (iWAG) scheme. The Integrated Asset Modelling technology was used to perform a multi-disciplinary modeling and simulation environment to take into account new system mass balance by integrating the different components of the production system with the dynamic behavior of the reservoir.

The study showed the following results:
• The impact of the facility bottleneck was identified and a debottleneck scenario was proposed
• The suboptimal conceptual design was identified and a revised design was recommended
• Production losses were evaluated averting significant impact to project financial metrics
On the Importance and Application of Integrated Asset Modeling of a Giant Offshore Oil Field (SPE 123689)

Osama Khedr and M. Al Marzouqi, SPE, ZADCO, and Richard Torrens and Ahmed Amtereg, SPE, Schlumberger

Abstract

This paper presents an application of integrated asset modeling to a giant offshore oil field. The field is located northwest of Abu Dhabi Island and is one of the largest offshore fields in the world. The asset comprises several individually modeled reservoir layers sharing a common surface facility. The traditional method of modeling this field involves running separate simulation models assuming fixed boundary conditions at the wellhead. This does not accurately model the effects of the constraints imposed by the surface facility.

The primary aim of this paper is to highlight the importance of integrated asset modeling in formulating an optimized, cost-effective development plan. This is achieved through the provision of realistic production profiles, taking into account the impact of system backpressure and changes in operating conditions. Secondly, integrated modeling acts to reduce uncertainty in the design data in terms of phased production for future facility upgrading and replacement. Finally, integrated modeling provides a framework for production system optimization under different development schemes.

Included in the discussions presented here are a validation of the integrated asset modeling tool, an overview of the business requirements for the operation of the field over the next 30 years, and analysis of selected development strategies highlighting the added value of integrated asset modeling.

The results of the integrated studies helped to formulate decisions on infill drilling based on realistic production profiles. Secondly, they served to reduce risk through better understanding of the surface and subsurface interaction. Thirdly, they helped to support the decision for commissioning a new concept facility layout (artificial islands), which represents a significantly lower CAPEX investment with more flexibility. Finally, the integrated study assisted in making decisions on the application and type of artificial lift and displacement mechanisms.
Application of Integrated Production and Reservoir Modeling to Optimize Deepwater Development (SPE 131621)

R. F. Stoisits and H. M. Bashagour, ExxonMobil, and C. G. Su, SPT Group

Abstract

A deepwater satellite field project encompasses two fields which are in the general vicinity of two existing Floating Production Storage and Offloading (FPSO) vessels. A number of development architectures that include various subsea tie-backs to two existing FPSOs and, in some cases, an additional FPSO were potential candidates for development. To accelerate the project schedule, Reservoir and Subsea, Umbilicals, Risers, and Flowlines (SURF) Engineering were conducted in parallel. In order to establish an optimal SURF architecture, a method to forecast production behavior of the various architectures is required. To achieve this objective, an Integrated Production Modeling (IPM) tool was developed. Components of this tool model reservoir material balance, well, flowline, riser, and facility performance throughout the project life. Flow assurance analysis, project planning, evaluation, and optimization are facilitated by this model. IPM achieves these objectives by enabling rapid generation of production forecasts consistent with available field information while honoring hydraulic and capacity constraints. When an optimal SURF architecture was developed, system operability was assessed by applying transient flowline and riser analysis to the production system. System operability requires that the SURF architecture is viable over a range of operating conditions spanning upside and turndown scenarios. Upon completion of the rigorous reservoir models, rate profiles were generated by reservoir simulation and compared to the range of rates used to develop the SURF architecture. The reservoir simulation rate profile was contained within the operating range used to develop the SURF architecture. Application of IPM resulted in an optimal SURF architecture, which was developed in parallel with the rigorous reservoir models. The parallel engineering effort allowed an extensive investigation of SURF architectures while accelerating the project schedule.
Reservoir to Surface: An Effective Combination to Unlock Oil Reserves From Aging Reservoirs (SPE 131990)

J. Moreno, G. Kartoatmodjo, T. Friedel, F. Zulkhifly, and L. Tan, Schlumberger

Abstract

One of the main drivers of field development is maximization of oil reserves. The value of assets and therefore companies is strongly linked to the amount of producible reserves of their holdings. Traditionally the full potential of the reservoir is locked due to a series of limitations both at the sub-surface and surface. Increasing in oil demand challenges the development not only to improve on oil recovery but also boost the near term production.

Subsurface models are extensively used to determine the optimum development strategy for the field, infill wells are used to target un-swept areas of the reservoir, while water and or gas injection may be used to preserve reservoir energy. In comparison surface facilities are not so extensively looked after especially in an offshore environment, and often times only a de-bottlenecking of the optimum sub-surface case is performed. The integration between surface network modeling and subsurface modeling is critical to ensure field operation is in line with reservoir management and the facility is adequate to handle the expected production.

This paper discusses the various stages of optimization, using numerical simulation combined with a surface model, to determine the impact of surface operations in overall field performance. The results allowed shifting of the resources to further understand the surface operations which affect the overall field performance as well as identifying near term production enhancement opportunity. This work shows how an effective combination of reservoir energy preservation by means of upgrading the current surface facilities and adding optimized existing wells accounts for as much as 50% of the total potential recoverable reserves.

Furthermore, after evaluating each development options, a matrix risk is formulated to take into account not only the quality and quantity of the data but also the degree of man interventions during the life of the field (surface optimization). Value-of-information figures were then associated to each of the suggested new data/equipment to help prioritize the development. As a result measurement efforts were carried out including horizontal production logs to minimize uncertainty of the reservoir contribution.
A Fully Compositional Integrated Asset Model for a Gas-Condensate Field (SPE 134141)


Abstract

A fully compositional Integrated Asset Model (IAM) has been built for a giant gas-condensate field. The field is a complex retrograde gas-condensate reservoir with a hydrocarbon column up to 1750m in height. The fluid composition varies significantly with depth, ranging from a gas condensate to under-saturated oil.

Production is centred on three processing facilities which are variously constrained by gas processing, gas compression & oil stabilisation capacities and overall export levels. There are some 100 producers and 15 gas injectors presently active in the field, with new wells and facilities planned as part of future development.

IAM’s for the total production system have been gaining in popularity for applications such as FEED studies, field development planning and optimisation. Their complexity has grown with the need to have fully compositional models, which are particularly important for gas condensate fields, where accurate fluid description is required for predicting condensate recovery and injection gas composition.

Development of this IAM has required close cooperation between reservoir, production and process engineers since each of the component models - a 3D reservoir simulation model, production & injection surface network models and a process model for the three production units – are complex in their own right. The IAM model honours the well, network, and facilities constraints, taking into account interdependence between the different elements of the system.

The IAM provides the capability to manage scheduled field events (well re-routing, plant maintenance, field uptime, etc) and optimizing field liquid production.

This work offers valuable insights for more accurate assessments while evaluating different field exploitation strategies.
Automated Field Development Planning in the Presence of Subsurface Uncertainty and Operational Risk Tolerance (SPE 135168)

P.G. Tilke, SPE, R. Banerjee, SPE, V.B. Halabe, SPE, B. Balci, SPE, M. Thambynayagam, SPE, and J. Spath, SPE, Schlumberger

Abstract

This paper presents an automated workflow to accelerate the well placement planning process in the presence of subsurface uncertainty and operational risk. The system allows the user to screen and rank development options in minutes. This automated field development planning system is an optimization application, integrated with a larger seismic-to-simulation workflow. A key piece of technology in this system is a high-speed semi-analytical reservoir simulator, which enables an optimal strategy to be computed very rapidly. The system also embeds key technologies for optimization in the presence of uncertainty and risk which leverages an advanced uncertainty framework.

The workflow starts with a reservoir model, along with existing wells and other operational constraints. Oil or gas production is computed using the high-speed reservoir simulator. Proposed well trajectories honor operational constraints, such as facility processing, water injection capacity, borehole dogleg severity, anti-collision with existing wells, and hazard avoidance on the surface and in the reservoir. The optimal strategy proposes well surface locations, trajectories, and completion locations and is calculated by optimizing the value e.g., net present value (NPV) or production.

This new methodology has many applications in the field development planning context. We are able to rapidly screen multiple field development planning scenarios and produce an optimal new/infill drilling strategy with primary production or waterflooding consisting of both newly proposed and existing wells. The final result includes performance predictions based on an optimized field development plan (FDP), risk, and subsurface uncertainties. The most promising scenarios can if necessary be used subsequently for detailed numerical simulation in order to validate results.

The value of this automated field development planning workflow, along with support for pattern, pad, and platform based strategies, is proved by its use on a variety of onshore/offshore mature and green oil and gas fields with wells in primary production and waterflooding environments.
A Conceptual study for Managing the Life of a Giant Offshore Oilfield in the UAE where Facilities and Infrastructure Mature ahead of the Reservoir (SPE 137542)


Abstract

This conceptual study addresses the subject field which has a current expected operating life of more than 100 years, which exceeds the life of the existing facilities. As an alternative to continuing development with Well Head Platform Towers (WHPT’s), the concept of artificial islands holding drilling and production centers has been introduced [ref.1]. The island concept brings enormous flexibility in terms of managing future development uncertainties both subsurface and surface. The new subsurface development concepts include extensive utilization of ERD/MRC wells specifically designed and placed in conformance with geologically defined drainage areas. This strategy predicts significant improvement in plateau duration and sweep efficiency with fewer wells.

