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Real-Time Integrated Field Management at the Desktop

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Abstract

Accurate individual well production rates are essential to meet corporate production target plans, optimize reservoir performance and make reservoir management decisions that may require well intervention. Short of installing rate measurement devices on each well, a "back allocation" method is generally employed to assign well production rates, using multiplying factors based on well tests conducted the month before. Apart from the inherent errors, based on the assumption that the wells produce at the same rate throughout the month, the process is also not suited for real-time field management that requires production rates to be known much more frequently.

This paper describes the implementation of a system that automates the calculation of individual well production rates using real-time pressure data from permanent sensors installed on the wells. The system, based on integrated physical models of the reservoir, well and surface network, has been successfully used to implement crude blend management in a large Saudi Arabian field, producing from three different reservoirs. The paper also describes how the system is used to automate the validation of well test measurements, allowing the engineers to focus their time on problem wells while ensuring that all wells are reviewed. In addition, field models are kept evergreen and can be utilized by different disciplines for production forecasts.

Application of the system could result in significant cost savings, due to reduction in the requirements for physical metering of well production. The system also provides unique optimization opportunities, allowing the engineer to determine the optimum settings to maximize production or revenue. Other benefits include, faster resolution of production problems due to early problem detection, focus on exceptions rather than bulk and massive troubleshooting, and zero-latency application-assisted decision making, all combining to bring real-time field management and optimization to the engineer's desktop.

Introduction

Saudi Aramco, like other major E&P companies, has been investing heavily in the acquisition real-time data from its fields. In the last several years, many Saudi Aramco wells have been equipped with permanent downhole and surfaces sensors, with many more scheduled in the coming years. There is the need to leverage this investment in data acquisition into actionable information to improve field performance, among other things.

In fulfillment of the I-Field initiative, Saudi Aramco has been piloting several projects aimed at addressing some operational challenges and improving reservoir and field performance. One such challenge is the need to meet corporate production target plans by blending crudes of different grades. This crude blend management requires accurate individual well rates on a daily basis, at the least. Unfortunately, the current process of assigning individual well rates from monthly production totals, relies on a "back allocation" method that uses multiplying factors based on well tests conducted the month before. This process assumes that the wells produce at the same rate throughout the month, which is obviously not the case. In addition, the monthly well test measurements, upon which the "back allocation" depends, are sometimes questionable, and need to be validated. There is therefore the need for a more accurate method of calculating the well rates to ensure accurate blend management and improve field management.

Lately, the industry has been moving towards fully integrated field modeling, with the objective of optimizing and improving field performance and management[1-3]. Through this, improved investment decisions can be made by integrating reservoir, production, process and facilities models, as well as economics models. With integrated models, that honor the physics of fluid flow in the entire production system, it is possible to derive accurate individual production rates by leveraging some of the real-time measurements such as pressure and temperature. By validating these models against periodic well test measurements, it is possible to keep the models “evergreen” for use in other task by different disciplines.

In this paper we start with a look at some of the typical field management tasks that an engineer is often confronted with, and how these can be handled. This is followed by a description of the proposed system for ensuring that valid reservoir, well and network models are available for well rate estimation and subsequent production optimization and forecasting tasks. Next we present some applications of the system, followed by a discussion on some of the benefits of using the proposed system.

Field Management Tasks

Some typical questions that an engineer entrusted with managing a field might ask include, how is my field performing? Can we do better? How much will my field produce? To answer these questions, the engineer will need proper field surveillance that includes knowing what each individual well is producing at any point in time. This will require accurate production allocation for each well. Where the field is not delivering as expected, there should be diagnostic tools that will help the engineer to determine the cause. On the question of whether the field can do better, the engineer needs an optimization tool that can offer different scenarios based on objectives, such as the need to maintain a certain production plateau, minimize water, maximize revenue, etc. Determining how much the field will produce requires the ability to forecast, based on available models. All these tasks can only be performed with a fully integrated model that incorporates the reservoir, the wellbore and the surface network facilities. This will allow the engineer to know how the field will behave under different conditions, while accounting for reservoir, well and pipeline interactions.

To monitor the field performance, therefore, there is the need to process the data coming from the field such as pressure and temperature measurements, into useful information such as production rates. By using physical models, not only do we estimate rates but also we can validate the measurements and troubleshoot problems. This will allow understanding the performance of the field and also keeping the models valid so they can confidently be used for other value-added tasks, such as optimization and forecasting.

System Description

The design of the system is rooted in the belief that sound production system models, comprising of reservoir, well, network and downstream models, can be used to gain an invaluable understanding of field behavior and to be used as solid basis for the field management tasks, such as well rate allocation, field production optimization, production forecasts, and real-time production monitoring and surveillance. The models provide the basic physics that relate the behavior of process variables in reservoirs, wells and production networks. On the other hand, a producing field is a dynamic process, and as such, it is changing every day. Well tests, field measurements, and operational events are field readings that require proper validation and that must be taken into account in the execution of field management tasks. With this system, the workflows are set out in a logical form consistent with the way a field model and activity are defined for the engineer and field manager.

