SPE 111693

DollarTarget - Optimize Trade-Off Between Risk and Return in Well Planning and Drilling Operations

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This paper was prepared for presentation at the 2008 SPE Intelligent Energy Conference and Exhibition held in Amsterdam, The Netherlands, 25–27 February 2008.

Abstract

A new cross disciplinary workflow and methodology for optimizing the hydrocarbon recovery of a well with respect to well placement, positional uncertainties, the net present value and risk assessment is presented. The methodology has been applied in integrated operations by well planning teams to identify the optimal well design, and was used as a base for decisions during drilling operations. It is implemented in a new internal StatoilHydro software tool called DollarTarget.

Focusing on a geological target of the well path, the methodology integrates geophysical and seismic pick uncertainty, uncertainty in the well trajectory and net present value variation in such a way that multiple drilling scenarios and different realizations of the reservoir model are considered when balancing risk and return of the planned well.

Using the methodology in planning and operation for several wells in the Norwegian Sea, a pilot project concluded that the methodology improved cross-disciplinary collaboration within the well planning team. In addition the well planning teams reported that the net present value risk analysis lead to a significant increase in the expected net present value and adjustments of the well path for several wells in the project. Moreover, improved risk evaluation was reported as a result. Use of the methodology made the well planning groups able to evaluate the economical consequence of increasing the risk with the purpose of maximizing the hydrocarbon production. This required input from the entire well planning team. With 3D visualization of input data and results, the new software tool worked as a facilitator for discussions and common understanding.

In this work application of the methodology in well planning and drilling operations for three wells in the Heidrun and Smørbukk fields in the Norwegian Sea is presented. The examples show the significant benefit and business value of using DollarTarget for net present value risk analyses, and support the conclusions from the pilot project.

DollarTarget introduces an integrated operations workflow and methodology which has proven to be highly beneficial in well planning and drilling operations. The technology is currently being implemented in the well planning and drilling operation work processes in StatoilHydro.

Introduction

The use of risk analysis and integration of uncertainty information from geological structures, well drainage potential, and the well trajectory for decision making in well planning and during drilling operations is considered to have great business potential. Experience from well drilling operations proves that performing an analysis of the major risk elements prior to drilling is highly beneficial for increased oil recovery (IOR) wells. Establishment of decision-trees and scenario mapping prior to drilling has proven to be of considerable value. However, in many cases individual optimization within each discipline in the well planning team leads to sub-optimal solutions. Moreover, in many of today's methods the focus may foremost be on the cost and consequences of unfortunate events. The potential in increased net present value of the well is often in danger of being ignored in favor of well trajectories which are associated with minimum risk. Here, a new cross-disciplinary methodology and workflow for risk analysis is presented. It takes into account the 3D positional uncertainties, the drainage potential and costs of the well for decision making in the well planning phase as well as the operational phase. Compared to available well planning tools on the market, the methodology operates on a more detailed level, which is suitable for IOR wells.

Application of the new technology, which has been implemented by StatoilHydro in a software tool called DollarTarget, was tested in well planning and operational work processes as a part of a corperate initiative on integrated operations. Working in integrated operations imply new work processes to enable a better collaboration between disciplines, organizations and locations to achieve safer, better and faster decisions. The value creation is related to improved HSE, increased production, increased regularity, more efficient operations, and optimal well placement, as well as better use of competence. During the testing of the methodology it was documented that use of the new technology increased the level of cross-disciplinary discussions in the well planning teams, and that the technology acted as a common platform for communicating uncertainties in drainage evaluations, geology, geophysics, and drilling. The impact of these factors on the optimal position of the well and on its expected value was better understood across disciplines, leading to improved well placement. Based on the test results it has been decided to implement the new technology in StatoilHydro.

This paper is organized in the following manner: The methodology section describes the DollarTarget technology and work processes. The next sections present three cases where the technology was applied. The first case presents the use of DollarTarget in the planning process of the Heidrun A-41 A well. Secondly, application on the Heidrun E-4 AH well is shown. Subsequently, application of the technology applied in drilling operations for the Smørbukk M-2 AH well is described. The final section presents a summary and conclusion.

Methodology

The new methodology integrates positional sub surface uncertainties and the net present value (NPV) variation for possible well positions within and outside the geological target area. This integration leads to an expected net present value (eNPV) map which is used to determine the most profitable drilling strategy and the optimal well bore intersection points with the geological target. Additionally, the robustness of the selected solution can be analyzed through histograms showing the distribution of NPV for a chosen trajectory. The goal of the analysis is to combine the knowledge from geological models, reservoir models, and drilling parameters with corresponding uncertainties to find the optimal trade off between risk and return. Visualization of the NPV variation together with positional uncertainty forms a basis for improved work processes in the well planning groups during the well planning process and in well operations.

The well planning process often starts with the reservoir engineer screening an area with the purpose of finding the optimal location in the reservoir for the new well based on the geological model and reservoir model of the field. This location is normally where the well is expected to drain the surrounding volumes as efficiently as possible, thereby contributing to a high NPV. In this process the reservoir engineer often gains knowledge of the variation in productivity between different well locations in the screened area. The next step in the planning process is for the geophysicist and drilling engineer to suggest a geological target and a corresponding driller's target.

PrecisionTarget[1] is a software tool developed in StatoilHydro [1]. PrecisionTarget calculates a driller's target with a given hit probability by combining uncertainties in geophysical processing, geophysical interpretation, and drilling survey, with accepted probabilities (risk factors) for drilling outside the geological target borders. The aim is to calculate a driller's target where the probability of missing the target does not exceed a predefined value.

