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Closing the Loop Between Reservoir Modeling and Well Placement and Positioning

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Abstract

We present a methodology of converting standard reservoir models to maps of production potential for screening regions that are most favorable for well placement. A technique is developed to apply this method to the problem of field development where field production profile moves through successive phases of buildup, plateau, and decline. This results from successive drilling and commissioning of wells at a prescribed frequency (e.g., quarterly) until the total well 'budget' for the field is exhausted and eventual termination of wells as they reach prescribed abandonment criteria. This method, in general, results in an irregular well placement pattern, as it attempts to conform to both time-invariant reservoir properties (e.g., permeability field which may be nonuniform) and time-varying properties (e.g., pressure and saturation field). As such it is a well placement strategy governed purely by reservoir drainage objectives rather than infrastructure considerations which may favor a more regular and orderly well spacing pattern.

We illustrate this methodology for the case of a strong water-drive reservoir to be developed by horizontal wells under primary production. Specifically we examine how the field production profile and recovery factor is affected as the irregular well placement approach, driven by drainage objectives, is applied, compared to a fixed spacing approach. For both cases, an identical field footprint is simulated, that is, the same number of wells, type of wells, production programs, and abandonment criteria are applied; also both follow the 'floor to ceilling' well placement strategy in the reservoir which field experience suggests is advisable for bottom water-drive reservoirs.

We observe a marked improvement in field recovery factor, as manifested by a higher and/or longer plateau, for the case of irregular well placement. The gain reveals the large impact that may result from the systematic use of automatic history-matching techniques and advanced drilling and measurement technologies, the two pillars for the implementation of the method described in this study.

This method also suggests that the same parametric group used to convert standard reservoir models to maps of production potential, can be used to convert while-drilling measurements to the expected production potential of the well as the well is being drilled. This method has been described in a separate study, but that study was limited to the problem of placing a well in a dedicated drainage area. The current study describes the methodology of sequential well placement across the entire reservoir, therefore complements and completes this prior work.

Introduction

The current study is a pragmatic approach of linking disparate activities which collectively can have a pronounced impact on the efficiency of reservoir drainage and recovery. Integration of these activities, however, requires a good deal of 'intelligent' technologies in the form of systematic data acquisition, validation, processing, and information-extraction to support the process of creating and constructing new wells based on measurements acquired from existing wells.

One activity is the task of reservoir modeling, which has a rich toolbox of methods and techniques. Nowadays, even during the early stage of exploration and appraisal, detailed reservoir models are constructed based on seismic information tied to well information, such as logs, cores, pretests and longer term tests. With the commencement of production these models are altered and conditioned to honor observed production data in the form of downhole shut-in pressures, production logs, and multiphase rates. Refs. 1-5 provide a good cross section of the application of these methods.

A second activity is the decision process for well placement strategy. Generally, it is the authors' observation that as fields move from land to platform, subsea and deepwater environments, it is the field environment and infrastructure that dictates to a large extent the arrangement and alignment of wells. Although this is partly understandable, we have to bear in mind that the ultimate purpose of field development is efficient extraction of hydrocarbons from the reservoir. Therefore, careful consideration has to be given to the impact of well placement strategy on recovery efficiency.

This is partly done by notions which exist in the "popular culture" of reservoir engineering, such as well placement from flank to crest in dome-shaped reservoirs under peripheral water-drive or injection. Another notion is well placement with minimum standoff (vertical distance) for bottom water-drive reservoirs and well placement with maximum standoff for gas-cap drive reservoirs. These notions are useful but should be confirmed for each particular reservoir with systematic studies (e.g., the minimum standoff approach breaks down in heavy oil reservoirs especially for high-rate wells).

Besides these notions certain techniques have been developed for a more rigorous approach to well placement planning. These methods are quite useful, but as they are based on stochastic optimization techniques, they do not readily provide a natural linkage to the subsequent problem of well positioning during the drilling process. Refs. 6 and 7 provide a good expose of these methods.

Finally, the third activity is the positioning of the well in the reservoir which, given the inherent uncertainty in reservoir models and methods of devising the most 'profitable' well placement strategy, relies on hard information acquired during the drilling process (i.e, logging-while-drilling). Although these measurements are quite sophisticated they remain local to the wellbore and their linkage to the production potential of the well remains somewhat uncertain. Ref. 8 provides a method of deducing from these local measurements some measure of the production potential of the well, which is suggested by the most plausible model or models for the drainage area of this well (as may be deduced from offset wells). Ref. 8 is therefore purely a study of the problem of well positioning within a defined drainage area and not of well placement across a full reservoir.

In the following sections we develop and illustrate a methodology of linking the first activity (reservoir modeling) to the second activity (well placement strategy). We compare the results between regular and irregular (productivity-oriented) well placement, both following the principle of populating the lower-most reservoir horizons first before proceeding to higher horizons. This is the so-called 'floor to ceiling' well placement strategy that field experience suggests is advisable for bottom water-drive reservoirs which do not have pronounced structural features (as is the case in our scenarios). The idea is to gradually 'lift' the oil-water contact through the oil column and achieve a uniform sweep of the reservoir. Therefore, the irregular spacing approach is gauged against a relatively favorable base case, consistent with field experience.

Given that the incremental gain is still significant, we must highlight the main factors that inhibit the application of such methodology in actual field development planning and projects. One of these factors is the limited use of automatic history-matching techniques. That is, even when these techniques are used, they are used infrequently, compared to the frequency at which new wells are placed in the reservoir. As such the subsurface maps used for well placement decisions are generally not up-to-date. This limitation however can be overcome by systematic acquisition, processing, and inversion of production data in line with the latest measurement technologies (e.g., multiphase flow metering), data management and processing techniques (e.g., data historians and data mining methods), and mathematical techniques for automatic history-matching.

A second factor is the disconnection between the process of delineating favorable spots for new wells and the process of actually positioning this well in the reservoir with advanced drilling and measurement technologies. Conventional thinking suggests that to create such connection one has to have a way of updating the reservoir model in real-time, as the well is being drilled. However, the method presented in this work suggests a more practical and possibly no less effective means of linking the planning and execution phases of well placement and positioning.