Figure 1 presents the system workflow, where the field reality is first modeled to capture its present state and equipment settings. Field well test data are then imported and screened for consistency and accuracy, using the models and embedded expert system rules. This process may require that the well test data be corrected or the models updated to reflect changes in the production system since the last test was conducted. With the models validated, real-time data such as wellhead and bottomhole pressure measurements from permanent sensors are then imported to calculate well production rates. Accounting for operational events such as well shut-in, the daily well production rate can then be estimated. Subsequently, other field management tasks such as field optimization and production forecasting can then be performed. The system models are continuously validated and maintained through consistency checks against measured field data, both at the well level and at the surface production network model level.

Well Test Validation and Well Model Quality Control

Well tests, which are often conducted on monthly basis, can be imported into the system from any database, or simply from a text file generated in Excel. In this implementation, the well tests are imported either from our Oracle database or from Excel files. The system allows for validating the well tests either on a single well basis or in batch mode for multiple wells.

Batch Well Test Validation

The system can be used to analyze well tests by comparing the liquid rate from the test, to the liquid rate predicted by the well's published model. This can be performed automatically for a large number of well tests with the click of one button. The process classifies all imported well tests either as Valid (if consistency between the rates is found) or Conditioned, which means that the quality of the data is suspicious and that the well test should be examined in detail by the engineer responsible for the particular well. After analysis of a Conditioned well test, the engineer may define that test as Valid or Invalid.

As a visual aid for quick identification and analysis, the system presents the results of the well test validation in a color-coded chart, indicating the assigned quality state for each well test. Figure 2 is a sample screen that shows some Valid well tests in Green, other Conditioned well tests in Orange and those deemed Invalid in Red.

In-Depth Analysis of Well Test Data

Once a well test has been deemed Conditioned or Invalid, the engineer can perform an in-depth analysis of each Conditioned or Invalid well test, so as to try and find a reason for the inconsistency between the well model and the measured data. During this in-depth analysis, the system will facilitate the quality review of the test against the model, by evaluating the inconsistencies and presenting the engineer with a list of possible reasons to explain the inconsistency. By eliminating the physically impossible reasons, the system enables the engineer to make a judgment on the model and test data quality on an objectives basis. Following this analysis, the engineer can then correct the well test, or invalidate the test entirely.

From our experience, one of the main reasons found to invalidate or render a well test Conditioned include gas measurement errors. Often the GOR is inconsistent with the fluid PVT description. Other possible sources of inconsistency include errors in water cut measurements, gauge pressure data outside physical boundaries, change in productivity index, and changes in fluid mobility from previous tests.

Well Model Quality Control

With a valid well test as a reference, the well model can be verified and fine-tuned to match the measured data. Following analysis and classification of the well test as Valid, the engineer can perform a series of model data quality control checks on the well model parameters. Once again, the system provides visualization tools to aid in the presentation of the results and data in a format that allows the engineer to quickly see the model status and prioritize his efforts on problems that than can be quickly resolved. Figure 3 is a sample well model quality control plot. In this figure, every well is represented by a colored triangle. The "Green" triangles are wells which have a valid well test within a recent time frame. The "Blue" triangles represent wells which have only a "Corrected" well test record within the same period, while the "Orange" triangles represent wells which have neither a single original Valid nor corrected well test during the period. The rest of the colors indicate varying degrees of information deficiency. A mouse-click on each well on the plot reveals what information is available. In this presentation, the wells on the lower left corner have the most recent valid information, while the wells on the upper right corner have no valid information at all. This plot then helps the engineer to determine which wells lack information, and so need to be tested in the shortest possible time.

Total System Quality Control

The system is designed to perform a total production system quality control, where consistency is sought between field measurements such as pressures, flow rates and , temperatures, against the predicted values from the network model simulation under the same field operational conditions. This process is initiated once the well models have been validated and updated. The current state of field measurements and equipment state, such as whether wells opened or closed, separator pressures, manifold state, etc., are imported from the Oracle database and/or the field PI server. This information is used to fix the present state of the model and then a simulation run is conducted against the reality. The values of all variables are compared to the measured data and the cause for any differences are analyzed and corrected in the model to better represent reality. Errors in field measurements are spotted and corrected. At this point the validity of the total production system network model has been ascertained. The model can then be used to estimate individual well production rates, given any system node pressure. Alternatively, the system model can be used to perform production optimization or run production forecasts.