The new islands based surface plan allows a phased installation of facilities, and space provisions to expand facilities to cater for subsurface uncertainties. It also handles the remnant life issues associated with the existing infrastructure (Wells, WHPT’s, pipelines and trunklines, satellites, central complex). This includes provisions for future requirements in terms of Water Injection, Artificial Lift and Gas Injection and other EOR applications.
Evaluation of Development Options for Marginal Offshore Green Fields in Angola (OTC 22648)


Abstract

The first integrated development study of a green offshore field in Angola comprising of two adjacent marginal oil reservoirs is evaluated as single entity and enables decisions to be made with a view of the bigger picture. The field under consideration comprises of two small reservoirs (Reservoir 1 and Reservoir 2) located in deep-water offshore, 85 Km off the coast of Angola and operated by Sonangol P&P (the Angolan National Oil Company).

The main challenge was to devise development strategies for these small reservoirs and produce them into common facilities from a nearby marginal field without jeopardizing current production profiles. Traditionally evaluation of oil and gas FDPs involves several teams evaluating various numerous independent simulation results of models representing sections of the entire system. Reservoir and network simulations would normally be executed separately and this separate analysis could result in biased development decisions being taken; and often lead to over or under designed production and process facility systems.

At a time of increasing demand for oil and gas, Sonangol is also working to squeeze assets for maximum, efficient recovery and optimum production while reducing operating and investment costs. Integrated asset modelling has helped to achieve these objectives.

Integrated asset modelling, couples the reservoir, surface gathering network and process facility models allowing the field-wide modelling and simulation of proposed technical developments and enhancement solutions to be evaluated as one complete system. Furthermore an economic model can also be included to evaluate the monetary impact of the solution for the entire asset. Work-overs and other remedial solutions can also be evaluated prior to taking decisions for implementation. With the use of this technology during the FDP evaluation, relatively fast analysis was performed on the entire asset, coupling these two sub-surface reservoir models to a new proposed surface gathering network model which finally links to an existing FPSO.

This paper presents processes and workflows applied in the asset modelling of this green field in order to arrive at optimized, fit for purpose and cost effective FDP. The work presented here covers the construction of the well models, surface gathering network; quality control checks of two subsurface reservoir models; simulation and analysis of the results of the integrated asset model.

The challenges encountered in studying this green field as an entire system, range from ascertaining reservoir global and well constraints through to network optimum sizing of down hole equipment, back pressure effects, de-bottlenecking and gas lift considerations with some insight into slugging at the riser base. Results and analysis used in the decision making process are also presented. Finally, a discussion on the impact this technology made to the entire FDP process is highlighted.
An Innovative Integrated Asset Modeling for an Offshore-Onshore Field Development. Tomoporo Field Case (SPE 157556)

Fernando Perez, Edwin Tillero, Ender Perez, and Pedro Nino PDVSA; Jose Rojas, Juan Araujo, Milciades Marroccoli, Marisabel Montero, and Maikely Pina, Schlumberger

Abstract

A reliable future development plan of an oilfield would require that all of the elements in the petroleum system are modeled in an integrated manner if a timely response, a more realistic economical evaluation, and risk analysis are needed for better decisions making.

The main goal for future development of Tomoporo field is to change the traditional focus (petroleum system elements by separated) by enabling to multidisciplinary team members to take advantage of their expertises within a collaborative environment based on interaction among petroleum system components.

The Tomoporo field’s hydrocarbon reserves have been largely developed in offshore, but barely in onshore. It has been planned to increase production twice through new producing wells in onshore area which presents several limitations for handling production. Also a plan for pressure support, and improved oil recovery have been considered by implementing a waterflooding project.

This paper shows an innovative integrated asset methodology, applied for forecasting scenarios where reservoir, surface network, geographic location aspects, economy, risk, and uncertainty analysis were considered. The evaluation of forecasting scenarios was performed by implementing an integrated asset modeling (IAM) where all of simulation scenarios were coupled with a surface network model. Such network modeling included itself three integration levels to address complexity of surface facility needed for future offshore-onshore field development. In addition, an innovative link from reservoir surface network models to the economic model was developed for a fully assisted asset modeling, resulting in faster and more reliable scenarios evaluation.

The IAM for Tomoporo field provided valuable information for all team members of the production stream, maximizing benefits from decision making based on a fully coupled asset model. This integrated approach determined that greater recovery factor and less reservoir pressure drop are achieved if an onshore flow station is added for new onshore wells in spite of existing capabilities in offshore surface facilities.

The IAM approach triggered warnings about future needs (investment, expenses), and also to be alert in minimizing bottlenecks in order to ensure no violation of surface capacity constraints. In addition, it allowed to define operating limits of water injection plants, enabling that optimum operation conditions are set, and the added value of the Tomoporo field development be maximized.
A Unique Integrated Asset Modeling Solution to Optimize and Manage Uncertainty in a Giant Offshore Oil Field Development Mega-Project (SPE 161280)

Osama Khedr, SPE, Jayant Amur, SPE, and Rakkad Al Ameri, SPE, ZADCO, and Richard Torrens, SPE and Ahmed Amtrege, SPE, Schlumberger

Abstract

This paper presents the application of an integrated modeling approach to the facility design and construction stages of a mega-project for a giant oilfield offshore Abu Dhabi. The scale of the EPC task is unprecedented in the UAE and requires careful design to optimize the capital investment. In addition, the project uncertainties require that a high degree of flexibility be factored into the design process.

The integrated modeling approach couples surface and subsurface flow models to achieve a complete system solution that incorporates many levels of constraints and realistically represents future behavior. This approach addresses a number of key issues. Firstly, multiple different quality reservoirs produce to a shared surface facility. Consequently, the field is highly sensitive to back pressure variation and so requires a rigorous treatment of well and surface physics. Secondly, the sub-surface uncertainties and sheer size of the investment requires a flexible approach to design, hence, many simulation scenarios are required to provide improved decision support. Finally, close collaboration is required between the sub-surface and surface teams to ensure optimization of facilities design and reservoir management for cost and recovery. The adopted methodology utilizes an integration framework which couples reservoir and topsides models into a predictive tool for development planning.

This paper describes how the integrated modeling approach was utilized to provide input to design process for several aspects of the field development plan during the design and construction stages. This will include discussion of the phasing of the production facilities, requirement for temporary facilities, modular compression and separation units and the optimization of the drilling program for planned infill wells.

The paper presents a best integrated modeling practice supporting facility design process which is applicable for similar scale projects, highlighting the role of integrated model as a means to foster collaboration between surface and sub-surface teams.
Challenges in Integrated Operations Centers (SPE 99485)

K. Landgren and S. Sood, Schlumberger

Abstract

Oil and Gas companies increasingly need environments that support real time E&P business processes, by linking well site information, applications, and experts with operational managers (decision makers) in one place, where daily operational parameters are viewed, decisions are made, and decisions are acted upon. Most companies believe that making decisions in real time while leveraging global resources and infrastructure will help improve their productivity from mature fields, while reducing costs.

Project team members are often collocated to ensure open communication and planning. However, E&P activities often take place in remote and hostile parts of the world, where it may not be possible or economical to deliver all the required resources and personnel. Global operations frequently require that operations centers be "virtualized" so the team members can be globally dispersed. Reliable and secure information flow is the key to ensuring success in the oilfield of the future.

Creating and supporting such integrated operations centers presents significant challenges in process, networking, security, hardware, and software infrastructure. For example, end-to-end real-time solutions require remote connectivity and "first mile" technology.

Successful creation of integrated operations centers requires clear definitions of the business processes to be supported and the infrastructure technologies needed to support them.

This paper discusses some of the special challenges faced in the upstream oil and gas domain, with examples of how some of the challenges have been met.
Progress in Integrated Operations Centers (SPE 111994)

Kenneth Landgren, Sanjaya Sood, Daan Veeningen, and Rolf Berge, Schlumberger

Abstract

Oil and gas companies increasingly require environments that support real-time E&P business processes, where wellsite information, applications, and experts can be linked with operational managers and decision makers in one place so that daily operational parameters can be viewed and decisions executed. Most companies believe that making decisions in real time while leveraging global resources and infrastructure will help to improve their field productivity while reducing costs.

Project team members are often collocated to ensure open communication and planning. However, since E&P activities often take place in remote and hostile parts of the world where it may not be possible or economical to deliver all the required resources and personnel, global operations with dispersed personnel frequently require such operations support centers to be "virtualized." Reliable and secure information flow is central to ensuring success in the contemporary oil field.

In a previous paper, the authors outlined the significant challenges of process, networking, security, hardware, and software infrastructure encountered in creating and supporting these integrated operations centers. These challenges include the end-to-end IT infrastructure such as wellsite and field IT, the design of the work processes to be supported, and the business model for company implementation.

