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Online Production Optimisation on Ekofisk

Andrew Shere, SPE, and Yvonne Roberts, SPE, Weatherford/EPS, and Synnoeve Bakkevig, SPE, ConocoPhillips

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Abstract
As part of the long tradition of innovative production growth and enhancement projects in the Greater Ekofisk Area, in 2004 ConocoPhillips Norway AS (COPNo) implemented the Onshore Operations Centre (OOC). The OOC facilitates improved collaborative working processes that optimise production and streamline operations through more proactive use of both field equipment and software tools. This paper describes the specification, development and implementation of the online production optimisation software used in this project. This software was provided and developed by EPS Ltd, a Weatherford company, in collaboration with COPNo.

Specification of the system started in 2005, based on years of prior experience with network production modelling tools in the Ekofisk area, to simulate and optimise production from the reservoir to the export meter. The system is designed to fully utilise the OOC's continuous measurement and recording systems, throughout the entire production and process network. This production optimisation system aims to complement the existing informational displays and charts by the calibration and optimisation of complete network models several times a day. The optimisation results and comparison with real-time data and operating objectives are made available to users through a web interface so that they can be used by the operator and partner company staff at any location.

Models of the wells and production/process network have been developed, following extensive discussions with all relevant disciplines, to ensure that these models can resolve the regular questions faced by the Greater Ekofisk operations teams. In addition to the daily simulation and optimisation scenarios run by the full, online system, the constituent parts of the full model can be also run offline to help evaluate exceptional production issues.

The operator is experiencing benefits in two main categories firstly by identification of production problems with wells or plant that prevent the system from achieving target production and secondly by having continuously updated production scenarios available on which planning decisions can be based. These results will be discussed, with many examples.

Introduction
The Ekofisk field is located in the Southern North Sea in Norwegian production license PL018, operated by ConocoPhillips and was discovered in 1969. The ConocoPhillips Group includes Total E&P Norge, Eni Norge, StatoilHydro and Petoro and operates several other fields within this license including Eldfisk, Embla and Tor. Current production from the 150 natural flow and gas-lifted development wells in these fields is over 300,000 barrels of oil with over 300 MMSCF/D of associated gas. The Ekofisk field and the Eldfisk field are also currently being waterflooded (Hermansen 2002) with a total injection rate of approximately 600,000 barrels of water per day. Production from the license block fields is commingled and processed on a centrally located facility, Ekofisk J, and products exported to the market through an oil pipeline to Teeside, UK and a gas pipeline to Emden, Germany.

The production network modelled in this project, including the main facility and pipeline system, is shown in figure 1. The Ekofisk A, B, C, M, X, Eldfisk A, B, Tor and Embla jackets all support production wells with limited separation facilities. The other jackets support compressor and process facilities.

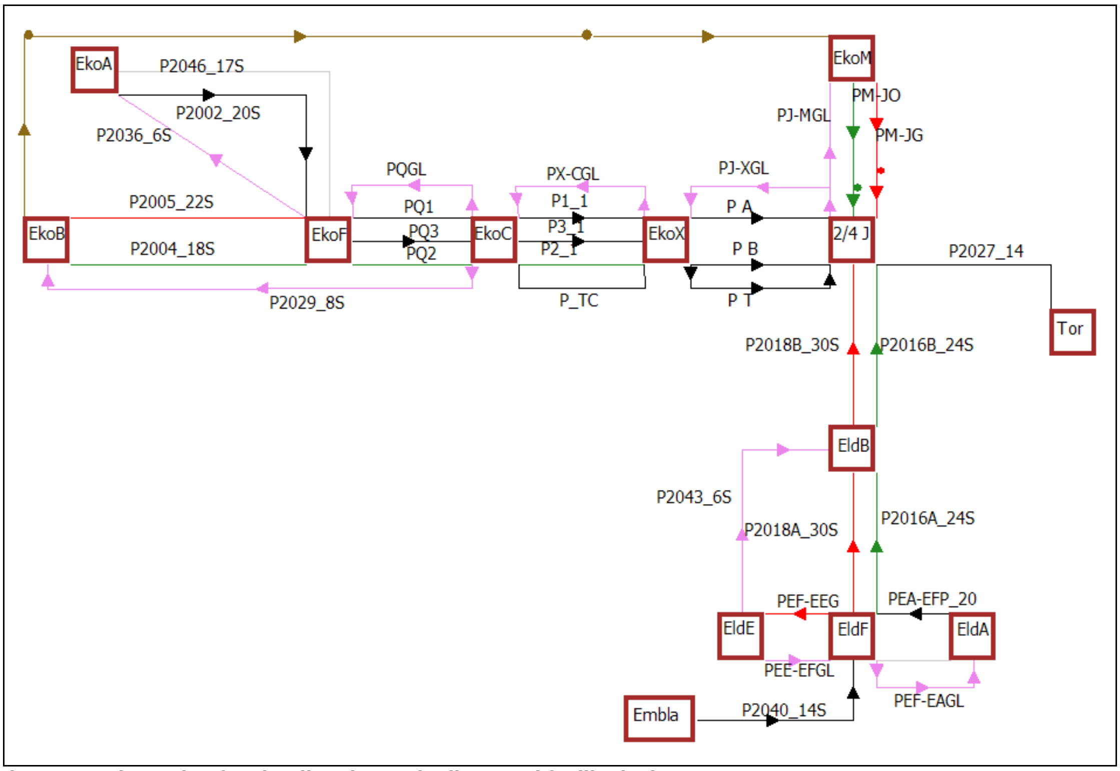

Figure 1: Schematic of main oil and gas pipelines and facility jackets

The Ekofisk J process plant is used for oil/gas/water separation, gas processing, gas lift compression as well as oil and gas import and export. Clearly, the capacity and performance of these facilities is a governing factor in the overall production performance of Greater Ekofisk. A variety of surface network models have been used to assist in the optimisation of the facilities, ranging from conventional process simulation models to full well to export models. The latter type of model (Handley-Schachler, 2000) has been used on the Greater Ekofisk complex since 2000 for total system optimisation. It was initially used for de-bottlenecking studies to evaluate the benefits of re-sizing pipes or chokes or re-routing fluids. More recently, it has been used to perform online well production allocation. However, in a constantly changing environment, updating and calibrating models can be a man-power intensive and time-consuming business..