Well Rate Estimation

Following the total system quality check, we now have validated well models with respect to well production tests, and a validated surface network model against field measurements. The system can now be used to estimate the production rate of each well taking as a basis the well models. Theoretically, any pressure measurement taken at any node along the well can be used to estimate the fluid rate flowing through that node. For this implementation, real-time well head pressure (WHP) for each well is taken as the input to calculate the well production rate for that well. In this fashion, for each measured well head pressure an oil, gas and water rate can be calculated for each well in real-time. The direct output of the system calculation is the well liquid rate. Using validated GOR and water cut, the system then calculates the oil, water and gas rates corresponding to the measured WHP. The calculated flow rates from the system have been compared to measured rates from a physical meter, with an excellent degree of accuracy. Figure 4 shows a real-time well production plot, and the corresponding WHP, for a sample well.

As can be seen from Fig. 4, the well production rate is never constant even over a period of just one hour. Thus, the assumption of a constant rate for a period of one month used in the "back allocation" method, is definitely erroneous. Figures 5- 7 are schematics that illustrate the errors that can be caused by assuming a constant monthly production rate in the "back allocation" method.

One challenge encountered during this implementation was the reporting of abnormally high well rates for some wells at certain times. Subsequent investigation revealed that the wells were actually shut-in during such periods. Upon further investigation, it was realized that because the well shut-in occurs upstream of the pressure gauge, the gauge tends to read the flow line pressure when the well is shut-in. Since this line pressure is significantly lower when the well is shut-in than when it is flowing, the calculated rate tends to be abnormally high. Subsequently, a logic was implemented that uses a combination of the pressure and temperature measurements to detect when the well was shut-in, thereby prompting the system to return a zero rate for the well during that period. Figure 8 shows the results of the implementation of this logic, where the well downtime is properly accounted for.

Well Production Allocation

The well rates estimated by the system are instantaneous rates. To calculate the daily well rate, we need to take into consideration certain operational events such as well shut-ins. The imported operational events represent the operational changes in wells and other field equipment. These include well shut-in, a manifold alignment change, a change in a choke setting or a separator pressure change. Operational events can be unplanned, such as those caused by equipment failure, or planned in the case of scheduled maintenance shut down. In the system, operational events can be imported from such repositories as field operational databases, planning and maintenance tools or from stochastic event simulators. These events are taken into account whenever they influence the response of the models.

With the well shut-in periods and other operational events included, the result is a trend of the well's real-time produced rates during an allocation period. Subsequently, the total cumulative well production can be calculated giving a total produced volume per well for the given allocation period. Figure 9 illustrates an instance where taking proper account of well down times resulted in the discovery of an additional 30,000 barrels of oil being incorrectly allocated.

Real-Time Well Surveillance

Using the latest published well models and any available real-time surface or sub-surface pressure measurement, a well's production can be monitored in real-time to detect abnormal situations and minimize the effect of unplanned production deferment.

Well Rates can be estimated in real time using the well model, the latest valid well test results and real-time measured down-hole and surface pressures. In addition, if pressure and temperature measurements are available across a choke in the well's flow line, another rate can be estimated using the choke equation. All these possible well rates can be calculated in real time, with each adequately filtered real-time data reading. If the model has been validated, all rate estimations should match within a certain tolerance. If they do not match, this could be an indication of an abnormal situation in the well's performance that can be detected and further investigated. Figure 10 compares well rate estimates from.bottomhole and well head.

Real-time well surveillance can be facilitated by the extensive use of trend plots and multivariable visualization techniques so that in a single graph, the engineer can monitor all the wells in a field and immediately spot the wells with the most important abnormal situations

Field Optimization

With validated reservoir, well and network models, ensuring consistency between the field's surface network simulation and physical field measurements, it is possible to optimize the field performance, using the systems rigorous nonlinear optimization engine. The objective of the optimization may be to maximize oil production or total revenue, taking into account multiple constraints in the system. After inspecting the optimization results, the engineer may propose an alternative field production strategy or decide to optimize the field under a different field configuration scenario. Examples of such different operational scenarios could be connecting producing wells to alternate manifolds, or finding the optimal operational settings in case of a major equipment failure, such as compression plant shut-down. The engineer may also consider what-if scenarios of adding new pipelines, separators or other equipments to the field model. The results of such different scenarios can then be compared to each other, and an optimum solution selected with the required settings. These settings can then be implemented either remotely or manually in the field. In one example implementation, this optimization process was applied to a crude blend management program, with excellent results.

Crude Blend Management Example

The challenge was to come up with operational settings that will ensure a production plateau of 500,000 BPD crude of a specific API gravity, within a very small tolerance. The production environment was quite complex, with production coming from three different reservoirs with different API gravities, and flowing into an integrated surface network leading to two GOSPs. Four objectives were required to be met, including maintaining the API gravity, maximizing the plateau time, minimizing water cut, in addition to minimizing water injection requirements.

Previously, this task was carried out by manual calculations using data from scattered well tests, which were often at least one month old. To make matters worse, the calculations had done again if any condition in the field changed, for example, well shut-down, pipeline maintenance, or simply a change of reservoir conditions. With this new system that couples reservoir, well and network facility models with real-time data, the calculation is done automatically in real time. Moreover, several different production scenarios can be generated in a very short time.