We provide no explicit illustration of the further linkage to the third activity (well positioning), but that step is adequately outlined and treated in Ref. 8 and need not be repeated here. We believe with this methodology a non-trivial step may be taken towards closing the loop between the worlds of reservoir modeling and that of well placement and positioning.

Definition of the Productivity Parametric Group

Based on material balance and Darcy's law, the parametric group of the productivity potential should contain some form or combination of three terms – oil saturation, oil phase pressure, and the absolute permeability. As the permeability field has a large variation and it is believed to have a log-normal distribution within a reservoir, the natural log of permeability would be reasonable to use in the parametric group, such that the variation of the permeability field alone does not dominate the variation of the productivity potential field. Moreover, for the well placement problem, a restriction term in well location is required. It is more favorable for production if a well is placed far away from boundaries. So the distance from a well location to the nearest boundary is also a concern. For the purpose of scale balancing in variation, the distance term is in natural log form in the parametric group.

The productivity potential is in the form of:

$$J_{i,\,j,\,k}(t) = S_{o,\,i,\,j,\,k}(t) \cdot P_{o,\,i,\,j,\,k}(t) \cdot \ln K_{i,\,j,\,k} \cdot \ln r_{i,\,j,\,k} \qquad \text{for } i = 1,\, nx;\; j = 1,\, ny;\; k = 1,\, nz. \tag{1}$$

where n_x, n_y, and n_z are the number of gridblocks in x, y and z direction of the reservoir model, respectively. $J_{i,\,j,\,k}(t)$ is the productivity potential at the gridblock $(i,\, j,\, k)$ at time t. $r_{i,\,j,\,k}$ is the distance from the gridblock $(i,\, j,\, k)$ to the closest boundary. Eq. (1) states that the productivity potential of a certain gridblock at a certain time is the product of oil saturation, oil phase pressure, natural log of permeability and the natural log of distance to the closest boundary. **Figure 1** shows an example calculation of the productivity potential field. The resulting productivity field reflects the effect of all the four parameters shown above it. It is easy to observe that gridblocks with high productivity potential are at central regions with high oil saturation, pore pressure, and permeability.

The productivity potential oriented well placement as described above is applied to two production cases, slow recovery and intensified recovery. The recovery results from both cases indicate that at late time when the oil saturation distribution in the field is highly heterogeneous, the productivity field described above still tends to place wells in high permeability regions although these regions have low oil saturation (which accentuates the problem of rising water-cut). Therefore, the productivity potential in Eq. (1) is modified and expressed in the more physically significant form of *mobile* oil saturation, and *effective* pore pressure (pore pressure in excess of the pressure maintained in the well). The modified productivity is therefore calculated as:

$$J_{i,j,k}(t) = (S_{o,i,j,k}(t) - S_{or}) \cdot (P_{o,i,j,k}(t) - P_{\min}) \cdot \ln K_{i,j,k} \cdot \ln r_{i,j,k}$$
$$\text{for } i = 1, nx;\ j = 1, ny;\ k = 1, nz.$$

where S_{or} is the residual oil saturation, and $P_{\min}$ is the minimum well bottomhole pressure. The modified productivity potential is applied to both the slow and the intensified recovery schemes and has shown improvement in production performance.

Productivity-Oriented Well Placement Scheme

Depletion area

The early stage wells provide knowledge of the reservoir through wellbore measurements and production data. Inversion methodologies assimilate these data to update the reservoir model parameters. When the permeability field is up-to-date, the productivity field at later time steps only varies with the pressure and the oil saturation fields. Pressure and oil saturation at each gridblock are obtained from reservoir simulation conforming to the actual production history of the field. When the productivity field is generated, well location is highlighted based on high productivity regions. In order to avoid the problem of overlapping wells and reduce interference between wells during production, the restriction of well drainage area is applied in the automatic process of productivity-oriented well placement. The well drainage area is a square region centered on a well and within which only one well is allowed. As a common practice, the number of wells per reservoir horizon is calculated based on the available oil in place and the expected recovery of each well. So if the depletion area assigned to each well has the same size, the maximum possible size of each depletion area should be no bigger than the layer or horizon area divided by the number of wells allocated for that horizon. While in most cases, there are regions left between the depletion area of existing wells, which are not big enough to justify a new well. So the maximum allowed depletion area is actually only estimated.

Moving average method

Gridblocks with high productivity potential may not necessarily be in a high productivity region. So the moving average method is used to determine the optimum well location, which should be in a high productivity region. **Figure 2** illustrates the application of the moving average method. First assume a depletion area (a 4 x 4 grid in this case), then compute the average productivity potential within each of the depletion areas and give this value to the center point of the depletion area. The center point of each depletion area is called a node, which is represented by the big dots. The optimum well location should be centered at the node with the biggest value. In Fig 2, if the node with the biggest value is the one in red color, then the corresponding depletion area of a new well is the red square around it. When the center of the new well is decided, further work is needed to find the optimum well trajectory or alignment.

Automatic well placement

The process of placing wells in the reservoir based on productivity criteria is done automatically as shown in the flow chart in **Figure 3**. First initialize the input data file for the simulation, then run the simulation until it is time to place a new well (this time depends on the frequency of drilling and commissioning of new wells, we consider both quarterly and bi-quarterly frequencies in this study). The current productivity field is calculated from recorded pressure and oil saturation in the simulation output. Based on the productivity field, compute the nodal value using the moving average method, and rank the nodal locations by descending value. Pick the optimum well location, and optimize the well trajectory within the depletion area. Then check if the proposed well's drainage area overlaps with that of other wells. If so, pick the next best well location; if not, accept the new well location and record it into the simulation data file. As long as the number of wells in the reservoir is less than the allowed well 'budget', the program continues and the data file is updated by restarting the simulation for the next production period until it is time again to insert a new well. This continues until the well budget is exhausted. Field production, however, can continue until the project lifespan is exhausted.

Model Description

The above procedure was applied to the following model.

Model Type: Black oil model with dissolved gas in oil.
Bottom aquifer drive.

Size: 20,000 ft x 15,000 ft x 400 ft, i.e. 40x30x20 gridblocks with each 500 ft x 500 ft x 20 ft. Note the thickness is dividied into 20 'layers' of 20-ft each.

Porosity: 0.15.

Residual oil saturation: 0.3.