The multitude and complexity of operations taking place in the Ekofisk area resulted in the operator constructing an Onshore Operations Centre (OOC) in their Stavanger office building. This digitally equipped collaboration centre has been described elsewhere (Bakkevig 2005). One of the objectives of the OOC is to support offshore activities by using real time tools and sharing data and information to contribute and add value to the decision making process. The specific opportunity addressed by the project described in this paper was to optimise daily operational performance to improve infrastructure utilisation.

Typically, offshore and onshore staff meet via the OOC each morning to discuss and prioritise operational activities. One of the main functions of this meeting is to maximise daily production and hence meet business objectives. For example, at this meeting OOC attendees may decide:

- Eldfisk arrival parameters, such as how much gas can be processed,
- Whether to produce or inject ‘swing’ wells,
- Which wells to test or adjust,
- Which equipment to maintain. For example a “water wash” on a LP gas turbine powered compressor will reduce the oil production capacity of the plant for several hours.

Understanding the impact such decisions have on production can be highly complex, especially in a dynamic environment where the conditions can change dramatically from one day to the next. Consequently, decisions often are based more on experience than robust engineering calculations.

The aim of this project was to implement both the technology and methodology to fully understand the implications of actions and recommend the optimised equipment set-points required for each. Prior to each OOC meeting the Online Production Optimisation System (abbreviated to OPOS in this paper) updates production scenarios and can allow attendees to easily review and assess the upside opportunities available and/or minimise the deferred losses. Thus decisions can be based on both engineering data and operator experience. Clearly, not all possible production scenarios can be foreseen, so the OPOS was also designed to be used offline. In this mode it can be used as a ‘what if’ tool for de-bottlenecking, adding new wells, etc.

Robust proven systems were used rather than experimental technologies to ensure that the OPOS was reliable. To provide a complete ‘reservoir inflow to sales point’ asset optimisation model, calibration data was taken from standard production and real time process historian databases. Both the wells and network were calibrated and modelled using the same industry standard software that has been used by the Ekofisk asset teams for many years. During the configuration of the OPOS, all models were reviewed and updated to ensure that they contained the latest well and plant details. The systems were then linked using software developed with modern web and database server-based tools.

Throughout the development of this OPOS, many meetings were held with staff involved in well and process engineering and onshore operations to ensure that the models and user interface incorporated the key systems and constraints. It was decided to model only the production systems, but the optimisation model still has to take account of reservoir management constraints, such the maximum choke sizes imposed on wells to ensure optimal offtake form the reservoir without damage to the producing formation.

Well modelling System

Prior to this project, well tubing and inflow performance had been modelled for many years using industry standard software (EPS' WellFlo). However pressure of engineering time had resulted in the models only being updated when critical well operations are being planned, such as gas lift valve changes or formation stimulation treatments. Various spreadsheets had been developed using open interface links to the well modelling software but maintenance of such bespoke solutions is notoriously time consuming and difficult to share as staff rotate between projects. Although each well is only tested about once a month on this group of fields, manually recording and calibrating some 1200 well-tests a year is a significant task, particularly if it is to be carried out in a timely fashion.

The software solution chosen is described later on in this paper, but for the engineer it had to fulfil the following objectives and so improve workflows:

- Calibrate a well model automatically within minutes of well rate measurement tests being completed. Any deviations from trends or extreme calibration parameters should be raised as alarms to the users or initiators of the flow tests. The calibration should use simple principles, so that data errors or well problems are always discovered and not masked by complex and perhaps dubious matching technology. The engineer then remains in control and only has to focus on a much reduced subset of higher-priority wells.
- In addition to warning when calibration parameters have gone out of range or changed too rapidly, allow the engineer to chart parameter and measurement trends in order to help diagnose the cause of well problems highlighted by the system or other indicators
- Provide surface performance charts of oil rate as a function of wellhead pressure and if applicable, gas lift rate, which could be used for operations staff to understand the well's potential compared to the actual operating parameters.
- Ensure that the models and calibration parameters available to users and other online systems are held in a single, defined place, and represent the most up-do-date and accurate versions.

The selected calibration parameters are illustrated in the pressure/depth diagram, figure 2, and described below:

- A tubing length multiplier or "L-factor", was used to match the pressure drop between the measured tubing-head pressure (THP) and the corresponding measured downhole pressure gauge pressure (DHPG) if available.
- A productivity index calculation is performed, using an estimate of reservoir pressure supplied by the user. A similar calculation is available using an assumed productivity index and returning a calculated reservoir pressure, but was not so far utilised.
- For gas lift wells, the measured casing head pressure was matched by calculating the apparent orifice size that matched the measurement. This calculation required the user to pre-select a single lifting valve in the well.

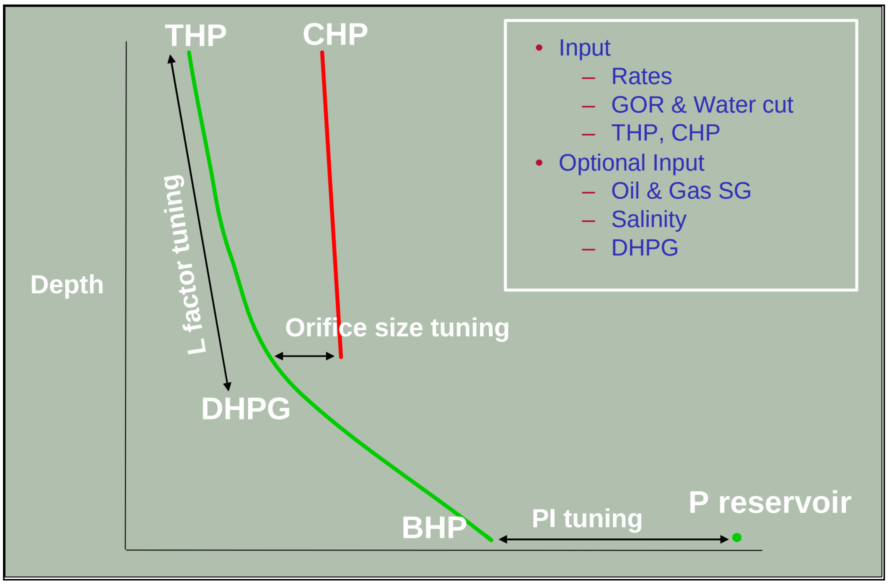

Figure 2: Pressure/Depth diagram of calibration parameters

Well modelling and monitoring examples

The functionality is best illustrated by examples which highlight OPOS monitoring or performance warnings. In each case, the systematic monitoring of well performance by the OPOS system ensures that problems with well production are always spotted, rather than relying on an engineer having the time to review well operating results on a regular basis. There are many production performance monitoring issues in the Ekofisk area wells (Wade 1998), but the following examples illustrate the use of the OPOS in monitoring and remedial planning. It should be noted that these examples all illustrate interpretations of well rate tests, typically conducted on a monthly basis per well. Daily optimisation is carried out by the OPOS network system described later.