Production Forecasting

Using the latest valid field model, and different events imported into the system from a maintenance planning tool or from a stochastic event simulator, a number of different field production forecasts can be set-up, run and compared. Running the network model in the production forecasting engine in the background, the system can drive the creation and execution of a forecast case using a published model. By inserting the appropriate events into the forecasting schedule, and running the forecast, the results can be saved into the system database, for further inspection, plotting and comparison.

Overall Benefits

Application of the system has resulted in a number of benefits including improvement in the productivity of field management engineers. The system also ensures faster response and resolution to problems due to early problem detection. This can reduce problem detection and resolution time to a matter of hours, instead of days. It also allows the engineer to focus on exceptions rather than bulk and massive troubleshooting. Using a unified set of validated models the engineer can perform scenario-based process optimization to improve field performance. The system also ensures the availability of up-to-date field models throughout the life of a field.

Summary

In this paper, we have presented the implementation of a system that automates calculation of real time production rates, using validated integrated models of the reservoir, well and surface network facilities, together with real-time data from the field. System also automates the validation of periodic well test in batch mode with visualization tools that allow the engineer to focus and take remedial action on problem wells, while ensuring that all well tests are reviewed. The system has been applied successfully to manage the production of blended crude from multiple reservoirs. Application of the system could result in significant cost savings, due to reduction in the requirements for physical metering of well production.

