Improved Oil Recovery with Infill Drilling

EiT – Gullfaks Village 2012

NTNU – Trondheim
Norwegian University of Science and Technology

In cooperation with

Statoil

Group 4

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April 2012

Abstract

This report is a study of the possibilities for improved oil recovery from the Gullfaks main field, specifically looking at a situation with reduced communication in Lower Brent of segment H1. In part A the recovery factors for different parts of the field is assessed, an approximate number of isolated segments similar to H1 is determined and a ranking of different IOR measures based on their potential for the Gullfaks main field is made. In part B the potential for improved recovery by drilling new wells in the case of reduced communication in segment H1 is evaluated. An Eclipse 100 simulation model of H1 was provided by Statoil and used to simulate a base case and closed fault cases where the transmissibility across faults was set to zero and new wells were added. Our best case involved drilling a production and an injection well in a pocket of high oil saturation in the northwestern part of H1. This gave an increase in total oil production between 2012 and 2025 of 48.6% compared to the base case without closed faults and 85.1% compared to a reference case with closed faults but no new wells. Attempts with new wells in the main part of H1, in addition to the two wells in the northwestern pocket, were either not economical or led to an unacceptable decline in reservoir pressure. Even though faults are closed the pocket appears to have some communication with the main part of H1 and is not completely isolated. Based on a condition with closed faults our recommendation is to drill two new wells, one producer and one injector, in the northwestern pocket in H1. This area also has some parts with high oil saturation in the base case and could therefore be interesting even without closed faults.

Preface

This report is written as part of TPG 4851 Experts in Team, Gullfaks Village spring 2012, in cooperation with the Statoil Gullfaks license in Bergen. The goal of this village has been to challenge the students to come up with innovative solutions that could increase the oil recovery by 10% from the Gullfaks field.

We would like to take the opportunity to thank the village supervisors Jon Kleppe and Jan Ivar Jensen, and the student assistants Ane, Cornelia and Thor Helge for guidance throughout the project.

We would also like to thank the Statoil project supervisors Petter Eltvik, Rasim Huseynov, Rune Instefjord and Erik Hodneland for their advice and support.

Trondheim, April 2012

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1. Presentation of the problem

Knowing the transmissibility of faults in oilfields is one of the keys for planning a good production strategy in terms of well placements, recovery factor assessment and so on. But the challenge is that, geologically, the behavior of faults is uncertain. We are not able to have the exact value of the transmissibility of faults so we always assume the behavior and its effect on recovery processes.

In the Gullfaks field, there are a lot faults. That makes the field one of the most challenging oilfields in the North Sea. The challenge is that we don't know exactly how the faults effect on recovery of hydrocarbons from the field is. Factors such as pressure communication, flow patterns and injection effects between different segments are difficult to predict when we don't understand the faults. In our project, we assume that all faults in our area of interest (the H1 segment of the Gullfaks field, Lower Brent group) are closed. This means that there is no flow or communication through the faults. This can in a way be considered as the worst case possible because then the communication inside the segment will be hindered, which in turn will require us to compensate for the "lost" production.

In our simulations we set the transmissibility of faults to "zero". This assumption will reduce the cumulative oil production of the segment. The goal of this project will be to match the base case's, with open faults, cumulative oil production level by drilling new wells in the optimal targets.

2. Part A

2.1. Geological introduction

In this first section of the report we will discuss the geological aspects of the Gullfaks main field as well as the oil recovery factor.

The Gullfaks field covers an area of 75km^2 and has been under production since 1986. The field is located on the western flank of Viking graben (Figure 1). It is a fault block trending NNE-SSW which is one of the series of an easily visible fault blocks in regional seismic line across the North Sea.

The Gullfaks field consists of two structural compartments; an eastern horst complex with steep faults and a western domino system which is characterized by domino-style fault block geometry. (Haakon Fossen)

The Gullfaks field has been described as one of the most complex structure so far developed on the Norwegian Continental Shelf. There are several reasons for this description, but the main one is the complex fault pattern that intersects and divides the field into many small fault blocks. The large number of fault blocks has required that a rather large number of exploration and appraisal wells be drilled, and high-quality seismic data be acquired, in order to achieve a reasonable confidence in describing the field and seismic interpretation. (Ole Petterson, 1992)

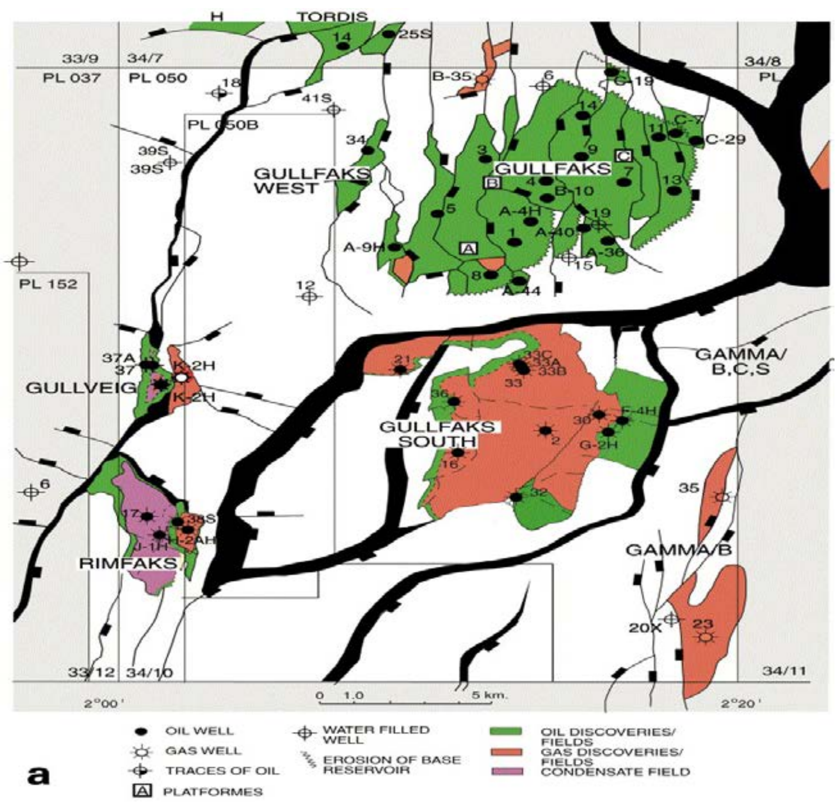

Figure 1: Map of Gullfaks area (StatoilHydro, 2007)

2.2. Oil Recovery factor

Currently, the cumulative oil production in the Gullfaks field is 350 Msm^3 (Helland, 2009). The main reservoirs of the field are Tarbert and Lower Brent which so far produced 130 Msm^3 and 96.1 MSm^3 respectively. Cook, Krans and Lunde are operated with a lower production respectively 17.5 Msm^3, 0.2 Msm^3 and 0.5 Msm^3. As we can see from table in the Statfjord formation, particularly in segments K&L more oil has been produced than initially expected. This might be because recoverable reserves data for this formation or segments is not updated in report.

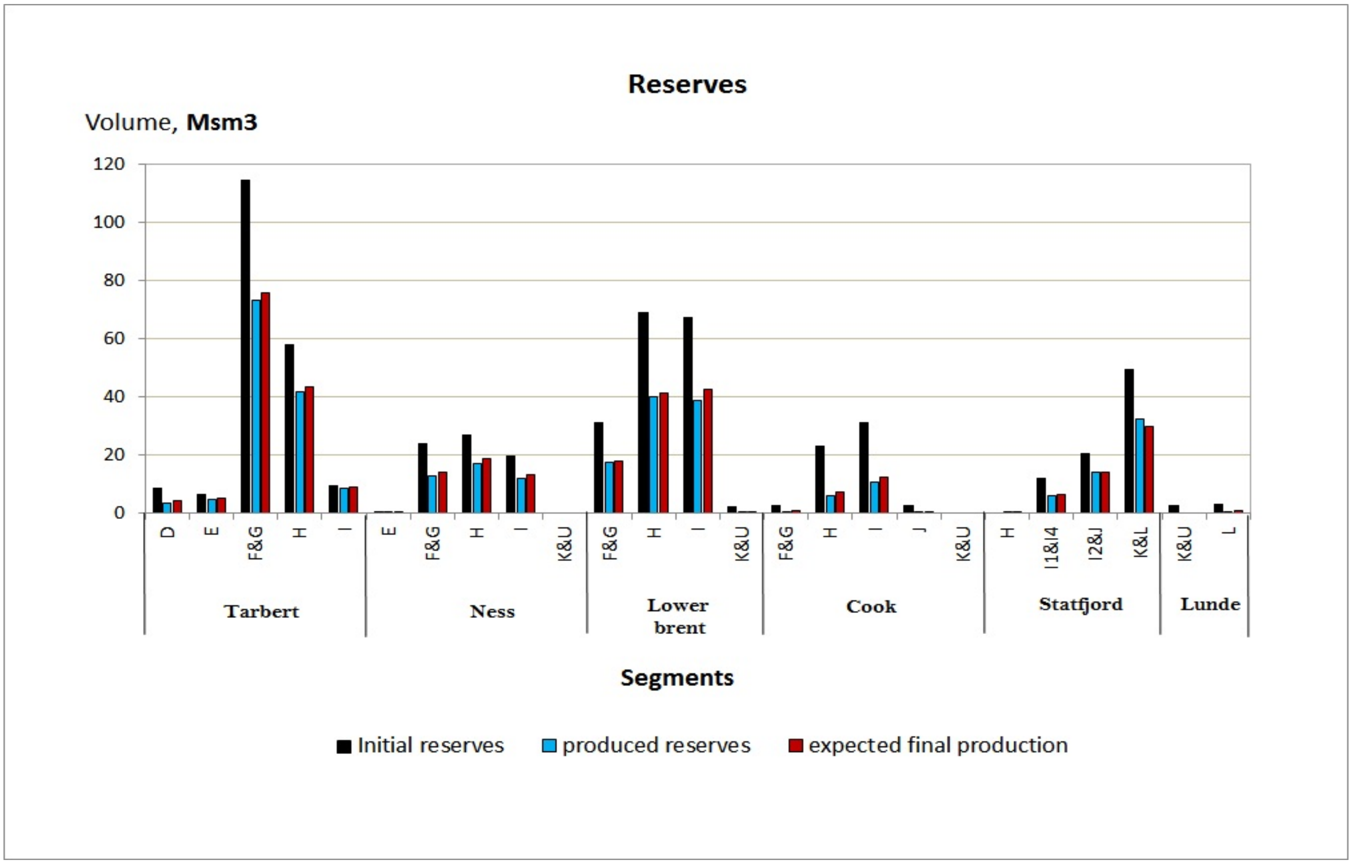

Figure 2: Reserves of different segments (Data from Helland, 2009)

From these bars, we can see that the Tarbert formation of segments F&G, Lower Brent formation of segments H and I are the most hydrocarbon bearing layers of the field. Also from the Figure 3 below, we can see that the recovery factor from these formations of segments is high. That is why they are considered the field's main reservoirs.

However it is obvious that it is not only depending on formation but also on segments, which determines the location of spots and we know that geological formations can have property changes in different directions.

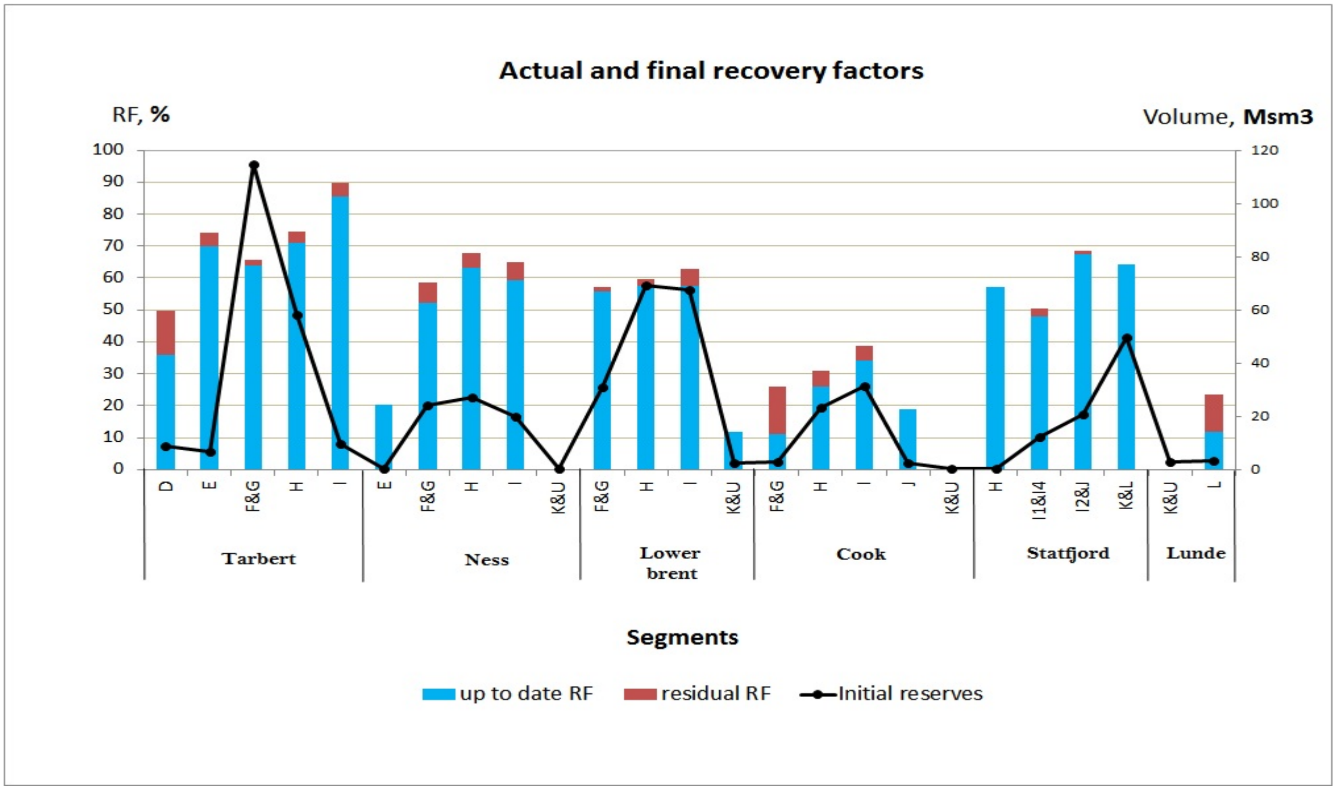

Figure 3: Actual and final recovery factors

Also, the reservoirs in segments that are isolated from each other can behave quite different in terms of fluid flow behavior and pressure communication which may lead to big differences in recovery factor. Here we can see that, as we have very high recovery factor in the Lower Brent formation of H and I segments, but very low recovery factor in the K&U segments in the same formation.

2.2.1. Estimation of the number of isolated segments

We have here tried to estimate which segments are isolated on the Gullfaks main field by examining structural maps (StatoilHydro, 2007).

Table 1: Isolated segments at Gullfaks main field

Name of formation	No of segments	Isolated segments
Tarbert	14	G1, G2, G3, F1, F2, F3, F4, H1, H2, H5, E1, E2, E3, E4
Top Ness	5	E2, H1, G1, G2, G3
Base Ness	13	H1, H2, H4, G1, G2, G3, E2, E3, E4, F1, F2, F3, F4
Lower Brent	11	G1, G2, U1, I1, E2, E3, F3, F4, F5,

		H1, H4
Cook	19	D2, D3, F1, F4, E1, E2, E3, E4, G1, G2, G4, G5, H3, H4, H5, I1, J1, J2, J3
Statfjord	15	D2, E1, E2, F1, F2, F3, F4, G1, G2, H1, H2, H3, K1, J1, J3
Lunde	3	H3, K1, J2

In some points the information we get from the RSP 07 report (StatoilHydro, 2007) and what we see from the maps contradicts each other. We think it may be because of uncertainty of fault behaviors. Even if we consider here that these segments are isolated because of impermeable faults, the isolation will not be 100%.

2.2.2. Reasons for differences in oil recovery

There are several reasons for having a different recovery factor between different formations and segments. In same formations, but different segments the main reasons for differences in recovery factor are:

- No pressure communication between isolated segments because of impermeable faults
- Different recovery strategy (well placement, injection, production rates and etc.)
- Strong changes in reservoir sand permeability in different directions

Also, we can have big differences in recovery factor from one formation to another one. The reason for this is usually the geological difference of formations, which are the sediments that deposited in different time. For example in the Gullfaks field, we see that the recovery factor in Tarbert and Lower Brent is very high, whereas in Cook we usually see low recovery factor values. This might be related to reservoir parameters of sand in these formations. It can be different permeability values, hydrocarbon saturation and physical parameters of fluids that accumulated in these formations.

2.3. IOR measures

In this section we will try to evaluate the potential for improved oil recovery at the Gullfaks main field, before we rank the different methods.

IOR is a term which implies improving oil recovery by any means. For example, operational strategies such as infill drilling and horizontal wells can improve vertical and areal sweep, leading to an increased oil recovery. Another term often used interchangeably is EOR, or enhanced oil recovery. However EOR is more specific in concept and it can be seen as a subset of IOR (Thomas, 2008). The following table is a summary of our evaluation of the IOR measures and their potential for the Gullfaks main field (Utvinningsutvalget, et al., 2010) (SPE, Talukdar, & Instefjord, 2008).

Table 2: Summary of pro and contra of IOR methods at Gullfaks main field

Infill drilling

Pro	Contra
Important short term mean of IOR	Rig availability and cost
Access to isolated pockets	Problems due to depletion.
Well known, tested and proven method	Risk of blowout

Smart, advanced wells, MPD, UBD

Pro	Contra
Possible to reach “unreachable” zones	Cost (upgrade rig, equipment in wells)
Better well control	Requires better training of personnel
Possible to produce one or several zones at a time	Risks/problems related to equipment during drilling and production
Can shut off/diverge gas and water production	
Increased production from low permeable zones	
Reduces the amount of wells necessary to drill	
Possibly less problems with sand production?	

More water and gas injection

Pro	Contra
Cheap	Availability of gas
Widespread and well known	Treatment of fluids
Used as a basis for more advanced methods	Limited recovery relative to more advanced methods
Very high recovery possible in Gullfaks from zones being flooded with water	Can lead to formation of H_2S in the reservoir
Pressure maintenance in reservoir	(Possibility that injected fluids will mainly displace water or gas instead of oil?)

Better use of data: Integrated Operations (IO)

Pro	Contra
Less people necessary offshore	Opposition to change
Better and more accessible information	Time consuming implementation
Improved and faster decision making	Equipment cost
Reduced operating costs	Information security

Reservoir mapping: 3D and 4D seismic

Pro	Contra
Better understanding of reservoir. Gives better reservoir models and more accurate drilling	Expensive
Shows development of fluid saturation/flow in reservoir over time	Time consuming (data processing, modeling etc.)?
	Difficulties due to present installations, requiring ocean bottom acquisition?

WAG and FAWAG

Pro	Contra
Increased sweep compared only water or gas	Gas availability
Combination with foam (FAWAG) can give even better sweep	Possible increased cost compared to water injection
Good use of surplus gas	Risk of not displacing as much oil as expected from simulation models (or displacing water/gas instead of oil)
Draining of attic oil	

CO_2 injection

Pro	Contra
May be more miscible than natural gas	Availability and cost uncertainty
Can be combined with CCS	Transport and storage problems
Mobilize immobile oil	Increase of CO2 content in produced gas may lead to new process requirements
High sweep because of compositional effects, reduced oil viscosity, high viscosity compared to natural gas, etc.	Large modification requirements
May decrease costs for other projects	Extra implementation cost

Low saline water (LSW)

Pro	Contra
Relatively low cost	Not well understood
Mobilize immobile oil	Field specific
Tests on cores from Gullfaks seem promising	Limited recovery increase

Surfactants

Pro	Contra
Mobilize immobile oil	High economic risk
Reduces interfacial tension and can be designed to alter wettability	Little immobile oil on Gullfaks
Can be combined with low saline water	Implementation risk (LSW)

Gel blocking and water diversion

Pro	Contra
Increase overall sweep efficiency	Can be an environmental hazard (red chemicals)
Reduce water cut	Can be expensive
	Implementation risk with new chemicals
	Can permanently trap immobile oil

Polymer injection

Pro	Contra
Increased recovery of viscous oil	Already good sweep on Gullfaks by water injection alone
Can be combined with surfactant	
Can improve water injection (drag reduction)	

Subsea wells

Pro	Contra
Increases the amount of wells that can be drilled	More expensive than drilling from the existing platforms
Can make it easier to reach certain targets	Requires subsea equipment
	Well intervention more costly and difficult (frequent intervention necessary at Gullfaks)
	Long reach, deviated wells from platforms can be a better solution
	Availability of drilling rigs

We have also tried to rank the different IOR methods according to their potential for the Gullfaks main field. Furthermore, an explanation of our reasoning follows.

Table 3: Ranking of IOR methods for Gullfaks

1	Infill drilling
2	Gel blocking and water diversion
3	Smart, advanced wells, MPD, UBD
4	WAG and FAWAG
5	Reservoir mapping: 3D and 4D seismic
6	Better use of data: IO
7	More water and gas injection
8	CO_2 injection
9	Low saline water
10	Surfactants
11	Subsea wells
12	Polymer injection

Infill drilling is placed at top given that it is the best short term method for higher recovery, with the assumption that there are promising target zones and that drilling is possible and economic. With a very complex and segmented reservoir as on Gullfaks, there is a need for a large number of wells to get good recovery from all the different zones and layers.

Gel blocking and water diversion is ranked second. With possibly large volumes of bypassed oil in the reservoir between injection and production wells, combined with water sweep giving very high recovery from flooded zones, this method has a very good potential. Gel blocking is an even better choice if there are green or yellow chemicals available, and that they are both efficient and economical to use. On the Gullfaks main field gel blocking could be very effective in the Lower Brent Formations, by blocking the Etive-Rannoch override (explained in part 3.1) resulting in improved sweep in the rest of the Lower Brent.

Smart, advanced wells can improve drilling by making it possible to reach difficult targets, or even targets earlier considered unreachable. Wells can also be drilled so that they hit multiple productive zones. Production can be increased with among other things having longer deviated wells in low-permeable zones, by causing less damage to formation during drilling and by better control in the wells using DIACS to optimize production and possibly also injection. In this complex reservoir, with faulting and large permeability differences, more advanced wells would probably be very useful to improve recovery.

WAG and FAWAG can increase vertical sweep, and could also be considered as an alternative to gel blocking and water diversion. Assuming that there is gas available, and that costs are acceptable, these methods could have a large potential, especially where gel blocking and water diversion is not used.

Reservoir mapping is very important on the Gullfaks field, particularly because of its very complex reservoir and the fact that it has been producing for some time. Collecting new data and increasing the quality of it would be very helpful with regard to e.g. better well placement and which methods of IOR to use.