DollarTarget combines the productivity variation knowledge and the positional uncertainty from PrecisionTarget in the NPV analysis of the geological target. One input to DollarTarget is a set of 'NPV points', i.e. a list of different well positions in the target area with the predicted NPV of the corresponding well. The NPV of each point can be based on reservoir simulations, volume trend calculations, variation in properties and/or production experiences together with variation in the cost for reaching well locations. The methods used for NPV estimation depend on the type of well location, the maturity of the reservoir, and on the available models. The costs of any possible corrective actions (e.g. side tracking) and related delayed production are also included. The NPV points are interpolated in the DollarTarget software to form an NPV map. Uncertainty in the NPV map itself is treated as a number of scenarios with predefined probabilities. DollarTarget combines the input NPV map and positional uncertainty from PrecisionTarget as well as steering precision, and calculates the eNPV with the corresponding robustness for any given well intersection point within the geological target.

Keeping the risk as low as possible may be disadvantageous for maximising the productivity of the well. Hence, the challenge has been to make the well planning group able to evaluate the economical consequence of increasing the risk with the purpose of maximising the hydrocarbon production. By investigating the expected NPV for all possible well locations within the area of interest, DollarTarget is able to give the well planning group the basis to take strategic decisions with regard to well placement and design.

Case I – Heidrun A-41 A

The Heidrun field is located on the Haltenbanken offshore of Mid-Norway in the Norwegian Sea. Since the field was discovered in 1985, 11 exploration wells and 111 development wells have been drilled in various parts of the Garn, Ile, Tilje, and Aare formations which constitute the main reservoirs of the field [3,4,5,6,7,8]. The main drainage strategy is to support upflank oil producers by downflank water injecting wells. Pressure support is also maintained through upflank gas injection

[1] PrecisionTarget is included in Halliburton Landmark's suite DecisionSpace.

located high on the Heidrun structure. The field production is restricted by the gas processing capacity and therefore by the gas oil ratio (GOR) in the producers.

Reservoir description

The objective of the A-41 A well is to accelerate the production and increase the recovery from the upper part of the Ile formation (Ile 4-6), see

Table 1, in the F segment. There are two other Ile producers in the segment, A-53 (shut in due to high GOR) and A-45. The A-45 well came on stream in November 2000 to accelerate the production from Ile. The well is a horizontal producer with a heel in Ile 2 (lower part of Ile) and the toe in Ile 6 (upper part of Ile). In October 2006 the well had a major water breakthrough and subsequent massive sand production. The well is now strongly reduced, producing at maximum sand free rate (MSFR). The A-41 A will be a replacement well for A-45 in the upper part of the Ile formation.

Table 1: Average horizontal (k_x) and vertical (k_z) permeability, and porosity (poro) in the F segment.

	k_x (mD)	k_z (mD)	Poro
Ile 6	3131	1982	0.30
Ile 5	870	622	0.32
Ile 4	255	156	0.29
Ile 3	20	9	0.18

In the Heidrun asset, 4D is an important tool for tracking fluid front movements. The base survey from 1986 has been repeated in 2001, 2004 and 2006. The 2006 survey was also processed for optimal structural imaging. Figure 1 shows the Bayesian 4D inversion [2] from Ile 4-6 for the 4D surveys 2001-2004 and 2004-2006.

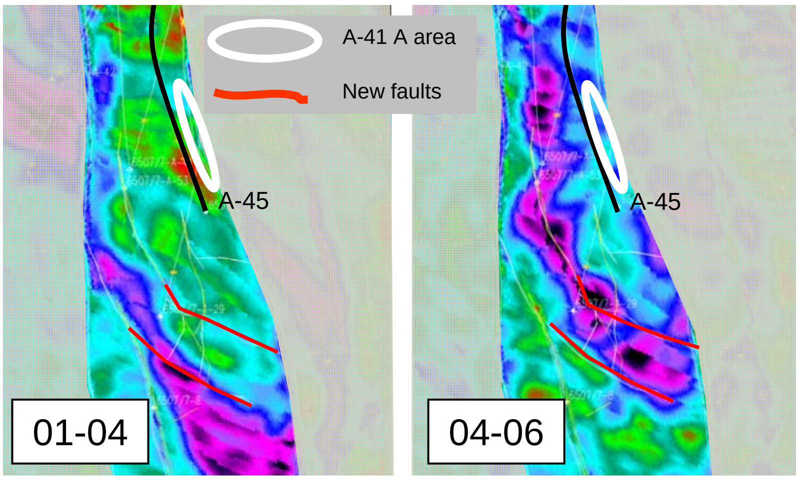

Figure 1: Average amplitude maps from Top Ile 3 to Top Ile 6, top view of the F segment, of Bayesian 4D inversion from the two latest 4D projects of Heidrun. Blue colors indicate an increase in acoustic impedance, i.e. water replacing oil or gas, and water or oil replacing gas. Red colors indicate a decrease in acoustic impedance, i.e. gas replacing oil or water.

In the 4D data from the period 2001-2004 the strongest change has occurred in the southern part of the F segment. This corresponds to a lift in the water oil contact in the segment. However, it is also evident that some water is coming in from the west. The upper part of the Ile formation in the F segment is juxtaposed with the water filled Garn formation in the west. So there are two active water fronts in the segment, one from the west and one from the south. The 2004-2006 4D survey confirms this pattern. Moreover, the survey indicates that the water break through comes from the west in the upper part of the Ile formation and not from the south. This is also indicated by the observation of massive sand production in the A-45 well. The water replacing oil response along the eastern part of the segment is mainly caused by water flooding of Ile 6. Figure 2 shows a simplified sketch of the interpreted fluid fronts in a north to south vertical section.