This paper discusses some of the progress that has been made in meeting these challenges over the past year, with particular focus on the actual applications that support oilfield operations.
Lessons Learned: Design and Use of Schlumberger's Newest Energy Center (SPE 112198)

William Matthews, Schlumberger

Abstract

Even with the experience of delivering nearly forty real time/collaboration centers worldwide for oil companies or for its own offices, there was little sense of the routine as Schlumberger Information Solutions approached the design, construction, and use of its newest center for its Houston headquarters. Completed in 2007, the center promotes real-time and cross-discipline workflows for E&P teams while managing the competing needs of R&D to experiment and create new, more efficient workflows to optimize the search for and recovery of hydrocarbons. This facility meets needs for both intra and inter-company use and is designed with evergreen capabilities and maximum flexibility. Lessons learned as the center moved from initial design to daily use are shared along with the business side of managing one of the world's newest intelligent energy centers.
Human Factor Principles in Remote Operation Centers (SPE 112219)

Jim Brannigan and Daan Veeningen, SPE, Mark Williamson and Zhao Gang, Schlumberger

Abstract

The uptake of operation support centers for monitoring and remotely controlling wellsite operations in real time is accelerating in the industry. This paper identifies and discusses the human factors involved with the successful design and operation of these centers.

The introduction of remote operation centers is having a significant impact on the physical and cognitive abilities of engineers working within the centers. Human Factors is a discipline that focuses on how people interact with tasks, machines, and the environment with the consideration that humans have limitations and capabilities. Human Factors must be considered in the planning, design and operation of any remote operation center to ensure productive and safe operation of the center. Locating operators remote from the tasks they are controlling or monitoring will affect not only the direct control and decision making processes, but will also affect their cognitive abilities and ongoing knowledge management and training.

In order to maximize the productivity of any system it is essential to design the workflow to take account of the new operational methods rather than trying to duplicate the existing workflows in a remote environment.
Remote Intelligence: The Future of Drilling is here (SPE 112231)

Ignacio Gorgone, SPE, Juan Gomez, and Gary Uddenberg, SPE, Schlumberger

Abstract

It is well recognized that oil and gas companies have increased the implementation of collaborative centers to improve real-time decision making. This reduces non-productive time (NPT) and improves efficiency in oilfield operations. Emerging technologies now enable end users to receive and send intelligent commands while tools operate under downhole conditions. This not only provides the advantage of fewer trips in and out of the hole, but also the ability to control operations from an office-based environment.

In the last few years, Schlumberger has increased the number of collaborative centers, known as Operation Support Centers (OSC™), to work closely with operators throughout the world. Surface and downhole data are currently transmitted to these centers in real-time as part of the execution phase in the drilling optimization process. While the focus of this paper is on drilling, real-time data is clearly not limited to the drilling phase and in many cases has been used for completion monitoring and control.

As the implementation of these centers has continued, drilling activity increased more quickly than experts could be developed in all areas of operation and support, despite aggressive recruiting and intense training and development. As a result, experts gathering in one room to advise jointly on several simultaneous rig operations became the norm and operators who experienced it quickly embraced the OSC™ concept.

Real-time centers, therefore, have become the chief venue for collaboration, data capture, sharing and training, in a way that better meets the needs of fast-growing operations. Interestingly, they have also become a focal point for better coordination of operational changes, as improved communication with tools downhole and with service personnel have facilitated reduced crew and support requirements.

This paper describes the challenges faced in implementing remote drilling operations, the work processes that allow one directional driller (DD) and one measurement while drilling (MWD) engineer to oversee several rigs simultaneously, and details the necessary infrastructure, communication systems and operating results.
Successful Interaction Between People, Technology and Organization—A Prerequisite for Harvesting the Full Potentials From Integrated Operations (SPE 112251)

Steinar Roland, Olav Yttredal, and Ivan O. Moldskred, StatoilHydro ASA

Abstract

The full value potential of implementing Integrated Operations on the NCS is estimated to $42 billion. In order to harvest this full potential we argue that a balanced integration of people, technology and organization (PTO) is necessary. Our focus is on the people and organisation aspects; what characterizes teamwork and collaboration in the new IO arenas; and, composition of teams and team performance.

IO represents a set of new work forms, and we argue that collaboration and teamwork are fundamental aspects in this new reality. Hence, we have used Dr. M. Belbin and his theories on roles and team composition to show how to design and develop good teams.

Our observations and findings indicates that it is important with continuously focus on the people and organizational aspects in order to harvest the full potentials from Integrated Operations. However, this focus must be balanced with technology in order achieve the most optimal work processes, which will give all parties safer and better decisions faster, and contribute to added value.
Using Integrated Operations Centers (SPE 122920)

Kenneth Landgren, Jean-Pierre Lhote, and Jean-Claude Vernus, SPE, Schlumberger

Abstract

Oil and gas companies increasingly require environments that support real-time E&P business processes, where field information, applications, and experts can be linked with operational managers and decision makers so daily operational parameters can be viewed and decisions executed. Most companies believe that making decisions in real time while leveraging global resources and infrastructure will help to improve their field productivity while reducing costs.

Project team members are often collocated to ensure open communication and planning. However, since E&P activities often take place in remote and hostile parts of the world, global operations with dispersed personnel frequently require such operations support centers to be "virtualized." Reliable and secure information flow is central to ensuring success in the contemporary oil field.

A previous paper outlined the significant challenges of process, networking, security, hardware, and software infrastructure encountered in creating and supporting these integrated operations centers. Another paper reported on some of the progress in meeting these challenges, with particular focus on the actual applications that support oilfield operations.

This paper focuses on challenges and solutions encountered in actually using such integrated operations centers, with particular emphasis on people issues, including change management, training, and collaboration. Real examples from working centers are used to illustrate the issues and solutions.
Collaborative Environment Infrastructure in Al-Khafji Joint Operations, A Case Study (SPE 127928)

Mohammed I. Bedaiwi, SPE, KJO, and Mohammad A. Dharmawan, SPE, Schlumberger

Abstract

In today's exploration and production (E&P) industry, information technology has become a critical component to support business and operational processes. The increasing volume of petrotechnical data with high-resolution 3D seismic data sets and well logs, combined with real-time data acquisition from well sites requires scalable and robust computing infrastructure.

E&P specific challenges, such as remote operation, shortage of experts, and knowledge retention, require changes in the working environment from a specialized and isolated traditional workflow to a multidiscipline collaborative workflow. This collaborative working environment requires technology to enable geoscientists and reservoir engineers to work in an interrelated way. The collaborative working environment can be enhanced further with a virtual workspace to overcome physical distance of collaboration with remote locations.

This paper describes the collaborative environment infrastructure project in Al-Khafji Joint Operations (KJO). Located in Al-Khafji, the border region between Saudi Arabia and Kuwait, KJO has to cope with the E&P specific challenges mentioned above. The project included the design and implementation of an information technology infrastructure to enable a collaborative environment, various geoscientist workflow tools, data management and human interaction.
Real World Remote Operations: A Spectrum (SPE 150064)

Mohammed I. Bedaiwi, SPE, KJO, and Mohammad A. Dharmawan, SPE, Schlumberger

Abstract

Starting in 2004, a major service company began investigations into moving tasks normally performed on the rig to an office environment (an operations support center). These “remote operations” have evolved into a spectrum: from splitting the day and night shifts between the rig and the operations support center to complete remote decision making by the project management team for well construction.

Common factors were observed and documented in the process of implementing remote operations. This led to standards and processes to support broader adoption of remote operations when they are operationally warranted. Standards and processes have been developed for change management, communications, IT infrastructure, and other issues.

Case studies illustrate the spectrum of remote operations, including work from the North Sea and land operations in North America, Central America, and Russia. Two perspectives on remote operations are given. One is from the point of view of a drilling service company responsible for directional drilling and logging-while-drilling services. The second is from the perspective of a project management team contracted for the entire well construction process.
Thermal Simulation and Economic Evaluation of Heavy-oil Projects (SPE 104046)

E.R. Rangel-German, SPE, Natl. Autonomous U. of Mexico and Secretary of Energy, Mexico; S. Camacho-Romero, SPE, and U. Neri-Flores, SPE, Natl. Autonomous U. of Mexico and Schlumberger; and W. Theokritoff, SPE, Schlumberger

Abstract

Many recent hydrocarbon discoveries in the Gulf of Mexico are heavy and extra-heavy oils. Additionally, given the imminent decline of lighter crude oil fields such as Cantarell (the primary Mexican oil field), it seems that most of the crude oil production in Mexico, in the midterm, will come from heavy-oil reservoirs. The need to analyze the feasibility of unconventional recovery methods becomes readily clear. This paper presents a methodology to evaluate heavy-oil projects using thermal simulation and economic evaluation.

Thermal recovery methods are used to exploit heavy oil reservoirs, where oil viscosity is very high and mobility low at the reservoir temperature. It is desirable to reduce the oil viscosity by increasing its temperature. An affordable and easy-to-implement technique is by means of heaters or an electric cable.

