How to establish an integrated production management system across the reservoir lifecycle

Stian Engebretsen[1*] introduces an integrated production management workflow.

Introduction

Successful reservoir management today is inextricably linked with the field's production system and a complete evaluation of the behavior of that system throughout the reservoir lifecycle.

Operator challenges include the need to efficiently design and safely operate production systems for optimum oil and gas delivery under any conditions; the ability to assess a wide variety of scenarios to understand the limits of the production system while still optimizing recovery; and the importance of minimizing downtime by effectively responding to events that impact flow.

There is also a need for operators to communicate between multiple technical domains from reservoir characterization, flow simulation and network simulation to processing facilities.

Yet, is today's exploration and production software able to effectively integrate reservoir engineering and production environments and effectively utilize reservoir models so that operators can obtain a complete picture of the field and have a fully effective reservoir and production management solution?

This article will examine whether this is being achieved and introduce an integrated production management workflow from Emerson.

The path to greater integration

In the last few years there has been an increased focus on integration where operators interpret and action real-time reservoir models and production information to optimize field operations.

Operators today can predict reservoir volumes and put in place effective simulations of the reservoir; establish real-time facility monitoring and production surveillance plans; phase in or re-route wells; and monitor the reservoir and the often complex production infrastructure of wells, flow lines and flow control devices. The result is an integrated production management and reservoir monitoring environment.

Yet, for all these new developments, obstacles still remain, particularly owing to the lack of integration between reservoir simulation and production management software. All too often, these consist of different domains, different workflows and the limited sharing of information.

There is a need for an integrated production management system and for the daily management of oil and gas production to be combined with simulation data to provide vital input to field development plans. The rest of this article will illustrate how this can be achieved, citing a number of application examples.

A new integrated production management workflow

Emerson has developed a new reservoir monitoring and production management software solution that meets many of these challenges.

Designed for reservoir engineers, production technologists and facilities personnel, Roxar METTE is an integrated flow assurance and production modelling software that is designed to evaluate production performances, monitor the reservoir, and simulate and optimize field development strategy and production facilities decisions.

The result is an integrated flow assurance and production modelling solution that:

1) provides operators with flow performance calculations for wells and flow lines;
2) integrated field modelling with network simulation and optimization throughout the life of a field;
3) transient flow for the dynamic analysis of wells and flow lines; and
4) virtual metering for the allocation and monitoring of production to wells.

Let us examine each of these stages:

Flow performance calculations for wells and flow lines

A key challenge for production engineers is to understand the fundamental flow and pressure relationship of the wells, flow lines and risers in a production system. A flow performance calculator is therefore an invaluable diagnostics and development tool for gaining insight into the duality of flow and pressure.

In selecting the optimal design for a single well or flow line to guarantee a successful field development strategy, several factors need to be considered. This includes determining the tubular size, quantifying the effect of artificial lift and pressure boosting, analysing the insulation effects on the thermal profile, and evaluating the impact of parameter changes.

It is with this in mind that the multi-phase flow simulator within the Emerson software addresses issues such as tubing sizes or thermal insulation levels for optimal system performance. Artificial lift elements, such as gas lift or Electric Submersible Pumps — ESPs), can all be simulated as part of the workflow to quantify effects. Furthermore, a network look-up module enables the user to perform characteristic calculations and run sensitivity analyses on parameter changes.

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Users can also look at different boundary conditions and assess the effect of different settings, such as valve positions for chokes and power for variable speed drive pumps. Figure 1 illustrates the evaluation of scenarios and running of a sensitivity analysis within the software.

Integrated field modelling and life-of-field simulation

Obtaining a deep understanding of network behaviour can often be a challenge, and for large, complex systems it can be close to impossible without the aid of network solvers. To this end, the software includes a life-of-field simulation module that models production networks and provides a seamless connection to multiple reservoir processes.

The module has been used extensively in fields such as the Ormen Lange field development offshore Norway and the Shtokman field in the Russian part of the Barents Sea, and currently plays a key role in bridging the gap between production and reservoir engineering.

Networks can include unit operations, such as choking, pumping and compression and heating/cooling, with the user able to adopt databases, proxy reservoir models and/or reservoir processes as data sources.

The simulation module takes into account user-defined production constraints and employs an event module that automatically determines the need for choking, artificial lift and pressure boosting.

By directly connecting to reservoir simulators, the software also provides concept-dependent production profiles, with reservoir outtakes reflecting production targets and constraints in the downstream production network.

This capability allows for the seamless simulation of hydrocarbon flow through the reservoir production system to a processing facility**.** This provides life-of-field variations in mass and energy balances for modelling, and optimized power, gas lift and hydrate inhibitor usage.