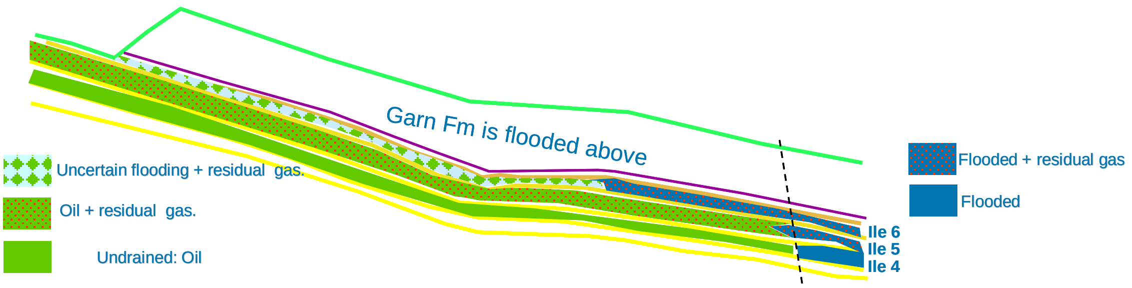

Figure 2: Simplified north-south cross section of the F segment with interpreted fluid fronts based on 4D data.

Two new parallel north-west south-east trending faults approximately 600 meters from the toe of well A-45 were interpreted in the 2006 3D survey (highlighted in red in Figure 1). Initially, the full field simulation model did neither match the observations from the 4D, see Figure 1 and Figure 2, nor the acquired production data. The water break through was almost two years early in the reservoir simulation model. Updating the reservoir simulation model with the new fault interpretation reduced the communication with the injector in the south, and a good match with the 4D observations and the production history was achieved. Figure 3 shows the saturations in the segment for each of the layers in the upper part of the Ile formation. This is in good correspondence with the 4D observations.

Table 1 gives an overview of the average properties in the segment per layer. Due to the high permeabilities in Ile 5 and 6 the reservoir zones can be expected to produce free gas from the gas cap.

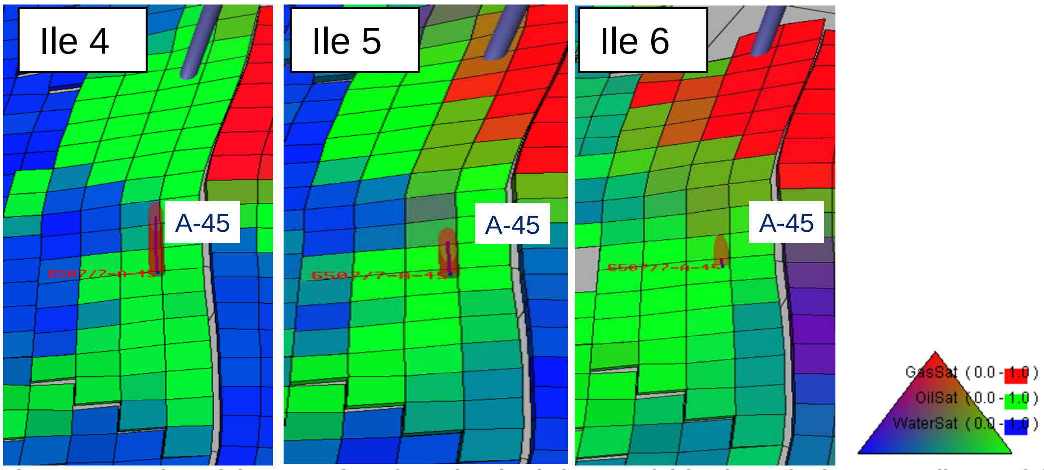

Figure 3: Top view of the saturations from the simulations model for Ile 4-6 in the A-45 well area of the F segment at the scheduled drilling time for A-41 A.

The well planning process

A well planning group was assembled to establish the most optimal well design for the infill producer A-41 A. The main target for the A-41 A, is in the area east of the A-45 well. The A-41 A will be a sidetrack from the A-41 well, placed in Garn in the F segment. On Heidrun, one distinguishes between shallow and deep sidetracks. A deep sidetrack only involves pulling the tubing and setting a whipstock in 9 5/8” casing. A shallow sidetrack involves both pulling tubing and one or more casing strings. In addition, to perform this extensive slot recovery the production riser needs to be replaced by the drilling riser whilst the whole operation can be performed through the production riser for a deep sidetrack. In order to swap the riser the significant wave height must be below 3 meters, which makes a deep sidetrack a more robust solution for the rough weather conditions in the Norwegian Sea. A shallow sidetrack gives full flexibility regarding well placement, but the expected cost will be higher compared to a deep sidetrack, in average 100 million NOK. The area that a deep sidetrack can reach is more limited. The maximum dog leg severity (DLS) for both solutions in the planning phase is 5 degrees per 30 meters in the overburden and 3 degrees per 30 meters in the reservoir section.

In order to optimize the well design several analyses were performed. First, sensitivities regarding the producing interval length per reservoir zone were analysed. A balanced well with regard to the productivity index (PI) per zone was found to be beneficial for the ultimate recovery, the water cut development, and the GOR. This formed the preferred template for the well design, a long layer dip parallel section in Ile 4, a shorter section in Ile 5, and with the toe just entering Ile 6.

To optimize the well further, the effect of well placement within the segment was evaluated. This was performed by placing the template well at different locations within the segment in the reservoir simulation model. In total, the template well was placed in 18 different locations, and the NPV of the well was calculated in each case. These results were used as input to the DollarTarget analysis of the geological target guiding the placement of the well within the segment. The geological target was defined on the Top Ile 4 surface and it was confined by the following parameters: water in the west, water in the south, the segment fault in the east and the gas cap in the north, see Figure 4.