Integrated operations could improve the use of the large amount of available data for Gullfaks, and also make the reservoir and production management more effective. Faster and more optimal decisions could give some increase in recovery without the need for more costly IOR methods. There is also the possibility of reduced operating costs, which could increase the lifetime of the field (maybe not very relevant for Gullfaks) or free up resources for other IOR projects. We have chosen to rank “Reservoir mapping” and “Integrated operations” as 5 and 6 because Gullfaks is a complicated field with large amounts of data, which require an active management to get the best recovery possible.

Water and gas injection alone is important since it maintains the pressure in the reservoir, and because water flooding alone gives very good recovery in the volumes that are swept. A lot of the recovery potential from water alone has probably been exploited in the parts of the reservoir that have been producing for a long time. Either way, water injection should be continued since it is a fundamental way of IOR and can be considered a basis for other IOR methods.

CO_2 injection seems to have a high potential to increase recovery, but it is a complicated project with big uncertainties. Availability, transport and costs for infrastructure and necessary modifications are some of the risks related to it. It could be a valuable project for Statoil as a whole, also increasing production on other fields and improve the company's reputation. For Gullfaks alone however it might be too risky, demanding a large commitment of resources that could give better results if focused elsewhere. Hence, depending on the feasibility, CO_2 injection could be ranked higher up.

Low saline water also might have some potential on Gullfaks, based on core tests. The method is still poorly understood, and for that reason there is still some uncertainty related to it. But costs are relatively low, which reduces the economic risk.

Surfactants have some potential at Gullfaks, but in general there is little immobile oil remaining in the water flooded zones. This could imply that it will not be very economic unless oil price is high. A combination of surfactants and LSW or polymers could have a larger potential than surfactants or LSW alone. Even though they are low in the ranking, the methods could be good if they are economical.

Subsea wells could have some potential since there are problems related to drilling enough wells, but rig availability and costs are a large issue. Also there is the likelihood of well intervention being necessary, because of reservoir complexity, which would be difficult and costly compared to having drilled the wells from the platforms.

Polymer injection is aimed at improving the sweep of movable oil in water flooded zones, which is already very good on Gullfaks using water injection alone. As such it is ranked very low, as it is not deemed to be necessary or giving a high increase in production.

3. Part B

3.1. Introduction

Part B is the main part of our project. First we will discuss the factors that lead to good communication in lower Brent. Then we will discuss the simulation of the H1 segment of the Gullfaks main field in Eclipse, where we have tried to improve the oil recovery from a model with closed faults. In the end we will analyze the economics of the investments we are simulating.

The Gullfaks field's main reservoirs are Tarbert and Lower Brent. Lower Brent has its subgroups which are Rannoch and Etive. These formations indicate different reservoir parameters in terms of permeability. In Rannoch we have low permeability, between 0.1-1 D, but in the upper formation, Etive, we have permeability between 3-10 D. Also there is vertical permeability that allows flow from one formation to another. This vertical permeability and laterally strong changes in permeability leads to communication (and flow) between the formations in Lower Brent. Fluid flow patterns always look for the easier way. In Lower Brent this results in the injected water into Rannoch formation, which is supposed to sweep oil of this layer, flows upwards into Etive and high amounts of oil is left behind in Rannoch. This is known as the Etive-Rannoch override and is one of the challenges in the Gullfaks field.

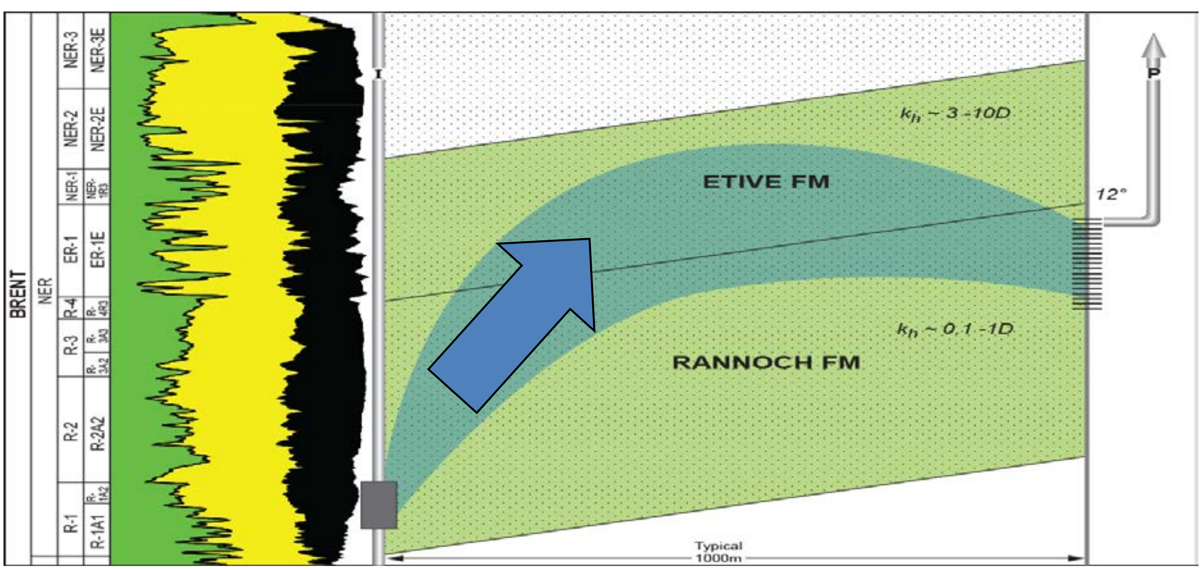

Figure 4: Low permeability in Rannoch causes vertical flow of fluids into Etive

3.2. Simulations

In this part we will briefly go through the software used, followed by a presentation of the base case and the reference case with faults closed.

3.2.1. Model and software

Simulations were done using Eclipse 100, which is a three phase, three dimensional black oil simulator, and is a part of Schlumberger's Eclipse reservoir simulation software family. (Schlumberger, 2009)

Statoil provided the Eclipse reservoir model of segment H1 used in the simulations. The model has Lower Brent in layers 24 to 52, and starts on the 1st of December 1986. In the model there are also many blocks that are outside the area of H1, which we assume are used to model possible external influences on the segment.

S3GRAF, and to a certain extent FloViz, was used to visualize the data and results from the simulations. Data was also exported from S3GRAF to Microsoft Excel for further analysis and to produce the graphs.

3.2.2. Task

The goal of the simulation parts of the project were to run a base case simulation with the existing wells, a case with the transmissibility across all faults set to zero, i.e. with closed faults, and to increase the number of wells in the closed fault case to get an oil recovery similar to the base case.

3.2.3. Base case simulation

A base case simulation was run, with just the existing wells, history matched from 1986 and giving predictions until 2025. On January 1st 2012 the cumulative oil production was 16 995 560 Sm^3, growing to 18 267 890 Sm^3 on January 1st 2025 (See Appendix A for graphs). This gives an increase from 2012 to 2025 of 1 272 330 Sm^3 or approximately 8 million barrels of oil.

The resulting additional oil recovery predicted in this simulation was used as the goal for our later cases with closed faults and new wells. This was done as it was assumed unrealistic that we could be able to increase the total production up to the level of the base case with faults closed and only a few new wells in our cases from 2012 to 2025.

3.2.4. Reference case with closed faults

A closed faults reference case was made where the transmissibility was set to zero across all the faults, except those known to be open. This was done using the DATA file with the MULTFLT-keyword, provided by Statoil. The case was run from 1986, giving predictions until 2025, without any new wells. As expected with closed faults, and thereby poorer communication and flow in the segment, the cumulative oil production was reduced compared to the base case with open faults. On January 1st 2012 it was 14 866 740 Sm^3, and at the end of the simulation on January 1st 2025 we got 15 888 050 Sm^3, resulting in an additional oil recovery from 2012 until 2025 of 1 021 310 Sm^3 or just a little over 6.4 million bbl.

The reference case with closed faults was then used to create a restart file which we could use in our later simulations. Doing this means avoiding the unnecessary and time consuming repetition of simulating the identical situation from the very start in 1986 until 2012 each time, instead starting the actual simulation from the 1st of June 2012.

The reference case was rerun, restarting in 2012, giving essentially the same result as when the simulation was run from the beginning in 1986. Any differences in the end could be considered insignificant, being around 0.1-0.001 % or well below that for the different characteristics.

3.3. Simulations with the number of wells increased

Here we will present the different cases where we attempt to increase the predicted additional oil recovery up to the level of the base case by adding new wells in the segment. We were advised that 3 new wells could be a realistic limit to how many new wells we could add.

When deciding potential positions for well placement, we looked for zones that still had relatively high oil saturation and reasonable pressure at the end of the simulation. Production wells and injection wells were then placed to give good drainage and sweep respectively of the areas with much remaining oil.

In most cases the total production rate was matched with the total injection rate for the entire segment, ensuring that produced liquids where replaced by an equal amount of injected water.

After simulations had been run, we analyzed the result by looking at field cumulative oil production and bottom hole pressure, oil production rate, cumulative oil production, water cut and injection rate where applicable for the individual wells. The grid map of the segment was also used to see how the pressure and saturation in the different grids developed.

Several cases were made using both production and injection wells, including attempts at reperforating the two old production wells, A-39A and B-37.

3.3.1. Case 1

In the reference case with closed faults, there was a pocket in the northwestern area of H1 with high oil saturation. We placed one new production well in that area on the 1st of June 2012, as an initial attempt to see how good production would be. The well was called NW (New Well), and was placed at coordinates 37 74 with perforations from layer 30 to 39, and a liquid rate target at 500 Sm^3/d (SCHEDULE-files for the different cases can be found in Appendix C).

Production was high, but the bottom hole pressure dropped rapidly, falling below the pressure level that we would want to maintain in the reservoir. As was somewhat expected based on the high oil saturation in that area compared to the initial base case, the pocket seems to have become relatively isolated by closing the faults. This means that an injection well is necessary in the same area, so that pressure is maintained during the simulation.

3.3.2. Case 2

In this case we added an injection well, called NWIW (New Water Injection Well), in the pocket of case 1, with an injection rate of 500 Sm^3/d and bottom hole pressure limit at 310 bar. This well was put in place south of the new production well, at coordinates 36 78 and perforated in layer 44 to 49, on the 1st of January 2016. The new production well (NW) was also put in place one year later than in case 1, on the 1st of June 2013, so that results would be more realistic with regard to planning and drilling time. The addition of a new injection well in January 2016 was done to keep the pressure in the new production well from dropping any further after that time. This proved to be successful, giving more than enough oil to cover the cost of the two new wells while the pressure was maintained at a better level for the new production well than in case 1. But due to declining pressure in the wells, additional pressure support seems to be necessary. The position of the wells present in case 2 can be seen in Figure 5 below. The parts of B-37 close to NW are in upper Brent, while NW is only perforated in lower Brent.

Cumulative oil produced until 2025 was 16 777 630 Sm^3 which means an additional 1 910 890 Sm^3 after 2012, the new well alone produced 1 050 373 Sm^3 or about 6.6 million bbl. Compared to the reference case with closed faults it is clear that the total production from A-39A and B-37 must have gone down, as the total production is only around 900 000 Sm^3 larger in case 2 than the reference case. The lost production is in B-37, where the total production decreased by over 200 000 Sm^3 in case 2 compared to the reference case, while total production actually increased in A-39A by nearly 60 000 Sm^3.

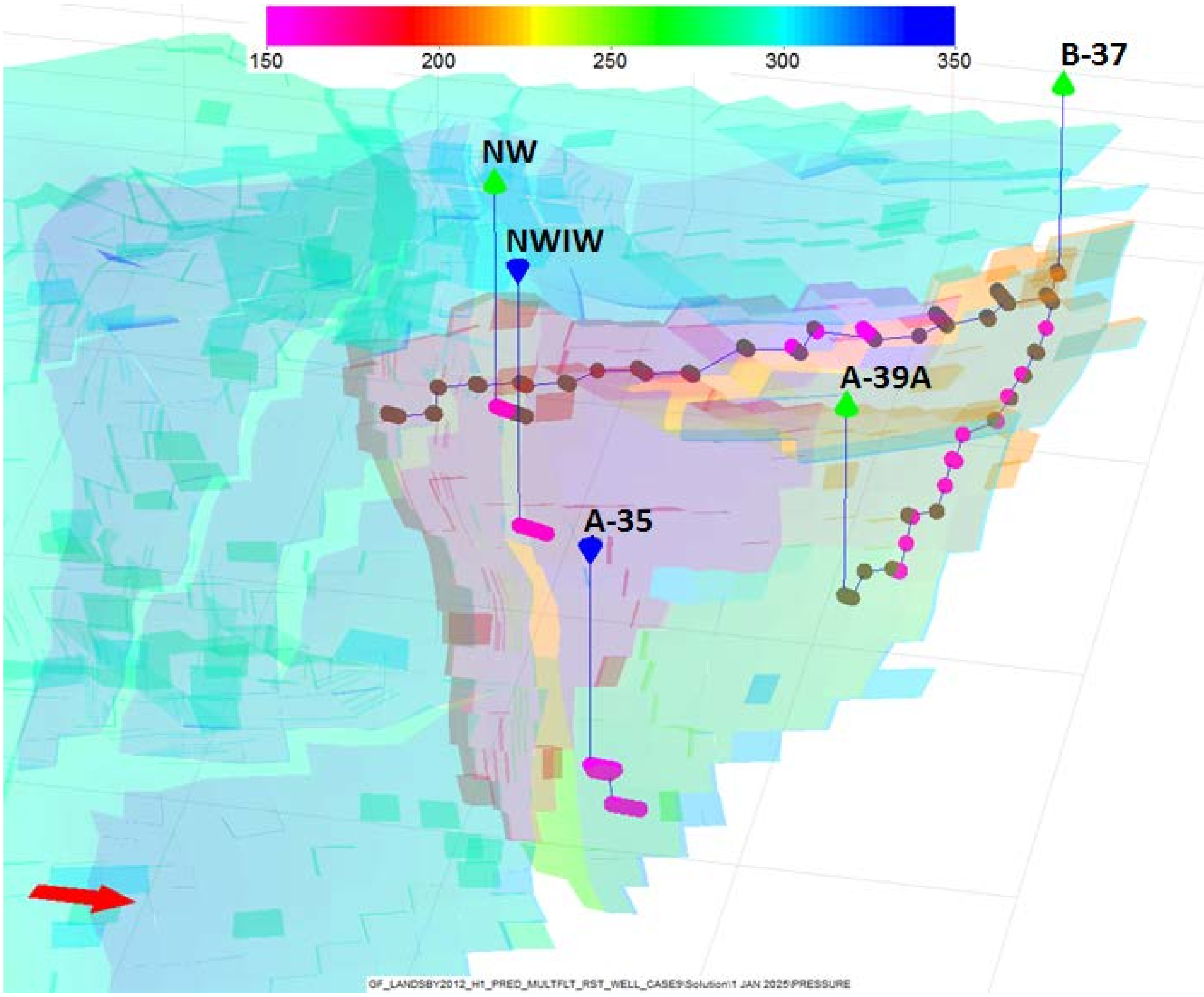

Figure 5: Active wells in case 2 and 9

3.3.3. Case 3

This case builds on case 2, with an additional injection well called NWIW2 west in the main part of H1. This second new water injection well was placed at coordinates 36 81 and perforated in layers 46 to 49 on the 1st of January 2014 with a target rate of 1500 Sm^3/day and a BHP pressure limit at 310. The goal of this second new injection well was to improve the sweep of oil to increase production, and secondly also to provide added pressure support to A-39A and B-37. This was mostly unsuccessful, with early water breakthrough from the new injector and increased water cut, resulting instead in a small decrease of roughly 135 000 Sm^3 in total oil production compared to case 2. BHP in the two wells did increase, but without increased oil production to cover the cost of the extra injection well it should not be drilled as there is also another injector, A-35, already in place that could be adjusted to give more pressure support if that had been the only goal in this case.

3.3.4. Case 4 and 5

These two separate cases are the same as case 2, but with reperforation of A-39A and B-37 respectively to see how reperforation of one of those wells impacted the simulation while the other well was left unchanged. The WECON-keyword was used to close off different segments if water cut went over a certain limit, as a way of simulating well intervention during the simulation. Several runs where made with different limits, and in the end we got what seemed to be the best result using a water cut limit at 0.90, with a secondary limit at 0.99 incase all the segments in the well were shut by the first limit.

In both cases the water cut between 2012 and 2025 generally improved for the reperforated well after reperforating, and total water production from the reperforated well was reduced. The produced volumes of oil and water are presented in Table 4 below, with case 2 included for comparison.

In case 4 where A-39A was reperforated in layer 44 to 46 over several horizontal segments, we got an increase in total oil production of about 30 000 Sm^3 and a decrease in total water production which was also close to 30 000 Sm^3. B-37 only had some minor changes in this case.

In case 5 with B-37 reperforated we got less oil, with a decrease in total oil production around 30 000 Sm^3, but there was quite a sizeable decrease in total water production of roughly 860 000 Sm^3. B-37 was reperforated from layer 41 to 49, and had an improvement over case 2 of nearly 100 000 Sm^3 more oil and almost 1 million Sm^3 less water produced. A-39A on the other hand had a slightly larger loss of total oil production than what B-37 gained, leading to the negative change in total oil production, and its water production increased by a little over 100 000 Sm^3

The new production well in the northwestern pocket had a minimal change in production in case 4 compared to case 2, but in case 5 with B-37 reperforated there was a much larger change. This could be seen as an additional indication that the new well and B-37 has some communication in the areas between them, and that the northwestern pocket is not completely isolated.

All in all based on additional oil production, combined with the extra cost of reperforation and later well interventions, reperforation is probably uneconomical. Even for case 5 with the large reduction in water production, the lost oil production combined with other costs is assumed to give a negative result. There is also the practical limitation that while WECON can make well segments close at any time step, actual well intervention might only be possible once a year and our simulation results may therefore be overly optimistic, unless the wells where equipped with DIACS. Due to this we decided that reperforation of old wells could be ruled out, and that we consequently should leave A-39A and B-37 as they were.

Table 4: Total produced volumes (1986-2025) for field and selected wells of case 2, 4 and 5

Case 2	Field	A-39A	B-37	NW
Cumulative oil production [Sm^3]	16 777 630	2 977 778	1 168 661	1 050 373
Cumulative water production [Sm^3]	31 594 730	13 170 390	9 180 698	1 065 628
Case 4	Field	**A-39A**	B-37	NW
Cumulative oil production [Sm^3]	16 808 410	3 011 596	1 165 825	1 050 169
Cumulative water production [Sm^3]	31 563 950	13 136 580	9 183 534	1 065 832
Case 5	Field	A-39A	**B-37**	NW
Cumulative oil production [Sm^3]	16 746 730	2 874 632	1 263 797	1 027 479
Cumulative water production [Sm^3]	30 732 730	13 273 540	8 192 655	1 088 521

3.3.5. Case 6

With case 2 as a basis we added an additional new production well, NW2, in the main part of H1, where we had found a grid block with very high oil saturation and relatively high pressure at coordinates 42, 81, from layer 37 to about 49. The well itself was perforated from layer 36 to 49, and added on the 1st of January 2014 with a liquid target rate of 500 Sm^3/day. This case was unsuccessful, the new production well produced for less than a year giving too little oil to cover the costs and the BHP also decreased rapidly. This small column still had very high oil saturation compared to the rest of the field at the end of the simulation, but as it seems to be quite isolated it would either require an injection well or possibly very low production rate to increase the recovery from it. Another alternative could be to drill a new sidetrack out from A-39A, since it lies close to the column with high saturation. Neither of these options however seem economically or practically feasible, in the end the extra oil from that small column is probably too little or will have to be drained too slowly to be worth the effort if the column is isolated.

3.3.6. Case 7

Basically a repetition of case 2, but in this case we tried converting the new production well, NW, of that case into an injection well after producing from the 1st of January 2013 until 1st of January 2016 when the new injection well was drilled in case 2. The new well that was drilled in 2016 as an injector in case 2 became a production well instead in this case. This was done because there was still some oil left in the pocket in case 2, notably around the injector of that case. By converting the new production well into an injector and drilling another new production well in the pocket, we hoped to get more oil out from the area close to the injector. In this case we are first producing from the northern part of the pocket before switching to producing from the southern part of the pocket and injecting in the northern part, this means that the sweep of injection water is also going in the opposite direction compared to case 2.

This case did not turn out as we had wanted, and ended up giving less oil production than case 2 in all the runs we tried. We did adjustments to which layers we produced from and injected into, after looking at the oil saturation between the two wells. Initially we tried producing and injecting in the same layers as in case 2, but later we increased the perforation intervals so that NW first produced from layers 30 to 45, and then injected into layers 44 to 49 while the other well, NW2, produced from layers 30 to 47. WECON was used on both wells during production, with a limit on water cut at 0.80. By doing this we tried to optimize the production and the sweep, but the total production was always over 100 000 Sm^3 less than in case 2. This is a loss of over 5 % of the additional oil produced from 2012 until 2025.

Without any additional oil and with the added cost involved in converting one well on top of drilling costs, our opinion is that case 2 is the best case out of that and case 7.

3.3.7. Case 8

Again building on case 2, we tried adding an additional production well north in the main part of H1 in January 2015. This second new production well, called NW3, was placed in an area with relatively high oil saturation at coordinates 42 73, and perforated low in Lower Brent in layers 42 to 49. The total production from the well was around what needed to cover its cost, but the BHP dropped below what was acceptable somewhere around 4 years after the well was drilled. With too low BHP, the second new production well would have to be shut in before production actually reaches a high enough level to cover the well cost, giving less than 50 000 Sm^3 of oil from it.

The total field production decreased with a little over 30 000 Sm^3 compared to case 2, because there was decreased production from all the other production wells compared to case 2. BHP would also be a problem, since the injection well A-35 could not give good enough pressure support for all the wells in this case.

All in all this case is worse than case 2, because the cost of the new well is not covered by any increase in production and the pressure cannot be maintained at a high enough level for all the wells.

3.3.8. Case 9

Due to BHP in A-39A and B- 37 decreasing in case 2, for B-37 it even went far below what we could accept, we decided to try increased injection rates in the injection wells. Attempts at increasing the rate in A-35 led to much higher pressure in A-39A and B-37, but also increased the water cut in the two wells. Increasing the rate in the new injection well in the northwestern pocket had a smaller effect on the pressure, but also gave a much smaller increase in water cut. In the end we increased the injection rate in both A-35 and the new injection well to 2600 and 900 Sm^3/day respectively, since this combination seemed to give the best balance between getting better BHP in A-39A and B-37 without the production dropping too much because of increased water cut. Figure 6 below shows the development of BHP for the different wells in case 9 compared to case 2.