References

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Figures

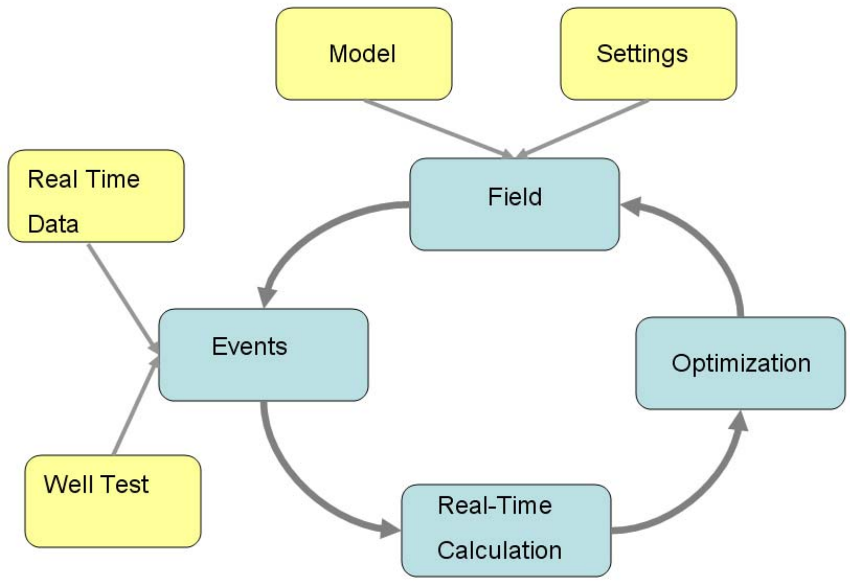

Figure 1: Schematic of System Workflow

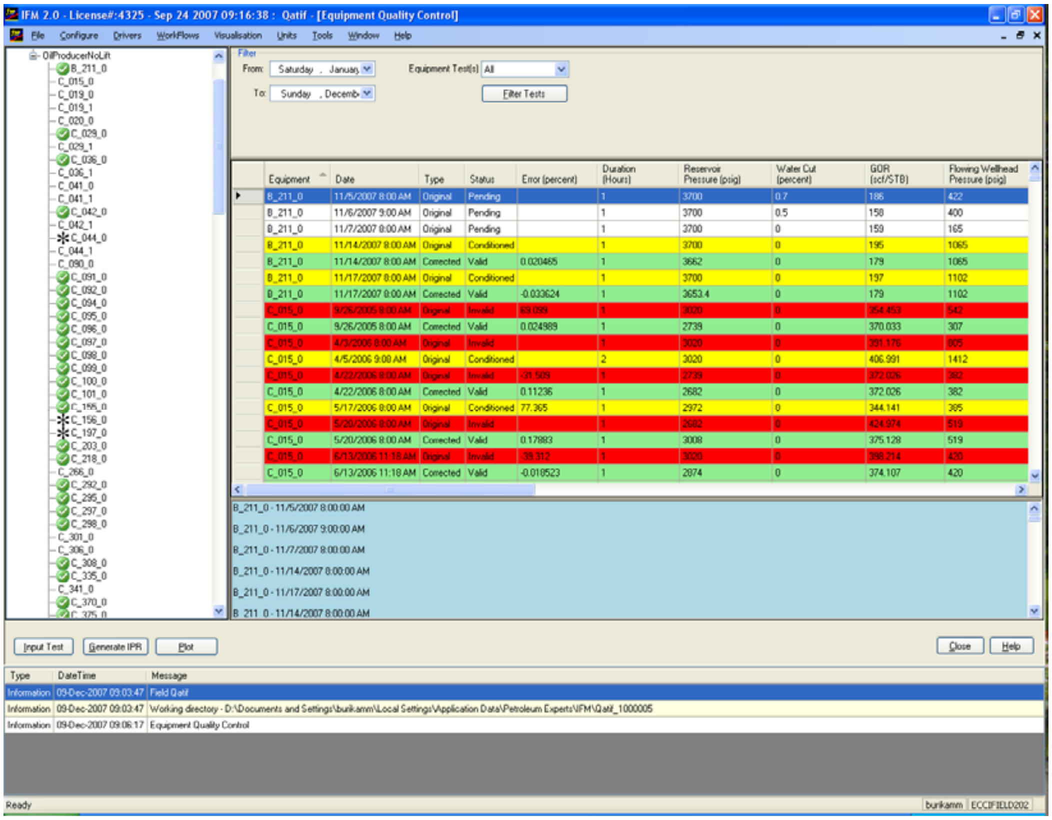

Figure 2: Color-coded chart helps speed up well test validation.