Example 1: Gas-lift well monitoring

When gas-lift well injection pressures are available for well rate tests, then the OPOS well lifting-valve calibration result provides a useful monitoring parameter for well gas-lift performance. The example plot, shown as figure 3, illustrates a significant increase over time for the calculated lifting valve orifice size for one of the Ekofisk wells. This increase coincided with the well's gas lift rate also increasing. Lifting efficiency was clearly reducing and the system was no longer working as installed, when the lifting-valve orifice size was similar to that calculated by the OPOS. The change highlighted by the OPOS, allowed the engineer to investigate further with the aim of improving well lifting efficiency. For example if the final rate of 7 MMscf/d could be reduced back to the original 5MMscf/d then the saved injection gas could be used for lifting other wells or the gas processing capacity used for producing other wells when production constraints are imposed.

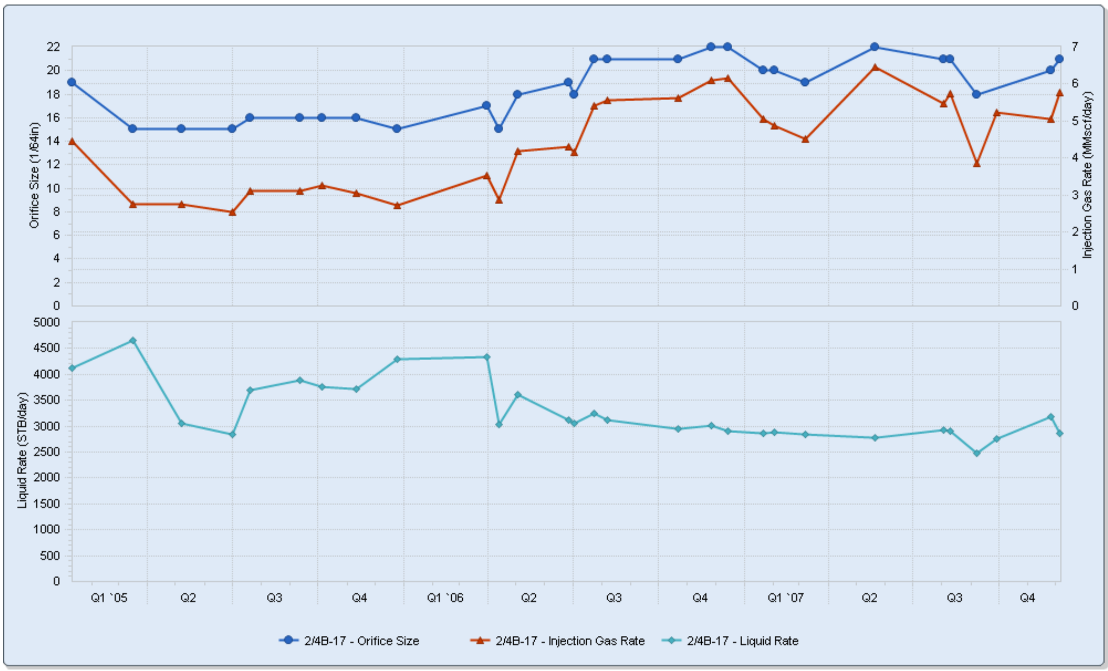

Figure 3: Calibration parameter and production trends from OPOS for gas-lift well example showing rise in apparent orifice size as gas lift rate rises

A set of gas-lift performance curves generated from the calibrated well models for the same well is shown in figure 4. Note that these curves show not only the production rate as a function of lift gas rate and wellhead pressure, but also the minimum lift gas rate for stable flow and the maximum lift gas rate for the avoidance of multi-porting, thereby giving the "operating envelope" of the well. Calibrating the model of this well by adjusting a single orifice size may not be strictly rigorous, but it gives a good indication of the stable range of operation. The results are used in the network optimisation model and ensure that the simulated gas-lift rate will lie between the minimum stable gas-lift injection rate and the maximum available for the compressor pressure.

