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WATERFLOODING OPTIMIZATION THROUGH A BETTER UNDERSTANDING OF PRODUCTION ALLOCATION

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Abstract.
Production allocation is the process of understanding from which horizons perforated in an oil well the production came from. This allows for material balance calculations to determine how much the different levels have produced of the different phases and where the remaining oil is located. It is an essential process in optimizing a water floods. In many studies carried out in the past, analytical techniques (such as decline curve analyses) have been very successful in identifying infill drilling potentials and workovers. However as the fields have become more mature a finer understanding of where the production came from has been required. Attempts have been made using horizon productivities combined with production logging to derive a better allocation of the production by sands. However as the level of water injection varies from sand to sand productivity or kh is a poor allocation technique.

A method is presented here to do the production allocation based on a 3D property model using streamline simulation. The streamline simulation allows for a study of a model with numerous cells. This model will take into account the injection production on a sand by sand level according to historic information. The model was matched primarily on liquid production and allocation factors for oil and water were generated for each of the sands and every month of the production history. The offset in the production match was adjusted by using the calibration factors in combination with the actual historical well performance. The outcome was a process that in 4 weeks would create a sand by sand production allocation for more than 100 wells, 13 sands and more than 20 years of production history. In addition for every injector it was possible to identify which producers were supported according to the property model. In addition the approach can be used to assess the uncertainty of the allocation given more geostatistical realizations and approximate water cut matches. Once the process is complete, the standard analytical processes can be run on a finer sand level.

The value of the approach is the speed and the ability to link the production allocation to the reservoir characterization.

1 INTRODUCTION

The reservoir engineer’s principal task is to account for the remaining oil to be produced from a reservoir at any given time. This is calculated as the oil in place times the recovery factor minus the oil produced to date. As a field becomes mature, the cumulative historical production becomes a significant value compared to the product of the oil in place times the recovery factor and the uncertainty associated with the assessment of the historical production becomes an important factor. If a field is assumed to consist of one reservoir this uncertainty is negligible. But in fields where the main reservoir units are found in fluvial depositions, a field consists of hundreds of reservoir units. If the reservoir engineer has to account for the cumulative production by individual reservoir in this type of fields, the associated uncertainty is significant. Normally the oil is accounted accurately for at the export point and the measure of water is made at the process facility. Using well test information this is then allocated back to individual wells. Today this can be done with on-line metering systems, but these have only been introduced over the last decade and in some regions, they are still being considered for the future. But the fact remains that in the majority of mature fields, which are on production to date, the first 20 to 50 years of production were carried out using a poor accounting of where the production oil, gas and/or water came from. This often leads to a common problem: A field assessment may determine the reserves potential, but where that remaining oil is in the field, is a significant problem.

In Colombia, a significant amount of fields came on production in the years from 1950 to 1960. These fields produced at depletion drive for 20 to 30 years before a secondary recovery scheme (water injection) was implemented. In the last 20 to 30 years these fields have produced under a secondary scheme. These fields often have numerous reservoir levels, which were produced co-mingled for the whole period. An example of a cross section of such a field is illustrated in Figure 1. The figure illustrates the observation of sands from well to well.

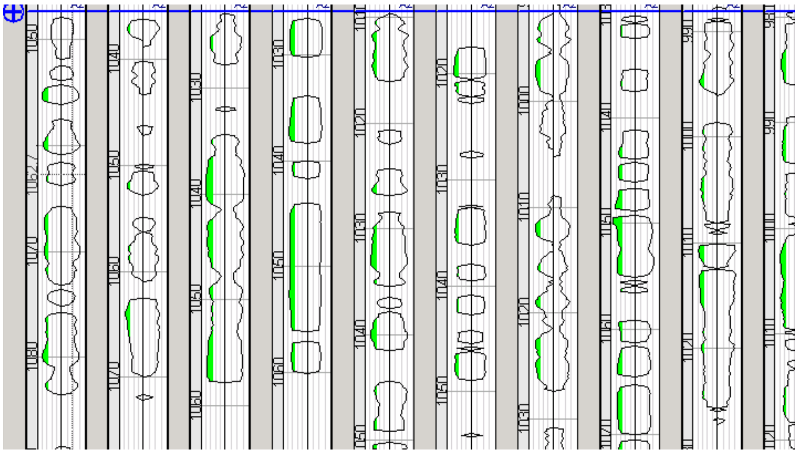

Figure 1: Example of a multi-reservoir field

These sand levels were all produced together and the issue to day is to quantify how much oil/gas/water came from each of these horizons to allow for an assessment of the remaining reserve. The process of quantifying how much oil came from each of the levels is referred to as production allocation. In the following section, the traditional approach will be explained and how a numerical approach can be used.