Permeability: Channel sand model, heterogeneous and isotropic. (See **Figure 4**)

Reservoir top depth: 5000 ft.

Pressure at the top layer: 4500 psi.

Bubble point pressure: 4000 psi.

Water oil contact: 5380 ft (at the bottom of the layer 19 and the top of layer 20).

Capillary pressure: Ignored.

Aquifer: Infinite aquifer at the bottom of the reservoir with constant pressure.

Simulated Scenarios

From the preceding data, initial oil in place can be easily calculated as:

$$FOIP = \frac{V \cdot \phi \cdot S_{oi}}{5.615 B_o} = \frac{2\times10^4 \times 15\times10^3 \times 380\times 0.15\times 0.8}{5.615\times 1.54} = 1.58\times10^9\ STB \tag{3}$$

As the reservoir is mainly driven by the bottom aquifer and the residual oil saturation $S_{or} = 0.3$, the total mobile oil is $9.88\times10^8\ STB$.

Based on the large volume of oil in place, high-rate horizontal wells will be put on production (e.g., every 6 months) at an initial rate of 15,000 STB/day. In this way the production plateau is established around the 5th year. When the water cut of a well reaches 95%, the well will be automatically shut and abandoned. The perforation length of each well is 2828 ft (862 meter). The drainage area for each well is 3,000 ft x 3,000 ft (6 gridblocks x 6 gridblocks).

Case 1: Slow Recovery

Wells are placed from bottom to top in layer 15, then layer 10 and finally layer 5, with seven wells per layer. This is the case for both the "ordinary" or fixed-spacing well placement and the irregular or productivity-oriented well placement. As a new well is put into production every half year, the process of well placement finishes by the end of the 10th year.

Ordinary Well Placement

Wells are placed diagonally across the reservoir as indicated in **Figure 5**. After producing for ten and half years, all the 14 wells in layers 15 and 10 are shut in due to high water cut, which are wells in gray color. The first producer is shut in at the end of the 4th year. Fig. 5 shows the final oil saturation distribution in layer 18 and above layers. It reflects large amount of oil (in red color) left behind from using this recovery scheme. **Figure 6** shows the field oil production rate profile and the field water cut profile. The production reaches the plateau of 7.5×10^4 stb/day at around the end of the 5th year and starts to decrease by the 10th year. Corresponding field water cut at the end of the 5th year is 43%. Though the water cut drops to 40% with the commencement of production from layer 5, it rapidly bounces back. At the end of the 10th year, the total field oil-in-place is 1.35×10^9 stb, so the oil recovery factor is only 14.28%.

After all the 21 wells are placed in the reservoir by the end of the 10.5 years, production continues for another 4.5 years. Large amount of oil is still left in the reservoir, while most of the wells are shut in due to high water cut. The final recovery factor is 19.80% of the initial oil in place.

Productivity Oriented Well Placement

The basic idea of this approach is to improve oil recovery efficiency by orienting horizontal wells towards regions with high productivity. In this case, the productivity is calculated as the parametric group J = So·Po·lnk·ln(r), where r is the distance of a gridblock to the closest boundary. The term ln(r) in the productivity parametric group is the penalty to regions close to reservoir boundary. **Figure 7** is an example of the productivity field at the end of the first half-year. The first well is placed in the center of the lower-most horizon, similar to the case of ordinary well placement (there is no production data to calibrate the model). After the first well produces for half a year, the second well is drilled along the highest productivity region. As shown in Fig. 7, the second well (on the right) is located on the depletion region with the largest average productivity value within layer 15 and is oriented also along the high productivity region.

Figure 8 shows the oil saturation distribution in the reservoir at the end of 15 years production. The wider swept area reflects better sweep efficiency than in the case of ordinary well placement. In **Figure 9**, the oil production rate reaches the plateau at the end of the 7th year with a rate about $9.25\text{x}10^4$ stb/day. The plateau rate is kept for 3.25 years. Although the oil production rate is much higher than in the case of ordinary well placement, the water cut is also high. It reached 52% after producing for 5 years. The total oil production by the end of 10th year is 2.455×10^8 standard barrels, 15.6% of the initial oil in place. The total recovery by the end of the 15th year is 23.74%.

Case 2: Intensified Recovery

In this case, 13 wells are placed in each production layer, i.e. layers 15, 10 and 5. By increasing the number of wells, the production plateau level is expected to be higher, and the oil recovery should also be increased. The time interval between two well placements is reduced to 3 months, so 39 wells are placed in the reservoir in a space of 9.75 years.

Ordinary Well Placement

In the intensified recovery scheme, the ordinary well placement has 3 more wells on each side of the main diagonal in comparison with that of case 1. The well pattern in each production layer is shown in **Figure 10**. Wells along the central diagonal are placed before those on the flanks.

Figure 11 is the inside view of the final oil saturation field above layer 18 after 15 years of production. Note that all the wells in layers 10 and 15 are shut-in after producing for 5017 days (13.7 years). At the top of the reservoir, there is only a small amount of free gas as the constant pressure aquifer drive has maintained the reservoir pressure. As shown in **Figure 12**, the production plateau reaches $1.4\text{x}10^5$ stb/day after 4 years production. And the production starts to slip by the end of the 9th year. The average field water-cut during production plateau is about 48%. By the end of the 10th year, the oil recovery is 26.79%, and the final oil recovery after 15 years is 35.7%.

Productivity Oriented Well Placement

Figure 13 is the inside view of the oil saturation field above layer 18 after producing for 15 years according to the productivity oriented well placement scheme. The sweep efficiency is obviousely higher than in the case of ordinary well-placement. One well in layer 15 and six wells in layer 10 are still producing by the end of the 15th year. As shown in **Figure 14**, the production plateau reaches 1.5x10^5 stb/day after 6.5 years production. The production starts to slip by the end of the 9th year. The average water cut during production plateau is 58%. By the end of the 10th year, the oil recovery is 27.67%, and the final oil recovery after 15 years is 37.1%.