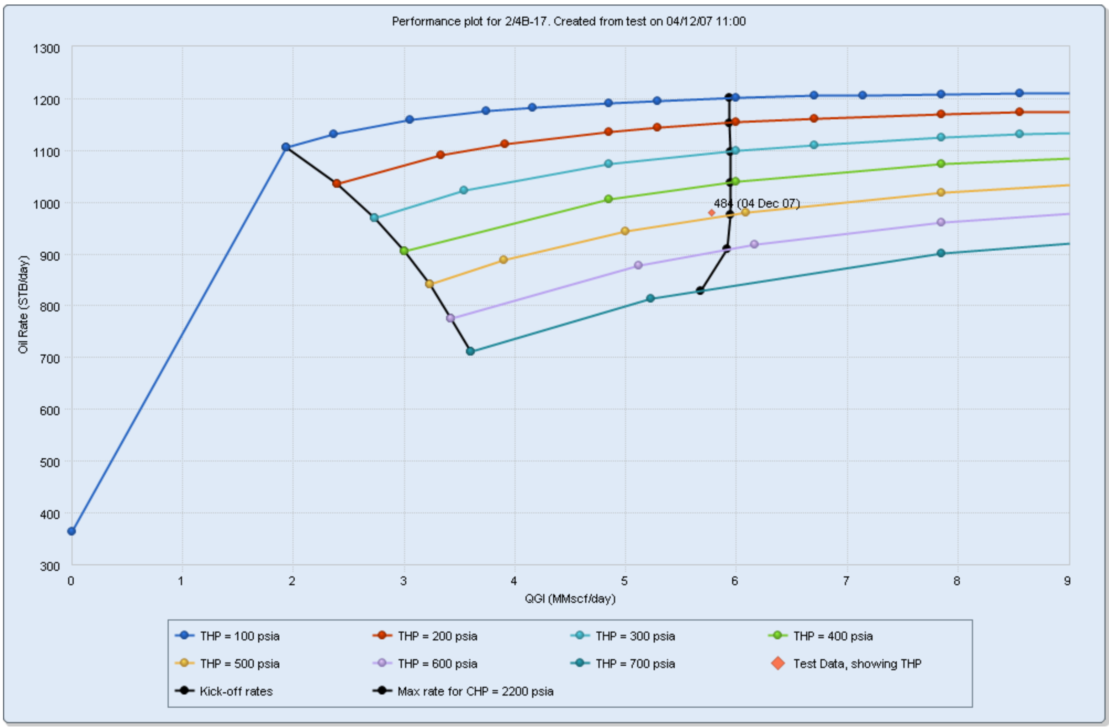

Figure 4: Performance plot from the OPOS for an example gas-lift well, showing lines of minimum stable rate and maximum rate for available injection manifold pressure superimposed on oil rate curves for a range of different wellhead pressures

Example 2: Reservoir Pressure Support

Monitoring the efficiency of the water injection support in Ekofisk is important for planning and maintaining production targets. Figure 5 is a trend plot for a typical natural flow well. It shows the liquid productivity index (LPI) estimated by the system over time, based on an assumed fixed reservoir pressure. In this case, the apparent drop in LPI is likely to be caused by drainage volume reservoir pressure dropping and eventually stabilizing as the well is brought on stream. The reservoir pressure assumptions in the OPOS can be changed to reflect such interpretations and then used for other modelling and planning. As noted above, an optional mode of operation for this diagnosis is to set the LPI (or to define a schedule for it) and to calculate the reservoir pressure as a result.

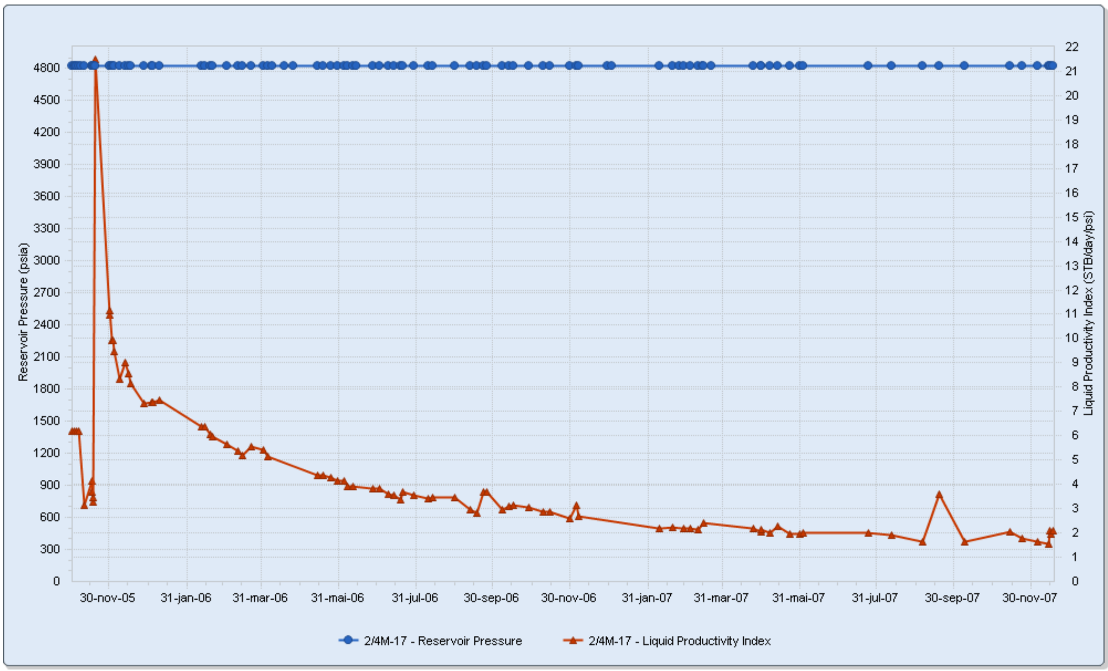

Figure 5: Trend plot from the OPOS for an example well, showing fall in calculated liquid productivity index

Example 3: Tubing flow performance

Many of the wells on Ekofisk are fitted with permanent downhole pressure gauges. The calibration L-factor that is calculated for such wells can help guide interpretation of well performance. The rise in L factor with time, shown in figure 6, is an indication from the well model of deteriorating lift performance. One possibility is that the lift correlation may be inappropriate but such information also prompts production engineers to check other production parameters to ensure that the reasons for the decline in this well’s flowrate are understood. The well may for example being suffering from a build up in scale.