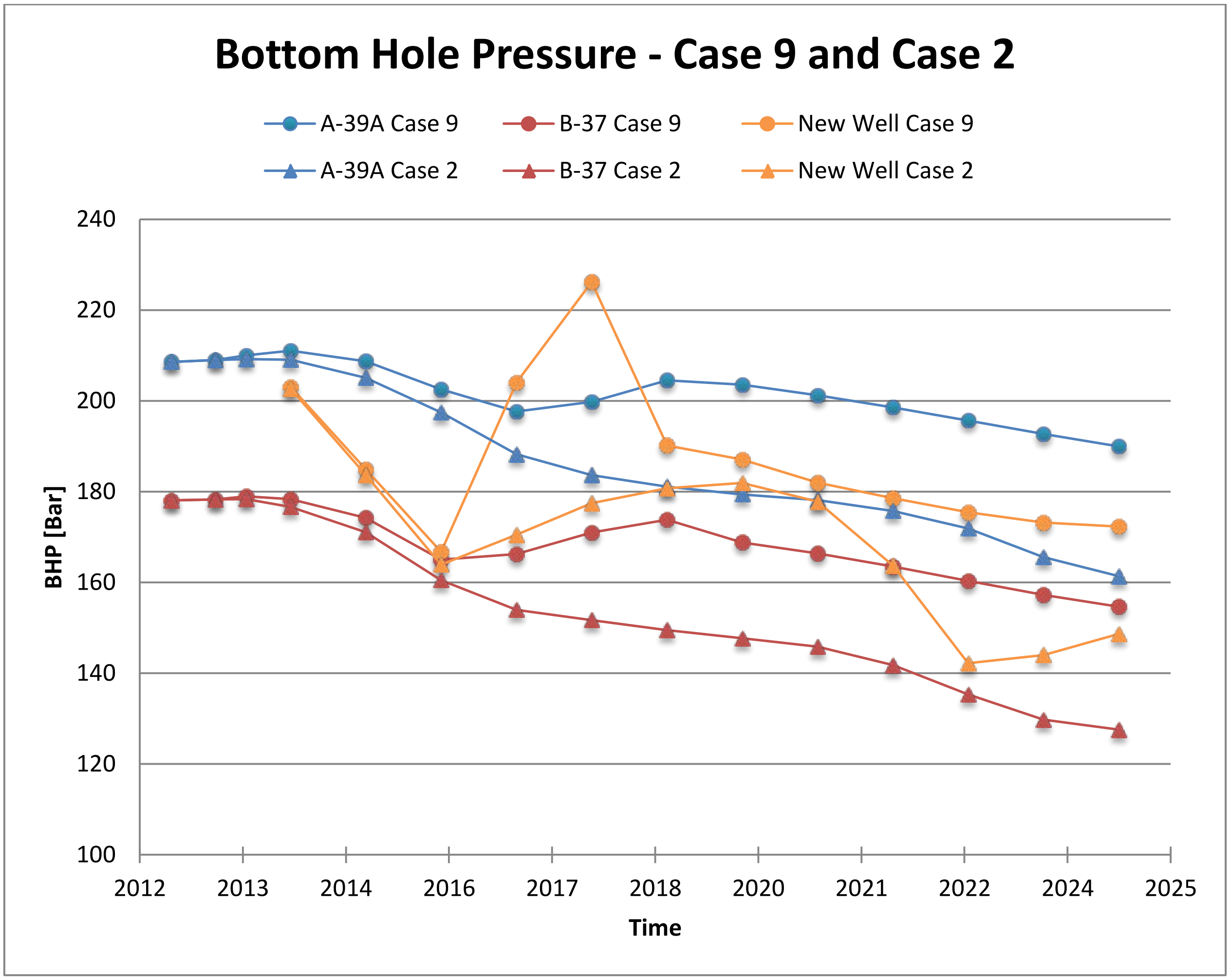

Figure 6: Bottom hole pressure of the production wells for case 9 and case 2

The loss in total field production between 2012 and 2025 was in the area of 20 000 Sm^3, about 1% of the total field production for that time, which can probably be considered a marginal decrease. There is also a slight change when the oil is produced as can be seen in Figure 7 with the cumulative oil production from 2012 to 2025.

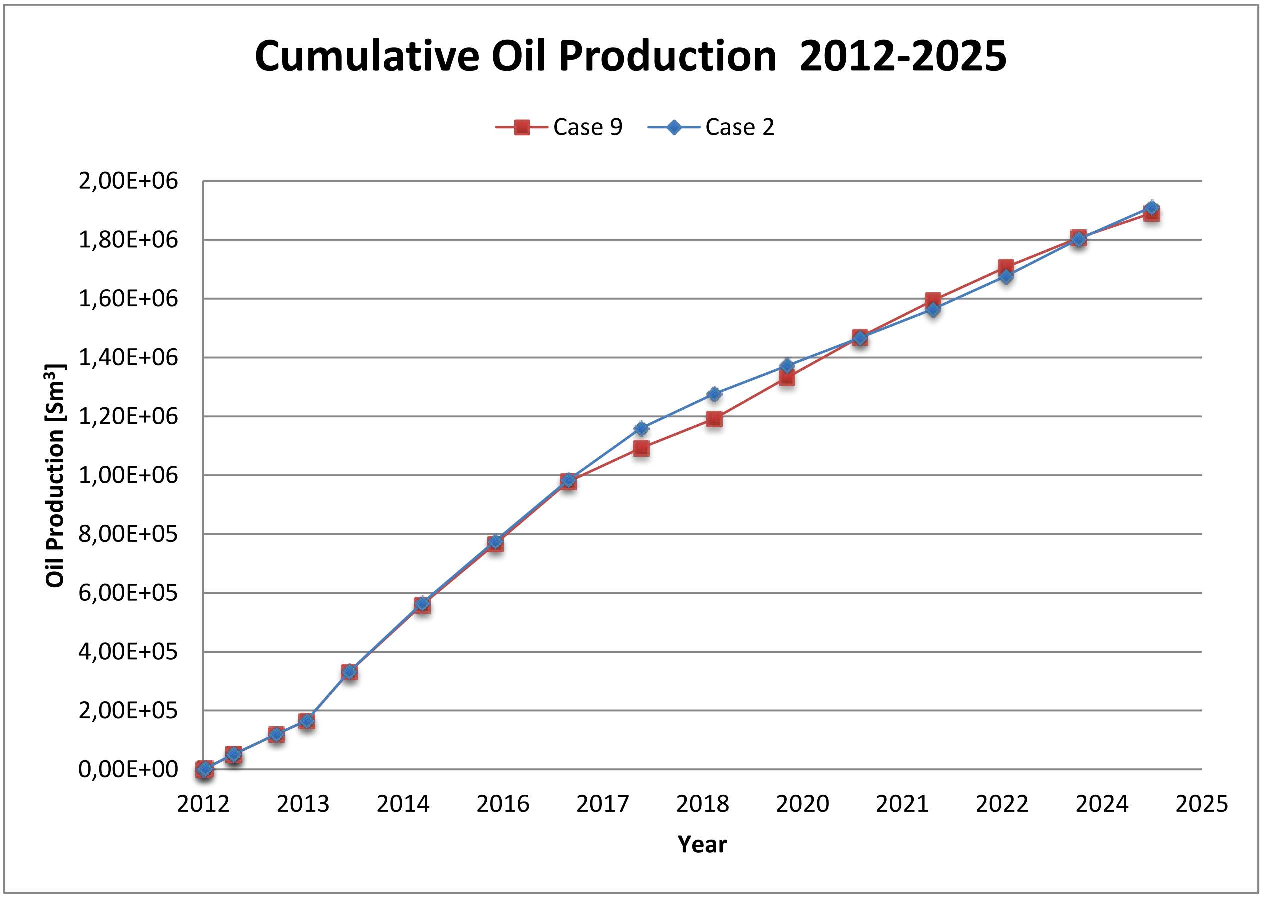

Figure 7: Cumulative oil production from 2012 to 2025 for case 9 and case 2

In the end case 9 is the best case we have, based on the practical limits that we have with regard to BHP in the wells and number of new wells we can drill. We thus ended up with only two new wells, one less than the advised maximum number of new wells. Adding a well somewhere in the main part of H1, giving three new wells in total, did not give a good result in any of the cases we tried. Based on this and case 9, a second new production well would probably lead to an unacceptable pressure decline in the segment or have to produce at such a low rate that it would not be economical.

3.4. Discussion and comparison of results

The results of the base case, the reference case and case 9, our best case, will now be presented in more detail and compared with each other, along with a discussion of those results.

Looking at the cumulative oil production all the way from 1986 we can see that the base case is better than the reference case and case 9, our best case. Focusing only on the oil production after 2012, case 9 is the best and is 48.6% better than the base case and 85.1% better than the reference case with closed faults. Due to the faults being closed there is a lot more oil left in the segment in 2012, and this makes it possible to produce more oil in case 9 between 2012 and 2025 than in the base case. Most of this oil has in reality probably already been produced before 2012, based on the history matched production of the base case.

Table 5: Total oil production [Sm^3] in the three cases

	Base Case	Reference Case	Case 9
Total Oil Production 1986-2025	18 267 890	15 888 060	16 757 270
Total Oil Production 2012-2025	1 272 330	1 021 320	1 890 530

Both the total and the additional oil production declined in A-39A and B-37 in the reference case and case 9 compared to the base case, but B-37 experienced a much bigger drop than A-39A in total production from 2012 to 2025. A-39A went down 12.6 % in the reference case and 9.2 % in case 9 compared to the base case, which actually means production from A-39A was larger in case 9 than the reference case. B-37 on the other hand had a drop in production of 25.2 % in the reference case and an even larger drop of 53.9 % in case 9 compared to the base case.

The new production well gave 1 059 367 Sm^3 or almost 6.7 million barrels of oil alone, which more than made up for the lost production from B-37, but it seems like a small part of the oil that the new well produced could possibly have be taken from B-37. Based on this there seems to be more communication than the grid maps alone gives the impression of, between the areas B-37 and the new well are producing from.

The production from the different wells can be seen in Table 6 and Figure 8

Table 6: Total oil production [Sm^3] from the two original production wells present after 2012

	A-39A			B-37		
Time period of oil production	Base Case	Reference Case	Case 9	Base Case	Reference Case	Case 9
1986-2025	3 506 061	2 919 652	2 937 870	2 186 882	1 387 581	1 179 219
2012-2025	548 635	479 672	497 890	723 691	541 639	333 277

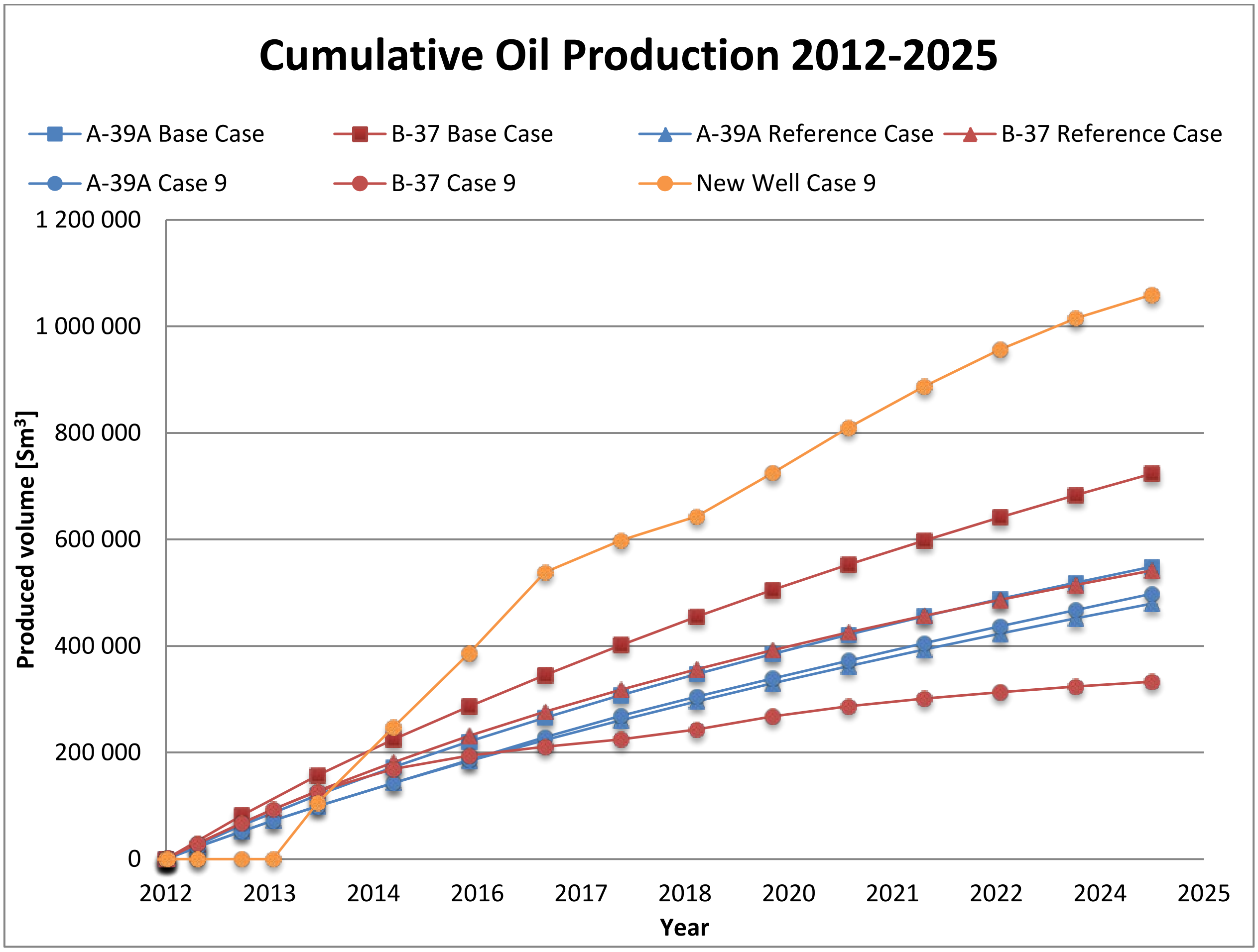

Figure 8: Cumulative oil production from 2012 to 2025 for the production wells in base case, reference case and case 9

For the wells the BHP remains stable both in the base case and in the reference case, with the pressures in the base case higher than in the reference case. In case 9 on the other hand BHP declines somewhat, with BHP of the new production well lying between A-39A and B-37, as can be seen in Figure 9 below. The reason for this is that even though the injection rates are adjusted up in case 9, so that more liquid is actually injected than what is taken out, the pressure in the new injection well becomes too high after a few years and the injection rate is therefore limited to stay below the max BHP of the injection well, 310 bar. The result of that is that the cumulative injection rate becomes about 100 Sm^3/day less than the cumulative liquid production rate. To keep the BHP in the production wells from becoming too low after and around 2025, the injection rate in A-35 should be increased by another 100 Sm^3/day to 2700 Sm^3/day. This should not be a problem, at least based on the pressure limit in A-35, since the pressure in that well is far below the limit. Increasing the injection rate in A-35 should probably have be done around 2019-2020, which is when the new injection well reaches the pressure limit, to keep the production and injection at the same level and to maintain the BHP in the production wells at a stable level towards 2025 and further on. This would of course give a slight increase in water cut, but the final impact of that should not lead to large changes in our results.

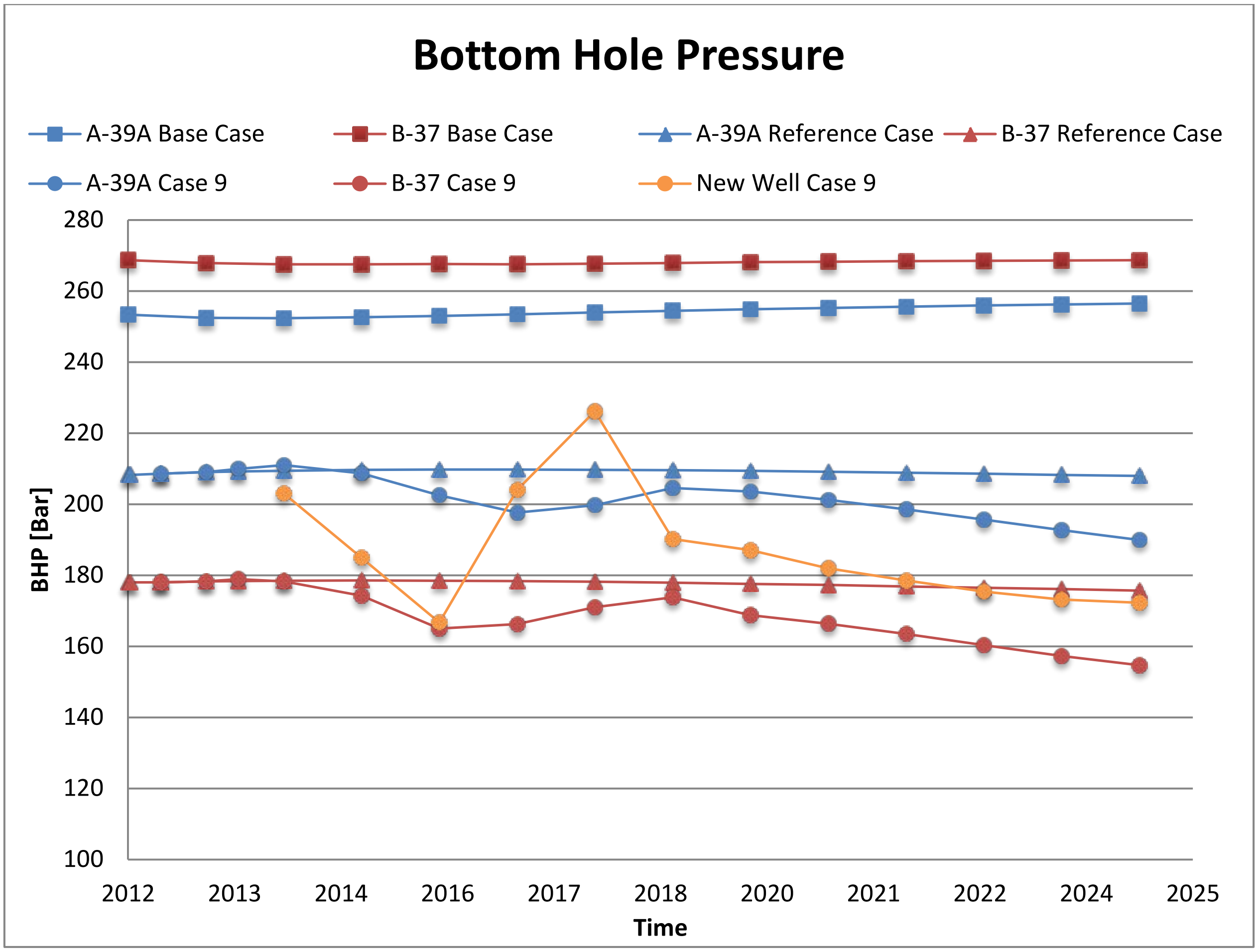

Figure 9: BHP of production wells in base case, reference case and case 9

The total water production from 1986 to 2025 increases in the reference case compared to the base case, and also increases somewhat more in case 9. The water production between 2012 and 2025 compared to the base case is 2.4 % larger in the reference case and 14.1 % larger in case 9. Even though field water cut, shown in Figure 10, is lower in case 9 than both the other cases, the additional production well leads to an increase in water production, but this increase is small compared to the increase in oil production between 2012 and 2025. The reason for this is that the new production well has a low water cut, both due to high oil saturation and the use of the WECON-keyword to shut of well segments with high water cut.

Table 7: Total water production in the three cases

	Base Case	Reference Case	Case 9
Total Water Production 1986-2025 [Sm^3]	28 544 240	30 368 310	31 615 090
Total Water Production 2012-2025 [Sm^3]	10 600 180	10 851 190	12 097 970

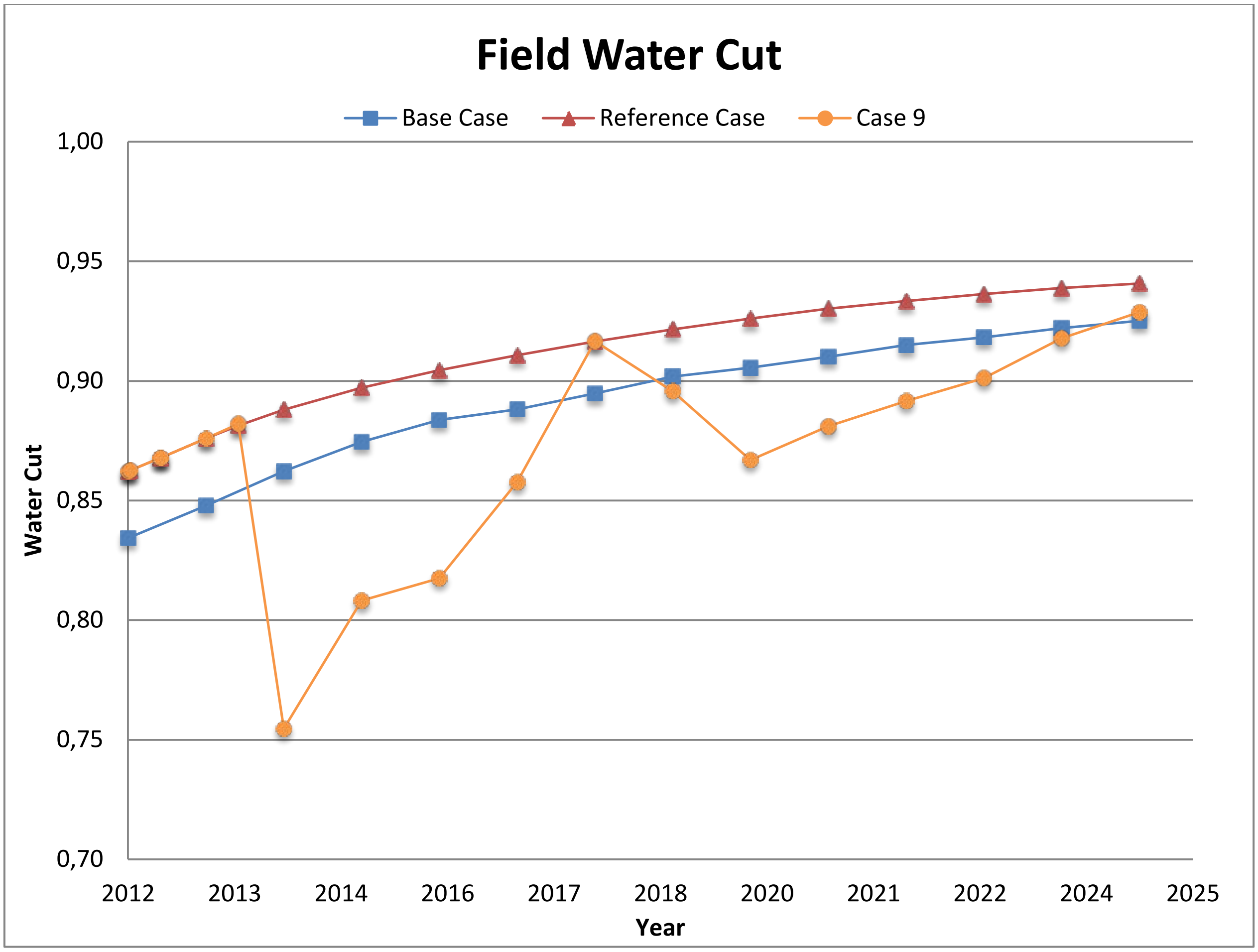

Figure 10: Field Water in the three cases

There was also an increase in total gas production for case 9, while the base case and the reference cases ended up with about the same total gas production in the end in 2025, but with more gas being produced earlier on in the reference case than the base case as can be seen in Figure 11.