Case 3: Modified Productivity Potential

The field recovery from the productivity oriented well placement is significantly greater than that of ordinary well placement. However, the water cut has also increased. This is the result of placing wells in high permeability regions. The ideal well placement strategy is one that places wells in the high permeability regions at early time when the oil saturation field and the pressure field are nearly uniform. While at late time when oil saturation distribution becomes very heterogeneous, wells should be oriented mostly by high oil saturation not high permeability (as those regions will be flooded). Based on this idea, modifications were made to the productivity parametric group used in case 1 and case 2. The modified parametric group is shown in Eq. (2). It amplifies the weights on oil saturation term and the oil pressure term by expressing these in ‘differential’ form (above the residual oil saturation and above the minimum wellbore pressure). So at early time when oil saturation is generally uniform within a layer, the permeability field dominates the parametric group, and at late time, the water swept areas will all have zero productivity.

The application of the modified productivity group is shown here only for the case of intensified recovery scenario (i.e., 39 wells drilled and commissioned one per quarter). **Figure 15** shows the final oil saturation field with part of the well population. Comparing the final oil saturation distributions from all the cases, the residual oil volume from this modified productivity oriented well-placement approach is obviously reduced. **Figure 16** illustrates the oil production profile and the field water cut during 15 years. The plateau production rate is 1.46x10^5 stb/day. It starts from the 5th year and ends after 10.25 years of production. The average field water cut during the production plateau is 56%. It gives the best recovery among all the cases. The final recovery after 15 years is 39.03%. By the end of the 10th year, the recovery reaches 28.60%.

Discussion

In the case of slow recovery, the production plateau of the field from the productivity oriented well placement is 23% higher than from ordinary well placement. Although the plateau length is shorter, the productivity oriented well placement achieves 20% more oil recovery than the case of ordinary well placement. Similarly, in the case of intensified recovery, the productivity oriented well placement yields a higher plateau and higher final recovery.

The modified productivity group achieves even a better solution by reducing early water breakthrough in high permeability zones. For the intensified production scenario, the final recovery after 15 years of production is nearly 2% more (in absolute % points of recovery factor with respect to OIP) than that from the case based on the original (‘non-differential’) productivity group. **Figure 17** compares the cumulative oil production after 10 years and 15 years production from each of the cases in this study. The modified productivity oriented well placement yields the highest recovery among all cases.

Figure 18 reflects the high water cut problem with the productivity oriented well placement, as the water cut in both the ordinary well placement cases are lower than those obtained from productivity oriented well placement. This problem could be attributed to the fact that water breaks through more easily through high permeability regions. The problem is especially obvious in the case of strong bottom aquifer drive reservoirs. The water production is reduced, however, using the modified productivity group for well placement. Ordinary well placement is basically a depletion strategy driven by oil saturation and pressure, whereas productivity-oriented well placement is also govered by the permeability field, which makes the decisive difference. This highlights again the importance of production data inversion or automatic history-matching for estimation of the reservoir permeability field.

Conclusions

1. An effective parametric group has been formulated to guide well placement strategy in strong bottom water-drive reservoirs.

2. A recursive scheme has been developed to take advantage of this parametric group for sequential placement of wells in a field development context.

3. Extensive simulations substantiate the positive impact of this approach on field production profile (e.g., higher and longer plateau) and distinctly higher recovery factors. There is however a side effect in terms of increased water production, which can be mitigated through a refinement of the parametric group that increasingly penalizes (over time) regions of high permeability (prone to flooding).

4. Practical implementation of this strategy requires frequently updated reservoir models, which in turn requires “intelligent” technologies for systematic acquisition, processing, and interpretation of production data, particularly multiphase production data.

5. Beyond the “natural” linkage provided by this method between the activities of reservoir modeling and well placement planning, the method also informs the activity of well positioning using while-drilling measurements. These measurements can be related to the production potential of the well through

the production parametric group (a physics-based proxy for well productivity) established above.

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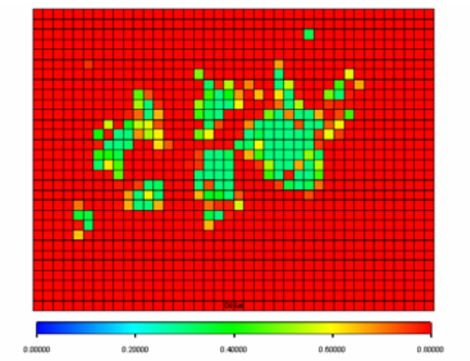

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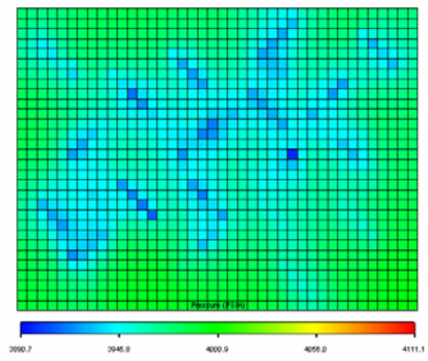

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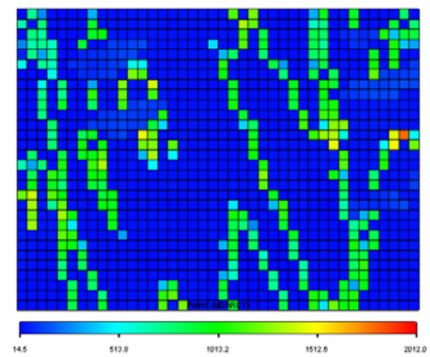

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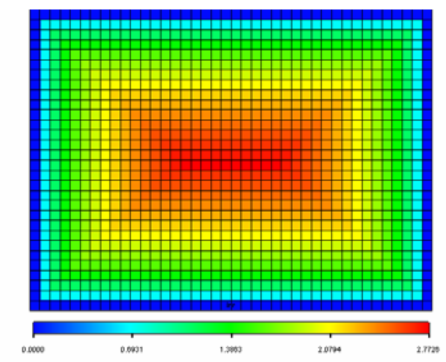