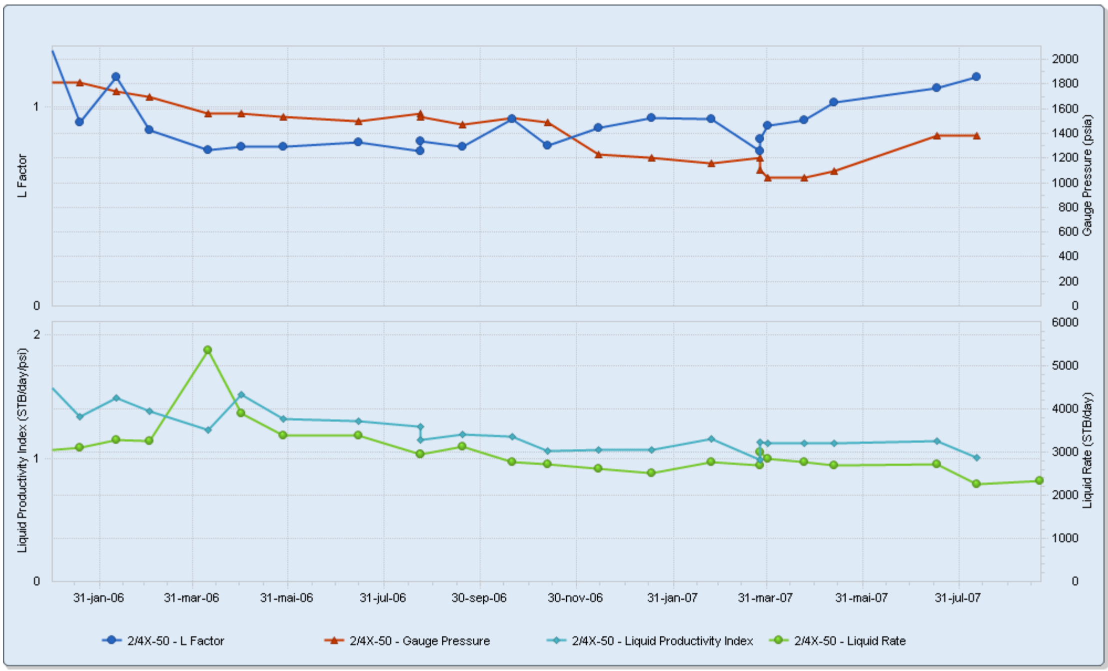

Figure 6: Trend plot from the OPOS for an example well showing a rise in "L-factor" during 2007

Network Model System

One of the main functions of any full-field network model should be to promote understanding of the system and its inter-dependencies as a whole. In order to achieve this broad objective, it is necessary to identify key elements in the network and to then rationalise and simplify them, whilst still maintaining a realistic influence on the rest of the system. Many of these key elements will be common to all investigations undertaken using the model, but some of them will be context-specific and any simplifications made should take this into account. Naming conventions are also important, so that the identity and approximate location of key equipment can be easily deduced.

On this basis discussions were held with engineers and further criteria for the online Greater Ekofisk model identified:

- That the model should be instantly recognisable to all personnel who have a stake in the model and its results. These included well, production, and process engineers from different fields and platforms.
- That it should be easy to trace specific flow streams through the model and to relate wellhead rates to overall production rates.
- That a consistent level of complexity be applied throughout the model, rather than being concentrated in certain areas, e.g. gas processing.
- That the model should be easy to update with future modifications, for example the addition of new wells.

With these in mind, the model was constructed using EPS' ReO software so that, at the top level, it resembles process flow diagrams commonly used by operations personnel, rather than being topological. The number of lower levels was minimised so that navigation of the model is straightforward.

Black-oil fluid descriptions, rather than compositional, were employed to facilitate fluid tracing through the model and allow for easy 'summation' of well and field contributions both pre- and post-separation. This necessitated modelling simplifications of those parts of the Ekofisk process platform which rely heavily on the gas-liquid phase transfer of specific chemical components.

Another area identified for simplification was the pipework on each of the platforms. Offshore platforms often have very convoluted piping systems, with many bends and minor elevation changes. For the sake of clarity and ease of use, the piping for the model was broken down into sections, for example based on pipe diameter, and each section is represented by a single pipe of equivalent overall length and elevation change. Specific waypoints, for example flow meters or pressure transducers, were identified and are incorporated into the model in their correct positions. Some very short pipes were entirely omitted from the model on the basis that they have an insignificant effect on pressure in the system so can be absorbed by other pipes and tuning factors.

Production and gas-lift manifolds on the main platforms were reproduced in the model with their full connectivity, so that wells can easily be added or converted from Natural Flow to Gas-Lifted. However, platforms outside of the remit of the Greater Ekofisk model that contribute to the production totals , e.g. Gyda, were simplified to point sources.

Once the basic physical network is in place, the elements of the system that control or constrain its performance need to be represented. The level of control and constraint in the model completes the description of the problem (scenario) to be solved, and determines the degrees of freedom that the solver has to find a solution, or to identify the optimal solution from a number of potential answers. If the model has inadequate controls, then it may present multiple solutions to the solver with insufficient information to distinguish between them. If it is over-constrained, then a feasible solution may not be possible.

The controls in this model were based on common physical characteristics, as below:

- Physical performance e.g. the maximum compression ratio of a gas compressor stage, wellhead deliverability curves,
- Capacity limits e.g. pipeline or process equipment,
- Wellhead pressures through production choke settings,
- Pressure control valves e.g. to control main separators,
- Flow control valves.

Some of the model constraints were also physically based, but mostly context specific, and were used to limit, encourage or discourage certain model behaviour, for example:

- Imposing measured lift gas rates,
- Minimising water production,
- Defining non-recoverable offtakes, such as Fuel Gas,
- Flow directing, e.g. reversing the flow in a pipe under specific circumstances.

The constraints were generally changed significantly on a scenario-by-scenario basis, or daily, whereas physical controls changed less frequently, if at all.

Scenarios

A number of model scenarios were configured in the OPOS. All the scenarios use key pressure and rate measurements from the process historian to update controls and constraints in the model, along with the most recent well performance curves, generated from the calibrated well models. The differences between the scenarios lie in the combinations of controls and constraints used. The scenarios all employ controls on separator pressures and on production choke diameter settings.

Allocation

The scenario entitled “Allocation” fundamentally differs from the others in the way that it handles the provision of lift gas to the platforms and how the wells are allowed to operate.

In Allocation, the amount of lift gas delivered to each producing platform is constrained around measured values and the solver then determines the allocation to each well based on its deliverability curves. However, the solver is further constrained in that the range of allowed wellhead pressures for each well is controlled by the fixed production choke setting. The model solution is compared against measured values for each well (lift gas rate and wellhead pressure), with any significant mismatches usually indicating that either the well deliverability curves are out of date (which should prompt a production test) and/or the choke performance requires tuning.

Optimisation

In the Optimisation scenario, there are no constraints on platform lift gas rates and the solver is allowed to raise individual wellhead pressures by reducing the choke diameter in order to favour other, more productive, wells. To ensure that any incremental oil gains are worthwhile, a unit cost is placed on all lift gas, which the solver balances against the value of the produced oil and other costs and values in the system.

Two further scenarios were set up, based on the Optimisation scenario, in which further constraints were applied to the low pressure gas processing capacity. These are described in more detail below with an example of the results.