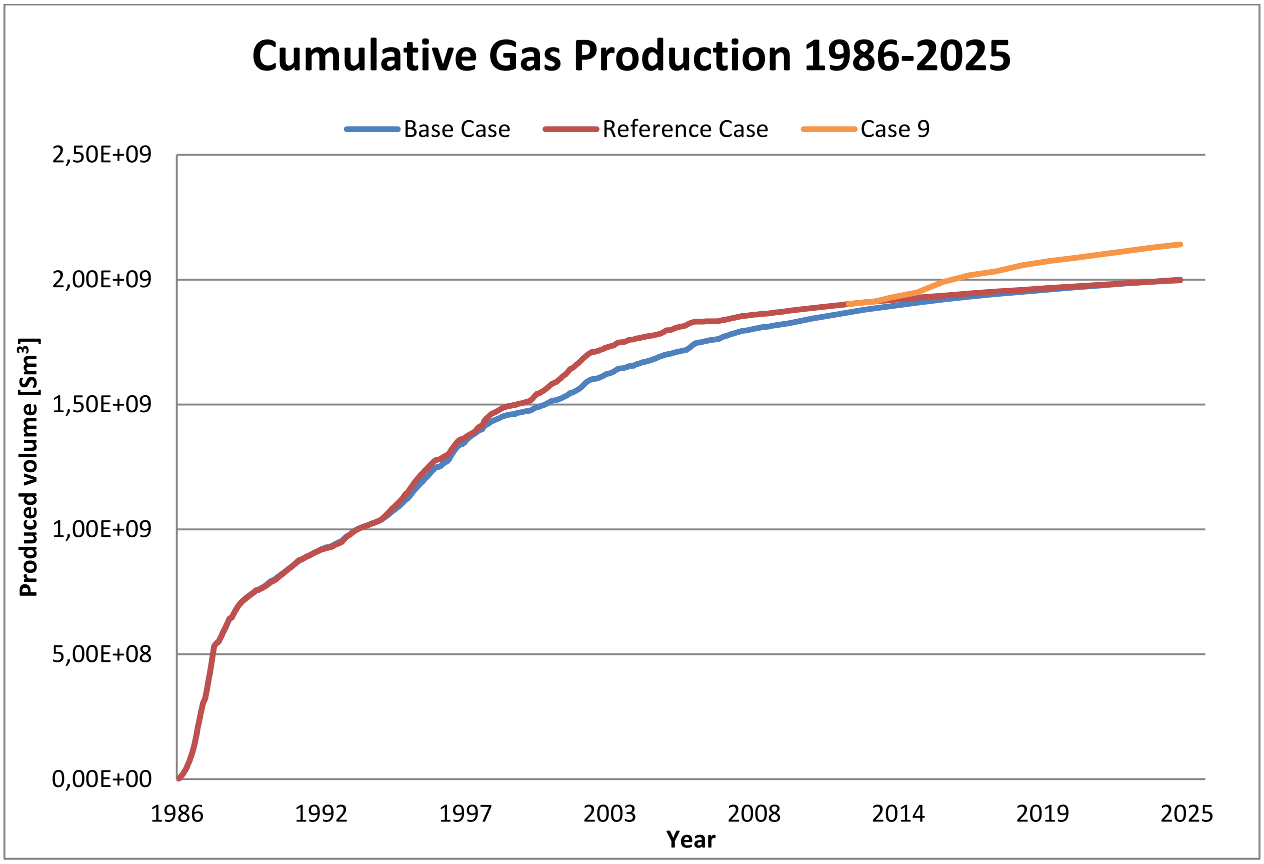

Figure 11: Cumulative gas production in the three cases

Field GOR is even for the base case and the reference case between 2012 and 2025, while it has some peaks and more uneven behavior in case 9 as seen in Figure 12. This is due to the new production well and B-37 having somewhat varying GORs in case 9.

The majority of the increased total gas production is due to the new production well. Although there is an increase in GOR for B-37 when comparing case 9 to the reference case, it does not produce a lot more gas than in the reference case, having an increase of only about 2.2 % in the wells total gas production.

In relation to this it can be worth noting that the data from the simulation after 2013 is only recorded once a year, on January 1st, even though the time step is much smaller, and therefore the graphs might not necessarily give an accurate and representative image of how the GOR (and e.g. production rates) vary over time. The value recorded in January can be much higher or much lower than what it is at other times during the year.

Despite all this, the apparent gradual increase in GOR due to B-37 from around 2020 could be seen as an indication that BHP is becoming too low, although the GOR of B-37 does increase to a certain degree even if the BHP is at a much higher level. As mentioned earlier injection rate in A-35 should be increased even more in case 9 to ensure adequate pressure support towards the end of our simulation in 2025 and later.

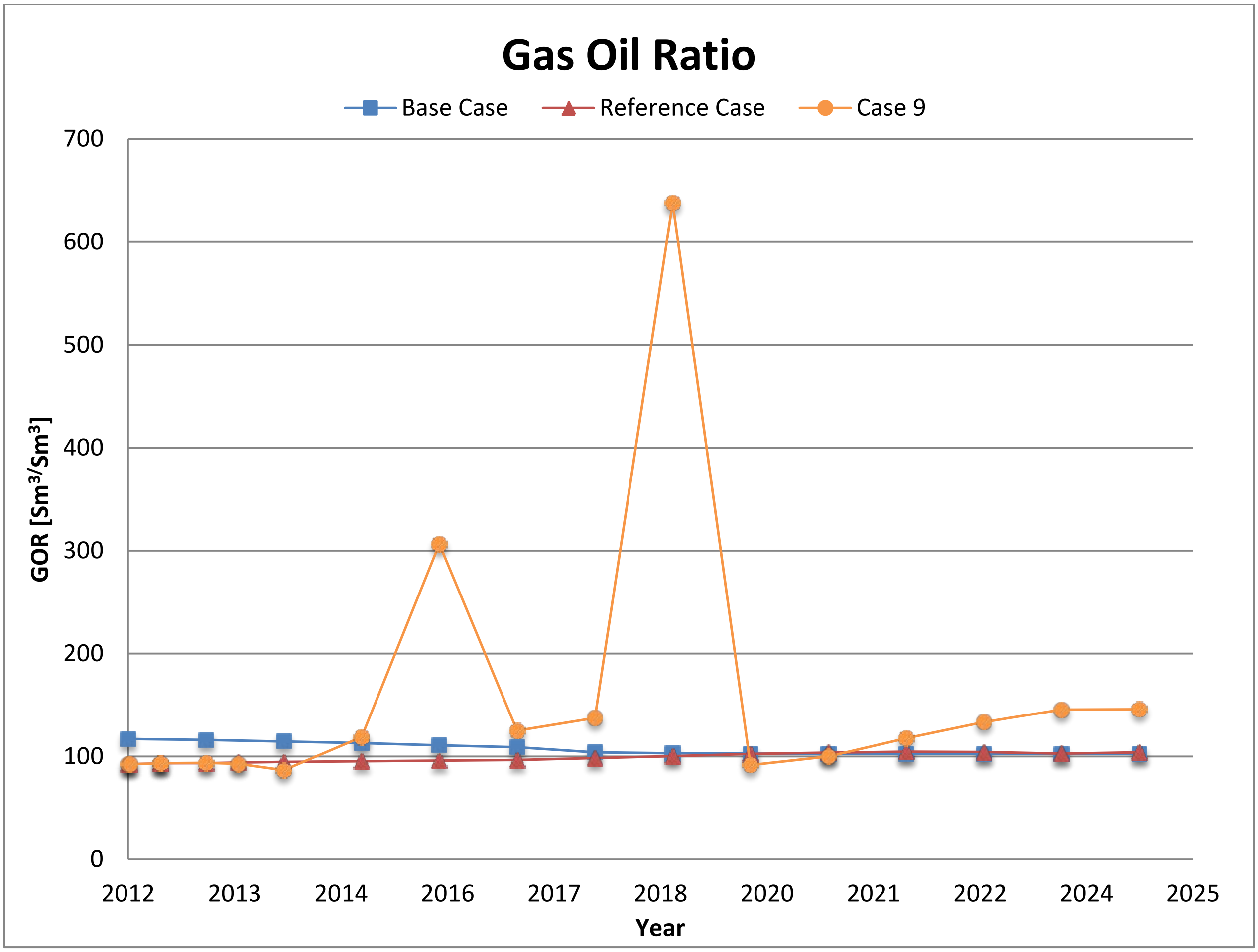

Figure 12: Gas Oil Ratio in the three cases

Oil recovery factor has not been calculated as we consider the uncertainties in trying to calculate it based on results from Eclipse and data from RSP as too large.

The grid maps (Figure 13 to Figure 15) show that oil recovery from the northwestern pocket is good in case 9 compared to the reference case and to some extent also the base case. There is still some oil left in the upper layers of Lower Brent in the pocket, which gives a future potential for more production by reperforating the new production well higher up than the layers we produced from. On the other hand though there is a sharp pressure decline and saturation change around layers 35-36 which seems to imply poor vertical communication between the layers above and below. This could make the left over oil high up, around the new production well, difficult to recover beyond 2025 without also injecting higher up, close to these layers. Horizontal wells have not been tried due to the possibility of poor vertical communication depending on which layers the wells are placed in and the small size of the northwestern pocket.

The area where the new wells were placed in case 9 could also be an interesting area to consider in the base case, as there are some layers, e.g. layer 36 to about 40, which have high oil saturations in that area. When looking at the pressure the same pocket also appears to be somewhat isolated in the base case from layer 36 and down, similar to how it was in the cases with closed faults.

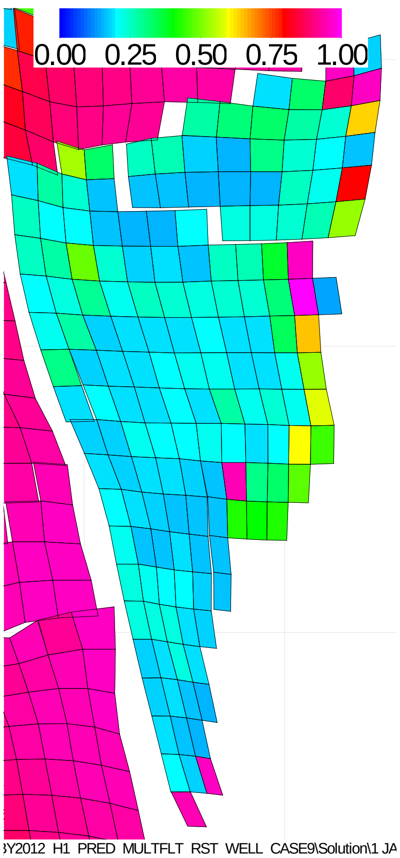

Figure 13: Case 9 oil saturation layer 40 in 2025

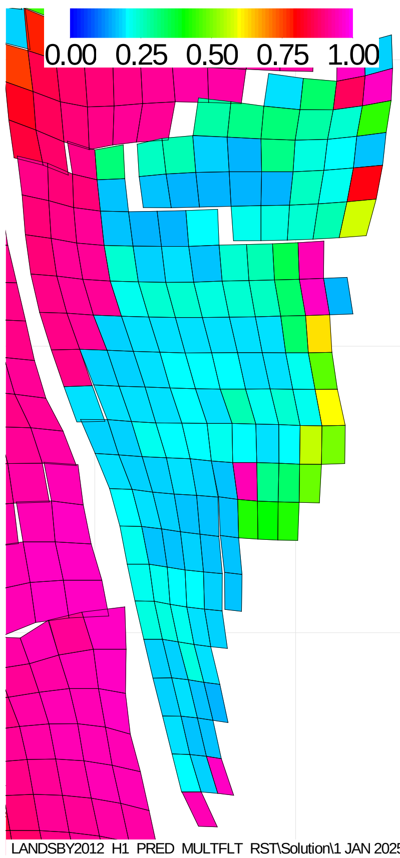

Figure 14: Reference case oil saturation layer 40 in 2025

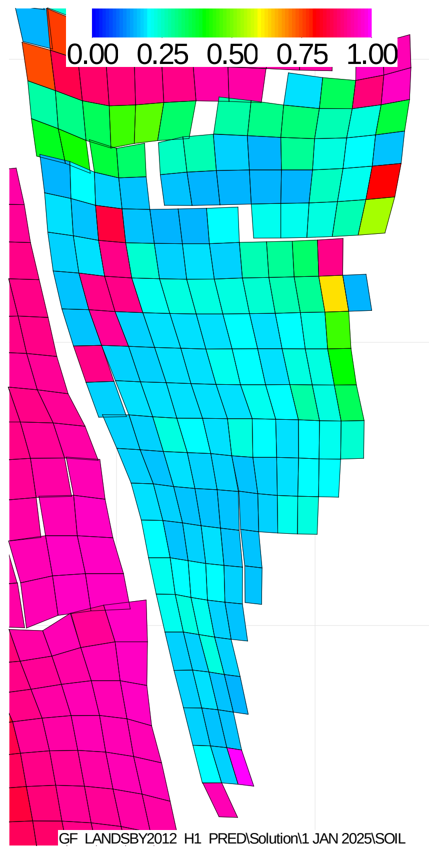

Figure 15: Base case oil saturation layer 40 in 2025

3.5. Economic Evaluation

In order to evaluate the economical profitability of investing in new wells we have several tools. It was suggested by Statoil to evaluate the ‘Net Present Value - NPV’ and the ‘Internal Rate of Return - IRR’ for this purpose. The Net Present Value is the sum of the Present Values and is a commonly used method for using the time value of money to evaluate long-term projects. It is defined as (Investopedia):

$$NPV = \sum_{t=1}^{T} \frac{C_t}{(1+r)^t} - C_o$$

Where:

- r = discount rate
- C_t = the net cash flow at time t
- C_o = initial investment
- T = analytic horizon

A negative NPV implies that the investment or project should not be undertaken. A positive NPV means that the project would add value to the company and hence may be accepted.

The Internal Rate of Return is a tool that allows easy comparison of the profitability of different investments. It can be defined as the "rate of return" (or discount rate) that makes the NPV of all cash flows from the investment equal to zero (Wikipedia).

3.5.1. Assumptions

The economic evaluation is based on the following assumptions:

- Oil price (constant at 2011 level) : 100 USD/bbl
- Discount factor: 8%
- Exchange rate: 5.8 NOK/USD
- Cost of a new vertical well: 200 MNOK

3.5.2. Economic analysis

The economic analysis is based on our final and recommended solution, with one new vertical producer and one new vertical injector in the northwestern corner of H1. The cash flow from the drilling of these two wells comes from the increased (total field, or H1) oil production for this case versus the reference case with all faults closed.

Table 8: Key figures of the economic analysis

Net Present Value	**1,831 MNOK**
Internal Rate of Return	195%
Total Value	2,771 MNOK

Table 8 shows the key results of the economic analysis. A complete table of all our results can be found in Appendix B. Figure 16 below shows the development of the annual present value. It can be seen that the well cost is made up for already during 2013, the first year of production, and another 150 million is earned. The sudden decrease in 2015 is due to the drilling of the injection well. The increase after 2018 is thanks to a simple well intervention, where we plug the lower water producing perforations. In eclipse this is done by the use of the WECON function, where we set the water cut limit to 80%. The total net present value is shown in Figure 17, and as the annual present value remains positive, it increases steadily over the years.

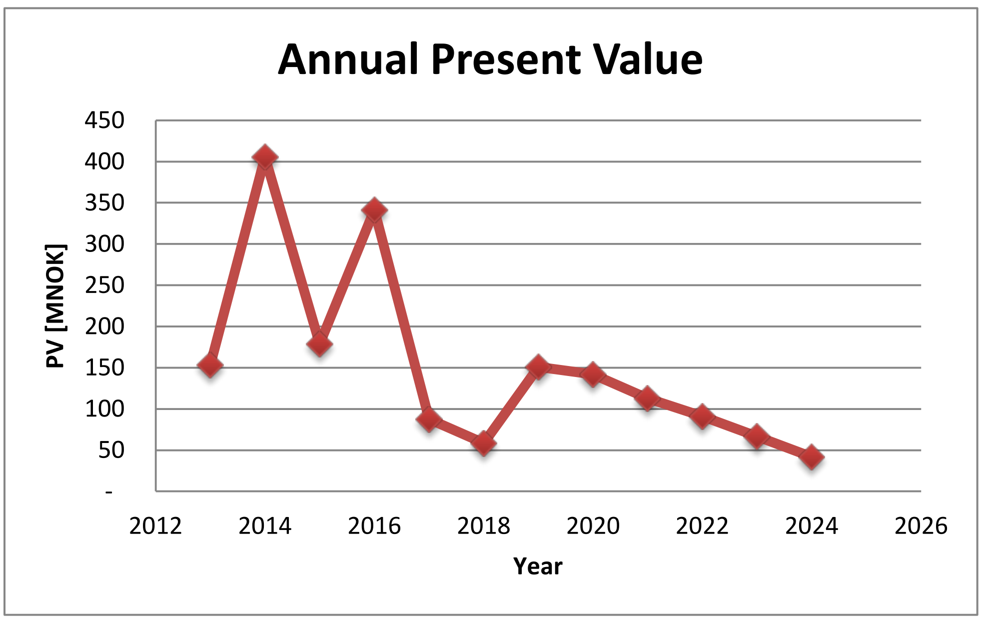

Figure 16: Development of the annual present value

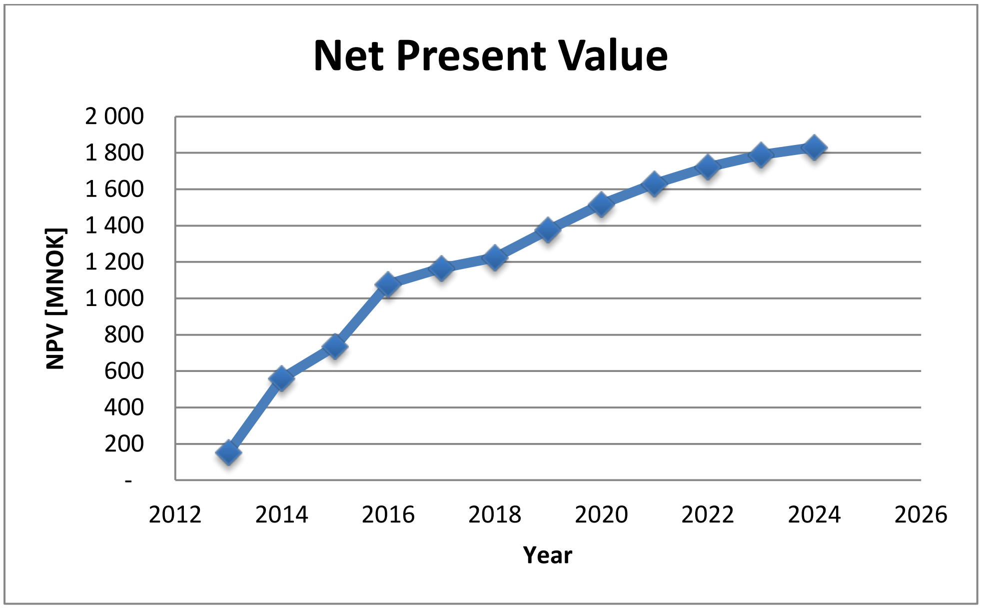

Figure 17: Development of the net present value

Table 8 shows that the NPV and IRR are significant. In particular is the IRR high, this is due to the fact that the investment of drilling the first well is already regained during the first year of production and when the injection well is drilled (2015) the income from the producing well makes up for this investment as well keeping the annual present value positive.

3.5.3. Sensitivity Analysis

In order to evaluate the uncertainty of our economic analysis it is necessary to perform a sensitivity analysis. This determines how different values affect a dependable variable, in our case the NPV and IRR.

Table 9 shows the results of the sensitivity analysis. The analysis is based on the following assumptions:

- Oil and gas prices increasing 5% p. a. /decreasing 3% p. a.
- Production: +/- 30%
- Investments: +/- 40%

Table 9: Sensitivity of net present value and internal rate of return

	Low	Base	High
Oil price			
% change	-3 %	0	5 %
NPV [MNOK]	1 505	1 831	2 528
% change (NPV)	-18 %	0 %	38 %
IRR	179 %	195 %	221 %
Production			
% change	-30 %	0	30 %
NPV [MNOK]	1 174	1 831	2 488
% change (NPV)	-36 %	0 %	36 %
IRR	131 %	195 %	329 %
Investments			
% change	40 %	0	-40 %
NPV [MNOK]	1 687	1 831	1 974
% change (NPV)	-8 %	0 %	8 %
IRR	134 %	195 %	329 %

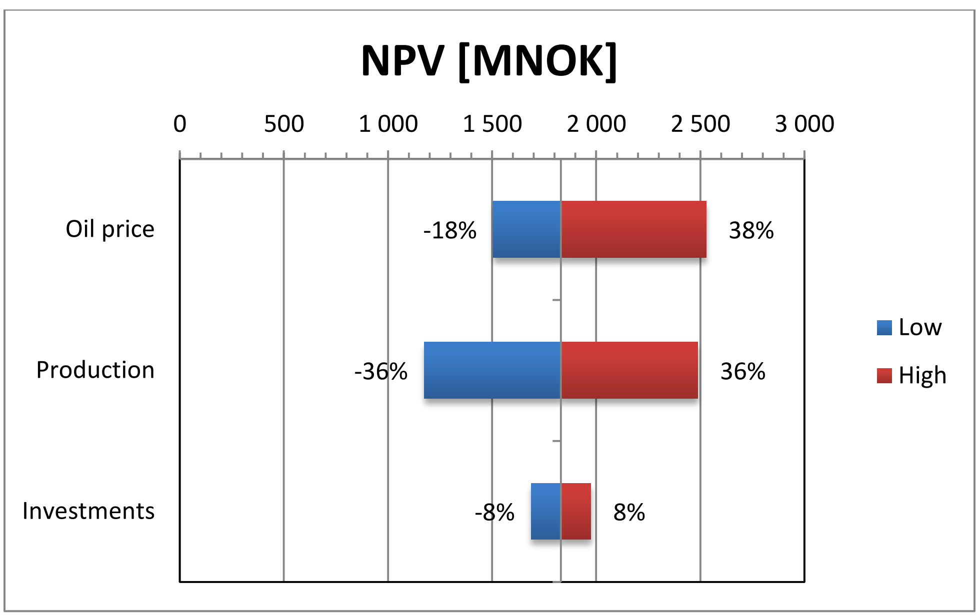

Figure 18: Clustered bar representation of the sensitivity of the NPV

The clustered bar representation of Figure 18 shows the influence of the oil price, production volumes and investment cost has on the NPV. The influence, represented by change in percent, is indicated at each bar. The figure shows that the NPV remains positive and above 1.1 billion NOK for all the assumed cases; giving the impression of a very robust investment.