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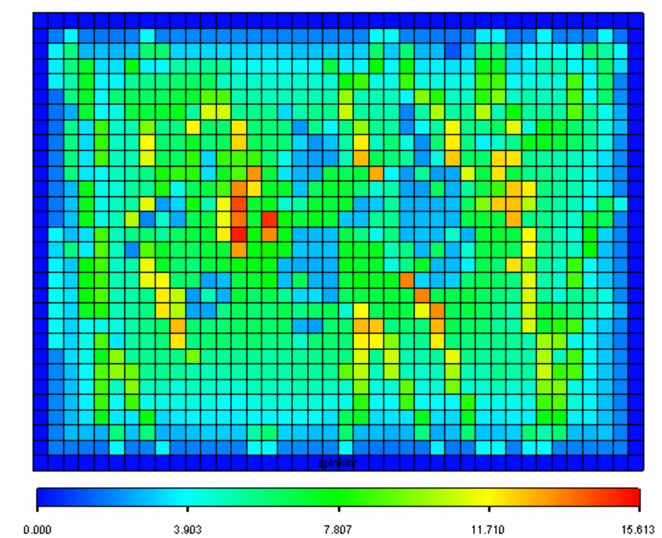

Productivity field

Figure 1. Example for productivity field calculation

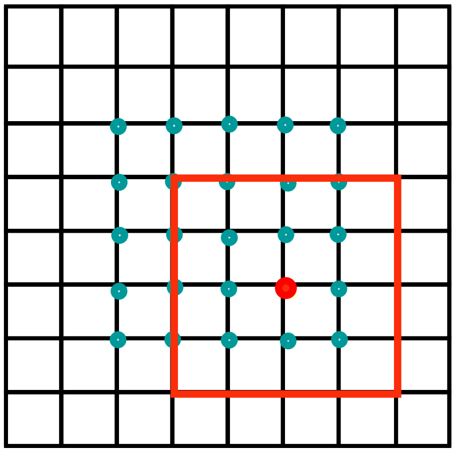

Figure 2. Illustration of the moving average method

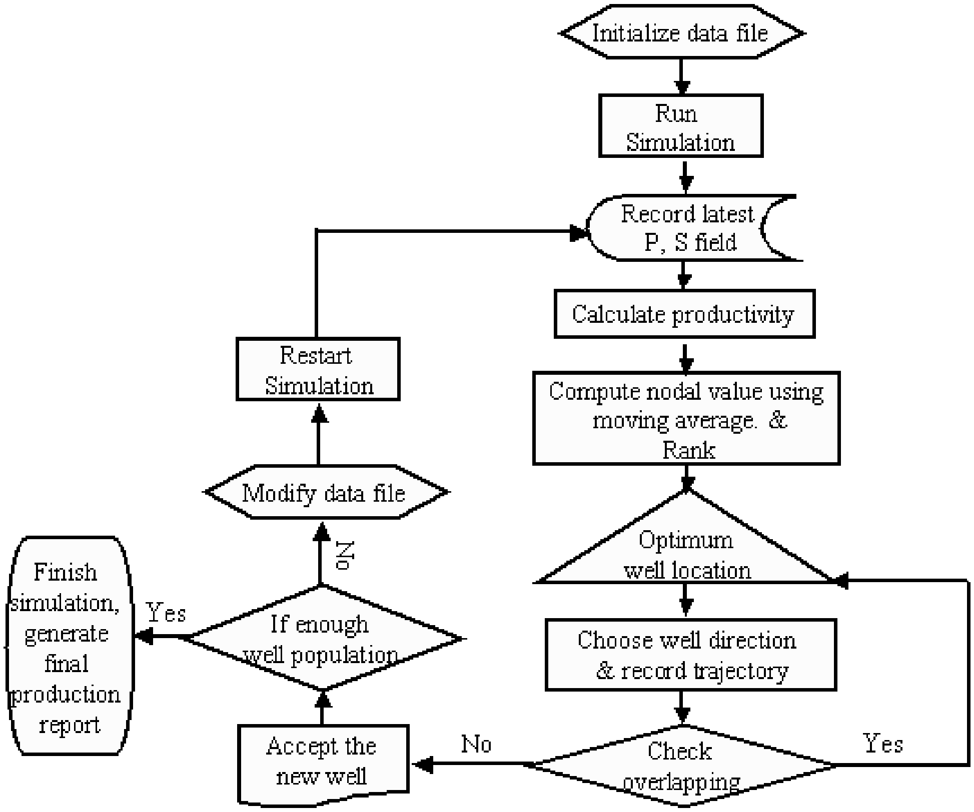

Figure 3. Program flow chart for automatic productivity oriented well placement

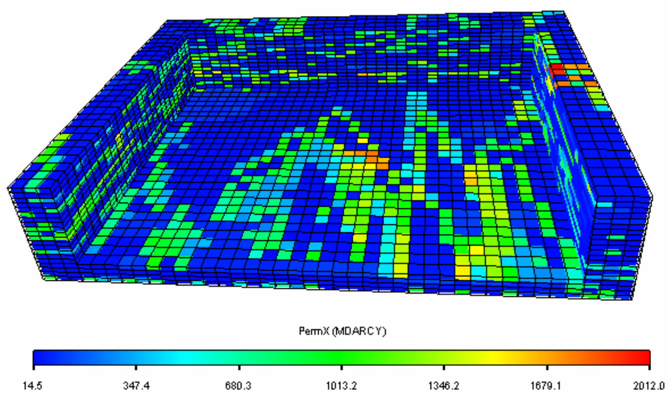

Figure 4. Inside view of the permeability field of the channel sand model.

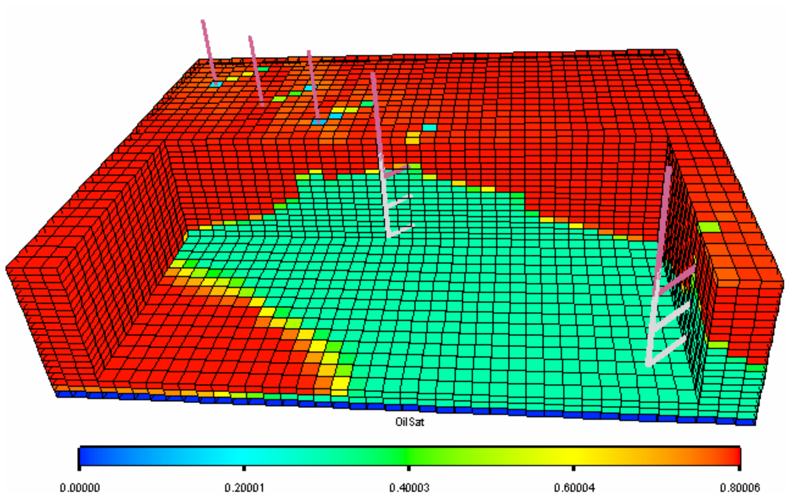

Figure 5. Final oil distribution from the slow recovery case with ordinary well placement