When coupled to reservoir simulation processes, the production network feeds guide rates back to the reservoir processes, with the guide rates reflecting current production system capacity. The production network can be interfaced to service networks for lift gas and/or continuous hydrate inhibitor distribution, with all networks being solved in each time step.

Well inlet boundary conditions in the network can also be derived from completed, coupled reservoir/network simulations to provide 'proxy' reservoir models. Using proxies for well boundary conditions life-of-field simulations can be carried out quickly, lending themselves to parametric studies for everyday engineering work. Figure 2 illustrates the network simulation module in operation.

The software's calculation speed is high and scales linearly. Dependent on field complexity, life-of-field simulation times

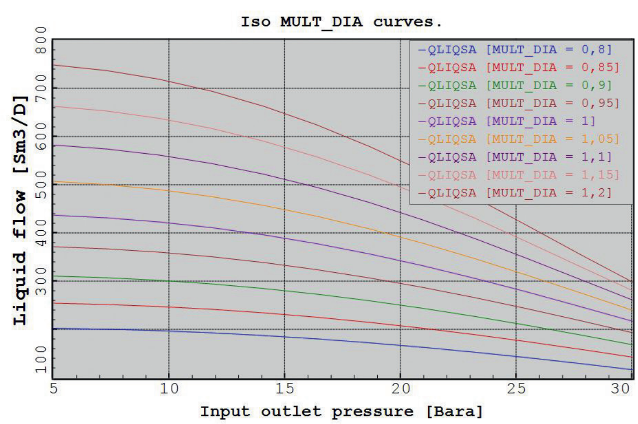

Figure 1 Well liquid flow vs outlet pressure at varying pipe diameters. Well performance calculations allows simple sensitivity analysis of different parameters.

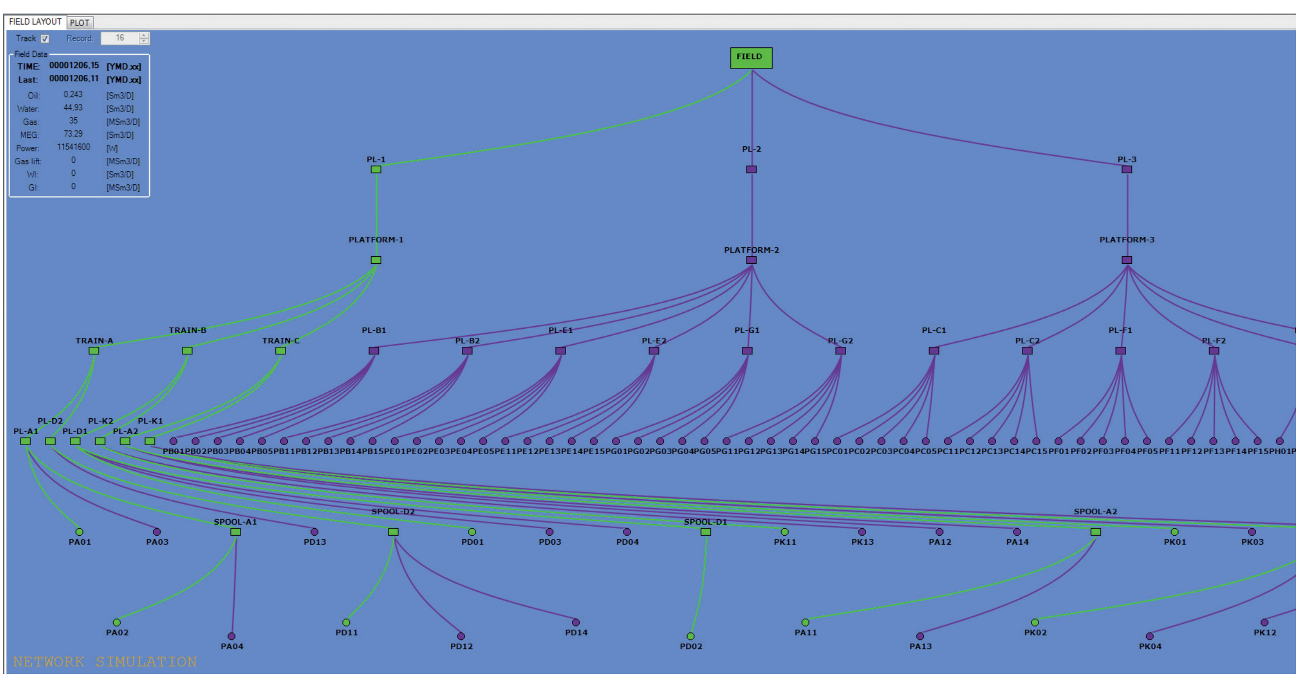

Figure 2 Network simulation: the software has a demonstrated capability for handling large and complex networks, either coupled online to one or more reservoir simulators or by using tank type models for well inlet boundary conditions. In this illustration, the purple line represents non-flowing/non-producing and the green line represents flowing/producing.