This paper presents the results of this methodology, which includes thermal compositional simulation of a synthetic grid model, with the fluid properties mimicking those of heavy oils recently discovered in the marine region of the Gulf of Mexico.

PVT analysis, viscosity curves, rock properties, relative permeabilities, capillary pressure, and reservoir pressure and temperature are also studied.

The economic analysis was performed using current capital expenditures for drilling and completion and operating and maintenance costs. Different scenarios for costs, oil and gas prices and capital investment were studied. A sensitivity analysis was performed to determine the variables having the highest impact on the economic value of the project.

This methodology showed that introducing heat by means of an electric cable is a technically viable and profitable alternative, even for projects under off-shore economic premises, which are considerably higher than those for on-shore projects. Implementing the heating from the beginning of the project and continuing to its completion, was found to be the most important factor for the economic success of this method.
Optimum Economic Development of Mature Eastern European Oil Fields - Case Study (SPE 113302)

Maximilian Fellner & Gabriela Dutu, OMV Petrom; Jon Ingham & Marina Vespan, Schlumberger

Abstract

Following the acquisition of 51% of Petrom by OMV in December 2004, the management team saw an opportunity to completely redesign their overall investment appraisal process aiming to bring it to a level comparable with the best in the industry. In particular, with the advent of the Sarbanes Oxley (SOX) legislation in the US, Petrom management wanted to achieve a level of consistency and transparency that would meet or exceed the highest international standards.

The processes in place under state ownership were focused primarily on production maintenance and lacked the economic and financial discipline required to simultaneously maximize return to shareholders. The implementation of a modern project appraisal and investment analysis system was therefore a major imperative of post-acquisition change management. In this situation availability of quality data was a major barrier to progress, however it was felt that establishing a level playing field was one of the keys for success.

Following the implementation of a suitable standard framework a business model was built for the entire Petrom E&P division using commercial software. This model was then used to forecast the outcome of several operational choices against three key strategic targets. The model contained details of more than 1,700 projects and producing fields and allowed Petrom to simulate prioritization or delay of any part of the program while honoring the links and dependencies between individual options. Goal seeking optimizers were used to find solutions that best fulfilled the corporate production target whilst staying within the established regional annual budget expenditures and other KPIs. The analysis ultimately led to selection of projects that would achieve the production and operating expenditure targets whilst requiring well below the anticipated capital budget in two of the three organizational Regions of the Romanian operations.

The paper describes how the application of business modeling practices, that have been applied effectively to long term portfolio decision making, can also be used for near term field development, capital investment, modernisation and budgetary decisions. The implementation stretched the boundaries of current practice and showed that significant insight can be gained; in particular the results show what can be achieved with far less than perfect data. An additional outcome was the accelerated development of several Petrom personnel in the application of modern business methods.
Methodology for Integrated Reserves Management: Providing Regulatory Compliance and Improving Decision Making (SPE 124168)

Lev Virine, Project Decisions, and Doug MacDonald, Schlumberger Information Solutions

Abstract

Effective corporate reserves management systems allow petroleum companies not only to track reserves and provide input for reporting to regulators, but also to serve as a decision support system. Implementation of such reserves management systems comes with a number of challenges. Regulatory bodies, including the U.S. Security Exchange Commission (SEC), require proper categorization of reserves based on evaluating whether the volumes can be economically recovered in a timely manner. The reserves management system should be able to provide technical and economic volumes based on up-to-date prices, capture and analyze uncertainties in the reserves volumes, provide secure data access and data archiving, and implement an approval and audit process.

To address these challenges, a methodology for integrated reserves management was developed. This methodology comprises three integrated processes: data management, which ensures fast and secure access to reservoir data; economic and technical volume calculation; and a flexible reporting process. The proposed workflow includes the following steps. Reservoirs, as well as prospects, are organized within a corporate hierarchy. In accordance with SEC regulations and SPE/WPC Petroleum Resources Management System guidelines, the data management process captures proven, probable, and possible reserves, as well as discovered and undiscovered resources for different petroleum products and companies with different working interests. Each category of each reservoir is associated with an economic case that contains information about costs, prices, and the fiscal regime. Economic volumes can be calculated based on the results of economic evaluations of the reserves. Uncertainties in reservoir data are captured using multiple scenarios for each reservoir and category. A regional pricing mechanism allows for updating prices for all economic cases at a particular level of the corporate hierarchy. All changes to the economic results data would be recorded and require approval.

This methodology for integrated reserves management provides for the comprehensive management of reserves data in the organization. It allows accurate reserves tracking and reporting to regulatory bodies by mitigating the negative effect of motivational biases. Through a consistent set of categories, scenarios, products, and companies, the proposed workflow provides evaluation and tracking of both technical and economic volumes.
Hydrocarbon Maturation: Integrating Reserves Management into Corporate Planning (SPE 130158)

Doug MacDonald and Jason McVean, Schlumberger Information Solutions

Abstract

This paper discusses the relationship between the reserves management and corporate planning components of a company’s business processes, and the techniques that can be implemented to facilitate better decision making and more accurate reporting.

Reserves and resources management and corporate planning are related in two major aspects:

- Reserve volumes and replacement ratios are important key performance indicators (KPIs) for most corporations. As such, decisions regarding corporate planning should take the reserve volumes, as well as the resource volumes that may become reserves in the future, into consideration.
- Once these corporate plans have been made, the reserves volumes (both current and projected) should reflect the impact of the corporate plan, for example, volume changes from acquisitions, divestitures, and exploration and development plans.

A changing reserves profile might have impacts on financial aspects of the business such as contracts, loans, and other accounting items. Using the reserves forecast in these calculations instead of the static, current reserves volumes would result in more accurate calculations and an improved planning process.

In order to model changes in reserves volumes over time, a stage gate type of process can be used. As certain events occur in the development plan, for example project approval, capital expenditure, or production start, this process would flag a predetermined change in the categorization of certain volumes. If the projected reserves volumes do not meet the corporate goals, a review of the corporate strategy may be needed.

Knowing the reserve and resource volume profile expected in the future is important for supporting better decision making today. This is especially true when considering volumes that, although they can not be reported as proved reserves today, may well be ready for reporting as proved reserves in the future. This is relevant whether or not a company is required to report its reserves to a regulatory body, for example, The Security Exchange Commission (SEC), as all stakeholders have an interest in understanding the status and certainty of a company’s resources.

Companies that employ robust planning techniques and integrate hydrocarbon maturation into their planning process should be able to clearly demonstrate their improved planning efficiency and are likely to deliver improved financial results.
Abstract

Portfolio management has become a mainstream discipline to support investment decisions and capital allocation plans for the oil and gas industry. With more than 70% of the top 50 oil and gas producers companies in the world applying it, the scope and reach of the subject is of vital importance.

The aim of this study is to understand how portfolio management is applied in strategic planning and operational optimization, and how the combination of these exercises allows the strategic guidelines to permeate operational decisions.

The first part of the study covers the best practices for the application of portfolio management when tackling strategic planning. Which are the critical business issues the exercise resolves, how to model the corporate long-term direction through measurable KPIs, and what key objectives companies pursue when allocating strategic capital.

The second section provides some specific examples of ways in which portfolio management theory can resolve operational issues such as rig scheduling optimization, key human resources constraints, and facilities management optimization.

The third section analyzes how the output of both exercises logically merges into a solid operation aligned with the company’s strategy.

The main outcome of this analysis is the definition of a framework that defines the most efficient way to materialize long-term strategic directions as day-to-day operational guidelines, creating an efficiently aligned organization. Efficiency of the planning process will be explored.
An Approach For Spreadsheet-Independent Reserves Management Tracking, Archiving, And Reporting (SPE 153414)

Hamad Al-Sumaiti, SPE, and Muhammad Usman Sethi, Schlumberger

Abstract

The tracking and management of both resources and reserves estimations are of primary importance for any oil and gas company. When managing reserves data using spreadsheets, organizations face numerous daily challenges in reserves tracking and reporting. This technical paper discusses the implementation and methodology adopted at one of the Middle East's leading oil and gas companies for a reserves management system free from spreadsheet-based tracking and reporting. The resulting system provides much enhanced security and efficiency in managing reserves, and improves the flexibility of reserves reporting.
An Integrated Portfolio Management Approach for More Effective Business Planning (SPE 162748)

Michael Back, Schlumberger, Graham Kirk, 3esi

Abstract

Portfolio management has become an important aspect of oil and gas business planning to support the efficient allocation of capital. As oil and gas becomes more difficult and expensive to find, petroleum companies are looking to portfolio management for providing both a more streamlined business planning process and an advantage over the competition in the industry. However, portfolio management has traditionally been deployed at a corporate planning level and has often missed the opportunity to consider the operational reality at the asset team or regional level. Each capital investment decision must be consistently evaluated for its ability to contribute to the corporate strategy while maximizing the usage of available resources. The aim of this study is to show how an integrated portfolio management solution can provide benefits when used at every stage in the asset development life cycle (from exploration through to production and abandonment) as well as at different levels in the corporation (asset teams through business units to corporate planning) to drive more efficient and effective business planning.