2 PRODUCTION ALLOCATION

2.1 Traditional Approach

Lets assume, that a well is producing from two reservoir horizons, an upper and lower zone. The two horizons are produced together through the same wellbore. The production at the wellhead, which can be detected relatively easy, represents the sum of the two horizons. The detection of the contribution of the individual horizons can be measured using a production logging tool at different times or downhole flow meters. However, these approaches are fairly expensive why they don't apply in many mature fields, where the oil rates and cash flow is low. Secondly such measurements only validate the production of today, not of the past.

Traditionally, the production by level is estimated by the conductivity of the different horizons. The conductivity is expressed as the product of the permeability times net height of the individual zones. The fraction of the production coming from a given horizon, A_i, is estimated as the permeability (k) times net height (h) of the horizon in question divided by the total sum of the permeability times net height of all the contributing horizons. This factor is used to represent the flow contribution for both oil and water.

$$A_i = k_i * {}_h i \ / \ \sum k_i * h_i$$

This approach is correct when the individual horizons are supported by the same pressure source and when single phase flow is assumed.

Knowing that this approach has its limitations, this approach is normally only used when no other source is available. When a production log is available, this normally overwrites the allocation factor calculated from the reservoir conductivities. This will provide an individual allocation factor for each of the produced phases for a given time. The allocation factors are then assumed constant until more information is available.

As a result, in mature fields the early decades of production is normally allocated by the individual conductivities and when production logging measurements are available the allocation factors are updated with respect to the factors calculated from the logs. However as these logs were introduced/invented after the start of field production, they only allow for a limited period of history.

May historical fields, especially in Colombia, have a significant uncertainty in the assessment of where the oil came from. In Venezuela, co-mingling has historically been banned due to the difficulty in allocation, why the problems is insignificant. In regions where co-mingling has been allowed, the problem exists; such as Colombia, Russia, West Africa and

Indonesia. . As these provinces mature the error associated with the allocation of the historical production becomes a key issue in understanding where the remaining oil is.

2.2 Numerical Simlation approach

As reservoir simulation approaches, it is now a day possible to define a model to simulate the historical approach and adjust the model, so it matches the historical production. This allows a much finer assessment of the allocation factors. The simulator will take into account different pressure sources, relative permeability effects, etc. However, a fully integrated reservoir study is often associated with a very long timeframe (6 months to 2 years). If the base information is uncertain, the cost of such an approach is questionable. Socondly, many of the fluvial fields have hundreds of reservoirs, why a fine static model must be created of the structure and the property variations. This is normally done in the frame of a grid. A fine grid may contain in excess of 1 millions grid blocks. Doing a reservoir simulation of a 1 million-block grid, is not possible in a reasonable timeframe using the standard finite difference solvers. The time frame for individual runs is so long that the iterative process of history matching becomes unacceptable.

Streamline simulation is an alternative to the traditional finite difference solver algorithms. The approach is based on using the pressure solution to calculate the pressure gradients and the streamlines and then to calculate the saturations along the streamlines either by a Buckley Leverett approach or by a series of one-dimensional simulation models. The governing equations are discretized but solved on separate structures, pressure by grids and saturations by streamlines. As long as the flow paths do not change dramatically in time, longer time steps can be taken so that models containing a finer resolution and more cells can be solved in a shorter timeframe. The concept of streamline simulation was introduced in the early 1990s [1].