Online Production Optimisation System

The OPOS was designed to make integration into the existing IT architectures as simple as possible. This was achieved by conforming to the following principles in the development of the system:

- Open Software Standards – at all places in the system where communication is required with enterprise systems, open and easily integrated technology was used.
- Component Based Design – the software was developed using industry standard component technology, conforming to standard interfaces, allowing easy replacement of components by others of equivalent functionality.
- Simple Deployment – the user interface was built using server generated web pages. Consequently system deployment is relatively straightforward and the system could easily be customised if required.

These principles were used to construct a system using EPS’ i-DO environment which comprises three logical parts:

- Web Server – processes the user interface and handles requests via web based protocols for OPOS functionality.
- Application Server – powers the engineering applications that are included within the solution and the system functions for accessing and managing these applications. In this project the applications were well modelling and network modelling/optimisation.
- Database Server – powers the database that the OPOS uses to maintain system state and the functionality required to access and manage that data.

Simple links were established to existing production databases for well rate tests and process historian databases for plant data. The well rate test results are automatically transferred to the operator’s in-house production database from the offshore SCADA and the linking software transferred these to the OPOS. Online data is generally available in the process historian shortly after acquisition and the historian software is also used for simple processing such as averaging, prior to transfer and use in the OPOS.

The OPOS was designed with an architecture that can make use of emerging standards, such as the PRODML information exchange protocols (Weltevrede 2007), for data retrieval once the standards are implemented. Results from the OPOS are made available to other systems either by providing views of the underlying database of results or by sending the results and warnings to other of the operator's systems. Again the flexibility to use PRODML is maintained.

One of the problems with using online data for steady-state well or network model calibration is that measurements will often fluctuate due to unsteady state phenomena such as slugging or intermittent operation of control valves. Errors in instrument readings are also a potential problem, particularly if they are non-systematic. The OPOS deals with these at several levels. At the lowest level, the process historian data interface can be used for filtering data. The historian interface includes simple checks for data going out of range etc. At the intermediate level, data is then filtered by rules applied in the scripts used for defining process historian data to the OPOS. For example, checks on consistency between two measurements might be made before passing a reading to the OPOS models. At the top level, model calibration error messages will indicate when there are data errors or inconsistencies. Although such checks are workable, there is scope to improve the automatic reporting of such instrument errors to maintenance staff and hence improve plant operation.

The web-based GUI of the OPOS is used for configuring and scheduling network model production scenarios. It is also used for displaying the results from such scenario runs in tabular, line-chart or diagrammatic form and comparing these results with actual values acquired from the process historian. These displays can be used to understand the detail of options suggested by the system and quickly determine if the actions are worthwhile applying. Results from previous scenario runs are held on the OPOS database as long as required for trend plotting or detailed investigation.

All the above features help reduce the time required for engineers for running network models and allow them to be used routinely to help in planning. Modifications to existing scenarios can easily be made and run via the OPOS GUI or the network model downloaded via the GUI, and then edited and run offline.

Reservoir to Export Optimisation Examples

The complete production system optimisation benefits can be categorized as:

- Optimisation of the system when planned changes are made
  - The calibrated network model can easily be exported, edited to reflect possible system changes and then either run offline or imported and run again with the latest online data. This allows convenient investigation of changes not envisaged with the routine daily scenarios, for example modelling the true field increment from a planned new well.
- Benefits shown up by the differences between daily optimisation model scenarios
  - Routine daily scenario runs may show up advantageous ways of operating the system, particularly when well or other performance has changed
- Allocation and data or system diagnostics
  - Differences between the network runs and the actual metering show up either potential parts of the system in which there are production problems or often where on-line metering has failed. Even in the latter case, production benefits can often arise from re-instating such failed meters and allowing them to be used for reliable monitoring again

Examples of each of these categories will be discussed below.

Example 1: Planned changes to production system

As part of a major upgrade of the Ekofisk production system the operator installed a new well and production separation jacket, Ekofisk M, which came on stream in 2006. Production from Ekofisk B was scheduled to be processed on Ekofisk M as part of this refurbishment and enhancement program. However, there was concern that the increased back pressure on the wells caused by the re-routing would significantly reduce this flowrate, which at the time of commissioning was much higher than previously anticipated.

An offline model was created in 2006 to investigate the effect on Ekofisk B production of flowing all the wells from the jacket to the HP (300 psia) separator on Ekofisk M rather than to the HP and LP separators on Ekofisk B, typically running at 350 and 250 psia respectively. The model showed that production would be little affected, mainly because wells were already constrained for reservoir management reasons and their wellhead pressures are effectively insulated from back-pressure effects.

There was concern whether this result would continue to hold as reservoir management criteria changed. A careful re-examination of well models was made for the Ekofisk B wells and new estimates of reservoir pressure made, based on knowledge of the wells' performance under gas lift at different rates. The network model was then put on line and periodically re-run as a scenario which could be compared against the normal mode of production. A loss of about 1000 stb/d was typically predicted as shown in the chart below. This loss was small compared to the total production of 35000 stb/d from the Ekofisk B facility and could be mitigated by other benefits from the upgrade.