This robust, integrated approach to portfolio management will drive more efficient investment across the corporation. The methodology can be applied to business planning processes at the asset team, the business unit, and at the corporate level within any petroleum company.

The first section provides the best practices in maturing opportunities as producing, development, and exploration properties are evaluated consistently in the context of the company portfolio. The second section of the study covers some specific examples in which the asset development plan is put together to create typical drilling and rig schedules with operational issues such as dependencies between assets and facilities resource constraints. The third section looks at various portfolio management techniques to define the long-term corporate strategy and bridge it with short-term operational constraints to determine an optimized portfolio.

The study concludes with specific recommendations on integrated portfolio management practices at every level in the organization to ensure that the corporate strategy is aligned with available resources. This integrated approach to portfolio management will allow corporate planners to balance long-term strategic goals with operational constraints from the business unit down to the asset team. It will result in a more balanced and diversified portfolio and drive better decisions in the capital allocation process.
Integrated Production Surveillance and Reservoir Management (IPSRM) - How Petroleum Management Unit (PMU) combines Data Management and Petroleum Engineering Desktop solution to achieve Production Operations and Surveillance (POS) business objectives (SPE 111343)

Mariam Abdul Aziz, Mohamad Kasim, Mohamad Som, and Ronny Gunarto, Petronas Petroleum Management Unit (PMU), and Hin Wong Lee and King Chai Ngu, Schlumberger Information Solutions

Abstract

The role of managing PSC's (Production Sharing Contractor) performance as the main function of PETRONAS's Petroleum Management Unit (PMU) poses challenges for Production Operations and Surveillance (POS) engineers to efficiently perform technical review and monitor performance of the fields across all Malaysian PSCs.

In order to address these challenges, PMU has embarked on an Integrated Production Surveillance and Reservoir Management project to implement a system that integrate cross-domain data into end users engineering software with a pre-defined surveillance workflow, processes, procedures and techniques. The objectives is to provide POS engineers with the required data and workflow templates at their fingertips to enable them to make quick analysis, hence, accurate decisions.

IPSRM implementation consists of two components. The first component involves the Data Management team to build the Data Hub to consolidate cross-domain data from PSC Operators. The second component consists of setting up the workflow and techniques templates in engineering software with online interface to the Data Hub. A unique hybrid Petroleum Engineering tools that combines parametric, user-driven and data driven analysis capabilities are introduced to allow full surveillance capability.

IPSRM implementation has been in operation and provides an effective way for PMU engineers to perform day-to-day surveillance analysis across Malaysia fields. Some benefits and achievements from IPSRM implementation are as follows:

1. Reduced analysis cycle time of engineers by eliminating engineers' time in data preparation and processing
2. PMU engineers are provided with a full spectrum of analysis capabilities to perform study and analysis, covering from user-driven, parametric to data-driven applications
3. Some studies have successfully identified potential for recovery improvement
4. Neural Network applications have successfully identified potential for injection/production optimization
Integrated Competence: Operator-Service Company Integration Increases the Performance and Value of the Well Construction Process (SPE 1122018)

Sanjay Kanvinde, SPE, Katy Heidenreich, SPE, Barry Parsons, SPE, and Greg Pearson, Schlumberger, and Tore Kristiansen, SPE, and Ketil Andersen, SPE, StatoilHydro

Abstract

This paper presents a framework and a systematic top-down approach for implementing a company-wide operator-service company integration program for well construction services called integrated competence. The paper describes the key aspects of implementing the integrated competence program: goals, objectives, critical success factors, levels of integration, asset selection and targeting, value creation and key performance indicators (KPIs), multiskill roles, onshore and offshore team configurations, training, and change management.

The integrated competence program developed by StatoilHydro and Schlumberger is an initiative under StatoilHydro’s Integrated Operations (IO) corporate initiative and was applied to StatoilHydro’s standardized well construction process. The joint team configurations in StatoilHydro’s Onshore Operations Centers (OOC) improved collaboration in all phases of the well construction process, and the Schlumberger Support Center provided remote support of drilling operations. In addition, the paper describes two case studies used in the development of the wider program.

The framework, program approach, challenges, and results presented in this paper provide the E&P industry with an example of operator-service company integration, with possible implications for their own current and future digital initiatives, particularly those focused on the well construction process.
GeDiG Carapeba—A Journey From Integrated Intelligent Field Operation to Asset Value Chain Optimization (SPE 112191)

C.B.C. Lima and C.F. Henz, SPE, Petrobras, and J.P. Lhote and A. Kumar, SPE, Schlumberger

Abstract

GeDiG is a Petrobras corporate initiative to implement Intelligent Energy technologies to achieve Integrated Digital Oilfield Management with the sole objective to maximize the life of mature and new producing oilfields. Carapeba is an offshore brownfield located in the Northeast area of the Campos Basin, comprising of 3 fixed platforms with 41 wells producing from three zones (all dry completion and equipped with Electric Submersible Pumps) and 4 water injection wells.

The key business driver is to increase the recovery factor by improving reservoir sweep efficiency with installation of ten intelligent completion systems, achieve production optimization and augment operational efficiency by upgrading field automation and integrated process optimization.

GeDiG Carapeba encompasses end-to-end seamless integration, spanning across various functional groups of the asset, integrating operational processes (fast, medium & long loops). It provides a toolset that gives the ability to make better informed decisions by multi-disciplinary teams in a specially designed collaborative environment to plan, monitor, control & optimize operational processes, making asset teams more agile. The solution is delivered through a portal platform which integrates information from Production Operations, Geotechnical and Financial systems, providing an information hub for the entire asset operations, shielding complexity of underlying sub-systems and empowering end-users with right information in-time. This is supported by field automation, smart simulation and optimization tools which integrate the well-bore, surface facility networks, reservoir, process and economic models. This level of integration provides more transparency to understand engineering and economic impact of various field development decisions.

This paper describes experiences and challenges of the GeDiG Carapeba project from conception thru implementation, integrating people and processes with the right balance of technology across field operations and how it has resulted in enhanced operational efficiency and recovery factor, coupled with a substantial increase in production.
A Case Study: Production Management Solution "Back Allocation and Advance Well Monitoring" - Litoral de Tabasco Asset (SPE 127924)

G. Olivares and O. Perez, Pemex, and C. Escalona, C. Vargas, M. Baarda, and J-C. Vernus, Schlumberger

Abstract

There has been a significant increase in activity in recent years in the development of exploration fields in Mexico offshore operations. Critical operational issues for managing these fields are the large volume of Excel files, disorganized acquisition, and minimal sharing of the different sources of available data. In 2005, some PEMEX (Petroleos Mexicanos) Assets decided to address this data gathering and analysis bottleneck by integrating all operational data into one single central data store to allow the Asset engineers, involved in the monitoring and diagnostic field process, to access a unique and shared source of field information, i.e. "One single version of the truth". One of the most recent developments is AILT (Activo Integral Litoral de Tabasco), located in the Marine Southwest Region – Gulf of Mexico, as is show in Fig. 1, where this case study was developed.

When the project started, AILT had 7 platforms and 15 wells and now consolidates all production in the area with 44 wells and 24 platforms using shared facilities. This required the implementation of a workflow to accurately determine the production of each well by applying back allocation and near real-time operational conditions using multiphase measurements. A series of automated workflows integrates all the operational data, from monitoring of the wells in real time to official accounting and reporting system.

The automated workflows have provided a cost-effective solution that minimizes uncertainties in estimating production volumes at the well level for the AILT area, and improves production consolidation required for official accounting purposes. The automatic workflows have further enabled the production team to integrate all operational data, and analyze and monitor the performance of each well as part of the integrated facilities network. In addition, rule-based concepts within these workflows assist in monitoring reservoir drawdown and proactively prevent the contractual penalties related to batch delivery delay to Pemex refineries.
Intelligent Field Centers (IFCs): Integrating People, Processes and Technologies to Optimally Manage Giant Fields (SPE 128469)

M.F. Barghouty and T.A. Al Dhubaib, Saudi Aramco, and A.A. Jama and O. Jaimes, Schlumberger

Abstract

As part of the implementation of its strategic goals, Saudi Aramco effectively leverages intelligent field (I-Field) processes and technologies. The I-Field initiative (development architecture) includes four levels: Surveillance, Integration, Optimization and Innovation, with a vision for full implementation and coverage of all producing fields within the medium term. The accomplishment of this ambitious goal requires a well coordinated approach company-wide to truly benefit and extract value from the I-Field approach and practices.

The value proposition of the I-Field program includes increasing production potential, recovery factor and efficiency with the most safe and environmentally sound practices. One facet of achieving this corporate objective is through enhanced reservoir management strategies and integrated multidisciplinary collaborations. One of the contributing initial elements is the creation of Intelligent Field Centers (IFCs) that will enable and facilitate collaborative decision making around reservoir management processes and tasks.

The first established IFCs had emphasis on reservoir management tasks with a longer vision and a wider objective of optimizing the company’s assets and operations in achieving its expanding goals. This first group of IFCs is foreseen as nuclei for a growing contemporary practice in managing the company’s assets.