Figure 2 illustrates why we are interested in streamline simulation. For the smaller models using a streamline simulation approach may be more time consuming than solving all the equations using finite difference. This is due to the time is takes to define the streamlines for every timestep when new pressures are calculated. Typically, when models are in the range of hundreds of thousands of grid blocks, then streamline simulation represents a reduction of simulation time compared to finite difference solvers. In general in Colombia, Ecuador and Peru many reservoirs are found in fluvial or delta depositional environments. As a result the sand distribution is often very complex with numerous reservoir levels and numerous rock types. Often a three dimensional static reservoir model is constructed to capture the heterogeneity in space. A sand thickness can be very small (3 to 5 ft), a high vertical resolution is required to capture the problems. In area the model is typically larger with block lengths somewhere in the range of 50 to 100 m. The result is often a static property model with a few million of blocks. Reducing the number of blocks for the dynamic model is always an issue. However, it is limited how much models can be scaled up. In Figure 3, the issue of upscaling is illustrated. This comes from a study of a fluvial reservoir. The reservoir units were identified in the property model and ranked according to size. The plot shows the cumulative oil in place in the largest, the two largest reservoirs and so on. The model was then upscaled by merging grid blocks and average properties to reduce the number of cells. With this upscaling the reservoir size distribution changed. The upscaling is associated with a smearing of the model, a loss of resolution. There is therefore, a desire to use the fine grids for numerical simulation.

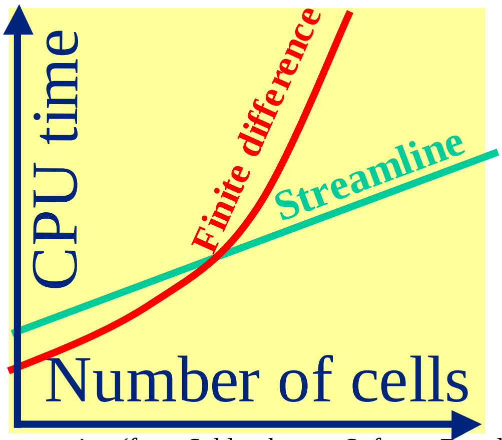

Figure 2: CPU time Consumption (from Schlumberger Sofware Development, Abingdon UK)

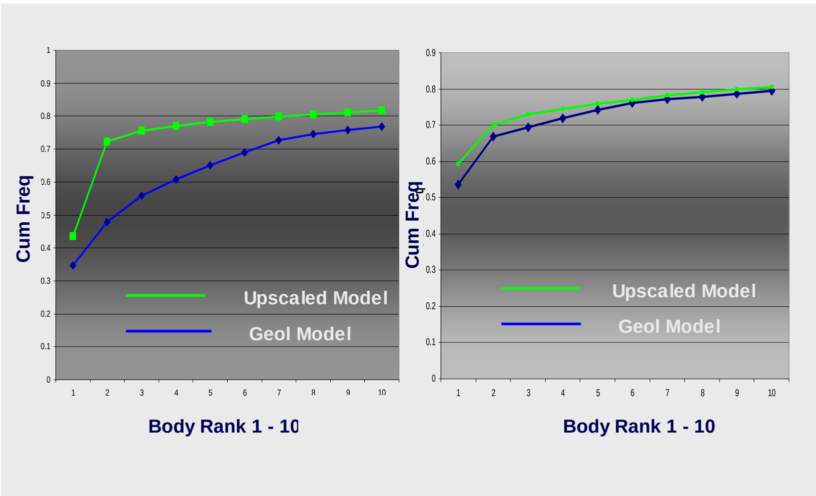

Figure 3: Problem Preserving Pore Volume in Upscaling

The calculation of the streamlines in a reservoir model allows for a stronger visualization of flow pattern and unswept areas, which can help to optimize the sweep [2]. First of all the streamlines can be used to identify which injectors and aquifers the water in a specific well comes from and the fraction of support from the different sources. Secondly, the volume of oil in place between each source and a producer can be quantified. This allows for an identification of the areas of the slowest recovery and areas of too high injection levels. The illustration on the left in Figure 4 shows the typical saturation distribution plot that can be obtained from any finite difference solver. The illustration to the right shows how injector producer pairs can be identified from streamlines for the same case, same timestep. From a typical finite difference model only saturations or pressures can be plotted. These values do not show as clearly the sweep pattern.