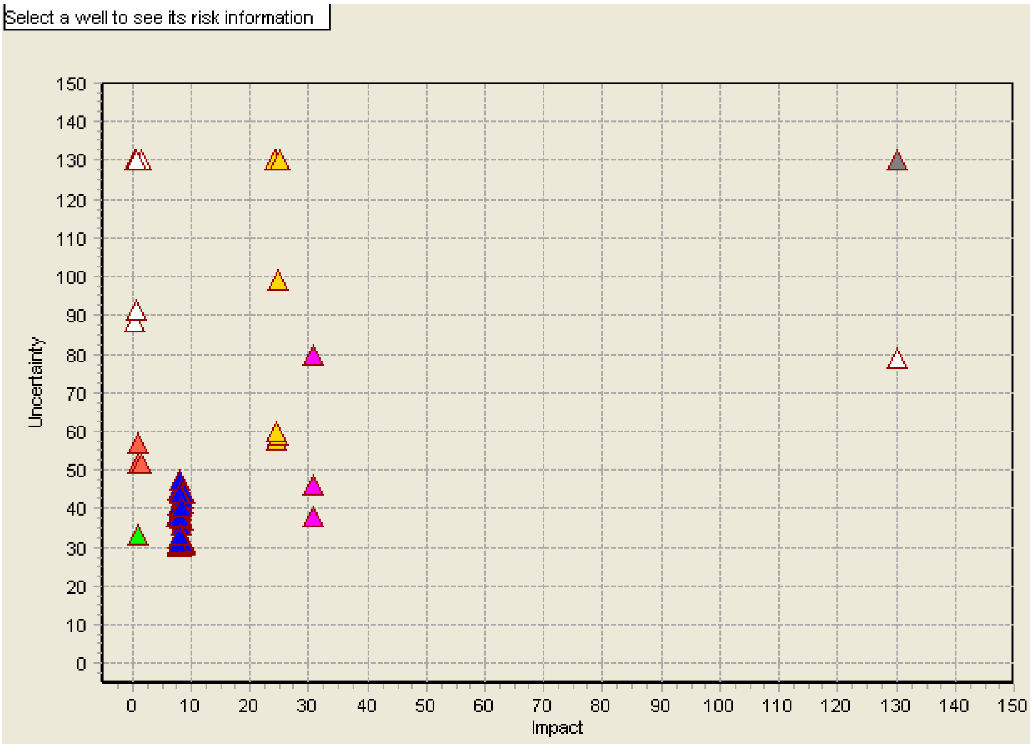

Figure 3: Well Test Validation KPIs

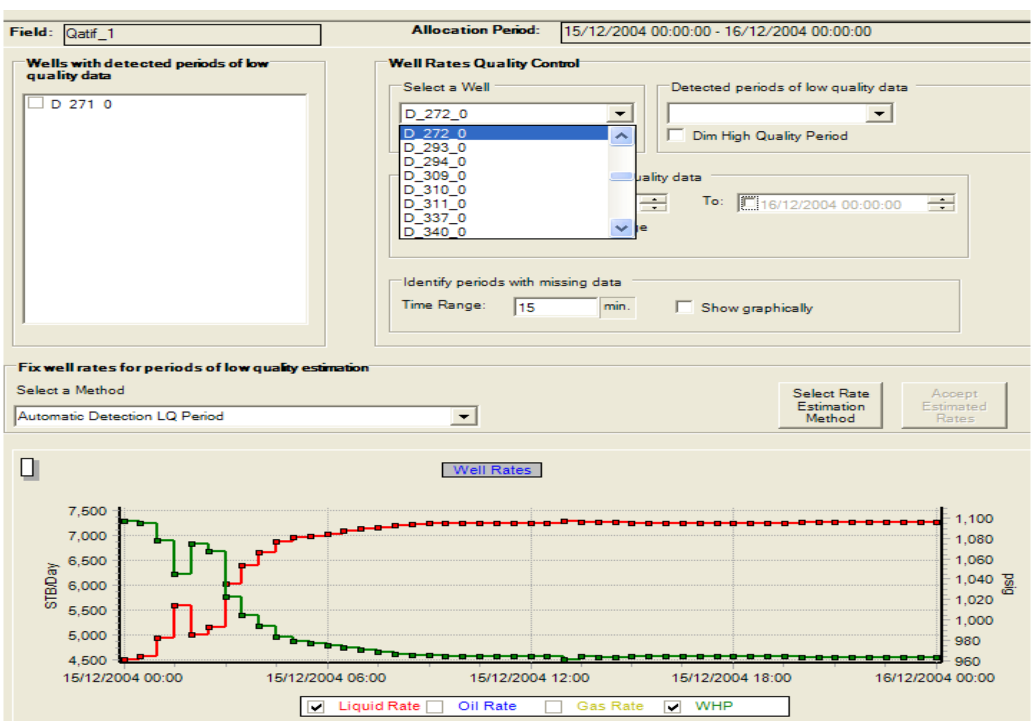

Figure 4: Sample well rate estimation using validated models and real-time WHP data