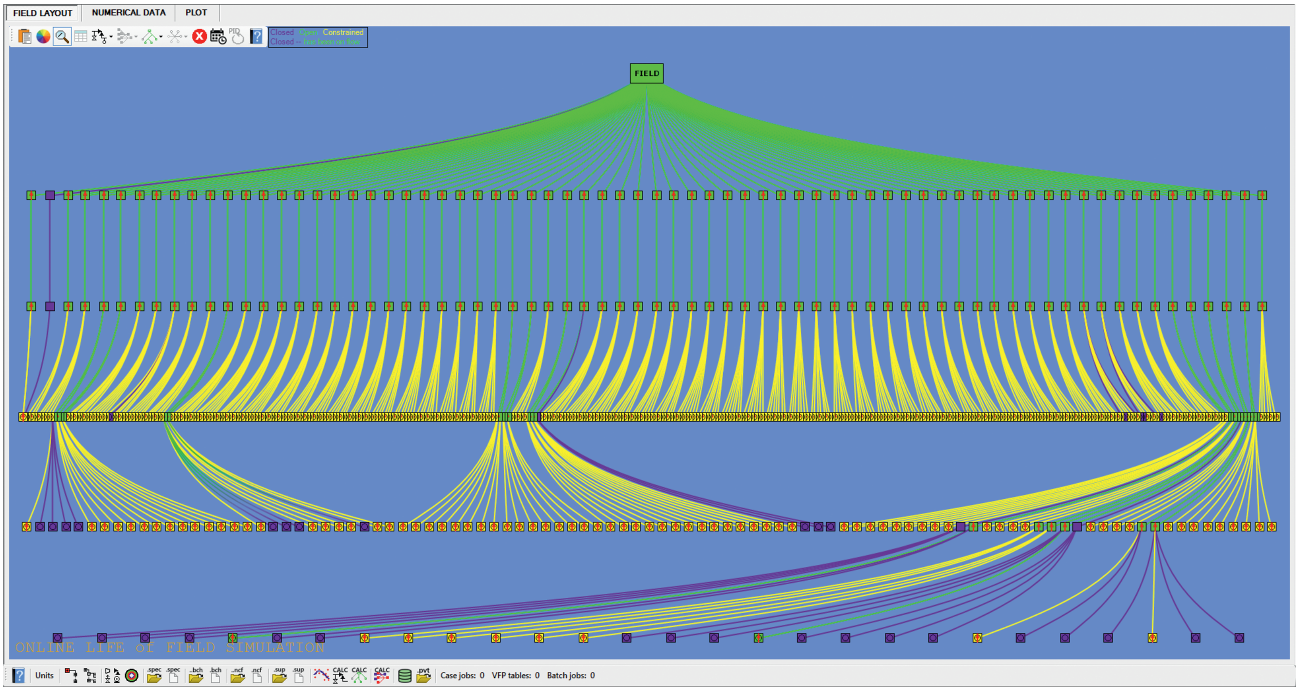

Figure 3 This system consists of more than 650 branches illustrating the software's ability to deal with large systems and complex boundary conditions.

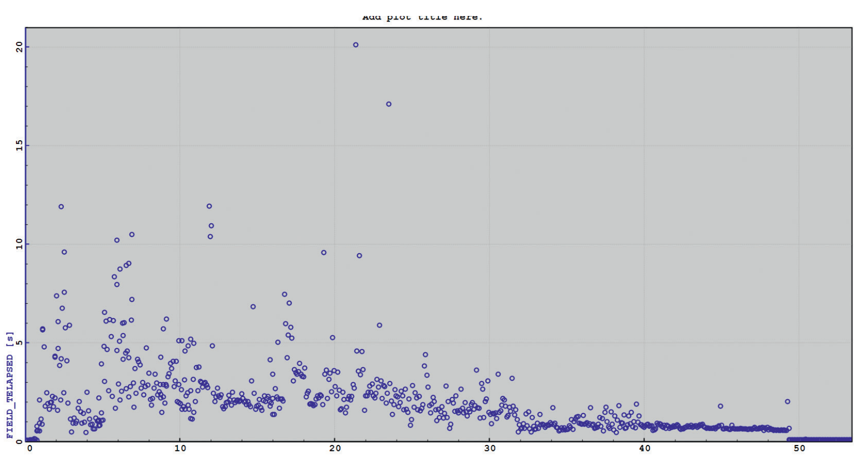

Figure 4 Using the software, field life simulations are typically measured in minutes. Any given frame is normally solved within a few seconds, even when performing gas lift optimization. The figure depicts time consumption for each frame in seconds for a 50-year life-of-field simulation with some 500 wells connected to several hundred flow lines.

are typically measured in minutes. Using type tank models (decline curves), multi-case production profiles can be made very quickly, providing a useful tool for quantifying system parameter changes.