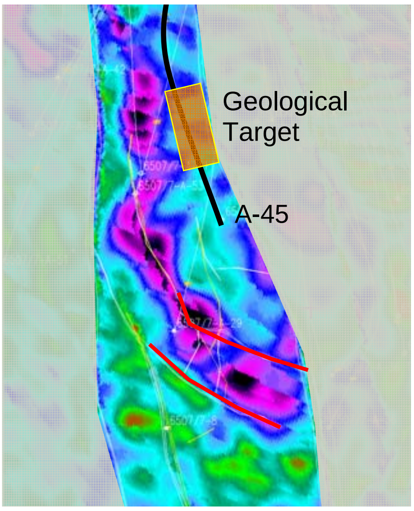

Figure 4: Average amplitude maps from Top Ile 3 – Top Ile 6, top view of the F segment, of Bayesian 4D inversion 2004-2006 with the geological target for well A-41 A.

The simulation model results were used to construct the NPV surfaces for the regions GT, A, C, and D, see Figure 5. If the well is drilled into region B, the well would be outside of the segment. This would be observed while drilling by discovering that the reservoir zones would be observed outside the vertical uncertainty bound and/or by the identification of the crossing of the fault zone on the real time logs. If this happens, the well would be plugged back and sidetracked. A penalty equal to the cost of a sidetrack is therefore used as NPV input for this region.

Figure 5 shows the main NPV trend within and outside the geological target. There is an increase in NPV towards the north east until the well is placed too close to the gas cap, region A, where there is a decreasing NPV. The highest NPV is found in the north eastern corner of the geological target.

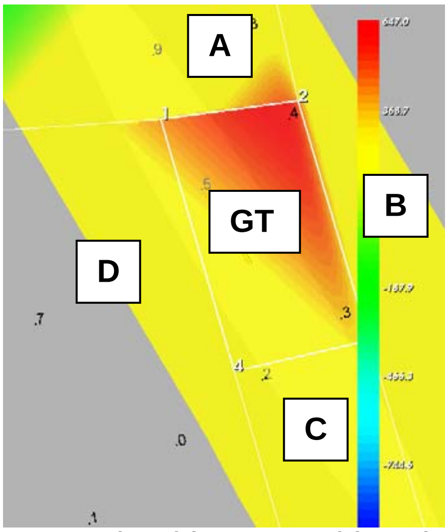

Figure 5: Top view of the NPV map of the geological target, GT, and the surrounding regions A, B, C, and D.

The expected NPV map, see Figure 6, is created by combining the NPV map with the uncertainties in geophysical processing, geophysical interpretation, drilling survey and steering precision. The positional uncertainties together with the lower NPVs in region A and B have drawn the optimal aiming point towards the south west, and away from the north eastern corner of the geological target. With the DLS restrictions in the overburden, 5 degrees per 30 meter, it is not possible to reach this point with a deep side track. This brought the following question to the well planning group: What has the highest expected NPV: A deep sidetrack and a non-optimal well path or a shallow sidetrack and an optimal well path? With a shallow sidetrack, there are no limitations with regard to well placement in the geological target. With a deep sidetrack the area which can be reached is the shaded area on the left hand side of Figure 6. The difference in expected NPV is about 40 million NOK in favour of a shallow sidetrack.

The well planning group continued working on the deep sidetrack options in parallel with the now preferred shallow sidetrack. On Heidrun, the standard well design is to land out in a tight reservoir, in this case Ile 3, and enter the producing interval from below. By modifying this design and land out in Ile 4 instead of Ile 3, the area that could be reached was extended; see shaded area on the right hand side of Figure 6 and Figure 7. Performing the analysis again showed that the difference in expected NPV was about 50 million NOK, now in favour of a deep sidetrack. The optimal well design and the recommended solution for the A-41 A well is to drill a deep sidetrack from the A-41 well, place it as far north-east in the segment as possible, and by geosteering ensure a balanced well with regard to the PI per reservoir zone.

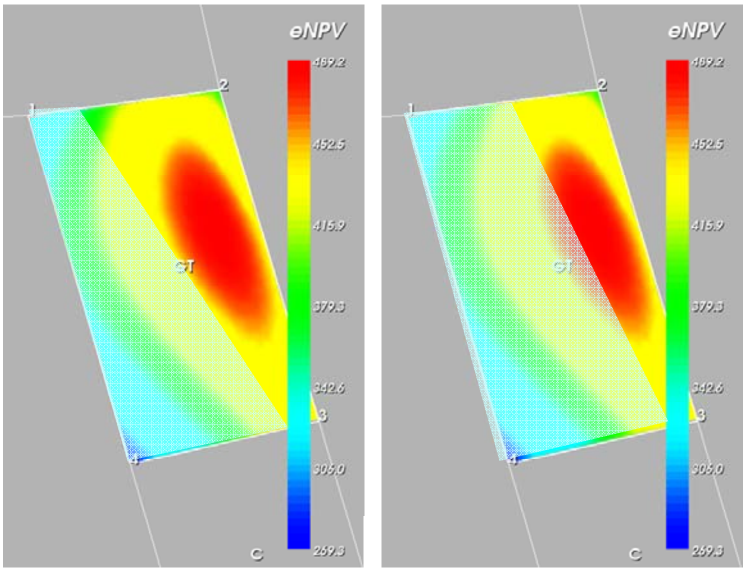

Figure 6: Top view of the expected NPV map of the A-41 A well in the geological target. The shaded area on the left hand side is the area that can be reached with a conventional deep sidetrack. The shaded area on the right hand side can be reached by a deep sidetrack with a modified well design.