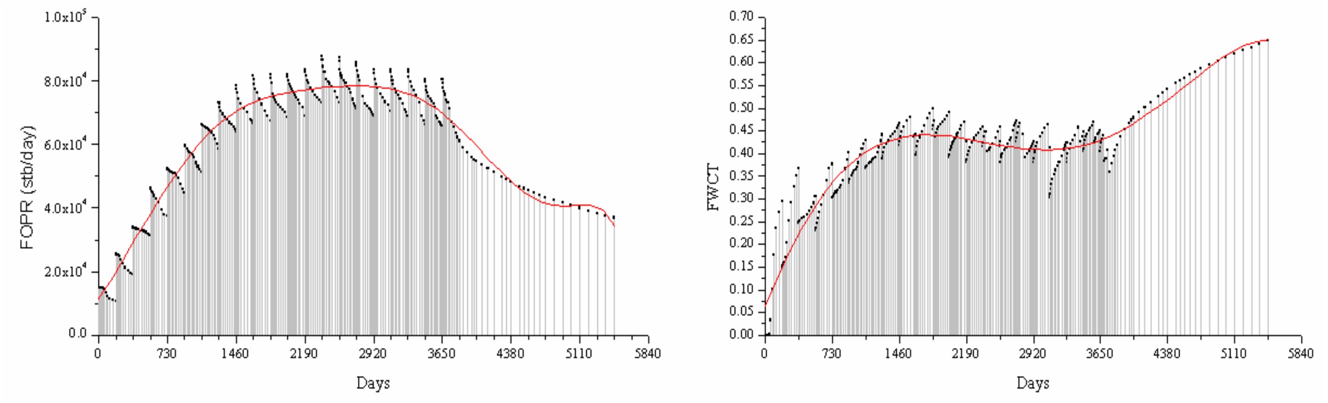

Figure 6. Field oil production rate and water cut in 15 years from the slow recovery case with ordinary well placement

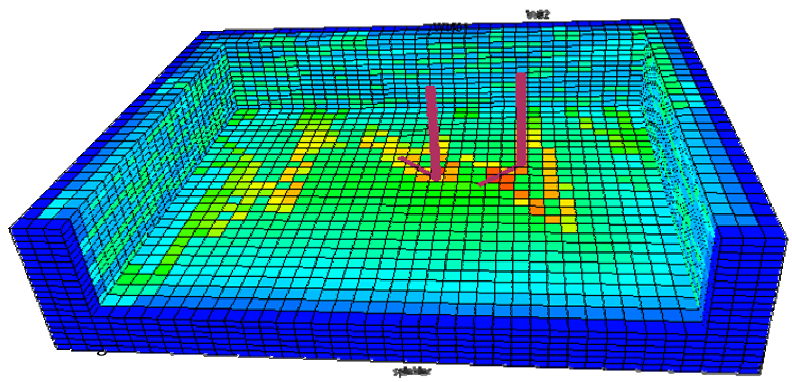

Figure 7. Productivity field of layer 15 at the end of the first half-year.

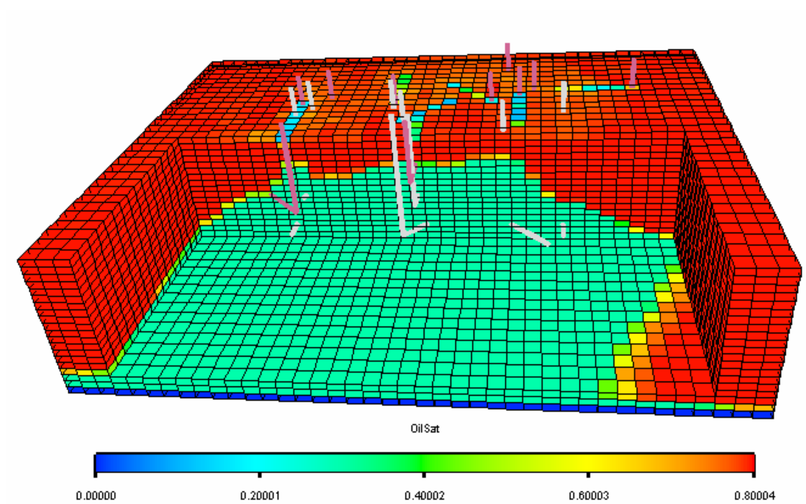

Figure 8. Inside view of the reservoir oil saturation distribution after producing 15 years, slow recovery case with productivity oriented well placement.

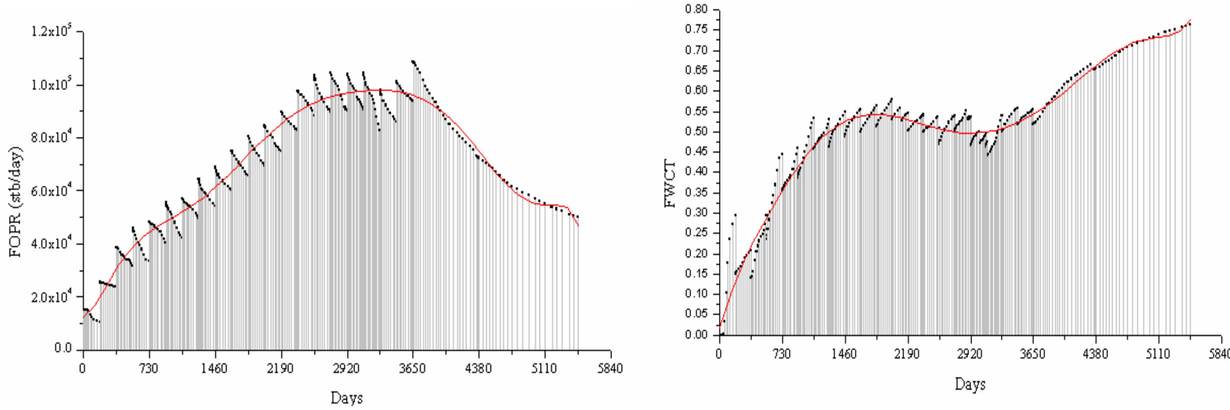

Figure 9. Field oil production profile and water cut in 15 years, slow recovery case with productivity oriented well placement.