Figure 3 demonstrates the software's ability to handle large and complex networks (as is also the case with Figure 2) with the system in question consisting of more than 650 branches. Figure 4 shows how field life simulation can be measured in minutes.

The variety of available options for production optimization makes the software a powerful tool for investigating different production strategies and seeing the effects on recovery. Among others, this includes options for pro rata, water cut and gas oil ratio (GOR) control using instantaneous values or rate of change in these parameters over a specified time window.

Transient analysis

Another key challenge in production management is the need to optimize the operability of the system – even during critical procedures, such as start-up or shut-down. This is where transient analysis comes to the fore — when used for the time-dependent simulation of well and flow line behavior.

Applications where the transient module can be deployed include cool-down times for different pipe wall insulation configurations, the calculation of the necessary hydrate inhibitor amounts during cold start-ups, and the evaluation of required times for flow line depressurization.

The transient analysis module simulates and tests critical procedures; determines grace times at start-up or shut-down before temperatures are too low and hydrate inhibitors are required; analyses inadvertent events, such as accidental valve openings or choke collapse; and validates established parameters for the PID control module.

In addition, with the significant difference in time constraints between thermal and momentum responses, functionality has been included for simulating thermal transients in steady-state momentum situations. Figure 5 shows the pressure along the profile of a well for a pre-defined choke bean-up during a well start-up simulation.

Virtual metering

Finally, there is virtual metering – a cost effective solution for determining well phase flows from distributed sensor measurements and an efficient alternative or complement to multi-phase flow meters. With virtual metering, operators can utilize available sensor measurements to gain insight into what's flowing in the pipes.

A downhole gauge would provide boundary conditions for the calculations and downstream measurements, and would be compared with calculated values to find the in situ flow rates that minimize the difference between calculated and measured values. A small investment in high-quality gauges when developing new fields can yield significant returns by enabling virtual metering.

Virtual metering can equally be used on historical data without the need for a direct connection to a central data source. Operators can also combine known well flow rates with the PID control module, provide set points for active components such as chokes and pumps, and gas lift supply to achieve production targets subject to defined system constraints.

Virtual metering results can also be used with reservoir model history matching as well as for daily or historical production allocation, providing that all-important link between reservoir engineering, reservoir monitoring and production management across the workflow.

Applications — Tanzania and the North Sea

There are a number of application examples of the new production system in operation – one from Tanzania and two from the North Sea.

At the Tanzania offshore gas field, which includes several high-pressure gas condensate reservoirs, there was a need for an integrated reservoir production system to achieve multiple production targets from individual reservoirs. The system needed to include a continuous hydrate inhibitor supply, an optimization strategy, and the ability to verify the viability of the well phasing and production strategy with respect to the big pressure difference among the reservoirs produced through the same network.

In this case, the software was adopted to validate the viability of the planned production strategy. This included integrating the supply of the hydrate inhibitor, monoethylene glycol (MEG) to the production network; the ability to predict the phasing of pressure boosting (compressors) and power requirements within the network; and the verification of the existing production strategy.

In the first North Sea example, the production management software was used as a flow assurance tool on a medium size

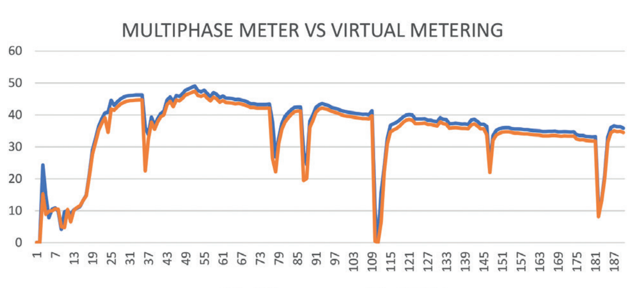

Figure 6 Virtual metering (VM) results for the primary phase of oil compared with a multi-phase meter. The VM is based on downhole pressure and temperature sensors, gauges upstream and downstream of the choke and a venturi with delta pressure. Gas lift is also included, with the amount of lift gas calculated by virtual metering.