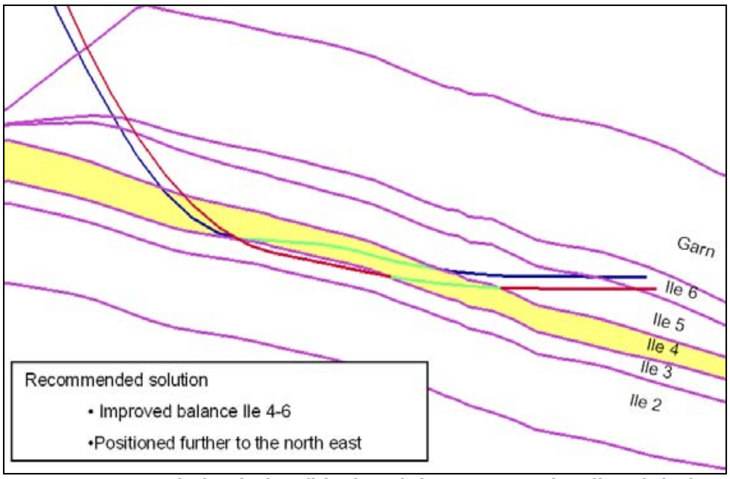

Figure 7: Recommended solution (blue) and the suggested well path before optimization (red) in a north to south cross section of the F segment. The Ile 4 production interval is highlighted in green for both well paths.

Quantification and visualisation of risk, value variations and constraints has shown to be very important for optimizing the well path in this case. The use of DollarTarget challenged the reservoir engineer to quantify and document the guidelines for the well placement within the segment. It has also been an important tool for communicating and creating a common understanding in the well planning group of the importance of optimizing the well placement within the geological target and for understanding the most important well placement issues. Having performed the NPV analysis in the well planning phase, the expected NPV map can also be utilized while drilling. In the case of steering problems where the aiming point cannot be reached, the expected NPV map can be applied as an aid in the decision to evaluate whether it is economical to continue or perform a sidetrack.

Case II – Heidrun E-4 AH

The well E-4 AH was drilled during the spring of 2006 as a commingled producer to the Tilje and Aare formations in a down faulted segment on the eastern side of the Heidrun field. The well received pressure support and sweep by the water injection well F-4 H. Internal faults intersect the vertically and laterally heterogeneous segment. The reservoir engineer in the well planning team incorporated DollarTarget in the planning process to optimize the well trajectory under uncertainty. The methodology presented here was used to optimize the trajectory of the final 300-400 meters measured depth (MD) of the well.

Reservoir description

The well was planned to penetrate from shallow Tilje layers in the hanging wall into a foot wall where deeper reservoir layers within the Tilje formation were expected. Seismic interpretation of the area indicated that the toe section would penetrate a normal fault with a throw of about 30-50m in the production interval. Uncertainty was associated with the fault throw, the thickness of the reservoir layers, and the extent of the deformation zone around the fault. The on-site well log interpretation of E-4 AH in the foot block was expected to be uncertain as the well would enter this area nearly parallel to the reservoir zones. The well would proceed at a constant inclination in the foot block through an observation zone where the geologist would attempt to localise the well within the stratigraphy. The constant inclination would also be maintained to verify that sufficient contact was made with the entered layer to ensure good productivity. When the well had passed through the deformation, observation, and contact zones it would drop to make contact with deeper layers as sketched in Figure 8.

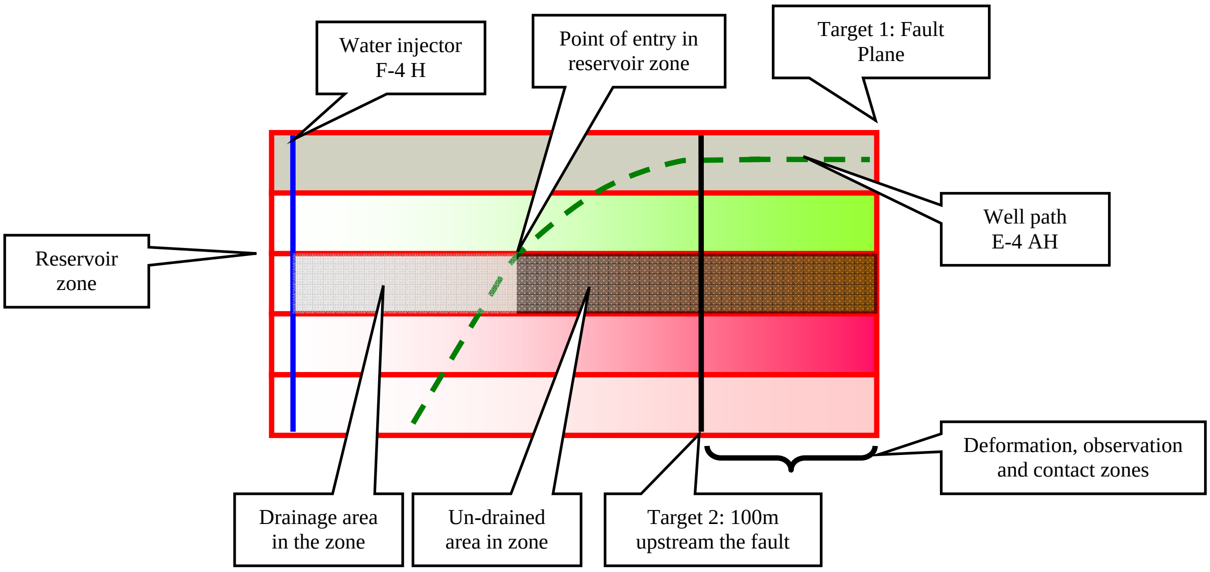

Figure 8: Simplified sketch of the reservoir layers in the foot block and the well entering through the deformation, observarion and contact zones, and into the reservoir layers. The colour scheme shows the layer trend in NPV from low to high in gray, green, light red and red colors. The horizontal color gradient indicates a reduction in NPV as the producer draws near to the injector. The layers from top to bottom are Tilje 4, 3.4, 3.3, 3.2, and Tilje 2.5+2.4. Target 1 is defined in the fault plane, whereas target 2 is defined for the NPV analysis 100 meters upstream of the fault.