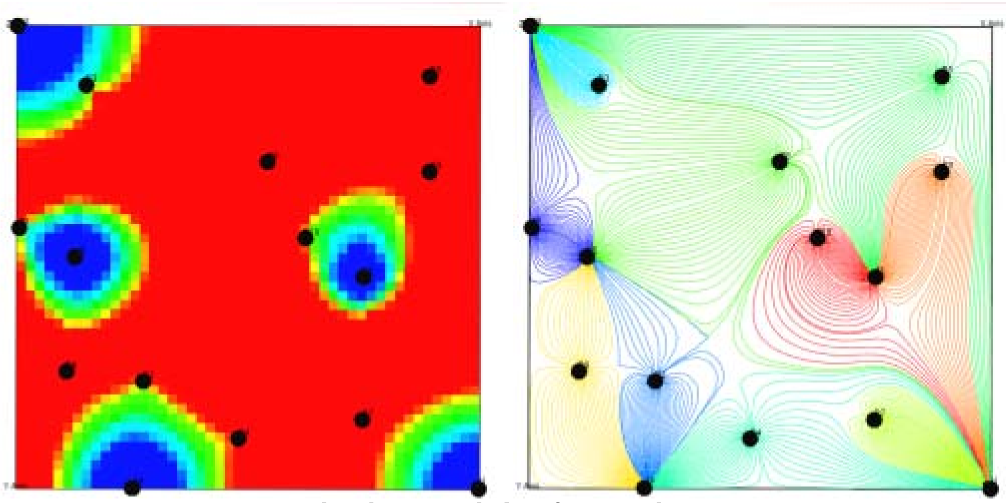

Figure 4: Saturation distribution and identifying producere to injector connections

The use of streamline simulation for production allocation is described through an example in this section. In principle the same workflow can be carried out using a finite difference solver. The benefit of using a streamline simulation application is to get results more closely aligned to the underlying static property model. The example is created to represent a generalization of a problem often encountered in the region in water-flooded reservoirs. The model consists of three reservoir levels of constant but different permeability and porosity. Two producers and 4 injectors are defined. The producers produce from all the reservoir levels but injectors only inject water into 2 of the 3 zones. Injection and production is controlled by pressure constraints. The geometry of the model is illustrated in Figure 5.

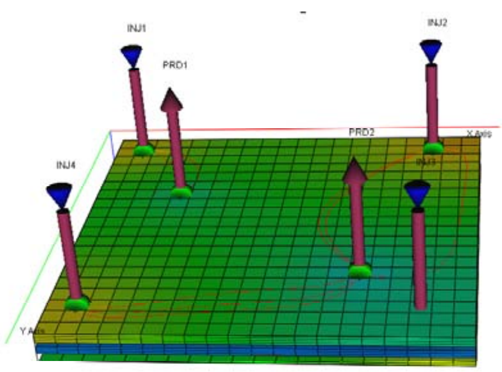

Figure 5: Model Structure

The model was executed and ran for a period representing the reservoir behavior. It is assumed that in general in simulation studies the productivities can be matched more easily than the fractional flow behavior. From the original case the production history is used as the model production constraints and a straight-line relative permeability function is used instead of the original Corey functions. The model now matches the original model in terms of liquid rate, but not in terms of fractional flow, which is often the case in many field studies (see Figure).

The issue is, can the model be used for production allocation prior to obtaining a good match on fractional flow? The reason being that the workflow to the point of having a match on liquid production and injection is significantly shorter than the time it takes to obtain an agreement on fractional flow behavior. To verify this, the allocation factors for oil and water for the top and bottom sands were calculated for every timestep for the reference case and the liquid match case. In the addition the allocation factor using a traditional permeability height approach was calculated. This is constant in time as the properties do not vary. The results are illustrated in Figure for one of the producer wells.