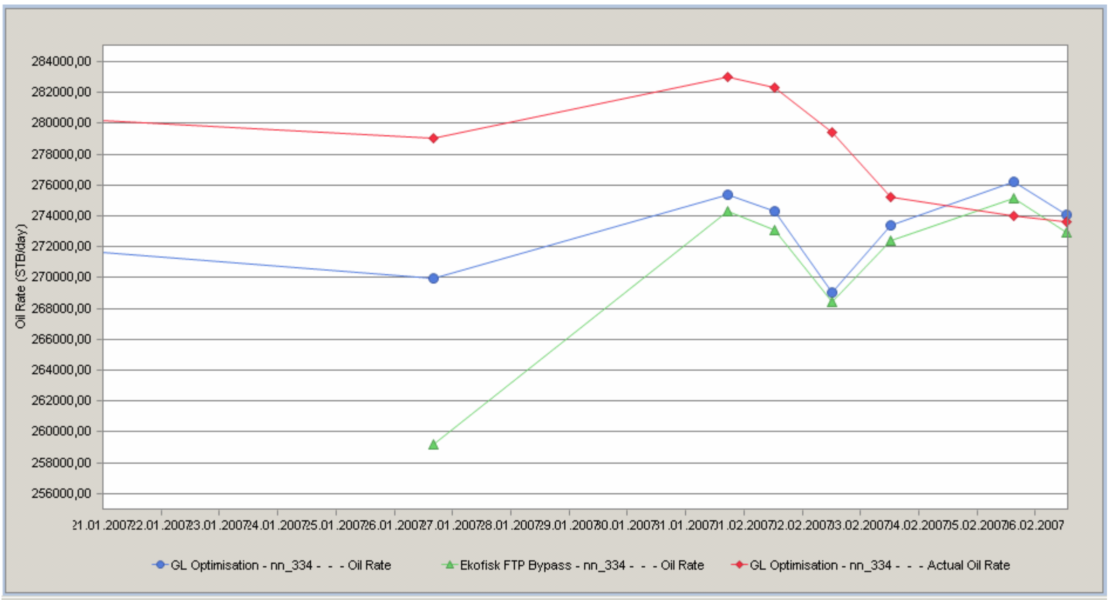

Figure 7: Trend plot of Optimisation scenario results with and without use of FTP bypass pipeline compared to actual rates. Effect of using pipeline is generally only 1000 b/d reduction in production.

When the new pipeline to Ekofisk M came on stream in Summer 2007 production was, as predicted by the model, similar to that through the decommissioned Ekofisk B separators, but slugging of water from the pipeline caused separation issues on M and the offline model was used to investigate the potential impact of actions that could be taken to reduce these. Although slugging is a dynamic effect, the steady-state model is still useful for determining potential production rates with or without slug-prevention measures, such as automatically controlled chokes. For example, the impact on production of increasing the import pressure at the inlet to the downstream end of the pipeline was calculated. This indicated when gas lift was no longer possible on some wells. In such circumstances, lifting valve depths may have to be changed in addition to cutting back production from other wells.

Example 2: Daily Scenarios

During 2006/7 a typical decision made in the OOC was on the utilisation of low pressure gas processing capacity on the Ekofisk J processing jacket. Restrictions may have to be applied because of maintenance work on a compressor. The options available included

- Continuing to produce the Eldfisk wells and restricting Ekofisk B and X low pressure manifold (LP) wells. This option is shown in Figure 9.
- Continuing to produce the Ekofisk X and B LP wells and injecting Eldfisk produced gas as well as shutting in some Eldfisk wells. This option is illustrated in Figure 8.
- A combination of the above two options.

Two scenarios were set up in the OPOS to aid these decisions. One optimised oil production with no export of gas from Eldfisk to Ekofisk and the other removed this constraint. Both scenarios included the LP gas restriction in the Ekofisk J process and assumed that gas injection could take place at Eldfisk. The scenarios were run each day or initiated by the user, using the latest updated well performance models, production policy constraints and where appropriate production routings.

Typically the scenarios showed that shutting in the Eldfisk gas production pipeline resulted in a predicted system loss of about 15000 bopd. However, the alternative scenario run with the network optimiser showed that this loss could be reduced to 8000 bopd if the pipeline was used, allowing the choice of wells to be shut-in to be extended across all production jackets, rather than just those on Eldfisk. The system showed which wells should be choked back or have gas lift rates reduced in order to achieve this strategy. The practicality of the options could then be reviewed by the operations team.

This improved strategy of reducing Ekofisk X production, rather than cutting back on Eldfisk, was applied during a prolonged shutdown of one of the two LP "flash gas" compressors in autumn 2007. The benefits were similar to those predicted by the optimiser model compared to the normal policy of shutting down Eldfisk gas export for short periods of maintenance on these compressors.

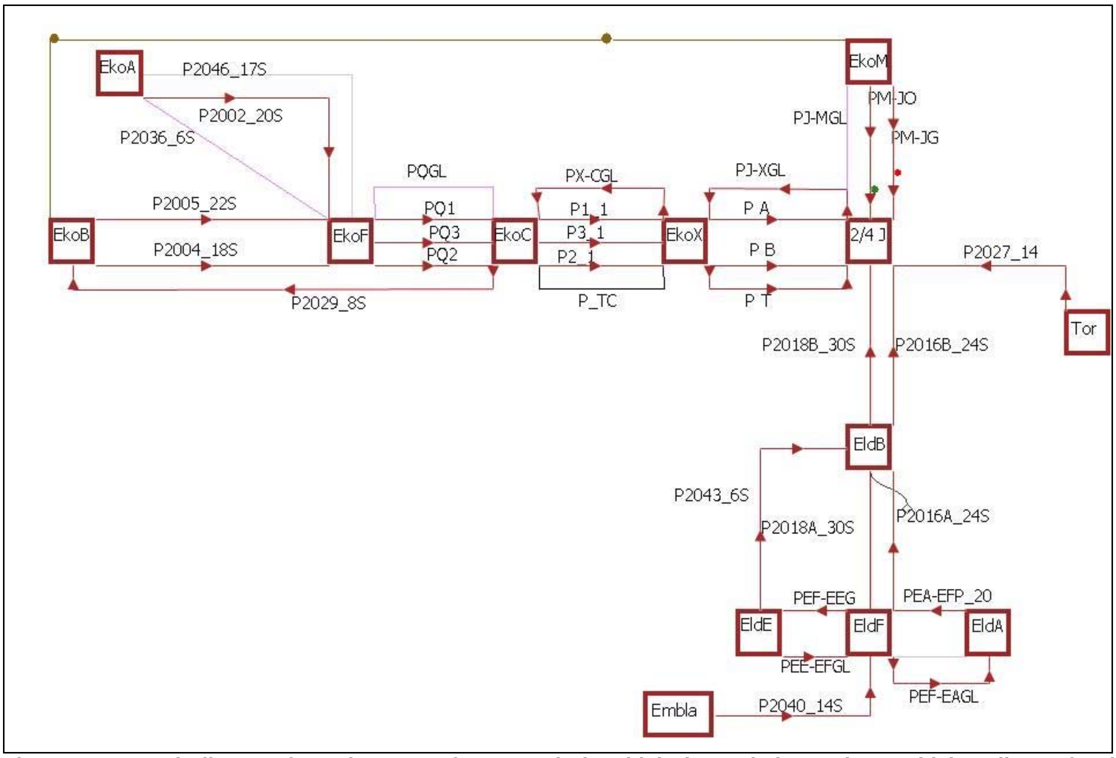

Figure 8: Network diagram from the OPOS for scenario in which the optimiser selects which wells to shut-in across all fields. Note that Eldfisk gas export in pipeline P2018B_30S is allowed, and no gas is exported from EldB to EldF