Drilling the well into deeper zones was limited to a drop with a maximum dog-leg severity (DLS) of 3.5 degrees per stand. This was to avoid complications when completing the well with gravel packed screens. It was also stated in the planning phase that the toe section could only drop at this rate and not build to shallower layers. Building the well inclination would increase the risk of being stuck when running the screens before the terminal depth of the well was reached.

The well planning process

A well planning team was assembled to find the optimal well design for the E-4 AH well. A simple conceptual model was designed to estimate the NPV of entering the hanging block in any layer, proceed horizontally through the deformation, observation and contact zones before the final part of the well drops toward the oil-water contact. Each reservoir layer was modelled with the shape of a rectangle limited by the above and below bounding layers, the expected oil-water contact and the segment boundary faults. The expected recovery in a layer was found by estimating the stock tank oil initially in place (STOIIP), end point saturation after water flooding, sweep efficiency, and distance from the well entry point in the layer to the water injector. The vertical permeability was set to zero, hence a negligible recovery was assumed between the well entry point and the fault. Simple layer production profiles were estimated from neighbour well production profiles scaled to the expected layer recovery. In this way the layer NPV contribution to the well for each layer was estimated for a total of five layers. This exercise was performed for several well trajectories with the same shape, and with target intersection points at varying depth.

The total toe-section recovery is the sum of the penetrated layer recoveries. The toe section was responsible for a certain fraction of the expected total production of the well. The cost of drilling and completing the toe section was estimated with the same fraction of the total cost. Water breakthrough was expected first in the toe section. Hence, operational expenses related to scale inhibitor treatment, production logging, and plugging off water bearing zones were entirely added to the toe section.

Two targets were defined vertically to the horizontal well with the PrecisionTarget software. The targets have an outer rim which bounds the geological target. This specifies the boundaries within which the well planning team finds it necessary to penetrate in order to hit the foot block. However, there are uncertainties associated with the location of all the boundaries, the location of the layers (fault throw), and the drilling of the well itself. When accounting for the uncertainties (geophysical, pick, and survey), the driller has to hit within the drillers target to make sure the well is within the geological target with an acceptable level of confidence, see Figure 9.

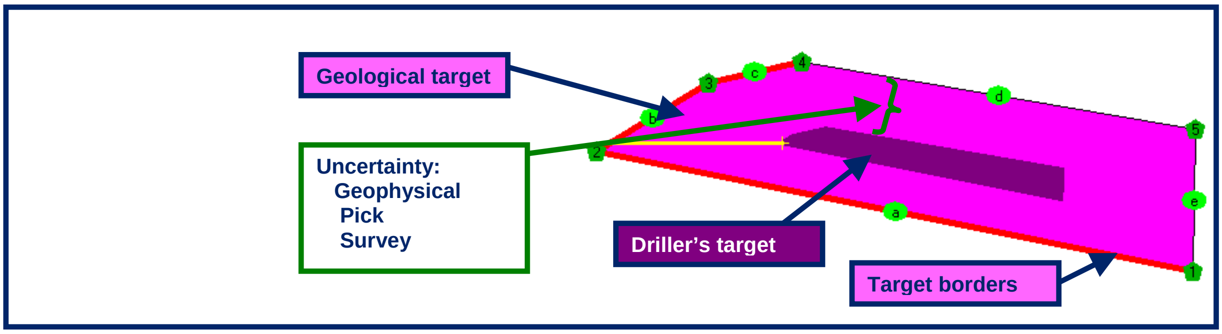

Figure 9: Side view of PrecisionTarget details showing the geological target and the driller's target (Target 1).

The first target (target 1) was located at the fault and was parallel to the fault plane. The target was a part of the well plan, meaning that the directional driller would aim for the associated driller's target in the drilling process. The second target (target 2) was a dummy target and was located 100 meters into the foot block, see Figure 8. This target was used for the economic evaluation. In the DollarTarget software the target was populated with NPVs estimated from the conceptual model. The NPVs for the well intersection in each layer were placed in the economic evaluation target in a vertical location coinciding with the expected location of that layer. This gave a map of NPVs as shown in Figure 10. With the uncertainties sketched in Figure 9 the eNPV map was calculated, and the eNPV of the toe section could be found for a specific well plan.

Two possible well plans were evaluated. In the first plan (plan 1) the well was set to drop at a DLS of 3.5 degrees/stand immediately after detecting the fault in target 1. In the second plan (plan 2) the well was shifted up by 3.5m in target 1. It would proceed through the foot block at a constant inclination to target 2 and drop to deeper layers. At target 2 the well was shifted up 7.5m true vertical depth (TVD) from plan 1 to plan 2. The second well plan had an estimated increase in eNPV of 137 million NOK compared to plan 1, see Figure 11.

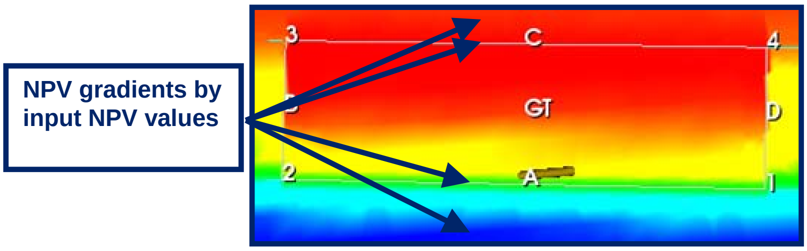

Figure 10: Side view of NPV map projected on target 2. Red and blue colors indicate high and low NPV respectively. The corners of the geological target (GT) are indicated with numbers 1, 2, 3, and 4, and the regions outside the geological target are denoted with letters A, B, C, and D.