The relatively high NPV and IRR of this investment show that it could be a good idea to drill the two new wells from an economical point of view. However there are two main uncertainties connected to our analysis. First of all we have not taken into account the increased operating expenses (OPEX) related to the two new wells. This includes the intervention cost related to using the WECON function described earlier. OPEX is a significant aspect of every investment, and one of the results of not including this is that the annual present value will never turn negative (since the investments is taken in years with high income). This can be seen from the Figure 16 above; in reality it will never be the case because at one point a well will start to produce less oil than what is needed to account for the running costs. The second problem is that the income of this investment is based on the reservoir model with closed faults which we know is not entirely true; it is not history matched. As mentioned earlier, this will in reality mean that we don’t know if the increased oil production we experience is from oil that has already been produced in the real world. Hence the production volumes are rather uncertain, and the NPV is sensitive to this. On the contrary we have not taken into account the economic aspect of the increased gas production associated with the two new wells. The gas could either be exported and sold (possibly through Statpipe and Kårstø) or reinjected, both of which will bring positive influence either in the form of direct sales or increased oil production.

4. Conclusion

Our final recommendation, based on an eclipse model with closed faults, regarding increased oil recovery form the Gullfaks H1 segment is to drill one production and one injection well in the north western corner. The main goal of the project was to achieve an oil recovery similar to the base case. As we have seen our two new wells have not been able to match total cumulative oil production (1986-2025), because of the reduced production with closed faults from 1986 to 2012. However we were able to match, and surpass, the base case oil production in the period 2012-2025. The two new wells were able to produce in total 48.6% more oil than the base case with faults open in this period. This results in a net present value of 1 831 MNOK, a significant value compared to the investment of two new wells estimated to cost 200 MNOK each. By this we have shown that infill drilling could be an effective solution for improving oil recovery on the Gullfaks main field, as we predicted in part A. However it remains uncertain how applicable the results we have seen are to the real world since we don't know if there is communication through the faults or not. But what we have shown is that the target we have drilled is very promising if the faults in H1 are closed, and that even if the faults have some communication (base case) the target area has high remaining oil saturation (in 2025), and hence could be an interesting target.

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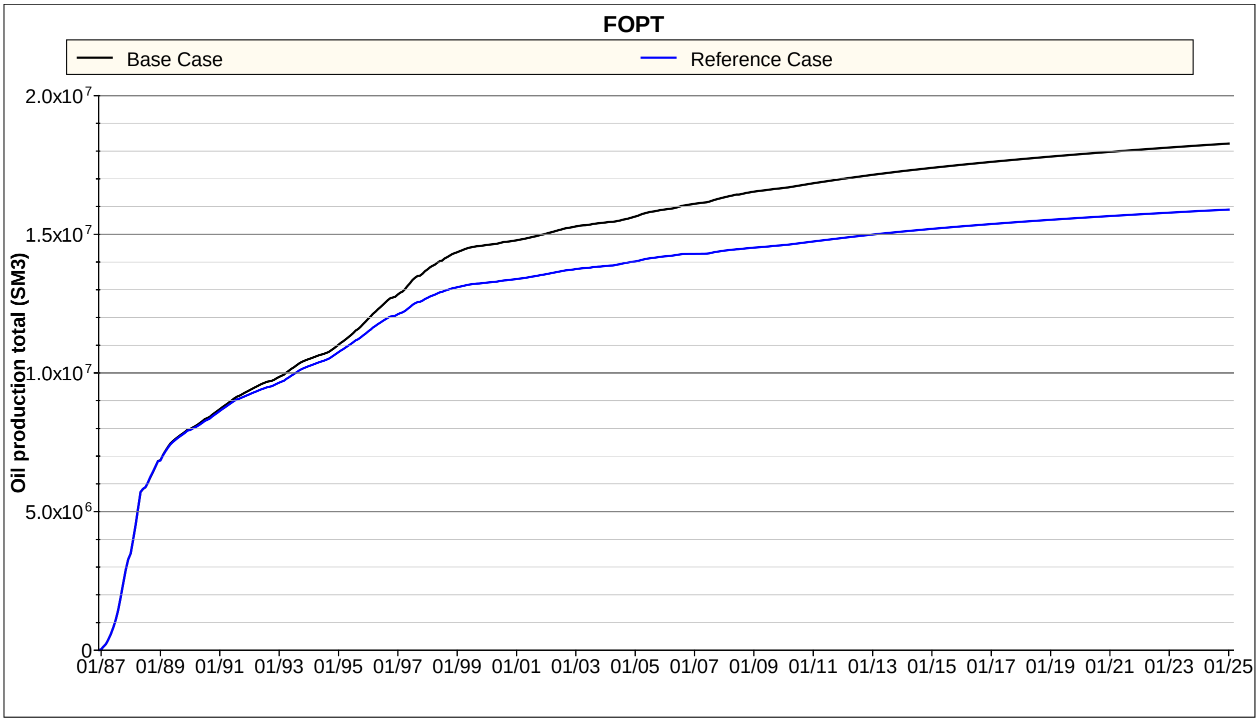
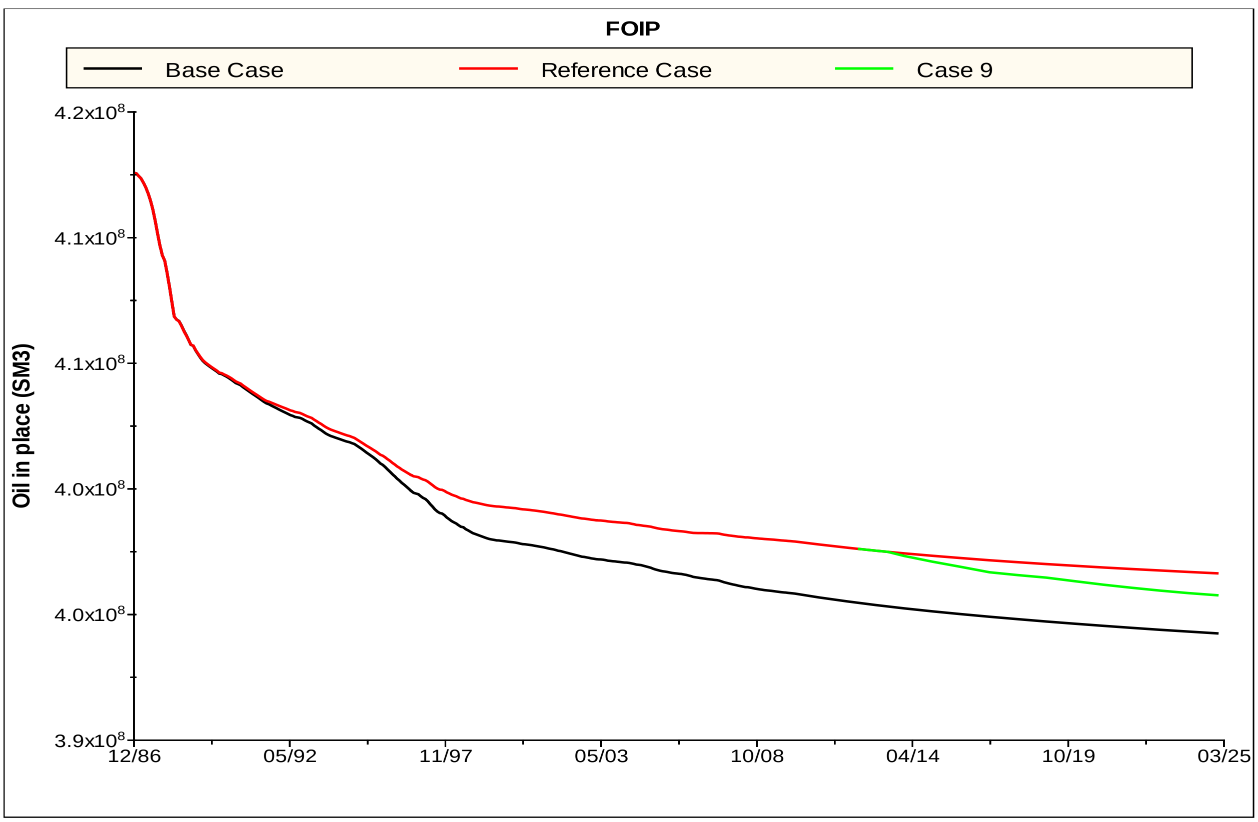
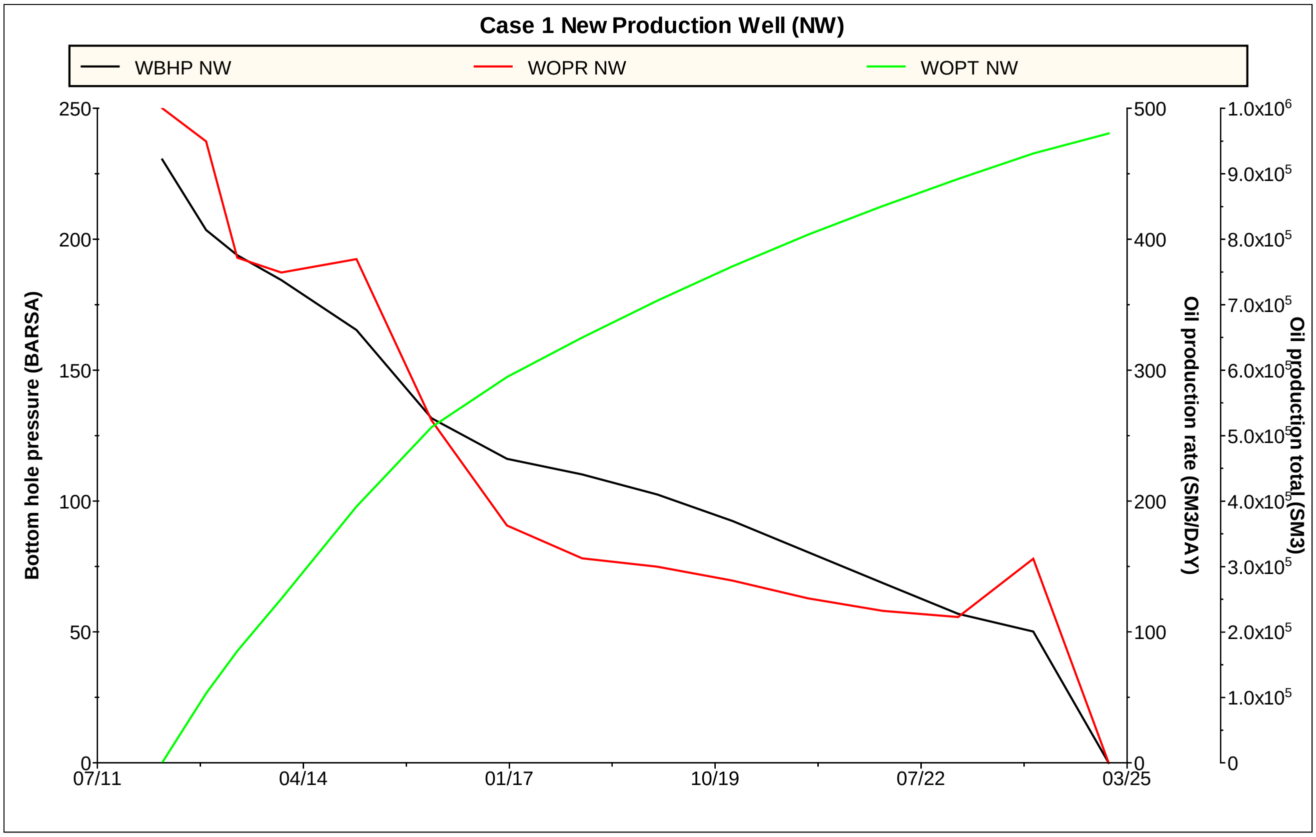
6. Appendix A

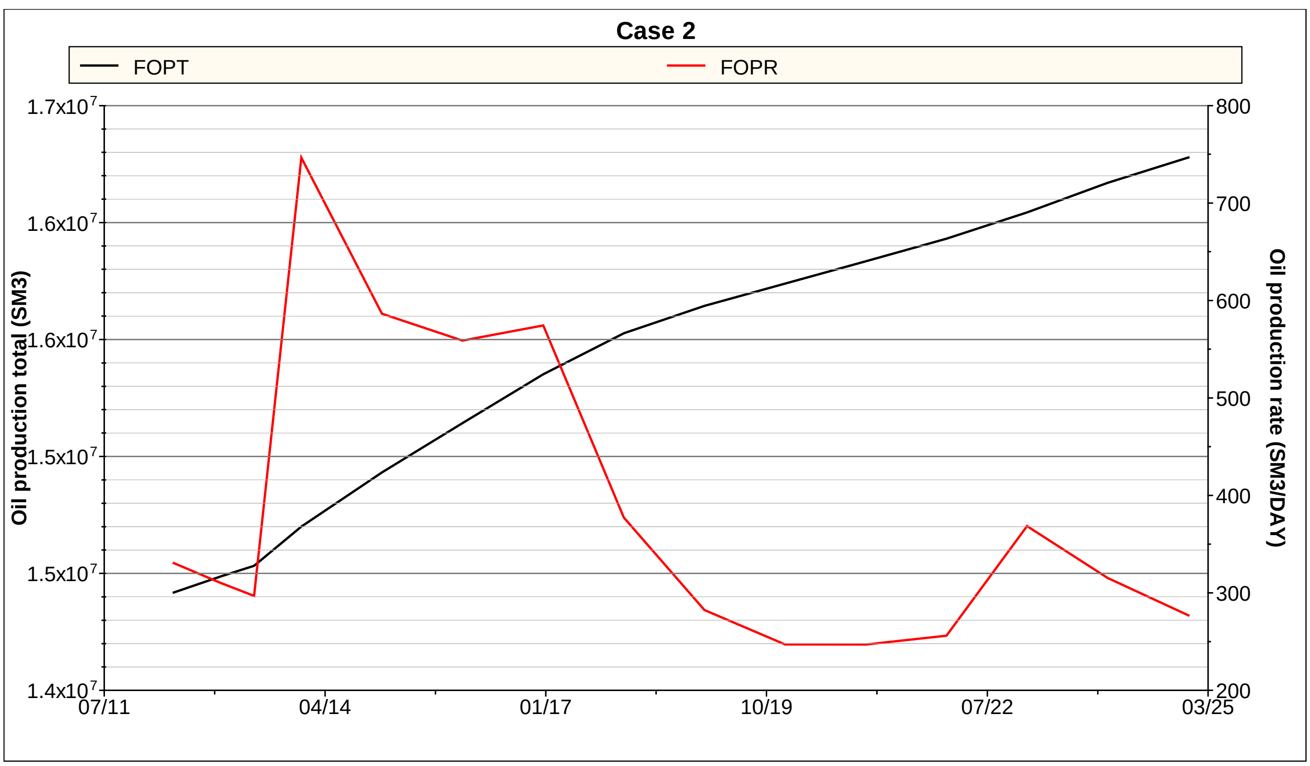


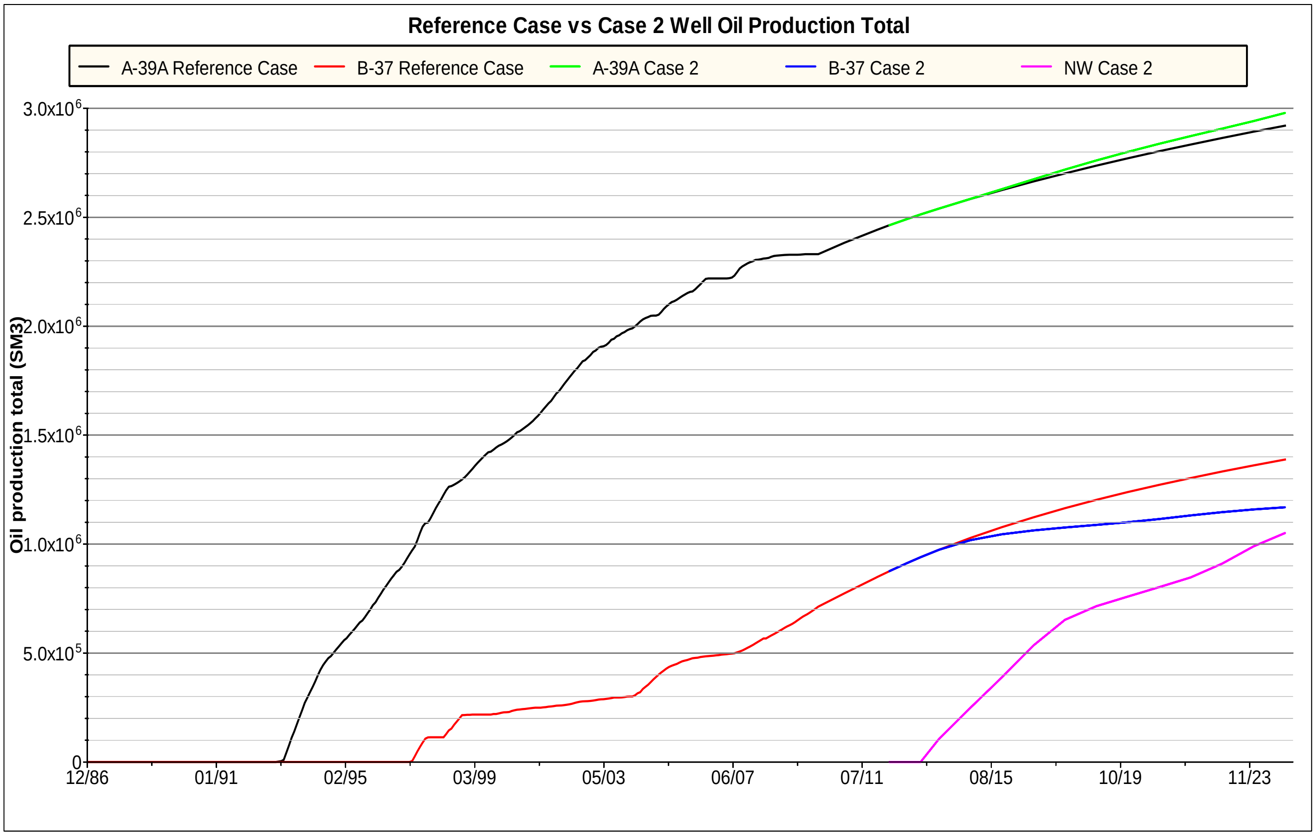
FOPT
Base Case
Reference Case
Oil production total (SM3)
2.0x10^7
1.5x10^7
1.0x10^7
5.0x10^6
0
01/87 01/89 01/91 01/93 01/95 01/97 01/99 01/01 01/03 01/05 01/07 01/09 01/11 01/13 01/15 01/17 01/19 01/21 01/23 01/25



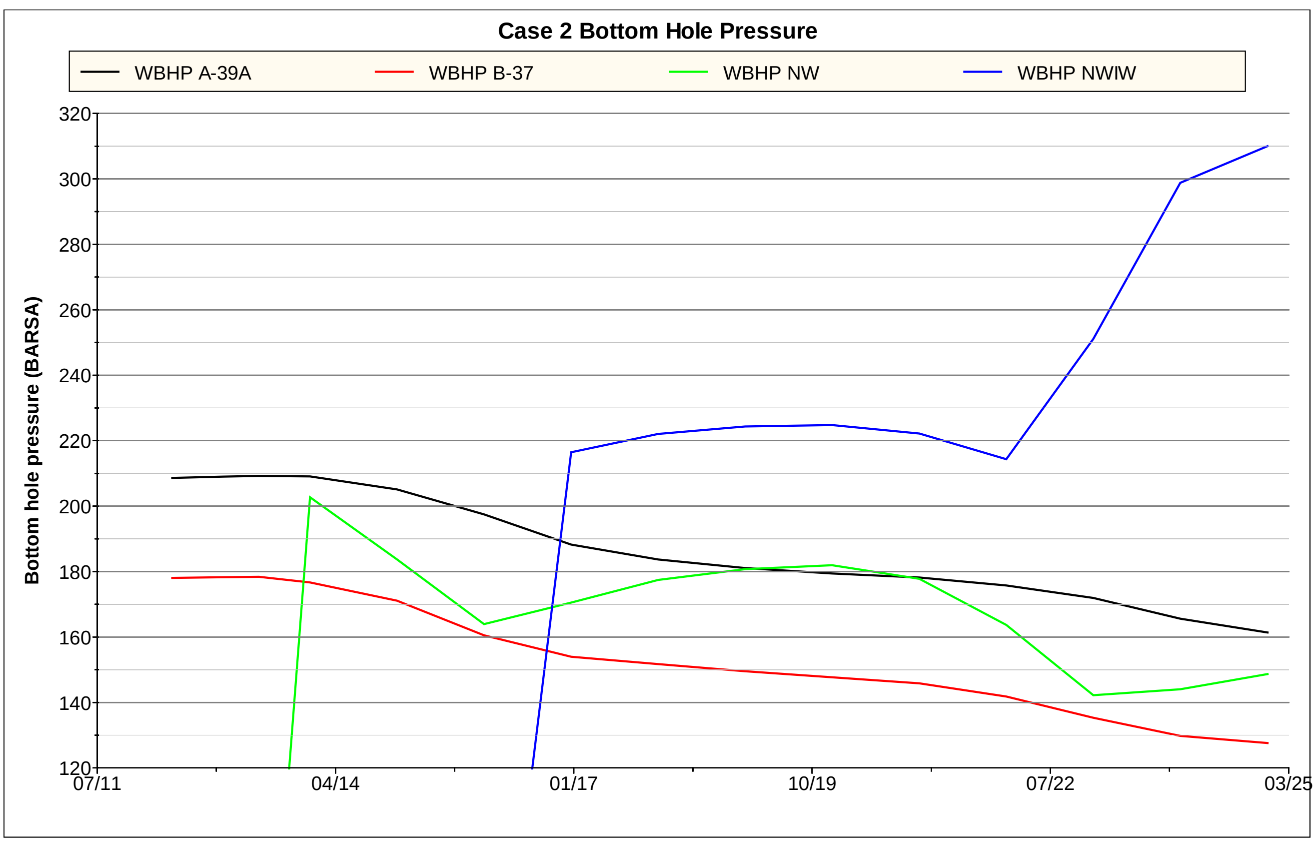
FOIP
Base Case
Reference Case
Case 9
Oil in place (SM3)
4.2x10^8
4.1x10^8
4.1x10^8
4.0x10^8
4.0x10^8
3.9x10^8
12/86 05/92 11/97 05/03 10/08 04/14 10/19 03/25


Case 1 New Production Well (NW)
WBHP NW
WOPR NW
WOPT NW
Bottom hole pressure (BARSA)
Oil production rate (SM3/DAY)
Oil production total (SM3)
250
200
150
100
50
0
500
400
300
200
100
0
1.0x10^6
9.0x10^5
8.0x10^5
7.0x10^5
6.0x10^5
5.0x10^5
4.0x10^5
3.0x10^5
2.0x10^5
1.0x10^5
0
07/11
04/14
01/17
10/19
07/22
03/25