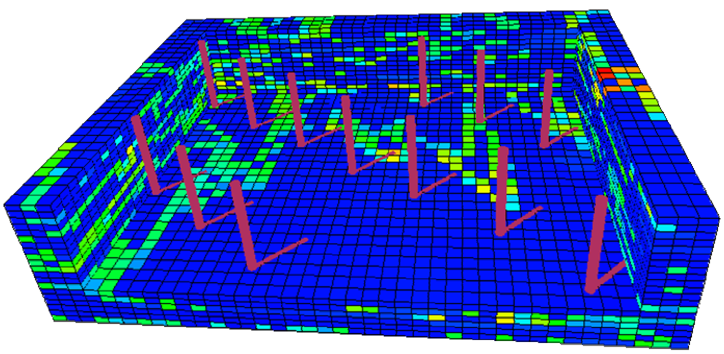

Figure 10. The ordinary well placement in layer 15 of the permeability field, intensified recovery scheme

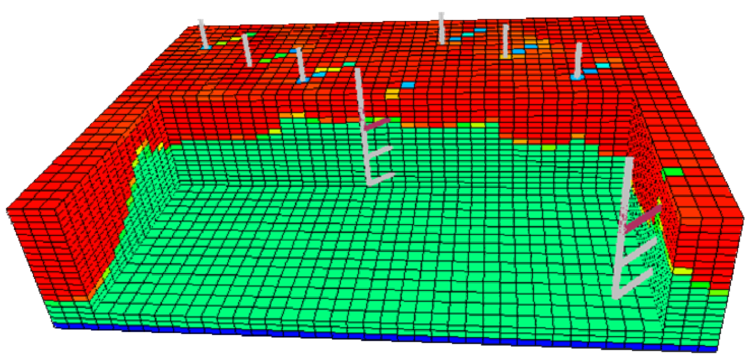

Figure 11. The inside view of the oil saturation field above layer 18 after 15 years of production, intensified recovery scheme, ordinary well placement

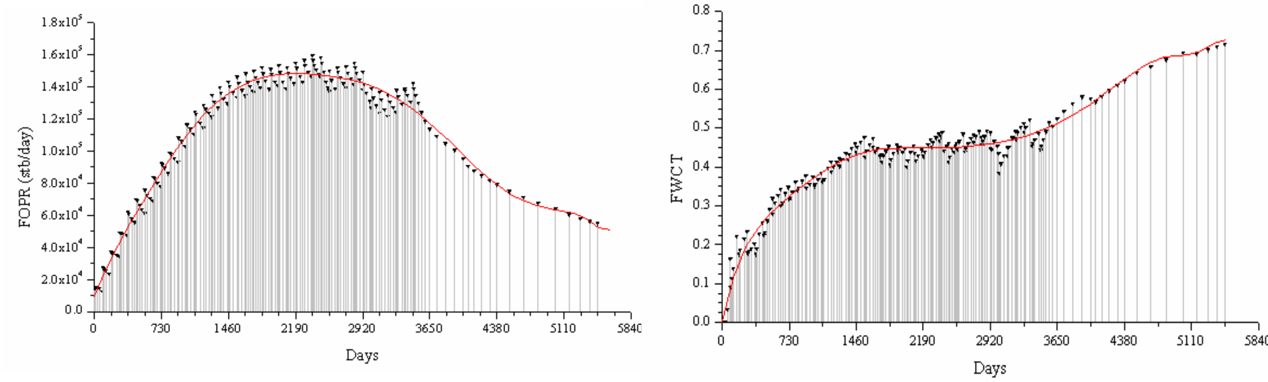

Figure 12. The field oil production rate and water cut in 15 years from the intensified recovery case with ordinary well placement.

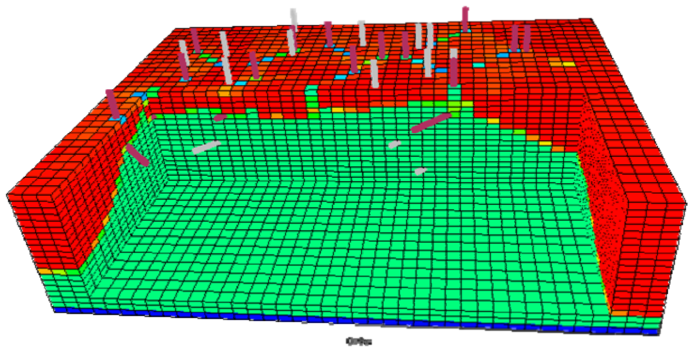

Figure 13. The inside view of the oil saturation above layer 18 after producing 15 years for productivity oriented well placement, intensifield recovery scheme

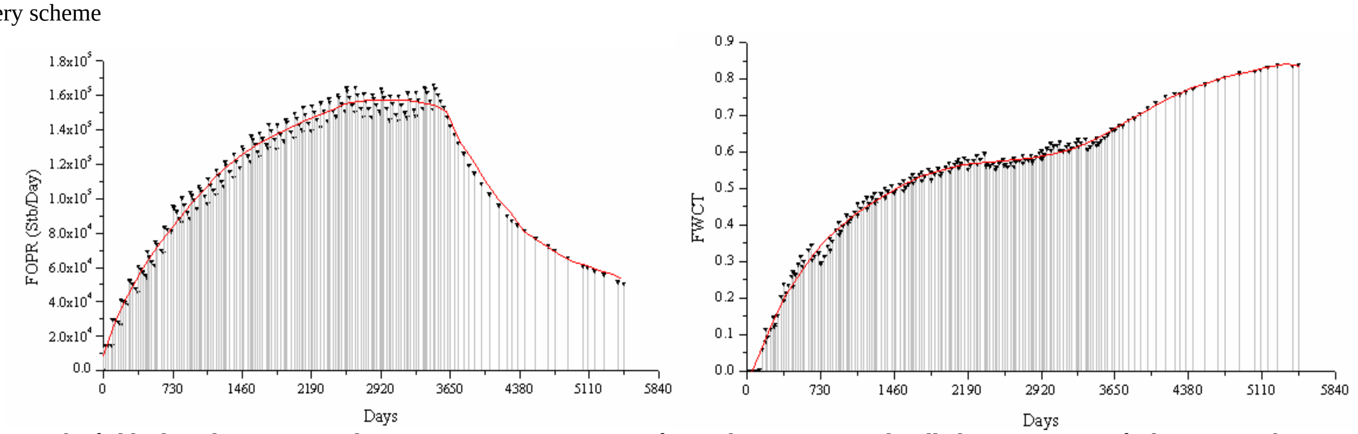

Figure 14. The field oil production rate and water-cut vs. time in 15 years for productivity oriented well placement, intensified recovery scheme