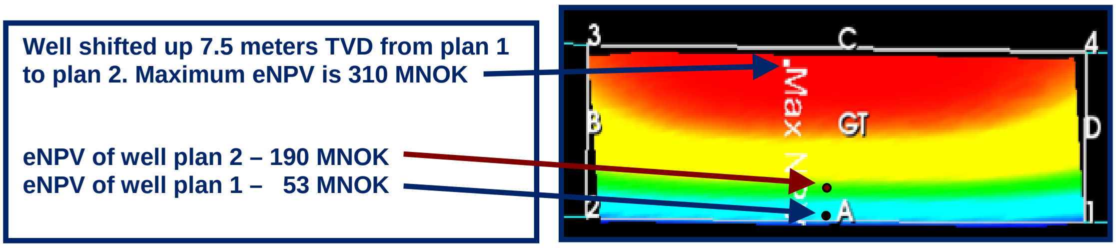

Figure 11: Side view of Expected net present value calculations for well plan 1 and 2 and the risked net present value map projected at target 2 located 100m upstream from the fault. Red and blue colors indicate high and low eNPV, respectively.

It was concluded that lifting the toe section of the well shows increased robustness in terms of eNPV. This is as expected since the high quality sandstones are located in shallow layers within the Tilje formation. Limitations set by drilling and completing in the mid and heel section of the well greatly limited the manoeuvrability in the toe section. During operations the well planning team was challenged to increase the azimuth of the well at the cost of dropping in the foot wall. DollarTarget was used the discussions to evaluate the consequence in terms of eNPV. It was concluded that the new well path suggested during operations was still located within the driller's target close to the plan 2 at the fault and the negative effect to eNPV as a consequence of increasing the azimuth was minimal. Using DollarTarget for this part of the well was a good experience in enhancing cross disciplinary cooperation within the well planning team. Limitations in drilling parameters and the reasons of those limitations were quickly understood and evaluated as corresponding changes in eNPV. Similarly, changes in uncertainty with respect to geophysical, seismic pick, and survey were also rapidly converted into corresponding changes in eNPV. Hence fewer changes to the well plan were needed and the well planning team could work faster.

Case III – Smørbukk M-2 AH

The Smørbukk field is part of the Åsgard license [8,9,10,11,12] in the Norwegian Sea, and comprises several Jurassic reservoirs, containing fluids in the range of condensate to volatile oil [13]. Structurally, the field is a large, tilted fault block with few internal faults. Major challenges with respect to maximizing recovery are horizontal flow barriers and heterogeneities due to depositional and diagenetial effects. Relatively high pressures (approximately 450 bar) and temperatures (approximately 170 degrees Celsius) posed challenges during drilling in the early production phase, and are now handled well. Hydrocarbons are recovered through 19 commingled subsea producers from the main formations Garn, Ile, Tofte, Tilje and Åre, and a substantial amount of the produced gas has been re-injected through 12 subsea injector wells.

The dedicated Åre injector M-2 H, drilled in 2001 and completed in 2002, showed a disappointingly low injection potential during the initial test. Subsequent efforts to improve the well by acid treatment and methanol treatment did not succeed. In 2005, after a revision of the geological model for the Åre formation, it was decided to sidetrack the well into a region with expected better reservoir properties. In order to create a recommendation to drill report (RTD) for the M-2 AH well, a well planning team was appointed. Early in the RTD process it was established that a kh-product of kh=600 milliDarcy meter was necessary to obtain a well with sufficient injectivity to guarantee required injection rates of the order 2.0 MSm3/d. With an expected net height of h=10 meters this corresponds to a 'required' average permeability of k=60 milliDarcy. This criterion was considered to be a key factor for choosing the final well target. To this respect, a map of the probability distribution $p(kh>600\text{ mDm})$ was constructed from ten independent realizations of the stochastic geological model (conditioned to well data) for the Åre formation. The realizations differ only in the distribution of properties, while reservoir thickness is constant. The geological target was then positioned within a region with $p(kh>600\text{ mDm})=0.8$, see Figure 12. Using seismic amplitude maps, the target intersection point for the well was chosen within the geological target such that it hit the center of a seismic amplitude 'hot spot'. The well was designed as a slant well with approximately 42 degree inclination.

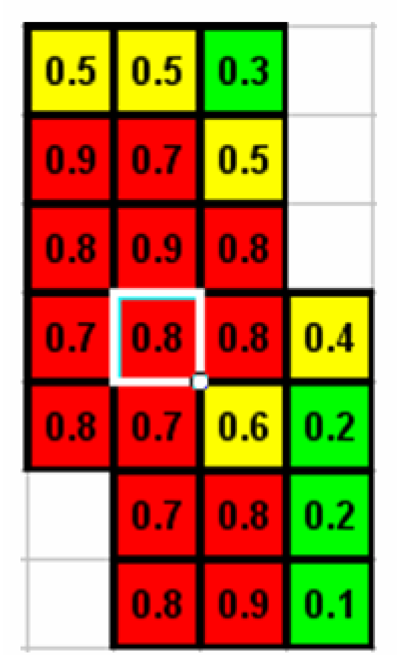

Figure 12: Graphic representation of the probability map p(kh>600 mDm) (top view) derived from ten independent realizations of the stochastic geological model. The outlined square corresponds roughly to the geological target for the well, compare Figure 13.