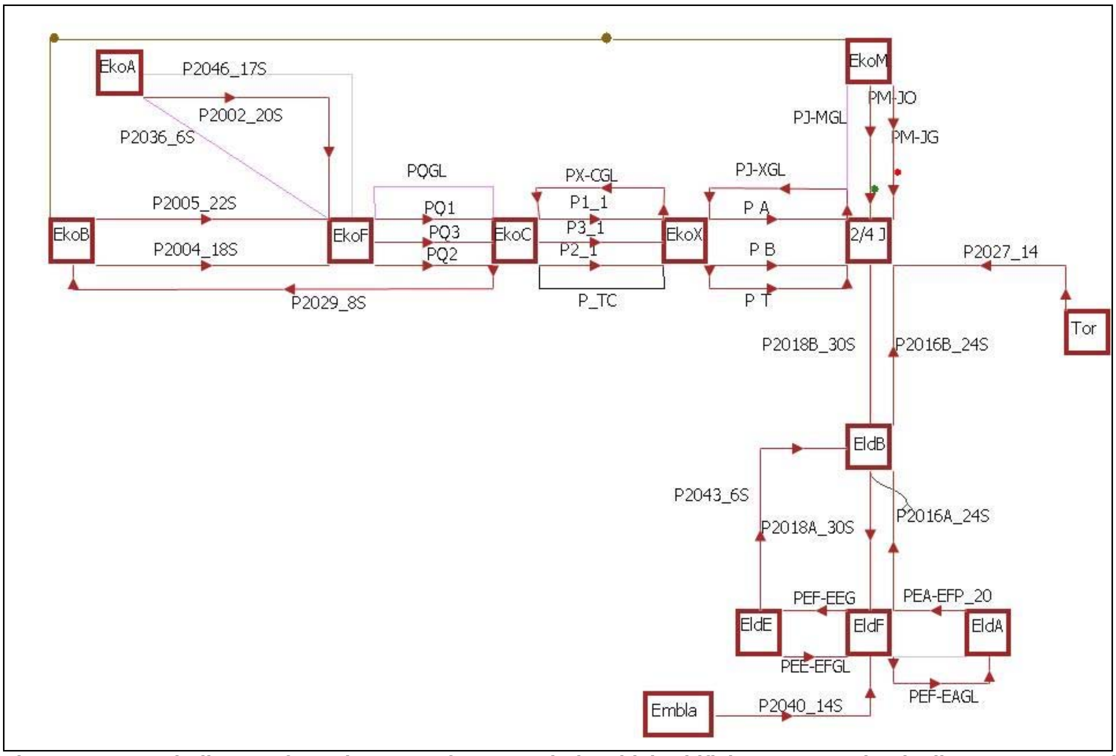

Figure 9: Network diagram from the OPOS for scenario in which Eldfisk gas export in pipeline P2018B_30S is not allowed. Note that all EldB gas is now exported to EldF via pipeline P2018A_30S. The latter pipeline normally exports gas in the opposite direction, from EldF to EldB.

Example 3: Allocation and data or system diagnostics

The network/well model system can also be used for allocating production between wells and hence identifying when parts of the network are not performing as expected. Useful indicators are wellhead temperatures, pressures at different parts of the system and gas lift rates. The start-up of the pipeline between Ekofisk B and M provides an example. Manifold pressures at

Ekofisk B were much higher than simulated. The calculated pipeline pressure traverse showed that the main pressure drop was at the surge control valve and so the pressure gauge at this point was registered with the process historian system. Calibration of the valve pressure losses could then be made and the production losses induced by this increased back-pressure determined by comparison with offline runs of the network model.

Daily or more frequent well monitoring is aided by the comparison of model-calculated well parameters with those recorded by the process historian from the field. Large differences are highlighted for further investigation by field engineers.

Erroneous instrument data often results in contradictory constraints being applied to the model. However, one of the advantages of the modelling system used is that it will attempt to find a solution and indicate where the conflicting limits are located. A simple example is when a gas lift flowmeter on a pipeline supplying gas to a wellhead jacket is used as an input to a model constraint and either over- or under-supplies the wells. Meter errors may cause partial model failures, but the problem area is identified and can then be corrected or ignored.

Conclusions

One of the major benefits of automatic calibration and optimisation systems like that described here is that they do the routine work that the engineer would like to do, but never has the time to do. The Ekofisk production system is complex and performance can benefit from engineers who get to understand well and plant performance. However, resources are stretched and having the routine well test monitoring and daily network allocation and optimisation runs carried out automatically helps engineers to prioritize the high value work. Resources can then be used for evaluating the most problematic wells and planning remedial treatments or tuning key parts of the process plant.

Introducing new systems into a mature field operation with many legacy computer tools is not always easy. An Online Production Optimisation System has to integrate into the asset and corporate information systems as they develop. The standard database and web server architecture used by this OPOS has made the linkage straightforward. The interfaces are essentially “open” and since it is a commercial package, will be updated as standards such as PRODML develop.

An integrated model like that used in OPOS, embraces all disciplines. Although there is close cooperation between the various engineering departments working on Ekofisk, having a common and comprehensive model does give everyone involved a better understanding of the factors governing overall asset performance. The operator is continually improving work practices to make better use of this type of technology and as it gets further used, better quantification of the benefits for working practices and improved production will be available.

As demonstrated by the examples in this paper, uses for the OPOS are evolving along with other improvements in systems such as better displays for online data. Amongst the issues that are being addressed are

- Improved display of well and other production objectives, allowing them to be more readily used within the OPOS,
- Better instrument and data error checking,
- Integration of the OPOS results with the corporate online reporting and warning systems.

This model-based approach to full online production optimisation has demonstrated considerable advantages over one solely based on trend-analysis of raw production parameters. This is principally because it allows users to further analyse problems with facilities or wells by downloading the models and running them offline. The parameters generated for the steady state models can also be used as input to more detailed dynamic well, pipeline or process models. Results from both online and offline modelling enable operations staff to maximise production either by increasing offtake rates or by minimising the impact of facility shutdowns. The examples have illustrated the scale of benefits that can be realised in this kind of high rate multiple-constrained system.

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