In order to come up with the optimum design of these centers and to ensure that they meet the objectives set out by the company, a rigorous, multistage methodology was utilized that started by a comprehensive assessment study. The results of this assessment revealed several high priority workflows being performed by the reservoir management groups, which, once implemented in the IFCs, should deliver improvements in efficiency and, therefore, impacting production and ultimately increasing recoverable reserves.

The assessment and design results showed critical cross-functional and I-Field requirements, such as collaboration, change management, integration, interoperability and openness, automation and knowledge capture.

This paper will detail the methodology followed in assessing the requirements and designing the use of the IFCs.
Integrating Data Mining and Expert Knowledge for an Artificial Lift Advisory System (SPE 128636)

E. De la Vega, G. Sandoval, and M. Garcia, PEMEX AIB, and G. Nunez, SPE, A. Al-Kinani, SPE, R.W. Holy, SPE, H. Escalona, SPE, and M. Mota, SPE, Schlumberger

Abstract

This paper describes a new workflow to accelerate and improve decisions regarding where and when to apply an artificial lift system in fields with a considerable number of active wells. The workflow deploys a hybrid combination of a user-driven expert system and a data-driven knowledge-capturing system calibrated with historic data. Both systems interact to determine the right point in time to support a particular well with an artificial lift system.

In the case presented, the mature gas field has a large number of operating wells, with predominantly manual operating data entry and a long processing time for newly acquired data. Due to the rapid decline rate in many wells, however, quick decisions are needed to improve productivity and hence the economics of each individual well. During the first two phases of the project, the asset team focused on data collection and workflow automation to speed up well production surveillance operations (e.g., gas rate calculation, estimation of critical velocity, etc.) (Mota, 2007). This paper documents the third phase, which addresses the knowledge-capturing and advisory components of the solution.

Mature fields typically have significant field and asset expertise and a huge amount of historic data. Both information sources—the expert documentation and historic data—can be integrated to investigate past decisions and identify an optimum approach to field interventions. This paper describes the setup and implementation of a hybrid model that combines expert knowledge from asset engineers with the new knowledge discovered through the latest data-mining technology. The resulting system is then implemented in a fully automated workflow that identifies which wells require artificial lift.

The results from a case study in a North Mexico gas field are presented. The reservoir is highly compartmentalized and requires fracturing as a way to increment well productivity. The data-mining approach used in this study is a special visualization technique, the self-organizing map (SOM), and a clustering algorithm (Zangl, 2003). The model was trained with historic production data, well test data, and information about historic well intervention decisions. In addition, expert knowledge from the asset engineers was introduced. The combination of data and expert knowledge enabled fast and reliable identification of the optimal time to install an artificial lift system to increase production while also effectively managing costs.

This system reduces the typical decision time from several days to a matter of hours. The automated workflow runs immediately after the data is acquired and provides a continuous, up-to-date, and ranked list of proposed wells for artificial lift analysis. When new decisions are taken, the model can be updated for future use. The rapid analysis and decision cycle reduces lost production and improves overall field and asset value.
Production Processes Integration for Large Gas Basin – Burgos Asset (SPE 128731)


Abstract

This paper presents the advances in Production System Optimization for the largest gas field in Mexico. The Burgos Asset is a large gas brown field with reservoir characteristics like gas-loading backpressure, reduced permeability and tight gas formations where production declines rapidly. Due to the large number of wells (more than 3500 active wells) and the fact that 95% of the measured parameters are obtained by field operators, it is difficult to continuously monitor and to plan the usage of operational resources.

To help solve this situation, PEMEX and the service company (Schlumberger) implemented a production surveillance system that gathers all operational information providing storage, quality control, and developed engineering processes to estimate gas rates and liquid loading, monitors KPI and detects anomalies in operational events.

Implementation of this operational surveillance environment started in 2007, with a functionality that has been focused on monitoring KPI calculation and event analysis at well level. Due to the large number of wells and activities carried out by the Asset, the need arose to generate additional workflows that contribute to the production optimization process, candidate selection workflow for workover and artificial lift installation, allowing upscaling of the current solution to a level that supports the technical and economical decisions of the Asset.

As part of this requirement the team took the initiative to incorporate workflows of candidate recognition for workover, de-bottlenecking and optimization of a particular set of facilities, allowing the Asset to take corrective action in these areas and to plan the recommendations accordingly. Additionally, as proof of concept, an intelligent candidate selection system was implemented for artificial lift installation opportunities, using artificial intelligence tools such as data mining, improving decisions and results.

The initiatives mentioned above help to increase, validate and rank the Asset's diverse candidate basket and to integrate the economic constraints into the decision making process. The positive results that have been obtained in these focalized areas show a significant opportunity to be upscaled for the whole Asset.
Abstract

The oil and gas industry has had a long-time vision to close the feedback decision loops in the Integrated Digital Oilfield. Petrobras has made initial steps toward this goal by integrating Production Surveillance (for wells, equipment, and facilities) with Remote Control Operations on five platforms that comprise 15% of production operations in the Campos Basin. This represents a step change from the way Petrobras has historically operated, and has required systematic and inter-dependent changes to various sections in the organization.

The first step in this direction entailed bringing remote control technical capabilities onshore, to be in closer proximity to the decision center. This ensures stronger person-to-person inter-relationships between production engineers and control operators. The decision center has been operational for over 18 months and has undergone a transformation from reactive to proactive surveillance and analysis approach on the processes supporting production operations. Now that proactive processes have been established, Petrobras has instituted combined surveillance-control processes, with each onshore team focusing on a single platform. As the project has matured, the role has changed so that now each onshore team manages multiple platforms with similar levels of operational complexity. This has led to a strengthening of the quality of remote control operations, has allowed technical expertise to be leveraged across operations, and has reduced overall HSE exposure.

This paper describes the initial steps taken by Petrobras to achieve integration between predictive surveillance and remote control production operations. It also describes the benefits that have been realized, such as reducing costs and the number of people on board platforms. Based on the early success of this work, Petrobras plans to expand the program to cover all of its operations in the Campos Basin. After proving success in the Campos Basin, it is expected that this approach will guide Petrobras as it prepares for the many challenges in Pre-Salt operations: complex logistics, personnel shortages, and environmental challenges.
State-of-Art Digital Oilfield Implementation in Petrobras Campos Basin (SPE 128766)

C.B.C. Lima and G. Sobreira, SPE, Petrobras, and D. Rossi, A. Kumar, and B. Sauvé, SPE, Schlumberger

Abstract

After its success with the implementation of Digital Oilfield program in Carapeba field, Petrobras decided to expand the concept to other fields and assets of the Campos Basin. These new fields had dissimilarities ranging from field instrumentation to varying production concepts and technical processes – posing a new set of challenges enforcing the need to review solution deployment strategy.

The solution methodology required analysis of the various functional processes from these fields and assets. Therefore, a functional committee represented by the assets was established to help define the standard business process along with rationalization of the appropriate tools and technology coupled with scalable IT architecture. This clearly led to help achieve consistency and transparency in managing production operations across the organization – resulting in better integration of information and significant increase in efficiency of the functional groups. The key to success was certainly driven by strong management sponsorship and willingness of the asset teams to adapt to the new approach.

The solution focused on key business processes which had a direct impact on the production of the assets e.g. Well Surveillance, Analysis & Diagnostics; Losses Control; Sub-Sea Integrity and Surveillance; Well Test Validation & Control; Turbomachines Surveillance – with clearly outlined objective to deliver immediate value to the assets and the business unit. This approach has helped establish Campos Basin as a potential role model for the other assets and business units within Petrobras.

This paper intends to describe the challenges faced during the expansion of the program beyond the pilot implementation and the strategies used to overcome them. It also highlights the key aspects of the implemented solution with specific examples - delivering value creation through standardization of infrastructure and production processes of the assets.
Integrated Production Operation Solution Applied in Brown Oil Fields - AIATG Asset PEMEX (SPE 157180)

Diaz, G., Mena, E., PEMEX-AIB., Mota, M., Yañez, J., Castrejon, R., Lombardo, L., SPE, Schlumberger

Abstract

This paper presents the advances in the Integrated Production Operation Solution applied in Brown Fields from Activo Terciario del Golfo (AIATG) Asset PEMEX, located in The north-east of Mexico. AIATG has about 3377 wells, 2112 are producing, 948 of them in natural flow, 1164 in different artificial lift methods, and the remaining are closed. The total production is about 65004 BPD of oil and 149 MMFCD.

Operational issues like, lack of well test event, poor well test by well, facilities constrains, production measured in conjunction with others sources, in combination with dispersion data the problems create a not trusty environment to detect abnormal conditions and events that impact directly in the production.

In order to improve this process, AIATG has raised a new approach which allows consolidate the operational data base, to implement workflows for capturing from different sources daily production and operational data along the entire production network and facilities, and which will include engineering and smart validation rules and alarms notification across web environment, which this will permit to act in advance before a potential issue become in production loses.