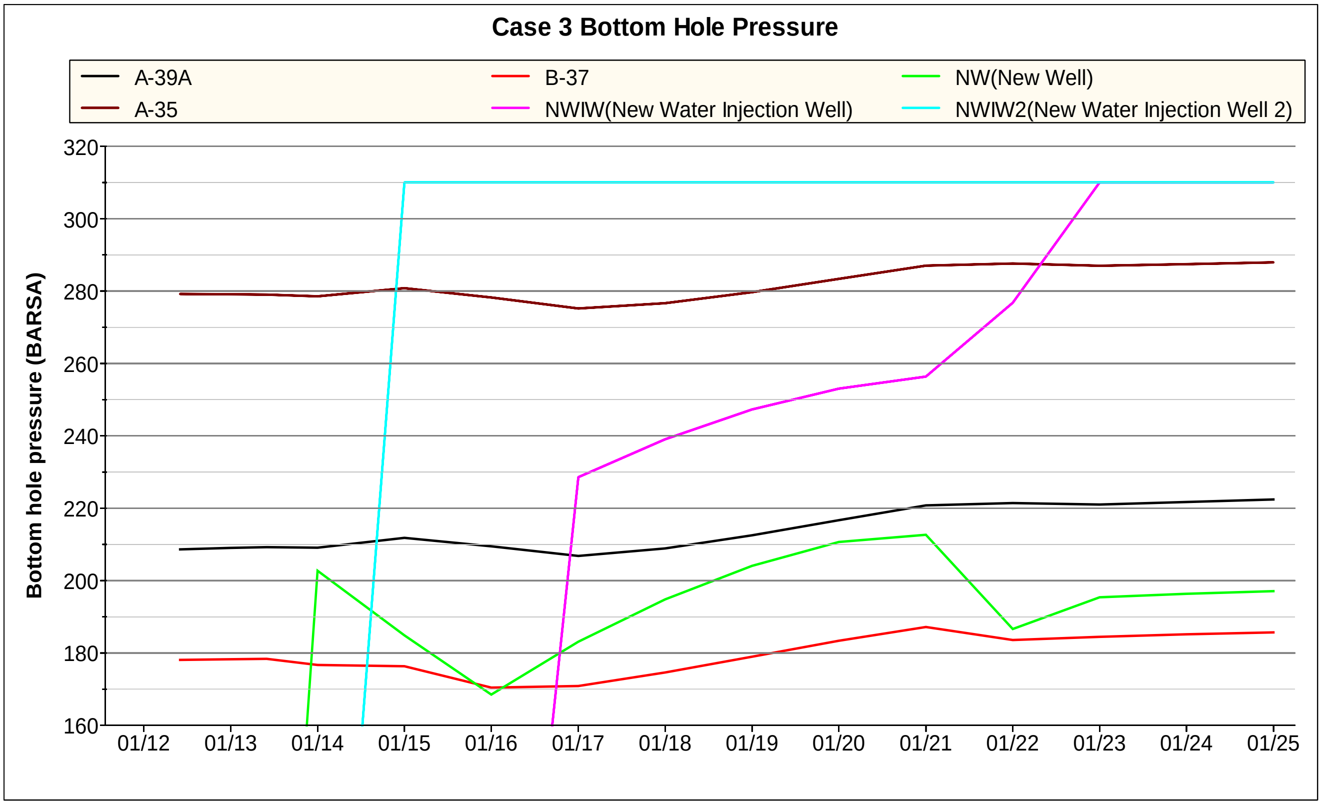

Case 2
FOPT
FOPR
Oil production total (SM3)
Oil production rate (SM3/DAY)
1.7x10^7
1.6x10^7
1.6x10^7
1.5x10^7
1.5x10^7
1.4x10^7
800
700
600
500
400
300
200
07/11
04/14
01/17
10/19
07/22
03/25

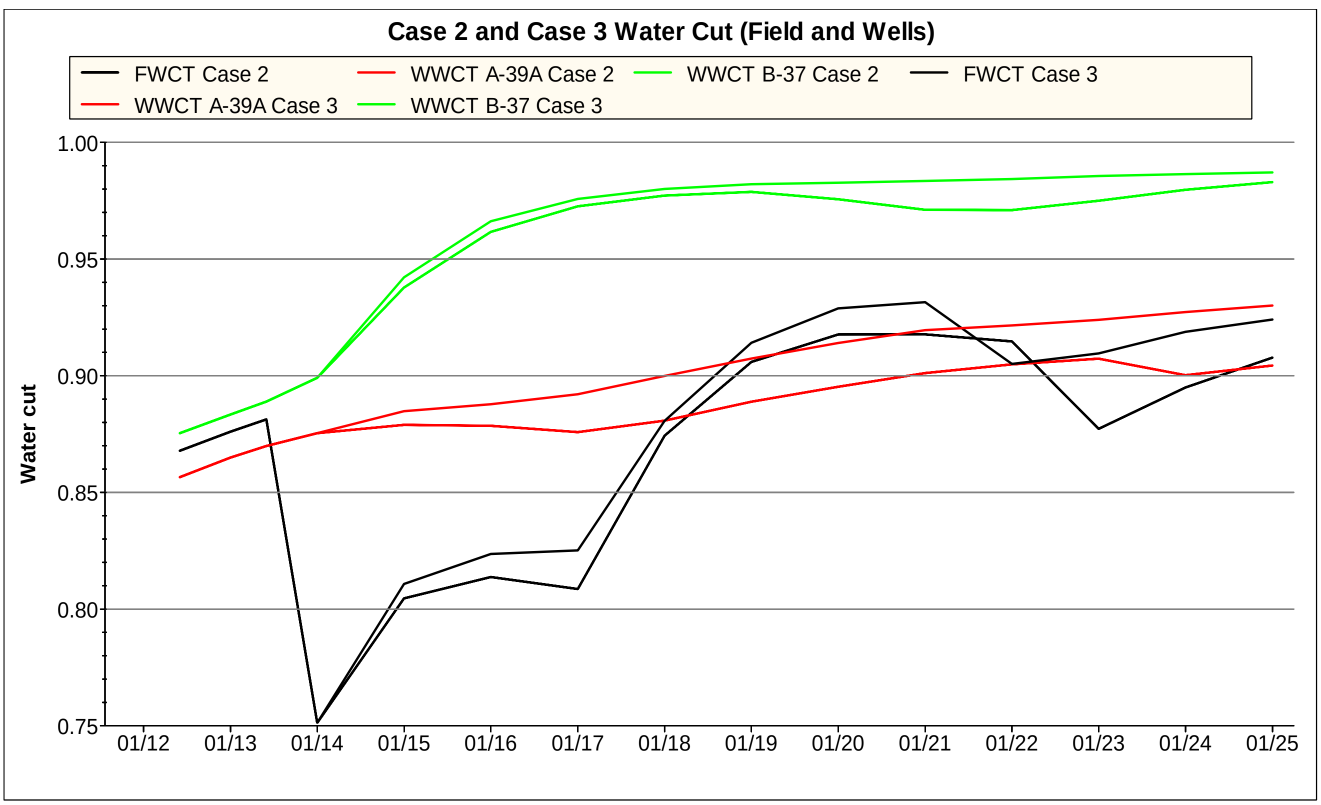


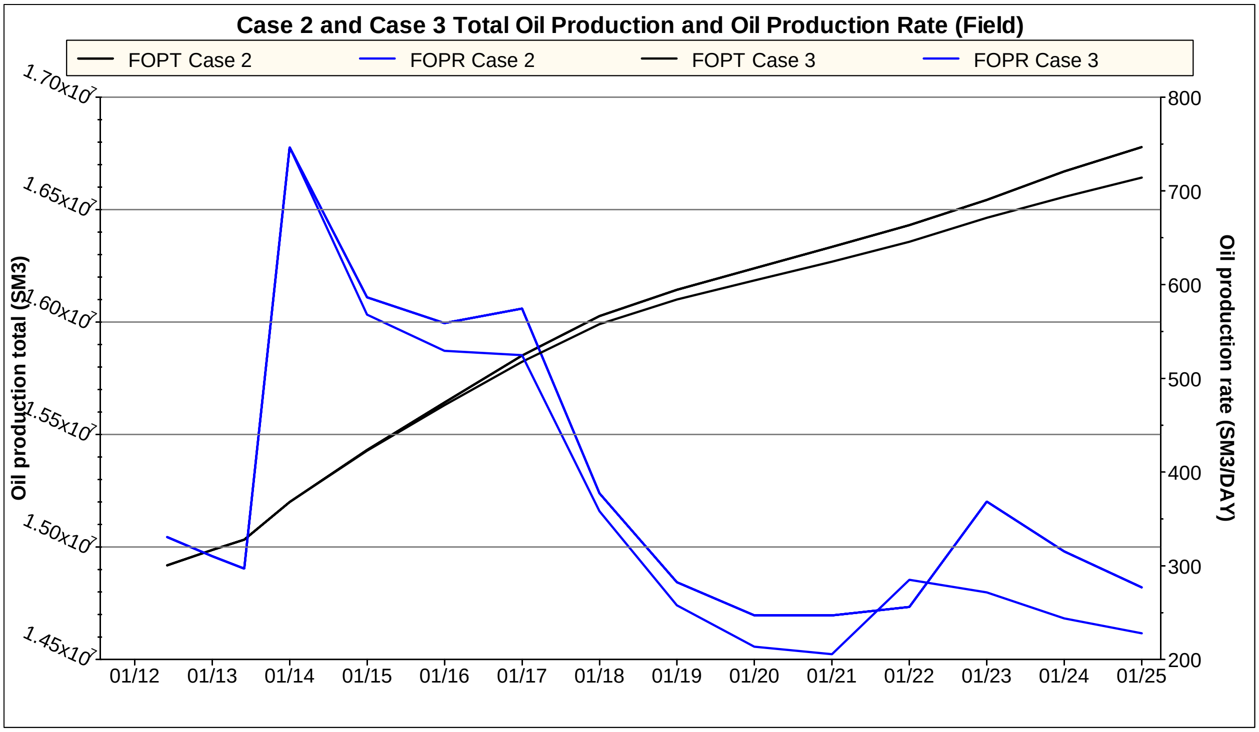
Reference Case vs Case 2 Well Oil Production Total
A-39A Reference Case
B-37 Reference Case
A-39A Case 2
B-37 Case 2
NW Case 2
Oil production total (SM3)
3.0x10^6
2.5x10^6
2.0x10^6
1.5x10^6
1.0x10^6
5.0x10^5
0
12/86
01/91
02/95
03/99
05/03
06/07
07/11
08/15
10/19
11/23



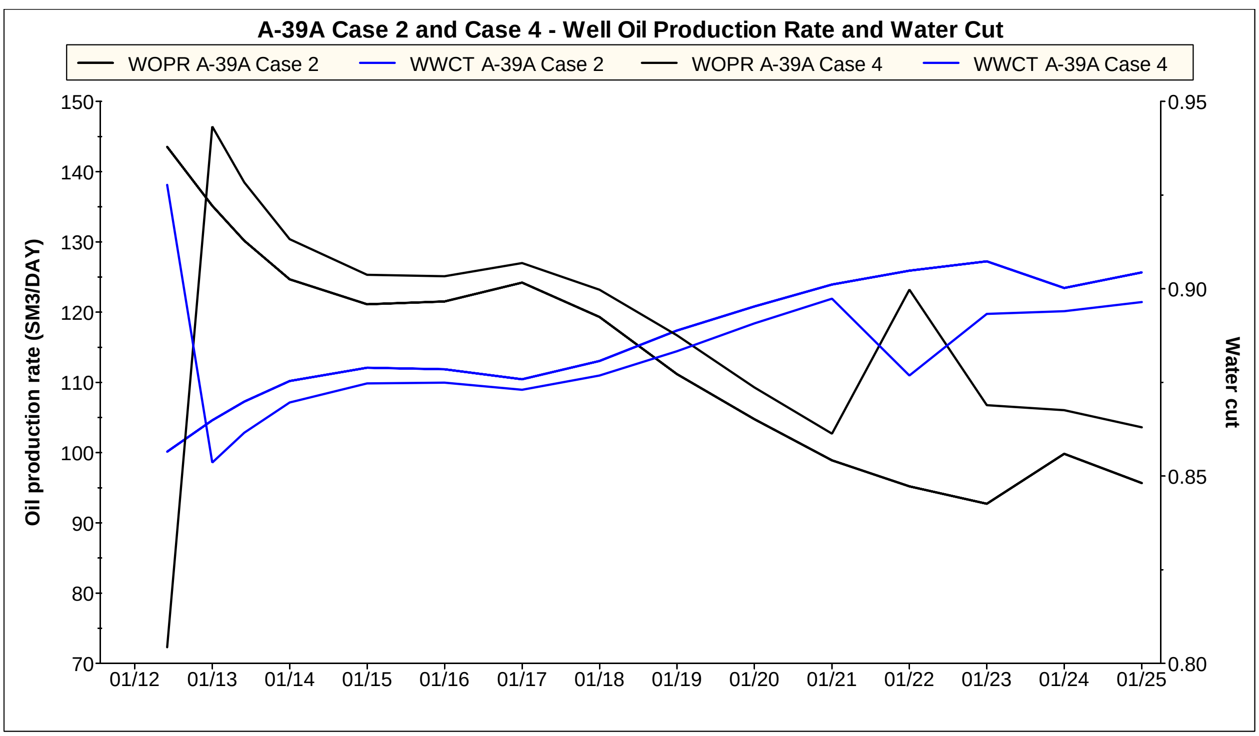
Case 2 Bottom Hole Pressure
WBHP A-39A
WBHP B-37
WBHP NW
WBHP NWIW
Bottom hole pressure (BARSA)
320
300
280
260
240
220
200
180
160
140
120
07/11
04/14
01/17
10/19
07/22
03/25


Case 3 Bottom Hole Pressure
A-39A
B-37
NW(New Well)
A-35
NWIW(New Water Injection Well)
NWIW2(New Water Injection Well 2)
Bottom hole pressure (BARSA)
320
300
280
260
240
220
200
180
160
01/12
01/13
01/14
01/15
01/16
01/17
01/18
01/19
01/20
01/21
01/22
01/23
01/24
01/25

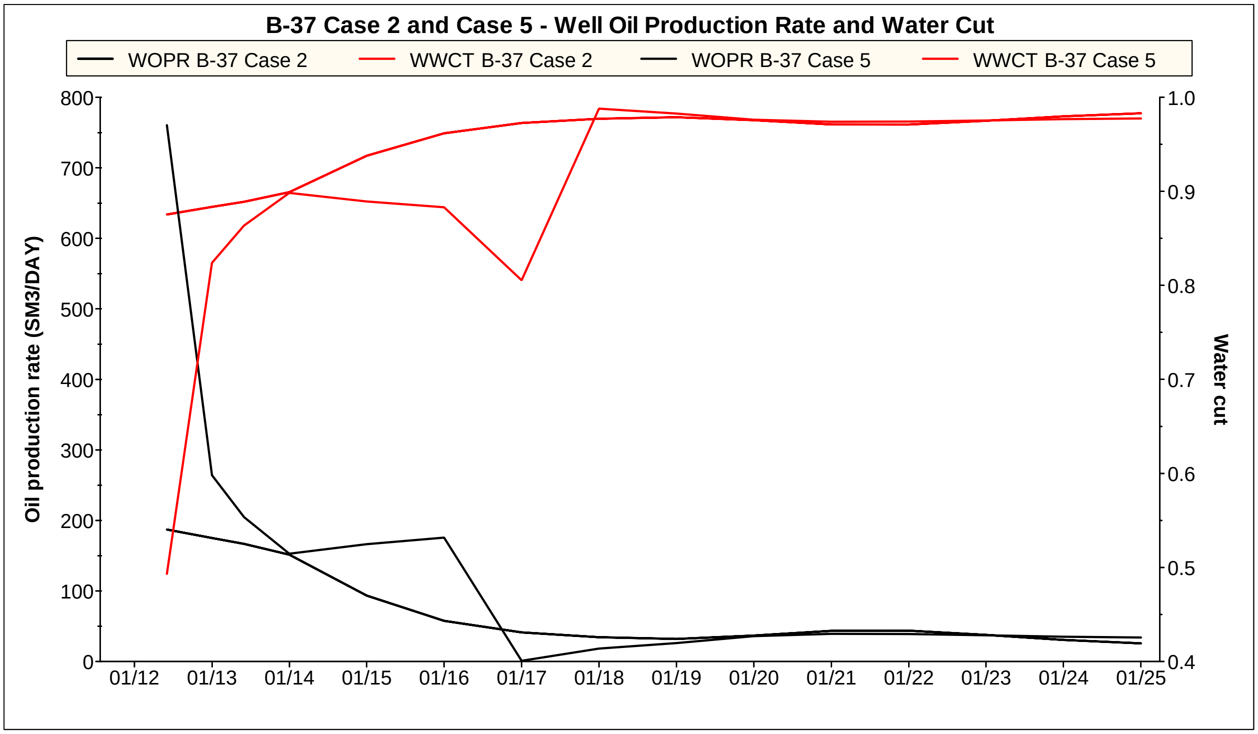

Case 2 and Case 3 Water Cut (Field and Wells)
FWCT Case 2
WWCT A-39A Case 2
WWCT B-37 Case 2
FWCT Case 3
WWCT A-39A Case 3
WWCT B-37 Case 3
Water cut
1.00
0.95
0.90
0.85
0.80
0.75
01/12
01/13
01/14
01/15
01/16
01/17
01/18
01/19
01/20
01/21
01/22
01/23
01/24
01/25

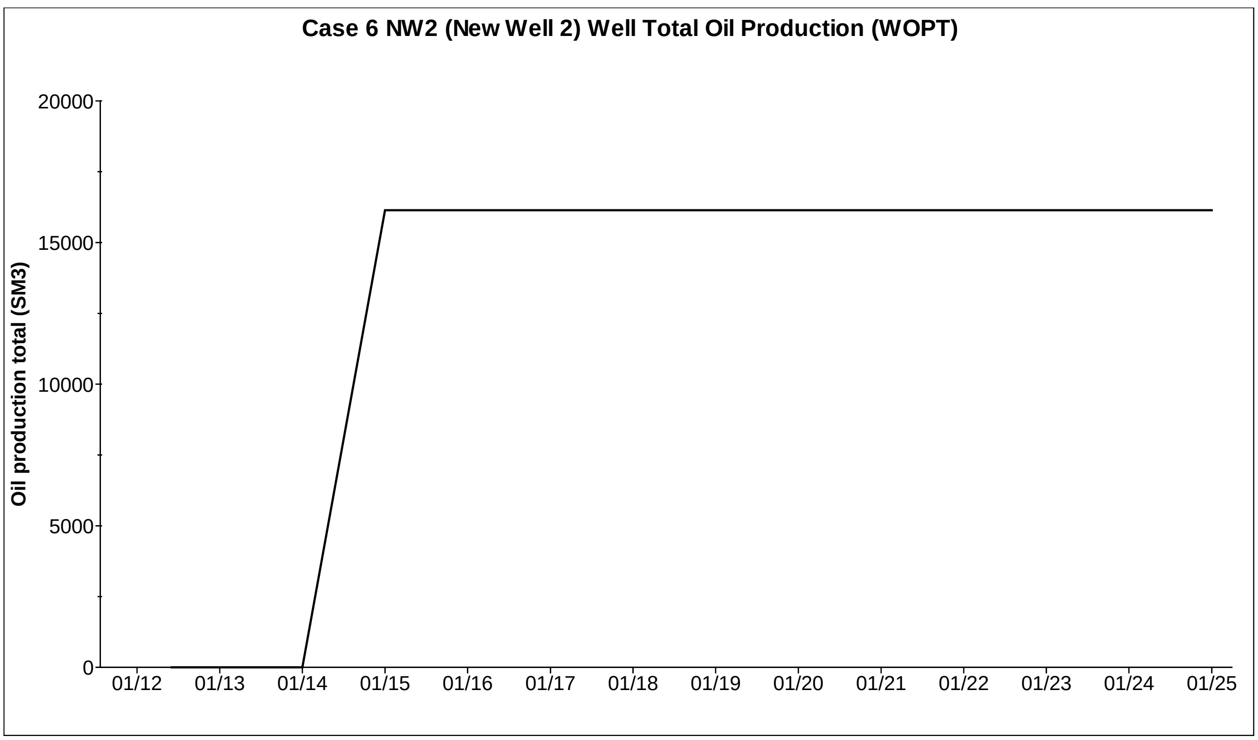


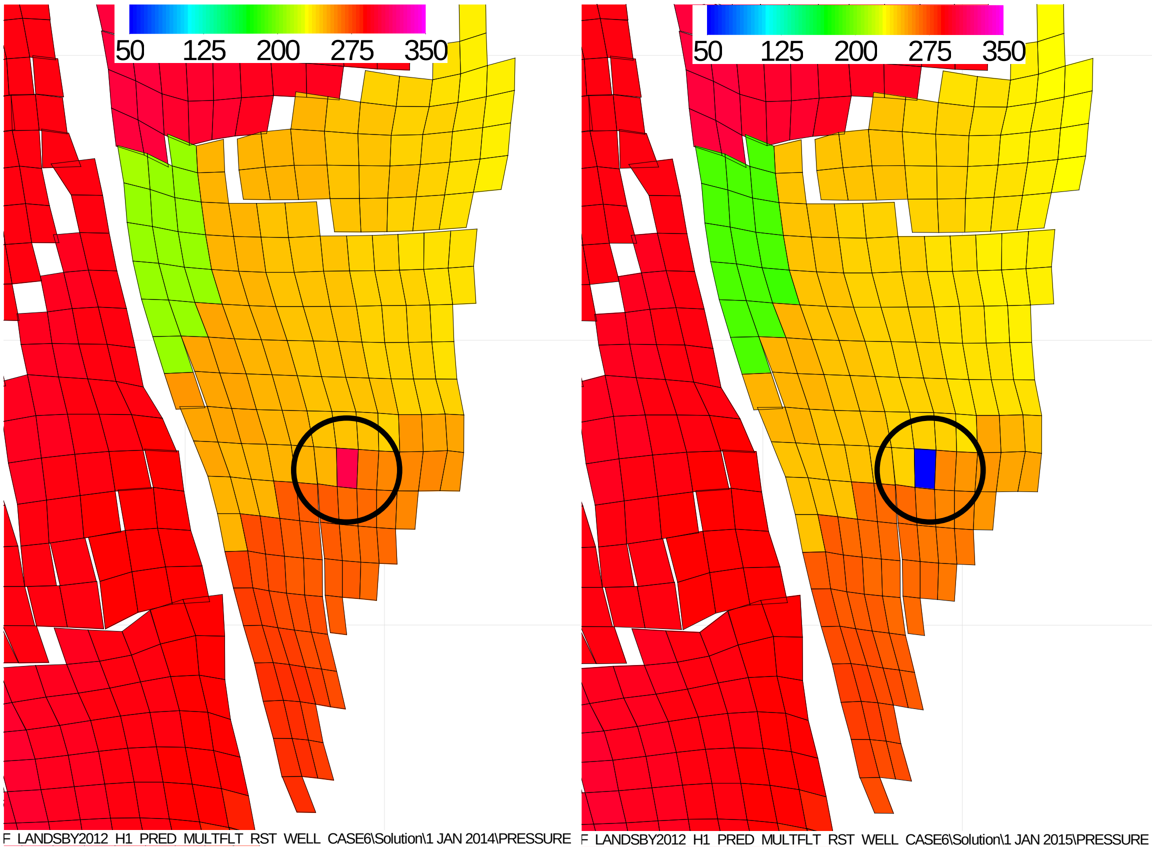
Case 2 and Case 3 Total Oil Production and Oil Production Rate (Field)
FOPT Case 2
FOPR Case 2
FOPT Case 3
FOPR Case 3
Oil production total (SM3)
Oil production rate (SM3/DAY)
1.70x10^7
1.65x10^7
1.60x10^7
1.55x10^7
1.50x10^7
1.45x10^7
800
700
600
500
400
300
200
01/12
01/13
01/14
01/15
01/16
01/17
01/18
01/19
01/20
01/21
01/22
01/23
01/24
01/25