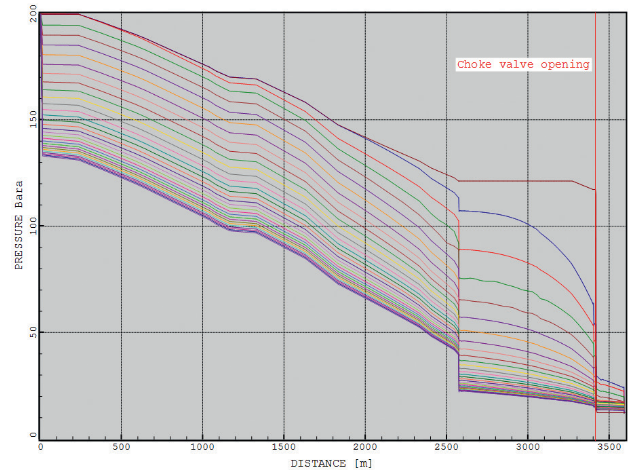

Figure 5 Pressure profile along the distance in a well plotted at varying time steps. The pressure converges to the bottom line in the plot as the well reaches a steady flow.

oil field in the North Sea comprised of three different reservoirs requiring artificial lift in the form of gas lift. With first oil in 2016, the reservoirs are predicted to have a 20-year life.

Many development alternatives were screened in the early phase to create concept-dependent production profiles. The production software was used to perform coupled simulations, interfacing the three separate reservoir simulation models with gas lift optimization.

The production network model was simultaneously interfaced with a gas lift supply network to determine its variation in mass and energy balances. Using decline curves that originated from these simulations, the effects of parameter variations, such as flow line and tubing sizes, were investigated to find optimum sizes based on reservoir model predictions over field life.

Other benefits delivered to the field included the establishment of temperature control at the compressor inlet and for compressor gas; fixed delivery pressure at the final processing facility; the sizing of flow lines for selected development alternatives; a power profile for the production network compressor; and much more.

The second application was in a marginal North Sea oil field with a heavy non-Newtonian fluid that required artificial lifting. In this case, the software provided functionality for the use of shear dependent viscosity data during both steady-state and transient simulations.

Decline curve data from the reservoir simulation model was used as input to a production network model, which was then used to predict artificial lift times, together with system lifetime mass and energy balances. These used two alternative lift methods in the form of ESPs and gas lift.

The strong gelling tendencies of the production fluid also required the implementation of experimental yield stress data to perform realistic transient start-up simulations of the wells and flow lines. The development concept also included SWAG (Simultaneously Water Alternating Gas) for gas reinjection into the reservoir, simulated by the use of the software.

Emerson's DeltaV Distributed Control System

Emerson has also demonstrated the ability to combine DeltaV with their production management software. In this way, operators can use network calculations from their digital control system to calculate optimal set points for active equipment.

The DeltaV DCS is an automation system that simplifies operational complexity and lowers project risk. The combining with the production management software results in the cost-effective allocation of well phase flows; set points for valves and equipment to meet production targets; better-informed decisions; and increased profits through model-driven operations.

Latest innovations

Emerson has also introduced new innovations to the production management software in the latest version — METTE 2.0 — to be launched in 2018.

The new version delivers advanced modelling capabilities to account for frequency-controlled pumps or compressors in the production system, enabling more realistic responses.

Wells can also be converted from producers to injectors or vice versa during simulation for increased flexibility, and outlet streams from separators can be routed to specific flow lines, providing produced water feed to a water injection system or oil and gas to dedicated pipelines, for example.

Predefined IPR (Inflow Performance Relationship) tables can also be used as data sources for wells. Such tables provide information on flowing bottomhole pressure, temperature and phase fractions, and can be combined with existing data sources (proxy/tank models, reservoir processes and databases) for network simulations, thereby complementing reservoir simulators and proxy models.

Furthermore, when coupling the software to the Roxar Tempest MORE simulator from Emerson, it is now possible to run the software on Windows while controlling simulations running on Linux clusters. The latest version also includes facilities for automatic calibrations to avoid time-consuming work in matching predicted model responses to measured field data.

The result is the ability to handle a wide spread of different scenarios, ranging from greenfield to brownfield, offshore to onshore, and field development planning to challenging mature field production optimization.

Conclusion

Operators today are looking for an integrated workflow – from reservoir and production system simulation through to day-to-day reservoir monitoring, production management and optimization.

This can now be achieved through a single engineering-focused application that combines solutions for reservoir flow simulation, production networks and daily production.