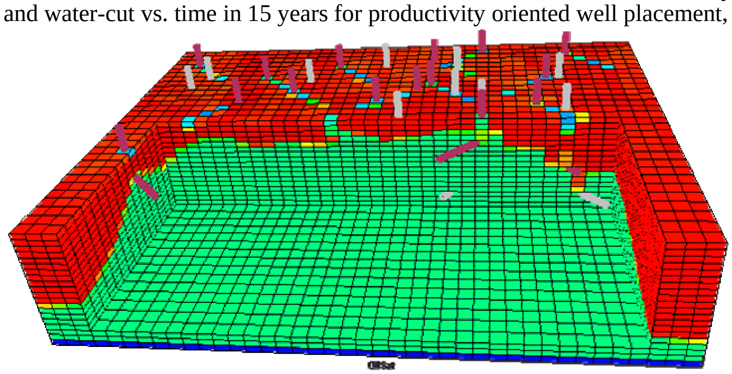

Figure 15. The inside view of the oil saturation above layer 18 after producing 15 years for productivity oriented well placement, intensified recovery scheme, modified/improved production parametric group

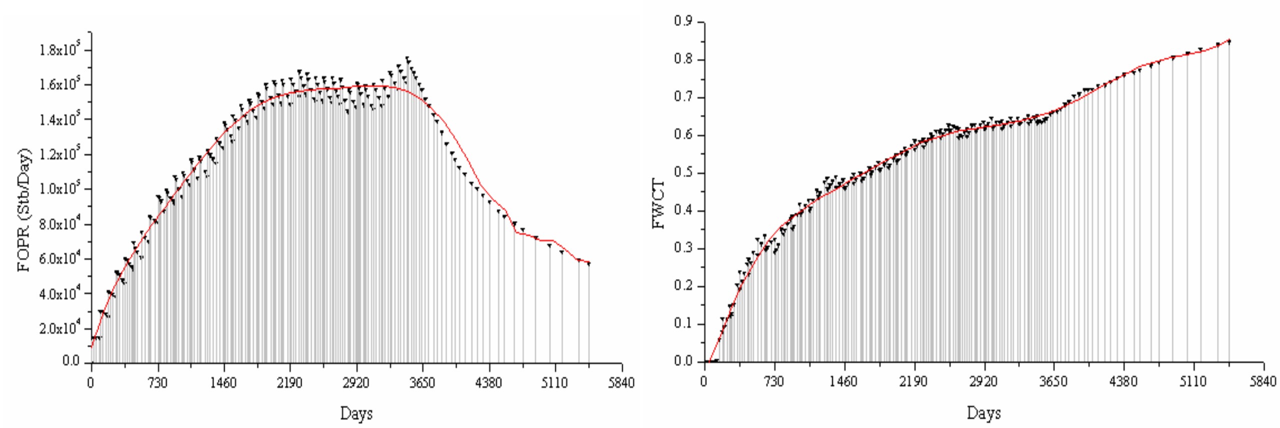

Figure 16. The field oil production rate and water-cut vs. time over 15 years for productivity oriented well placement, intensified recovery scheme, modified/improved production parametric group

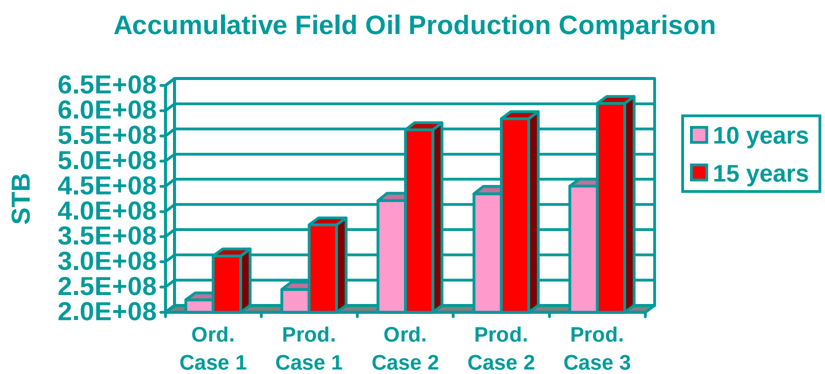

Figure 17. Cumulative field oil production at 10 years and 15 years for all the cases.

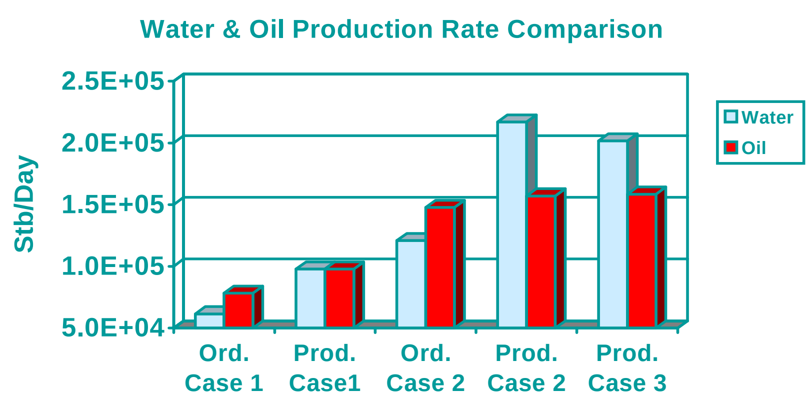

Figure 18. Average water and oil production rate at plateau period for all cases.