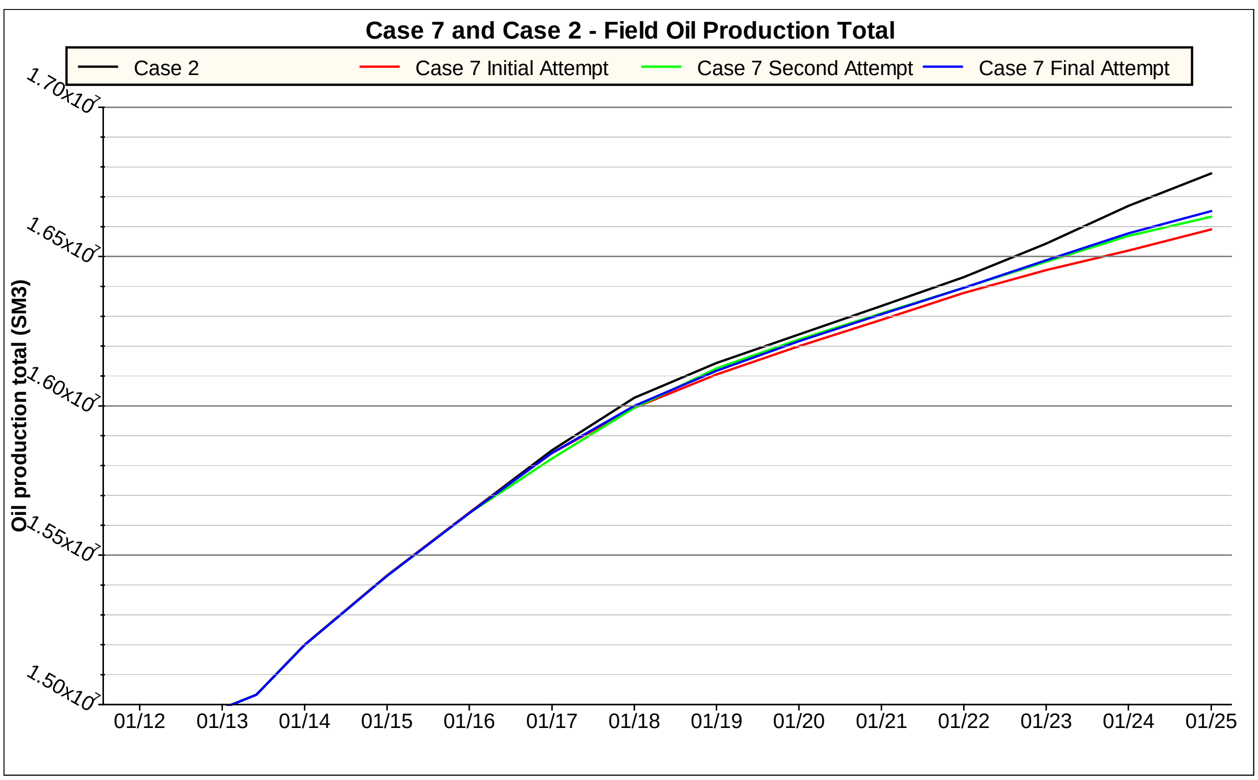
A-39A Case 2 and Case 4 - Well Oil Production Rate and Water Cut
WOPR A-39A Case 2
WWCT A-39A Case 2
WOPR A-39A Case 4
WWCT A-39A Case 4
Oil production rate (SM3/DAY)
Water cut
150
140
130
120
110
100
90
80
70
0.95
0.90
0.85
0.80
01/12
01/13
01/14
01/15
01/16
01/17
01/18
01/19
01/20
01/21
01/22
01/23
01/24
01/25

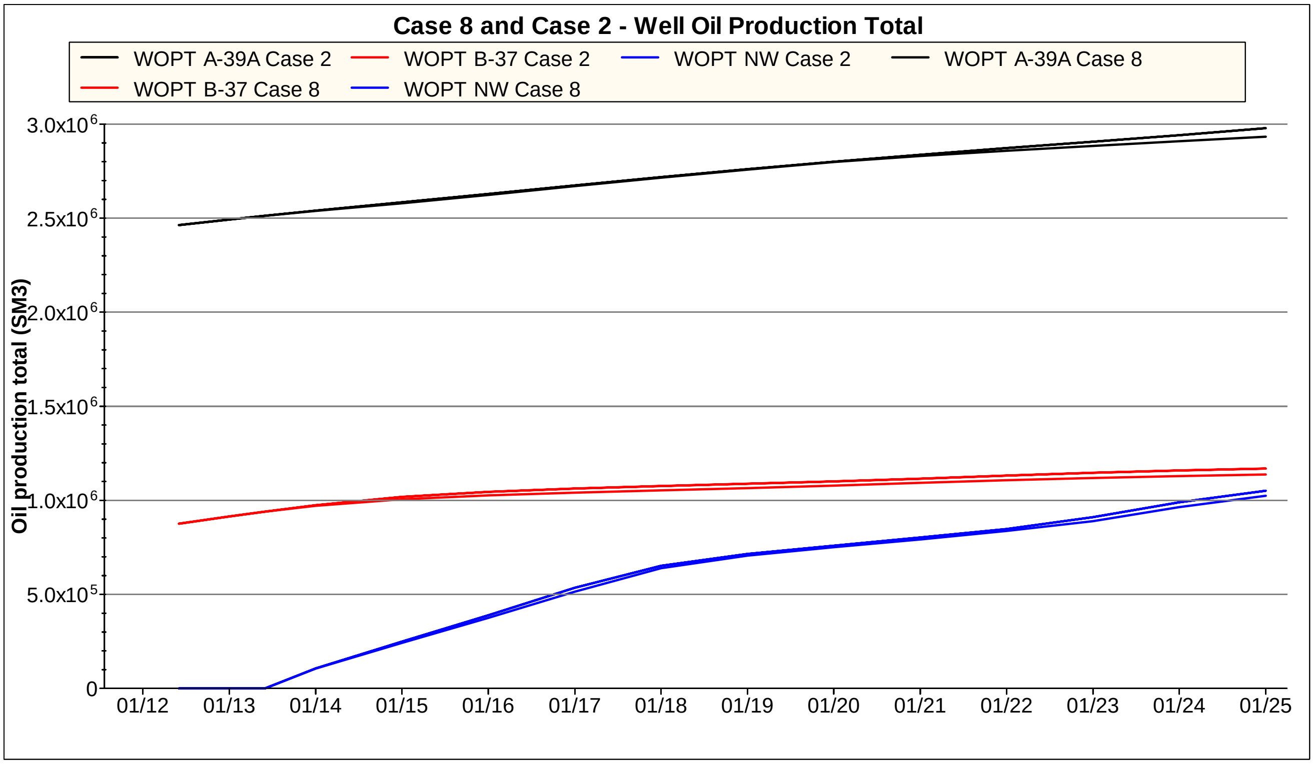

B-37 Case 2 and Case 5 - Well Oil Production Rate and Water Cut
WOPR B-37 Case 2
WWCT B-37 Case 2
WOPR B-37 Case 5
WWCT B-37 Case 5
Oil production rate (SM3/DAY)
Water cut
0
100
200
300
400
500
600
700
800
0.4
0.5
0.6
0.7
0.8
0.9
1.0
01/12
01/13
01/14
01/15
01/16
01/17
01/18
01/19
01/20
01/21
01/22
01/23
01/24
01/25

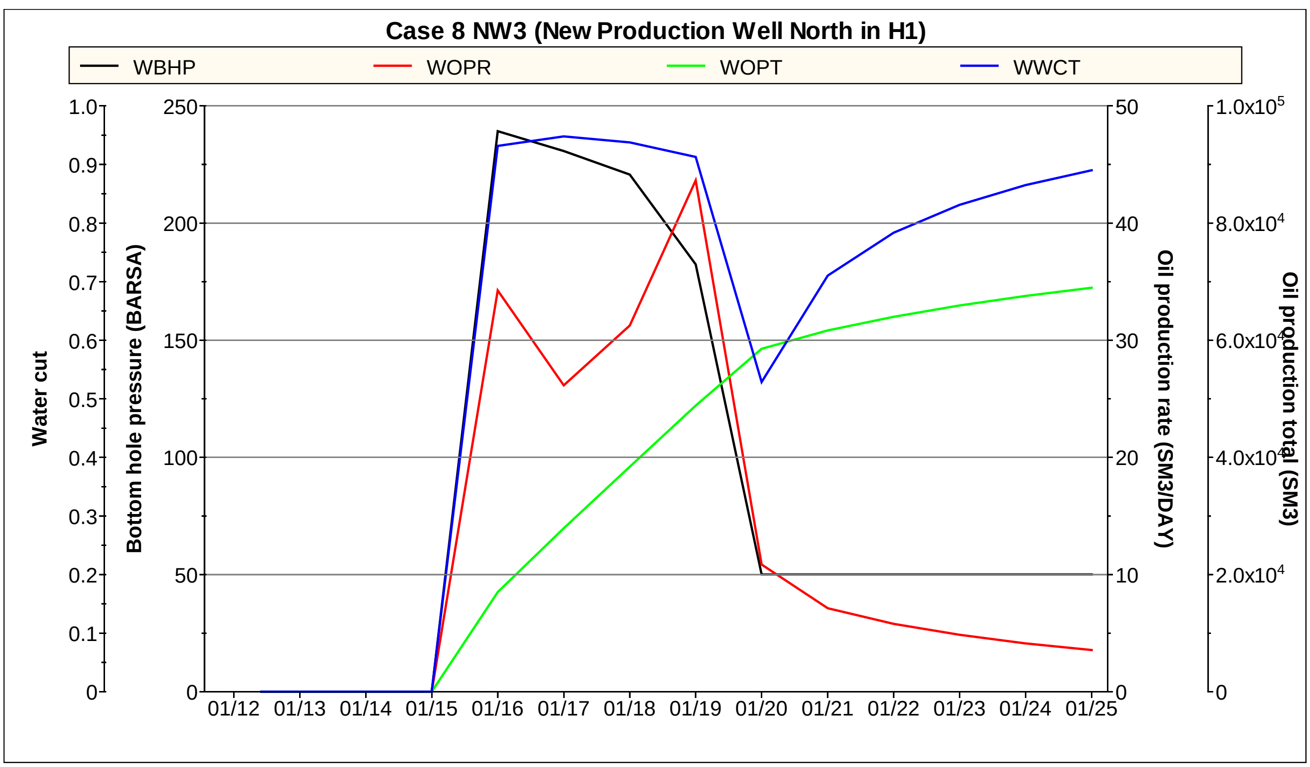

Case 6 NW2 (New Well 2) Well Total Oil Production (WOPT)
Oil production total (SM3)
0
5000
10000
15000
20000
01/12
01/13
01/14
01/15
01/16
01/17
01/18
01/19
01/20
01/21
01/22
01/23
01/24
01/25

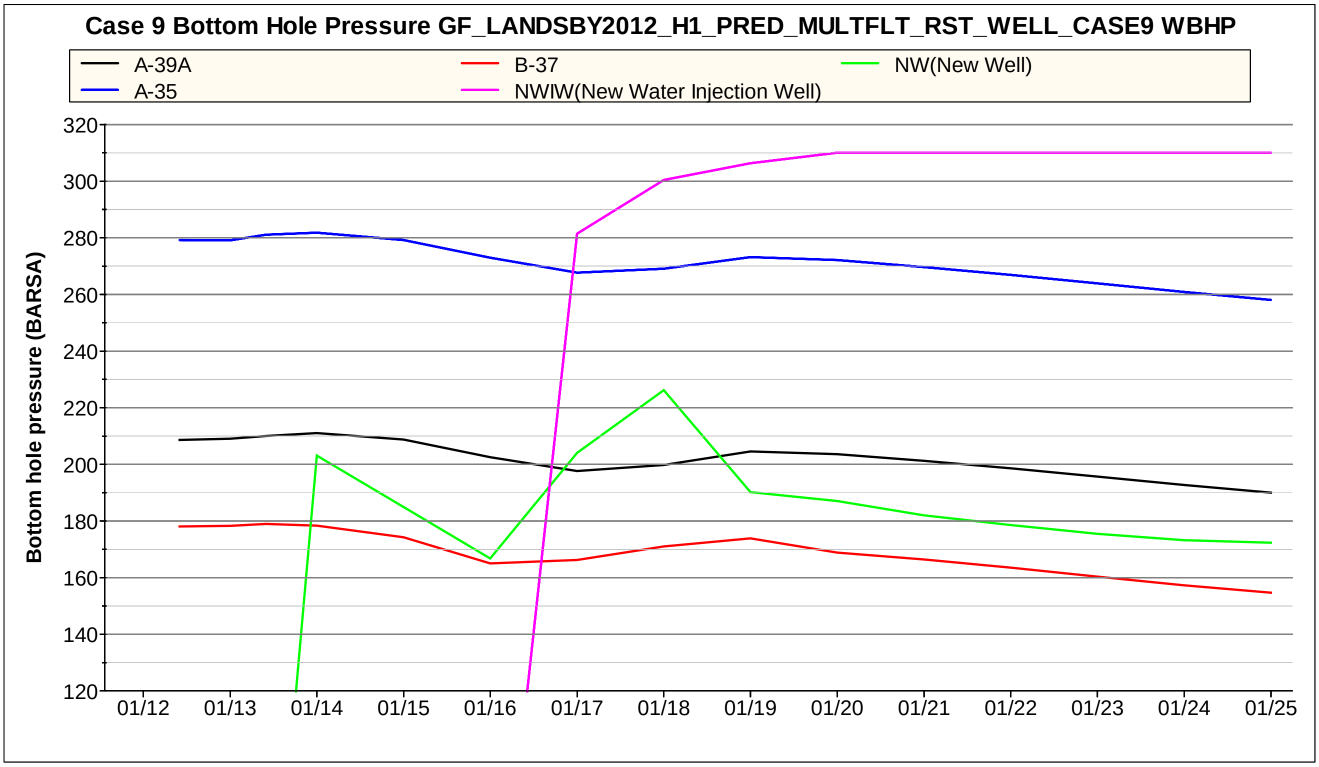


Case 6, layer 44, pressure in isolated grid block in January 2014 and January 2015, drops from around 310 bar to 50 bar after production well (NW2) was placed.

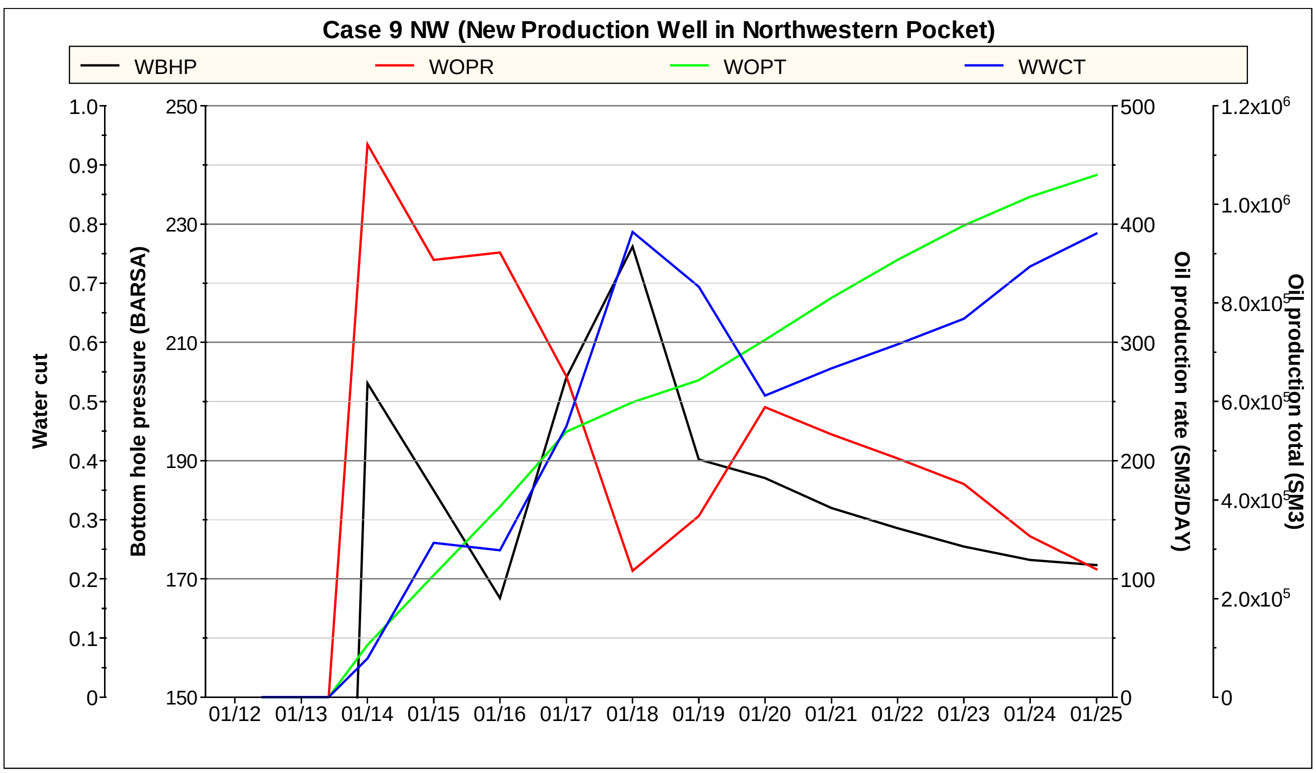



Case 8 and Case 2 - Well Oil Production Total
WOPT A-39A Case 2
WOPT B-37 Case 2
WOPT NW Case 2
WOPT A-39A Case 8
WOPT B-37 Case 8
WOPT NW Case 8
Oil production total (SM3)
3.0x10^6
2.5x10^6
2.0x10^6
1.5x10^6
1.0x10^6
5.0x10^5
0
01/12 01/13 01/14 01/15 01/16 01/17 01/18 01/19 01/20 01/21 01/22 01/23 01/24 01/25

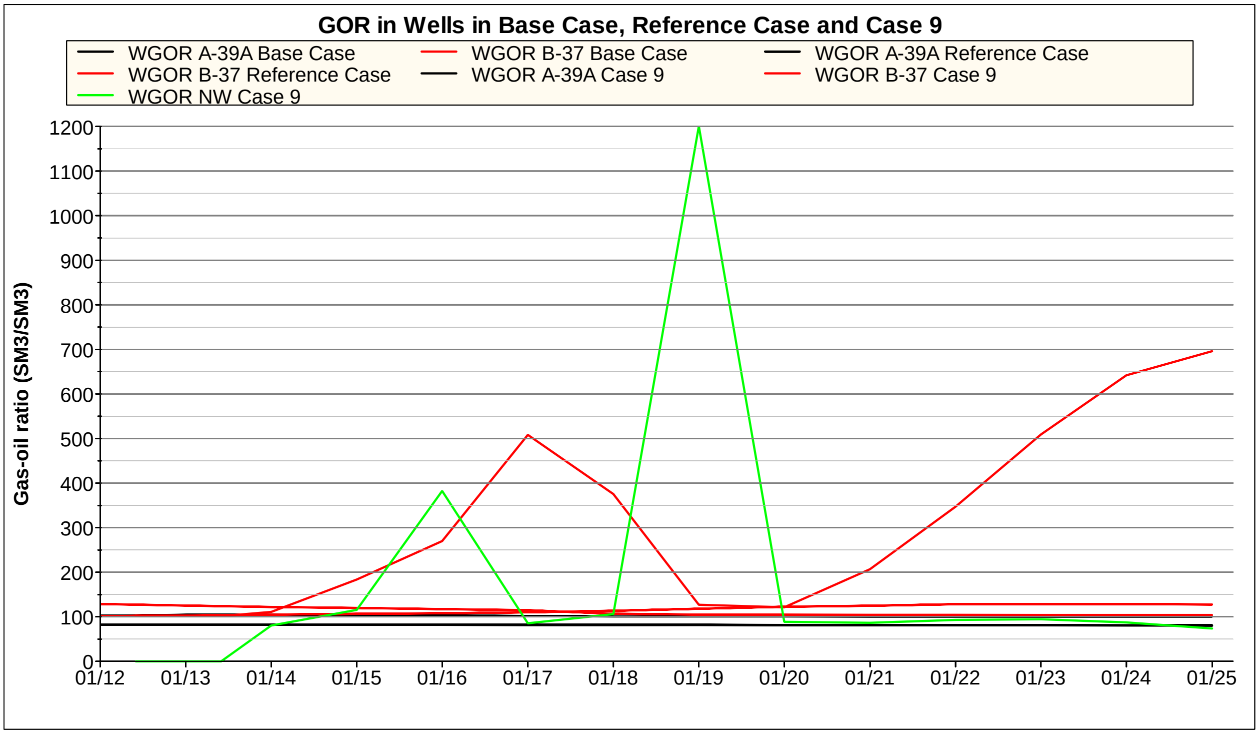

Case 8 NW3 (New Production Well North in H1)
WBHP
WOPR
WOPT
WWCT
Water cut
Bottom hole pressure (BARSA)
Oil production rate (SM3/DAY)
Oil production total (SM3)
1.0 0.9 0.8 0.7 0.6 0.5 0.4 0.3 0.2 0.1 0
250 200 150 100 50 0
50 40 30 20 10 0
1.0x10^5
8.0x10^4
6.0x10^4
4.0x10^4
2.0x10^4
0
01/12 01/13 01/14 01/15 01/16 01/17 01/18 01/19 01/20 01/21 01/22 01/23 01/24 01/25