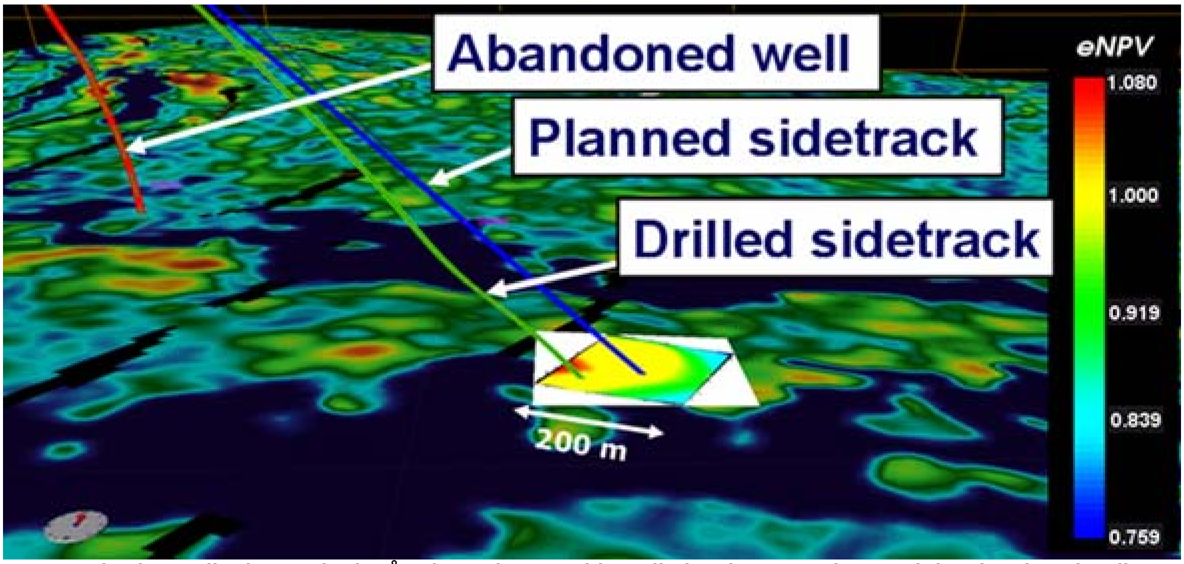

Figure 13: Seismic amplitude map in the Åre formation, used in well planning. Superimposed the abandoned well M-2 AH in red, the planned well path for the sidetrack M-2 AH is shown in blue and the actual well path of the sidetrack is shown in green. The geological target for the sidetrack, a *200* m *x 200* m rectangle is shown, coloured according to the expected net present value (eNPV) for individual hit points inside the target. The eNPV values are normalized by the final NPV value presented in the RTD document for the well.

When creating the *kh*-map, a great deal of horizontal variability was detected, putting a question mark on the robustness of the chosen target with respect to drilling and geophysical uncertainty. The new methodology presented here allowed us to integrate these uncertainties into the study in a systematic way: A net present value (NPV) map was obtained from multiplying the calculated NPV of the well with the calculated probability map *p(kh*>600 mDm). From this NPV map, the expected NPV (eNPV) value of any well hit point within the geological target was calculated in DollarTarget by averaging the NPV values in a certain region around the hit point. The size and shape of this region is determined by geological uncertainties, pick uncertainties and drilling uncertainties. This eNPV map is shown in Figure 13.

Although originally designed to be used only during the planning of the well, it turned out that the eNPV-map was most helpful during the operational phase, that is when the well was drilled. At one point the well team was informed that – due to operational limitations – it was required to 'steer the well', that is either drop or build angle. With reference to the eNPV-map the team communicated to the driller that the well path should 'rather drop than build' in order to maximize the value of the well. The point was understood quickly by the team members. In Figure 13, note that the actual well path hits the Top Åre surface within the geological target and indeed drops with respect to the planned well path, thereby hitting the Åre formation in a point with higher eNPV. The decision to drop was taken at a point in time when the well was heading to a point just outside the geological target in Figure 13.

After completion, the well M-2 AH was tested to a maximum injection rate of 2.8 MSm3/d, which is well above the success criterion of 2.0 MSm3/d. In other words, the well was a success, in terms of planning, drilling, completion and operation. The use of DollarTarget did contribute to this success in that it helped to integrate and communicate important uncertainties and sensitivities within the planning team, and towards the operational team.

Summary and conclusions

Planning and drilling of IOR wells requires that information from many different areas of expertise is evaluated consistently, with the primary goal of increasing the production of hydrocarbons. With many uncertain parameters and scenarios where high economical risk may be involved, one strives to find optimal solutions with respect to net present value of the well. In the cases presented in this work, the DollarTarget technology has proven to be a useful platform for integration of uncertainty information and the potential hydrocarbon value of a well in risk analysis. Cross-disciplinary collaboration has improved significantly in the well planning phase and during drilling operations. This made the decision makers more confident and the decisions more robust. Risk analysis may tend to focus on the costs of different scenarios. Through the DollarTarget technology one is able to evaluate the potential costs *and income* within the same framework, allowing a more reflected analysis of both aspects, which increases the expected net present value. Furthermore, the well planning teams experienced the benefit of a net present value risk analysis when drilling started. Decisions during drilling operations were made fast with a better chance of high recovery because drilling scenarios, uncertainties and net present value estimations were performed up front in a multidisciplinary environment. DollarTarget is currently being implemented as a part of the well planning work processes in StatoilHydro.

Acknowledgments

The authors would like to thank StatoilHydro ASA and the Heidrun license partners, Petoro AS, Norske ConocoPhillips AS, and Eni Norge AS and the Åsgard license partners, Petoro AS, Eni Norge AS, Total E&P Norge AS and ExxonMobil E&P Norge AS, for permission to publish this paper. We acknowledge Ivar Haarstad, StatoilHydro, for constructive input to this work, and for guidance and advice in the process of implementing the DollarTarget methodology and workflow. Moreover, we are thankful to Øivind Berggraf, Ståle Langeland and Torgeir Torkildsen, StatoilHydro, for their contribution to developing the DollarTarget tool and methodology.

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