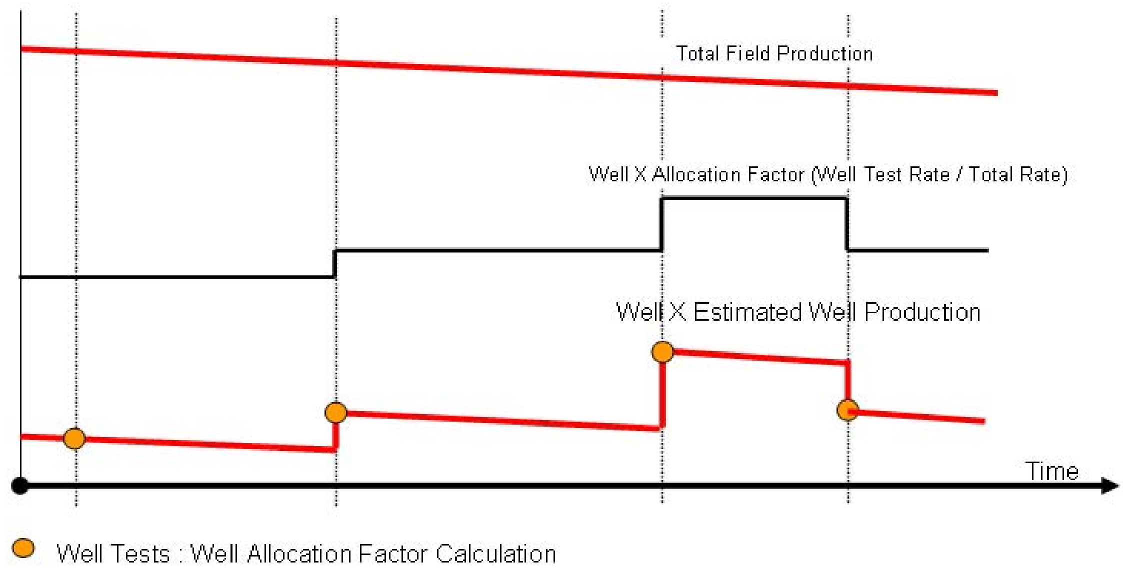

Figure 5: Estimating well rates without models

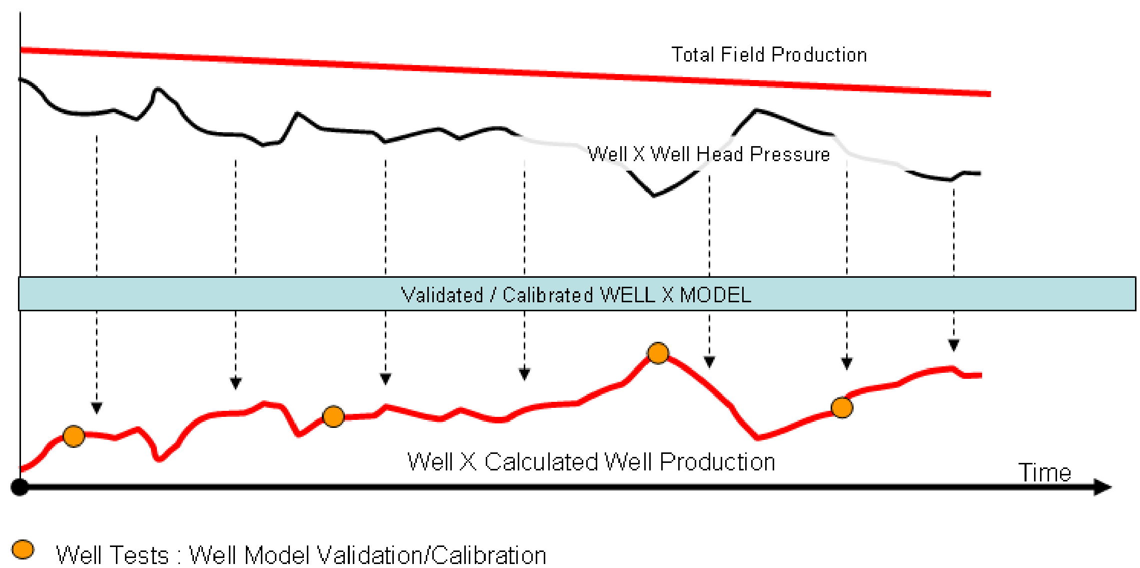

Figure 6: Estimatiing well rates using models

Figure 7: Comparison of well rate estimation with and without models

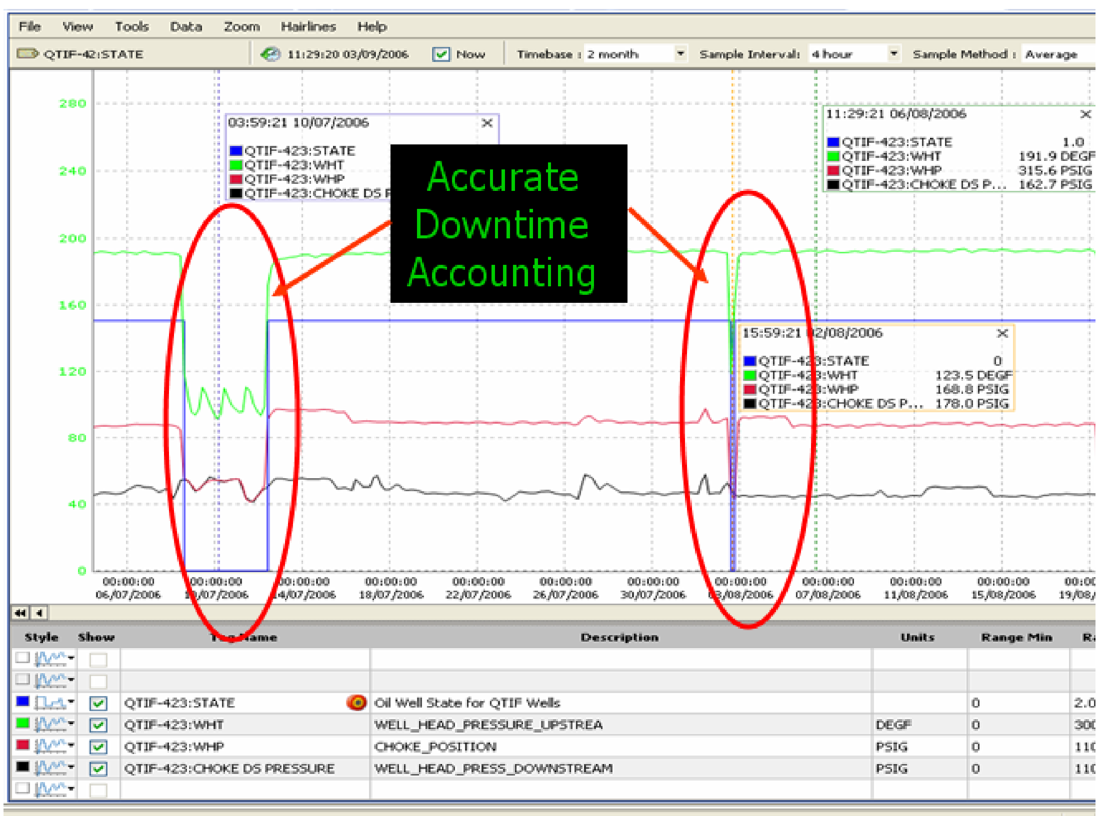

Figure 8: Accounting for well downtime using pressure and temperature information