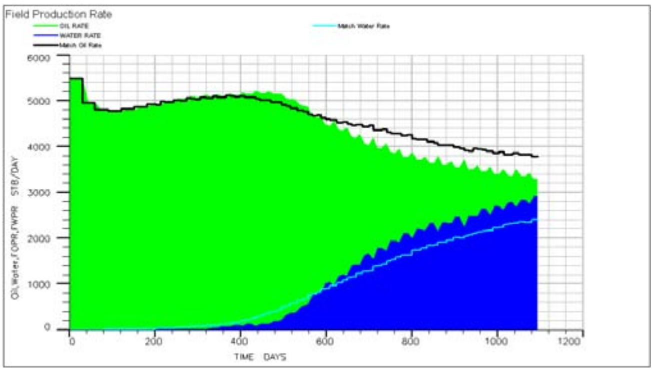

Figure 6: Model and Closest match using straight line relative permeabilities

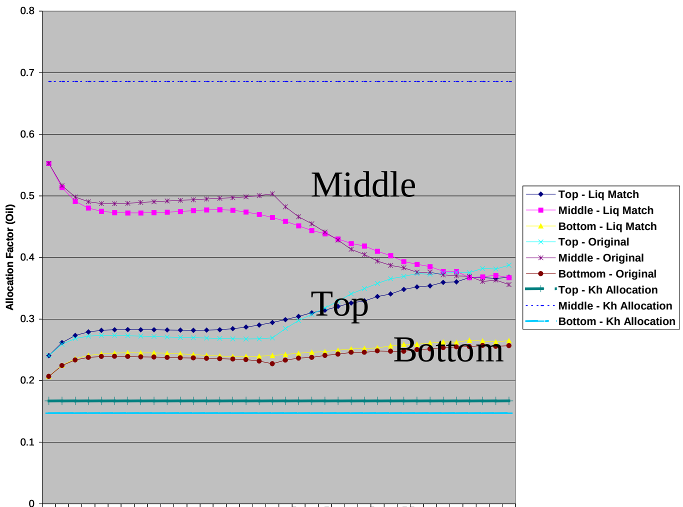

Figure 7: Calculated Allocaton Factors

The results show that in this case the allocation factors calculated from formation productivities are completely out compared to the allocation of the reference model. Even though the case using straight line permeability functions gives a poor fractional flow match it gives a close agreement to the allocation factor for the different phases by wells. All the reference cases studied gave a match in the allocation factor of less than or about 10 percent even though the fractional flow match was out of scale in some cases. It validated that the model could be used reliably to calculate the production allocation factors even though no match to the fractional had been reached.

2.3 Next step in the calculations

Once a simulation approach has been used the outcome is a production profile for each individual horizon. This estimate is based on the reservoir characterization and therefore takes into account the reservoir conductivities, connectivity and volumes as well as different pressure sources at different levels. But the fractional flow may not be matched why a correction is needed. As illustrated in chapter 2.2, the fractional flow match does not need to be perfect to have a reasonable basis for the production allocation. The first step is to take the calculated production by horizon for the individual time steps of the simulation and then to calculated the allocation factors by horizon for each of the phases for each timestep. The allocation factors are then multiplied by the respectful phase rate for each time step to calculate the corrected production.

Once the production by horizon has been established, diagnostic processes can be executed to evaluate potential areas for drilling and workovers. The numerical simulation model can be subdivided into smaller and finer sections for simulation of individual areas and a finer simulation can be carried out. This can later be recombined back into one model, which can be used for a sweep optimization.

3 FIELD EXAMPLE

The reported approach was used in a field study in Colombia of a mature field in the Upper Magdelena basin. The field had about 30 years of production history and current water cut in the range of 95%. The objective was to quantify the potential impact of a sweep optimization. Based on a 3D property model, a simulation model was constructed of about 1.5 million cells. The model was matched with respect to the liquid rates and production logging information and production allocation factors found for the about 250 wells and 13 producing horizons. This work took approximately 3 weeks.

Based on the allocation factors, the production allocation was carried out and a diagnostic study carried out looking at declines and oil in place distributions in the field, while an improved fractional flow match was worked on. Prediction cases in simulation are based on an iterative process whereas well documented analytical techniques exists. One of such applications is OFM (Oil field manager) though many other options exist in the market. The locations identified in the analytical process were then later tested in the numerical model. The study illustrated a potential additional 4% of oil in place to be recovered through an improved sweep plan.

Using the production allocation information to break down the study at individual reservoir levels helped to reduce the total study time significantly and with that the cost.

4 CONCLUSIONS

Production allocation based on a property model with no or little level of upscaling is possible using streamline simulation.

The creation of more smaller level models can accelerate the study time and bring results in a time frame of 1 to 2 months for a mature field.

Being able to breakdown the production on a level to level basis allows for a better determination of remaining oil and allows for the use of analytical calculations on a finer level.

5 REFERENCES

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[2] Lolomari, T., Bratvedt, K. Crane, M., “The Use of Streamline Simulation in Reservoir Management: Methodology and Case Studies”, SPE63157, 2000