Additional features for trend analysis, visualization and management of key performance indicators will be integrated with engineering workflows, which the automatic recognition of issues and behavior of wells using calculated rates at the well level and their reconciled production compared to the measurement at the gathering station level. With this automatic workflow we can then identify any condition that has drastically affected well productivity.
Strategies for Training Digital Petroleum Engineers (SPE 123896)

Iraj Ershaghi, SPE, University of Southern California; Donald Paul, SPE, University of Southern California and Energy and Technology Strategies, LLC and Mehrzad Mahdavi, SPE, Schlumberger

Abstract

Meeting current and future worldwide demand for oil and gas requires continuous improvement in the productivity of reservoirs and oil and gas operations. Upstream oil and gas operations are now focusing on the increased use of real-time information technology to the norm seen in many industries, including downstream manufacturing operations. Crossbreeding of oilfield science and culture and information technology is helping to implement advanced system engineering and optimization processes to total asset awareness for maximizing the performance of people and processes. This has opened up opportunities and requirements for the preparation of a new generation of petroleum engineers. There is a growing level of interest and curiosity from practicing petroleum engineers to understand and to potentially join the evolving professional track of digital petroleum engineers.

This paper brings points of view from the academia, industry and service companies to describe the opportunities, the Industry strategies, and approaches concerning the human element of applying digital technology. Strategies are discussed for training engineering graduates on the concepts and practices that are making this professional track perhaps the most evolutionary change in manpower training since the inception of the petroleum industry.
Plunger Lift Dynamic Characteristics in Single Well and Network System for Tight Gas Well Deliquification (SPE 124751)

Yula Tang, SPE, Chevron Energy Technology Company

Abstract

This paper presents a study for plunger lift characteristics to dewater tight-gas wells operated in the Piceance basin of Rocky Mountains with multiple-well pads and surface pipeline network. The wells' TVDs are about 6000 ft with deviated paths, and the water-gas-ratio (WGR) is 40~80 stb/MMscf. The objective is to understand the optimal operating conditions for reasonably controlling deliquification without severe liquid surge while maintaining maximum gas production.

The IPR and reservoir depletion are based on tight gas model, which considers the transient IPR due to very low matrix permeability, hydraulic-fractures and drainage radius. A transient dynamic multiphase flow analysis has been performed to investigate the plunger lift effectiveness, performance and optimization for different scenarios. Simulation runs were performed for early, middle and late field life which corresponds to different reservoir pressure and productivity index. It shows that liquid loading becomes severe and production becomes unstable (heading) with decreased reservoir pressure and increased water influx. Eventually the well production can stop due to liquid loading. Plunger lift helps to maintain the production and reduce the instability. A network model with 22 wells on a pad has been built to study the interaction of the system and the liquid surge control strategy.

Plunger-lift process for tight gas wells with liquid loading problems needs integrated dynamic modeling for both reservoir and wellbore systems. The philosophy of optimization is that, the reservoir and wellbore system should be the "master" for production optimization, and surface control should serve as a "slave" system.
A New Pressure-Rate Deconvolution Technique Based on Pressure Derivatives for Pressure Transient Test Interpretation (SPE 134315)

Mustafa Onur, Istanbul Technical University, and Fikri J. Kuchuk, Schlumberger

Abstract

In this paper, we present a new deconvolution method that removes the dependency of the deconvolved constant-rate drawdown responses to the initial reservoir pressure. As is well known, particularly the late-time portions of the deconvolved responses from the recent pressure-rate (p-r) deconvolution algorithms are dependent on the initial reservoir pressure. A small error in the initial reservoir pressure could make a significant difference in the late-time portions of the deconvolved responses that can easily lead to an incorrect interpretation model, particularly misinterpretation of the boundaries. The new method presented is based on pressure-derivative data rather than pressure data that are used in all published deconvolution algorithms. Using pressure-derivative data in deconvolution leads to a nonlinear least-squares objective function that is different from those used in the earlier deconvolution methods and eliminates the dependency of the deconvolved responses to the initial reservoir pressure. Hence, the new method minimizes incorrect interpretation due to an error or uncertainty in the initial reservoir pressure.

We apply the new method to both simulated and field pressure-transient data sets. The results show that the new method offers a significant advantage over the earlier deconvolution methods for pressure transient test interpretation in cases where the initial reservoir pressure is unknown or uncertain.
Ensuring Well Integrity in HP/HT Wells: Brunei Case Study (SPE 136884)

Salim Taoutaou, SPE, Schlumberger; Alanh Luangkhot-Bonnecaze, Total E&P; and Aaron Dondale, SPE, Bipin Jain, SPE, and Nazri Abdullah, Schlumberger

Abstract

Zonal isolation and long-term cement integrity in the high-pressure/high-temperature (HP/HT) environment are critical to optimizing production and minimizing future well intervention and replacement. In addition, the well stresses vary over a large amplitude during construction, testing, and production of such wells. There is, therefore, significant value in avoiding failure of the cement sheath.

In 2007, Total E&P Borneo commenced an HP/HT campaign in Block B offshore Brunei to drill development wells with deeper exploration sections. These HP/HT wells are the most technically challenging for well cementing in terms of preserving long-term well integrity; these wells are exposed to high temperatures exceeding 165°C, pressures exceeding 69 MPa resulting from different operations, including production. Cementing these wells using conventional cement and practices has proven not to be effective. This leads to the introduction of new technologies and newer cementing techniques to ensure long-term seal of these wells.

This study identifies first the risks associated with cement sheath failure under downhole stresses. Then it discusses the successful implementation of a solution that ensures a complete zonal isolation of these HP/HT wells, consequently avoiding unnecessary and costly well intervention.
Well Integrity in Heavy Oil Wells: Challenges and Solutions (SPE 137079)

S. Taoutaou, SPE; T.M. Osman, SPE, M. Mjthab, SPE, Schlumberger; N. Succar, Oudeh Petroleum

Abstract

Unconventional resources such as Heavy oil are becoming a target of most operators. Wells subjected to steam stimulation for heavy oil recovery are exposed to extreme temperature changes that can vary from 21°C to 348°C. This temperature cycling can have a drastic effect on the set cement sheath causing it to fail with a consequent loss of the well integrity. Loss of hydraulic isolation in the cement sheath will decrease control of steam placement leading to reduced hydrocarbon recovery and potentially health, safety and environmental challenges.

Oudeh Petroleum Company (OPC) has been producing heavy oil since 2006 using the Huff and Puff technique. Complete Well Integrity has been achieved using an Advanced Cement System in more than two hundred wells exposed to steam injection temperatures up to 348°C and consequent high induced thermal stresses (Fig. 1 & 2).

This paper will discuss the methodology of the risk analysis of the cement sheath failure under steam stimulation and selection criteria for the Advanced Cement System to withstand temperature cycling. Two case histories will be presented as well as a 50 well database.
Performance Model Analysis for Candidate Recognition (SPE 138229)

J.S. Tan, SPE, and Y. Del Castillo, SPE, Schlumberger DCS, and R.D. Reese and C. Pinzon, SPE

Abstract

The main objective of the project was to increase operation efficiency through monitoring production and injection performance in 18 Permian Basin fields (waterflood and natural depletion). A performance model (PM) technique has been developed to efficiently analyze massive amounts of production and injection data from thousands of wells. Using the PM technique, under-performing wells and patterns were rapidly identified and ranked for workover opportunities. Additionally, non-responsive injection areas (composed of several patterns) were also identified to enhance injection efficiency. The PM technique was implemented in 18 fields in the Permian Basin. The largest field having more than 1300 wells was evaluated.

The PM technique described here is based on a modified heterogeneity index (MHI) concept. This improvement was necessary since calculations using traditional heterogeneity index (HI) skewed the results and incorrectly quantified the performance comparison. The MHI has successfully corrected and overcome traditional HI weakness.

The PM is an improved candidate recognition technique that uses binary codes and personality concepts to effectively monitor wells and injection patterns. The personality characterization process creates and uses several interpretation scenarios to identify problematic wells, patterns or both.

PM methodology and personality concepts are discussed in detail and field implementation results are presented.
A New Methodology for Prediction of Bottomhole Flowing Pressure in Vertical Multiphase Flow in Iranian Oil Fields Using Artificial Neural Networks (ANNs) (SPE 139147)

M. Mohammadpoor, University of Regina; Kh. Shahbazi, Petroleum University of Technology; and F. Torabi and A. Qazvini, University of Regina

Abstract

In this paper, Artificial Neural Networks (ANN) are used to predict the bottom-hole flowing pressure in vertical multiphase flow. Two-phase flow of gas and liquids is commonly encountered in the production and transportation of oil and gas. Knowing the bottom-hole pressure (BHP) of a well and the productivity index (PI or J) can help predict the well potential during its life-cycle. In other words, well production monitoring can be performed, which is a key objective for oil production maximization and operational cost reduction. Different correlations considering different operating conditions and flow models were studied in order to find the most effective input parameters. ANN accuracy is highly dependent on the validity of the input and output data. After gathering the input and output data from selected southern Iranian oil fields, all the data were filtered with the help of existing models to eliminate the unreliable data. Then, 167 data sets were normalized and carefully imported into the ANN models. Different ANN models with different numbers of hidden layers and transfer functions were developed and tested, and the best one with the least error was chosen. The accuracy of the pressure predicted by the developed ANN model was improved by approximately five times as compared with existing correlations. To show the accuracy of the method, the results are compared with those obtained from the existing correlations.