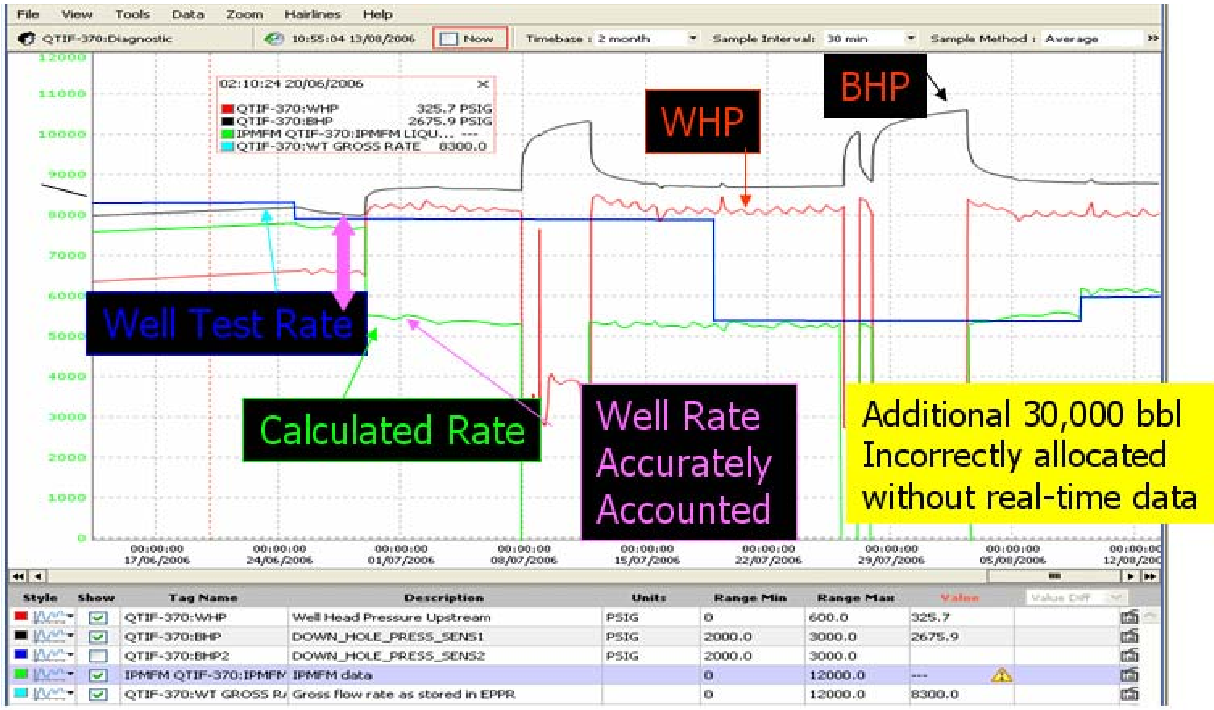

Figure 9: Proper well downtime accounting prevents misallocation of well production

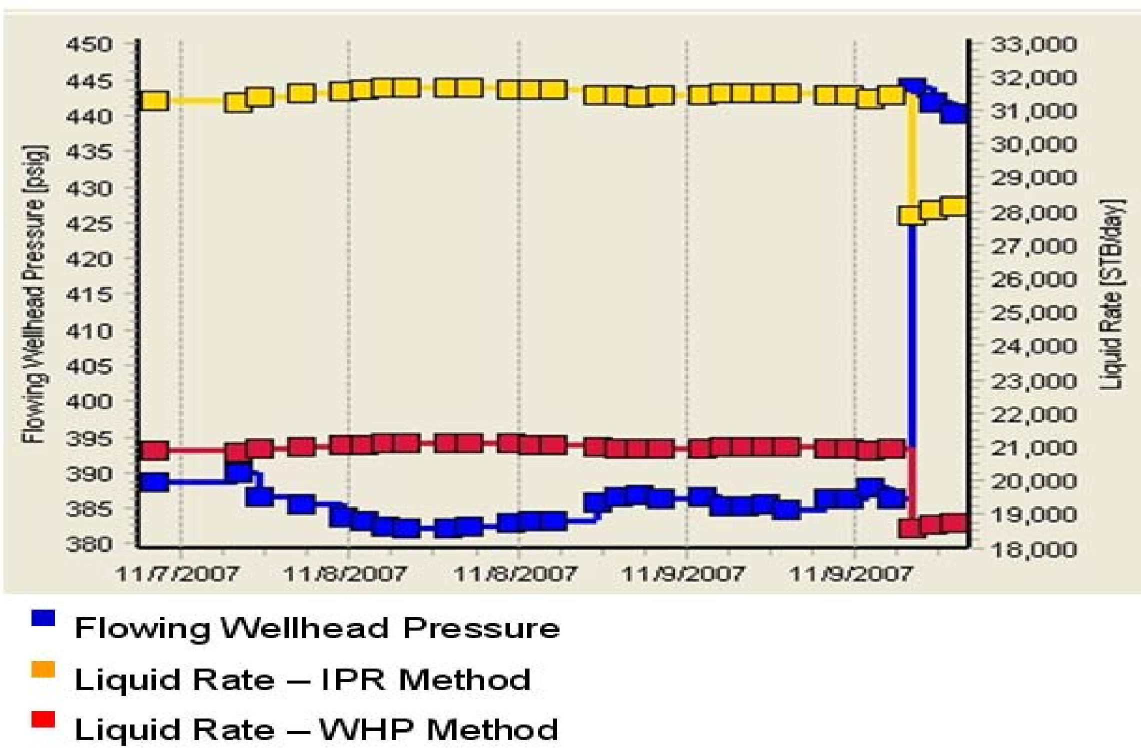

Figure 10: Comparison of well rate estimates from bttomhole and wellhead