Accurate prediction of pressure drop in vertical multiphase flow is needed for effective design of tubing and optimum production strategies. Different kinds of two-phase flow correlations have been developed and are currently being used in industry. In addition to the limitations on the applicability of all existing correlations, they all fail to predict the desired accuracy of pressure drop predictions.
First Installation of Five ESPs Offshore Romania - A Case Study and Lessons Learned (SPE 127593)

L.A.P. Camilleri, SPE, Schlumberger, and T. Banciu, SPE, and G. Ditoiu, SPE, Petrom S.A., OMV Group

Abstract

Petrom operates offshore oil and gas fields on the continental shelf in the Black Sea in Romania. These mature fields were discovered in the late 1970s and early 1980s in sandstone reservoirs with average well depths of 5500ft to 7200 ft (1700m to 2200m). Until recently, production has been with both free flow and gas lift. Over the past three years, ESPs have been installed in five wells resulting in production increases. The paper reviews the ESP completion designs and focuses on the impact of real-time data on the run lives and uptimes achieved over the past 3 years. To analyze the well performance, a new technique based on the ESP torque equilibrium equation between the pump and motor was utilized to reconstruct a continuous rate versus time profile using real-time data. This provided greater resolution in rate measurement than that provided by traditional surface well testing, which proved instrumental in understanding the ESP behavior in these wells which exhibited low flowrates (typically less than 100 Sm3/d, i.e., 600 bbl/d) and high GORs. The authors explain how the technique is valid in both transient and steady state conditions and therefore calculates the instantaneous flowrate at any time when real-time data are available. This continuous “rate log” as opposed to episodic rate data from well testing enabled superposition technique to be used to monitor drainage area average reservoir pressure, to confirm the relationship between motor temperature and well rate, and to observe the effect of high GVF (Gas Void Fraction) through the ESP. In the future this methodology can be used for back allocation and a reduction in surface well testing. In addition to the interpretation of rate data, there are important lessons learnt on how to achieve high ESP uptimes in excess of 98% using real-time data alarms.
Digital Oilfield Implementation in High Pressure High Temperature Sour Gas Environment: Kuwait Oil Company Challenges & Guidelines (SPE 149758)

Q. Dashti, A. Al Jasmi, and B. Al Qaoud, Kuwait Oil Company; Zaki Ali and J.C.G. Bonilla, Schlumberger

Abstract

In 2009, Kuwait Oil Company (KOC) launched the Kuwait Integrated Digital Field Jurassic (KwIDF-Jurassic) Project as a cross-domain solution consisting of a fully integrated infrastructure supporting field instrumentation, automated workflows, and ergonomic collaboration. The Jurassic gas field is a challenging environment consisting of heterogeneous carbonate reservoirs with natural fractures that can contribute significantly to productivity. Parts of the Jurassic reservoir consist of a tight matrix with a high density of connected fractures, but in other areas fractures are sparse and have limited connectivity. The high-pressure, high-temperature (HPHT) environment, the near-critical nature of the reservoir fluids, and the presence of H2S and CO2 are additional challenges for the development of the Jurassic complex.

This project is the first in Kuwait to instrument gas wells with pressure and temperature gauges; H2S, gas, and corrosion sensors, and safety and control devices as a first step toward delivering on KOC’s vision for integrated operations. The application of intelligent automation at the wellhead and advanced instrumentation minimizes the health, safety, and environmental (HSE) exposure of field personnel. Interventions at the wellsite can be supported by handheld portable devices embedded with work orders. New digital field work processes, supported by collaboration rooms, enable proactive, real-time decisions in accordance to the exploitation strategy defined for the field. One outcome is to use technology to leverage the competence of disciplines, such as the subsurface team, to contribute in real time to production operations as opposed to the traditional nonoperational role of studies and reviews.

This paper presents a case study demonstrating the methodology and tools KOC has used to achieve timely and reliable data delivery for the Jurassic asset as part of the KwIDF-Jurassic Project.

César Bravo, Halliburton; Luigi Saputelli, Hess Corporation; Francklin Rivas and Anna Gabriela Pérez, Universidad de Los Andes; Michael Nikolaou, University of Houston; Georg Zangl, Fractured Reservoir Dynamics; Neil de Guzman, Intelligent Agent Corp; Shahab Mohaghegh, West Virginia University and Gustavo Nunez, Schlumberger

Abstract

Artificial intelligence (AI) has been used for more than two decades as a development tool for solutions in several areas of the E&P industry: virtual sensing, production control and optimization, forecasting, and simulation, among many others. Nevertheless, AI applications have not been consolidated as standard solutions in the industry, and most common applications of AI still are case studies and pilot projects.

In this work, an analysis of a survey conducted on a broad group of professionals related to several E&P operations and service companies is presented. This survey captures the level of AI knowledge in the industry, the most common application areas, and the expectations of the users from AI-based solutions. It also includes a literature review of technical papers related to AI applications and trends in the market and R&D.

The survey helped to verify that (a) data mining and neural networks are by far the most popular AI technologies used in the industry; (b) approximately 50% of respondents declared they were somehow engaged in applying workflow automation, automatic process control, rule-based case reasoning, data mining, proxy models, and virtual environments; (c) production is the area most impacted by the applications of AI technologies; (d) the perceived level of available literature and public knowledge of AI technologies is generally low; and (e) although availability of information is generally low, it is not perceived equally among different roles.

This work aims to be a guide for personnel responsible for production and asset management on how AI-based applications can add more value and improve their decision making. It also illustrates how AI techniques will play an important role in future developments of IT solutions in the E&P industry.
ESP Retrievable Technology: A Solution to Enhance ESP Production While Minimizing Costs (SPE 156189)

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Abstract

The easy oil production is gone and current field developments require new approaches to produce oil and gas reserves in the most effective, economic and safe ways. Around the world, more than half of the wells are assisted by an Artificial Lift (AL) system. The use of these AL methods opens a range of opportunities to produce from low pressure reservoirs, low GOR, high water cuts and many others constrains that operation & production engineers are facing nowadays.

Electro Submersible Pumps (ESPs) are widely used around the world as one of the most common solution for the current field development conditions.

However, ESPs represents a challenge itself in terms of production management, intervention cost and run life cycle. Eventually, all ESPs will fail and the need of a workover will be present repeated times during the well life; and many causes of failure are beyond the control of either manufacturer or operator.

To solve this issue, several types of ESPs deployment systems were designed and are currently in use around the globe (e.g.: standard tubing deployed, thru tubing conveyed, CTU deployed), but each one of them has its own limitations.

In order to enhance ESPs installation conditions, capabilities and run life management, a new approach resulted on the design of an ESP Retrievable system that will complement current major ESP providers’ equipment portfolio. This technology gives the operator the opportunity to retrieve and rerun the ESP without a rig intervention by only using WL, sucker rods or CTU equipment.

The technology can be used either onshore or offshore to manage and optimize oil production by taking aside the rig need to change the ESP. This improves the oil recovery, minimizes environmental impact and increases the field safety management while reducing the overall well cost.

This paper will explore the technology design, capability and constrain, cost analysis and will conclude with installation experiences and results.
Managing LNG Deliverability: An Innovative Approach Using Neural Network and Proxy Modeling for Australian CSG Assets (SPE 160445)

Shripad Biniwale and Rajesh Trivedi, Schlumberger

Abstract

Accurate prediction of individual well potential and estimation of field capacity are the key for managing Coal Seam Gas (CSG) wells and its deliverability to Liquefied Natural Gas (LNG) plant. Because there are no downhole gauges in these wells there is limited reservoir data. The associated uncertainty, the absence of fast predictive wellbore models and challenges in generating accurate well performance predictions add to the deliverability challenge.

This paper presents a method used to estimate CSG well performance for Australian CSG assets using neural network (NN) and proxy modeling. Traditional methods for prediction of well potential, such as numerical simulation or statistical techniques, have significant limitations. Numerical prediction is traditionally accurate but very complex in setup and computation; statistical techniques have the advantage of being fast but often lack accuracy.

The approach starts with the automatic acquisition, validation, and quality control of static and dynamic production parameters in proxy modeling. Based on the relationship and similarity of key performance indicator (KPI) profiles, the wells are grouped into various clusters using a NN self-organizing map (SOM) technique. For each cluster group, a workflow is defined to estimate various well parameters used to predict individual well potential. A generic proxy model can be designed for each cluster for future prediction and capacity modeling. The workflow also allows tracking of capacity at different operating points on a daily basis for wells, group of wells, and fields and can be leveraged further by generating scenarios for various constraints on production parameters and facility controls. The entire workflow process can be standardized, scheduled to run automatically, and stored in a workflow library for secure deployment and sharing across the organization.