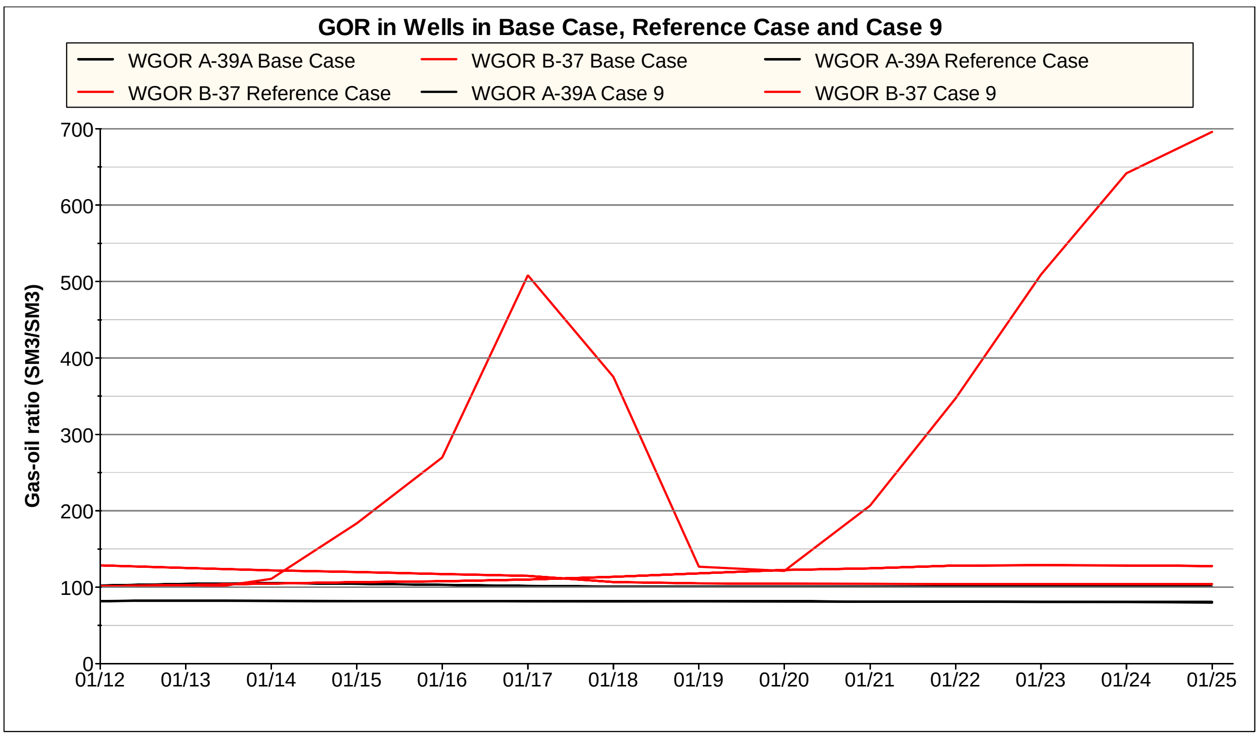


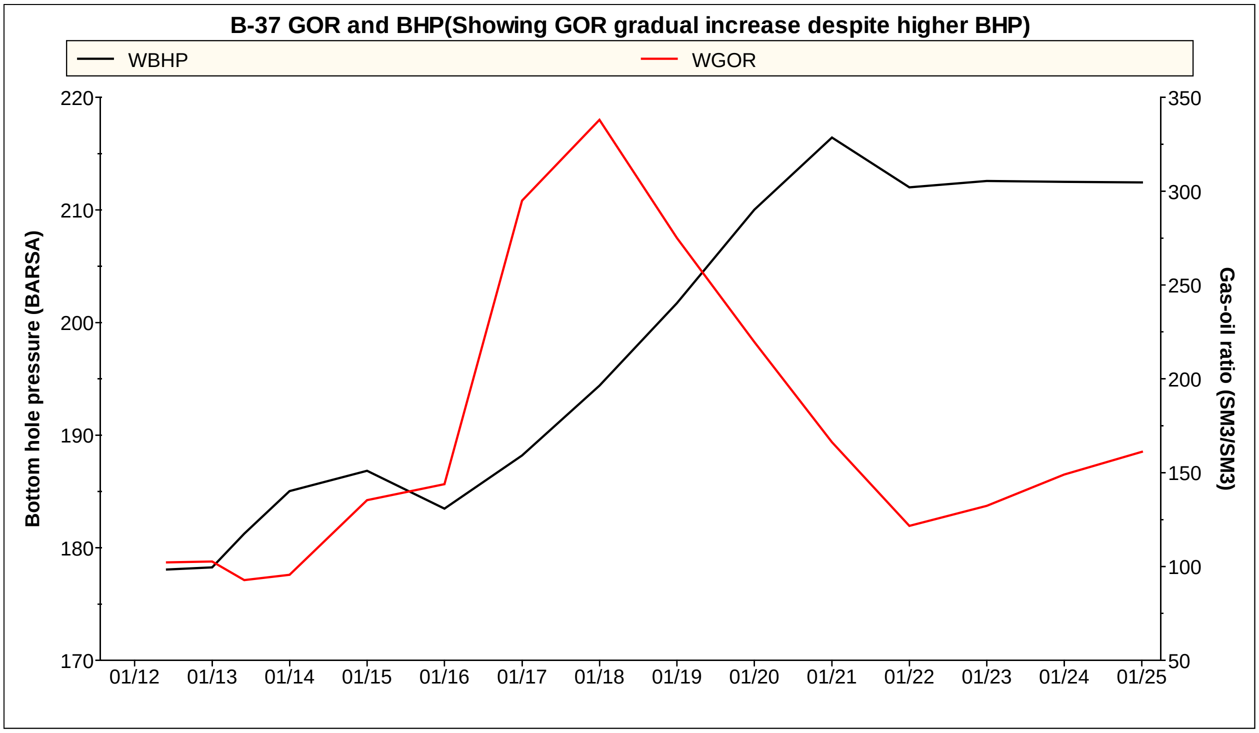
Case 9 Bottom Hole Pressure GF_LANDSBY2012_H1_PRED_MULTFLT_RST_WELL_CASE9 WBHP
A-39A
A-35
B-37
NWIW(New Water Injection Well)
NW(New Well)
Bottom hole pressure (BARSA)
01/12 01/13 01/14 01/15 01/16 01/17 01/18 01/19 01/20 01/21 01/22 01/23 01/24 01/25

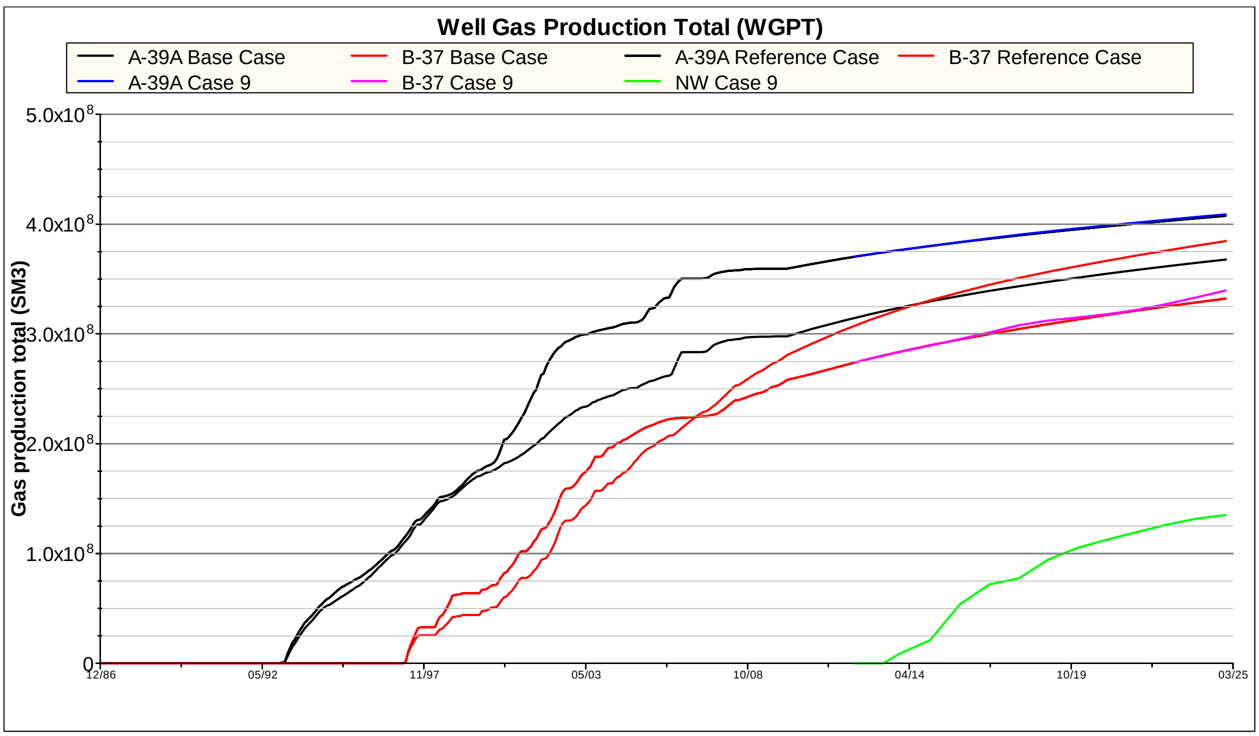


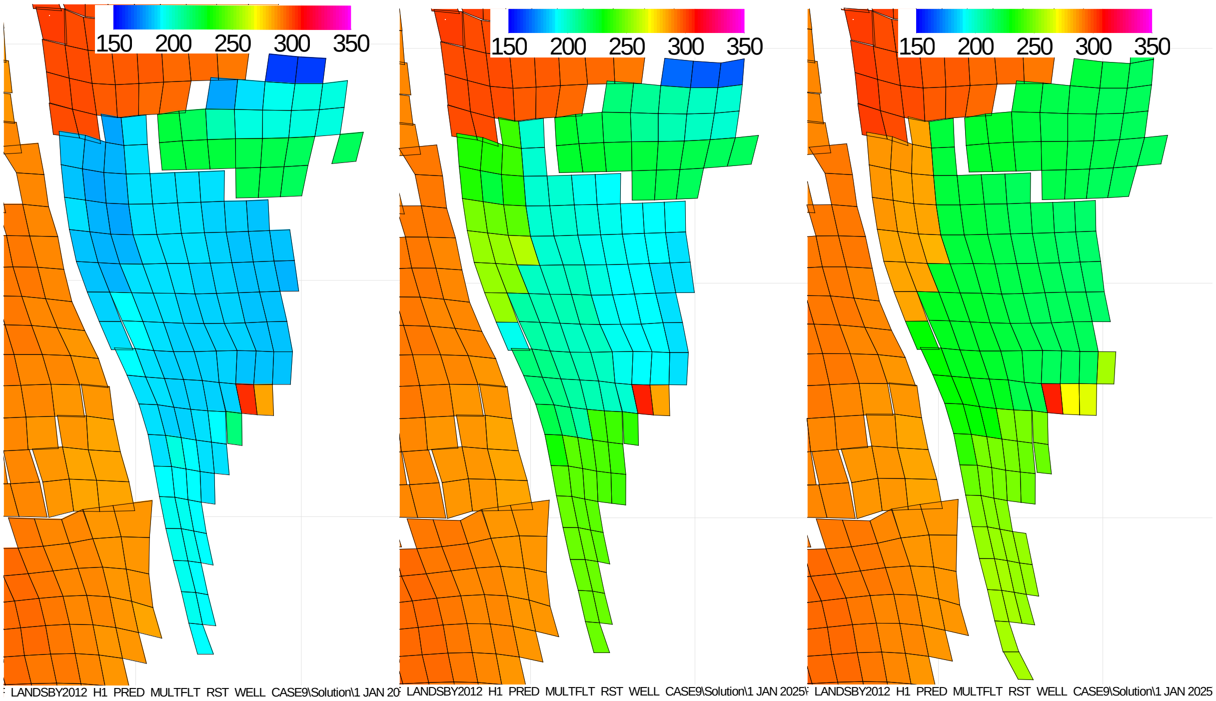
Case 9 NW (New Production Well in Northwestern Pocket)
WBHP
WOPR
WOPT
WWCT
Water cut
Bottom hole pressure (BARSA)
Oil production rate (SM3/DAY)
Oil production total (SM3)
01/12 01/13 01/14 01/15 01/16 01/17 01/18 01/19 01/20 01/21 01/22 01/23 01/24 01/25


GOR in Wells in Base Case, Reference Case and Case 9
WGOR A-39A Base Case
WGOR B-37 Base Case
WGOR A-39A Reference Case
WGOR B-37 Reference Case
WGOR A-39A Case 9
WGOR B-37 Case 9
WGOR NW Case 9
Gas-oil ratio (SM3/SM3)
0
100
200
300
400
500
600
700
800
900
1000
1100
1200
01/12
01/13
01/14
01/15
01/16
01/17
01/18
01/19
01/20
01/21
01/22
01/23
01/24
01/25

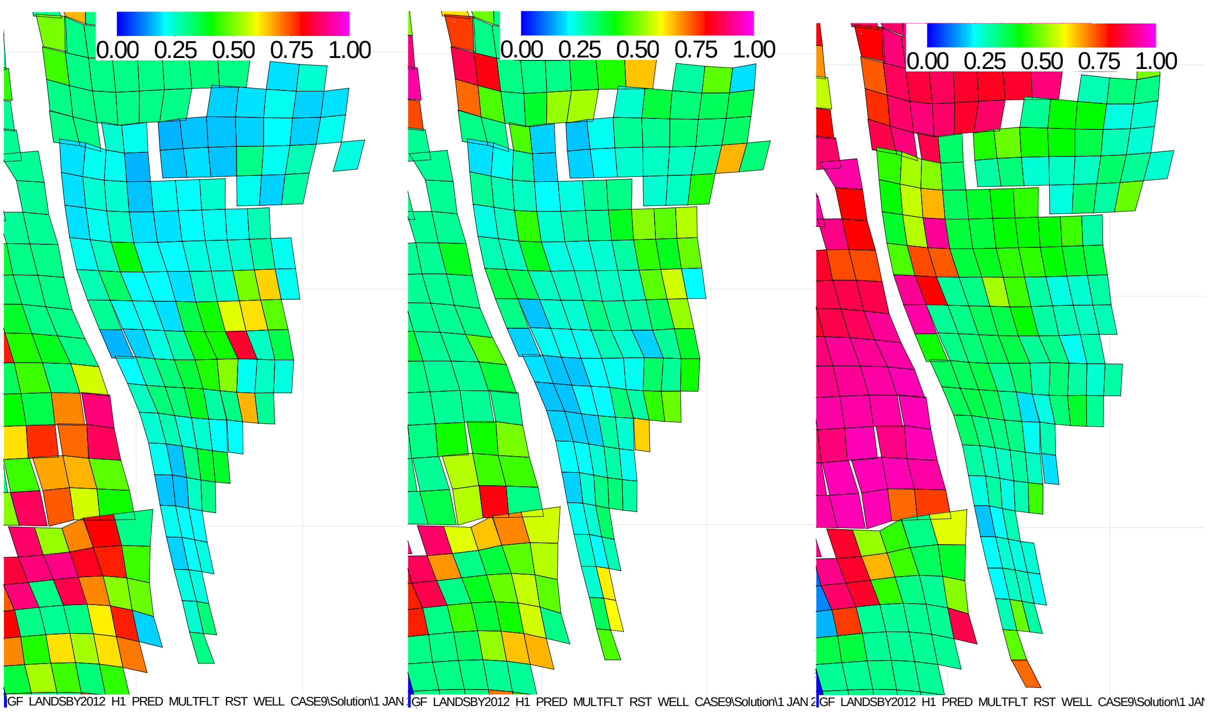

GOR in Wells in Base Case, Reference Case and Case 9
WGOR A-39A Base Case
WGOR B-37 Base Case
WGOR A-39A Reference Case
WGOR B-37 Reference Case
WGOR A-39A Case 9
WGOR B-37 Case 9
Gas-oil ratio (SM3/SM3)
0
100
200
300
400
500
600
700
01/12
01/13
01/14
01/15
01/16
01/17
01/18
01/19
01/20
01/21
01/22
01/23
01/24
01/25


B-37 GOR and BHP(Showing GOR gradual increase despite higher BHP)
WBHP
WGOR
Bottom hole pressure (BARSA)
Gas-oil ratio (SM3/SM3)
220
210
200
190
180
170
350
300
250
200
150
100
50
01/12
01/13
01/14
01/15
01/16
01/17
01/18
01/19
01/20
01/21
01/22
01/23
01/24
01/25


Well Gas Production Total (WGPT)
A-39A Base Case
B-37 Base Case
A-39A Reference Case
B-37 Reference Case
A-39A Case 9
B-37 Case 9
NW Case 9
Gas production total (SM3)
5.0x10^8
4.0x10^8
3.0x10^8
2.0x10^8
1.0x10^8
0
12/86
05/92
11/97
05/03
10/08
04/14
10/19
03/25



Case 9 pressure layer 34, 35 and 36 respectively, showing possible poor vertical communication.



Case 9 oil saturation layer 34, 35 and 36 respectively, also giving some indication of what the pressure shows.

7. Appendix B

Economic Evaluation

Assumptions			**Results**		
Oil prize	100	$/bbl	Net Present Value	1 831	MNOK
Discount rate	8 %		Internal Rate of Return	195 %	
Inflation rate	0 %		Total Value (in 2012NOK)	2 771	
Dollar exchange rate	5,8	NOK/USD			
Volume conversion	6,2898	bbl/m^3			
1bbl	0,15898	m^3			

Year		**CAPEX Well Cost**	**Production Oil**	**Oil**	**Price Oil**	**Value Oil**	**Annual PV**	**NPV**
Date	**Number**	**MNOK**	**SM^3**	**BBL**	**NOK/ BBL**	**MNOK**	**MNOK**	**MNOK**
Total		**400**	**869 210**	**5 467 166**		**2 771**	**1 831**	
	0	200	0	0		-200	-200	- 200
2013	1	-	104 590	657 851	580	382	353	153
2014	2	-	129 610	815 222	580	473	405	559
2015	3	200	116 600	733 392	580	225	179	738
2016	4	-	127 390	801 259	580	465	342	1 079
2017	5	-	35 240	221 653	580	129	87	1 167
2018	6	-	25 450	160 076	580	93	59	1 225
2019	7	-	70 930	446 136	580	259	151	1 376
2020	8	-	72 000	452 866	580	263	142	1 518
2021	9	-	61 850	389 025	580	226	113	1 631
2022	10	-	53 930	339 209	580	197	91	1 722
20	11	-	42 740	268 827	580	156	67	1 789

23								
20 24	12	-	28 880	181 650	580	105	42	1 831

8. Appendix C

Original SCHEDULE-file for base case and reference case

```
-- Prediction for H1 --------------------------------------------------
-- METRIC UNITS
-- SIMULATION START DATE 1 'DEC' 1986

WCONINJE
    'A-35'     'WATER'  1*      'RATE'   2500  1*   320.000  3* /
/

WCONPROD
    'A-39A'      'OPEN'      'LRAT'    3*   1000 1* 50    /
     'B-37'      'OPEN'      'LRAT'    3*   1500 1* 50   /
/

DATES
 1 'JAN' 2011 /
/

DATES
 1 'JAN' 2012 /
/

WTRACER
 'A-35' 'EOR' 10000 /
 /

DATES
 10 'JAN' 2012 /
/

WTRACER
 'A-35' 'EOR' 0 /
 /

DATES
 1 'JUN' 2012 /
/

DATES
 2 'JUN' 2012 /
/

DATES
 1 'JAN' 2013 /
/

DATES
 1 'JUN' 2013 /
/

DATES
 1 'JAN' 2014 /
/

DATES
 1 'JAN' 2015 /
/

DATES
 1 'JAN' 2016 /
```

```
/

DATES
 1 'JAN' 2017 /
/

DATES
 1 'JAN' 2018 /
/

DATES
 1 'JAN' 2019 /
/

DATES
 1 'JAN' 2020 /
/

DATES
 1 'JAN' 2021 /
/

DATES
 1 'JAN' 2022 /
/

DATES
 1 'JAN' 2023 /
/

DATES
 1 'JAN' 2024 /
/

DATES
 1 'JAN' 2025 /
/

-- END OF SIMULATION
```

For cases 1 to 9 only date points with changes from the original SCHEDULE-file is shown. Omissions of code are marked by "……"

Case 1 SCHEDULE-file changes

```
......

DATES
 1 'JUN' 2012 /
/
WELSPECS
'NW' 'H1' 37 74 1* 'OIL'/
/
COMPDAT
-- WELL I J K1 K2    Sat.  CF  DIAM   KH SKIN ND   DIR   Ro
'NW' 37 74 30 39 'OPEN' 2*  0.178/
/
WCONPROD
'NW' 'OPEN' 'LRAT' 3* 500 1* 50 /
/

......
```

Case 2 SCHEDULE-file changes

```
......

DATES
 1 'JUN' 2013 /
/
WELSPECS
'NW' 'H1' 37 74 1* 'OIL'/
/
COMPDAT
-- WELL I J K1 K2    Sat.  CF  DIAM   KH SKIN ND   DIR   Ro
'NW' 37 74 30 39 'OPEN' 2*  0.178/
/
WCONPROD
'NW' 'OPEN' 'LRAT' 3* 500 1* 50 /
/
WECON
'NW' 1* 1* 0.8 1* 1* CON N/
/

......

DATES
 1 'JAN' 2016 /
/
WELSPECS
'NWIW' 'H1' 36 78 1* 'WATER'/
/
COMPDAT
-- WELL I J K1 K2    Sat.  CF  DIAM   KH SKIN ND   DIR   Ro
'NWIW' 36 78 44 49 'OPEN' 2*  0.178/
/
WCONINJE
'NWIW'       'WATER'  1*      'RATE'     500       1*   310.000  3* /
/
WTEMP
'NWIW' 25 /
/
```

Case 3 SCHEDULE-file changes

```
......

DATES
 1 'JUN' 2013 /
/
WELSPECS
'NW' 'H1' 37 74 1* 'OIL'/
/
COMPDAT
-- WELL I J K1 K2    Sat.  CF  DIAM   KH SKIN ND   DIR   Ro
'NW' 37 74 30 39 'OPEN' 2*  0.178/
/
WCONPROD
'NW' 'OPEN' 'LRAT' 3* 500 1* 50 /
/
WECON
'NW' 1* 1* 0.8 1* 1* CON N/
/

DATES
 1 'JAN' 2014 /
/
WELSPECS
'NWIW2' 'H1' 36 81 1* 'WATER'/
/
COMPDAT
-- WELL I J K1 K2    Sat.  CF  DIAM   KH SKIN ND   DIR   Ro
'NWIW2' 36 81 46 49 'OPEN' 2*  0.178/
/
WCONINJE
'NWIW2'       'WATER'  1*      'RATE'    1500       1*   310.000  3* /
/
WTEMP
'NWIW2' 25 /
/

......

DATES
 1 'JAN' 2016 /
/
WELSPECS
'NWIW' 'H1' 36 78 1* 'WATER'/
/
COMPDAT
-- WELL I J K1 K2    Sat.  CF  DIAM   KH SKIN ND   DIR   Ro
'NWIW' 36 78 44 49 'OPEN' 2*  0.178/
/
WCONINJE
'NWIW'       'WATER'  1*      'RATE'     500       1*   310.000  3* /
/
WTEMP
'NWIW' 25 /
/

......
```

Case 4 SCHEDULE-file changes

```
......

DATES
 1 'JUN' 2012 /
/
COMPDAT
-- WELL I J K1 K2    Sat.  CF  DIAM   KH SKIN ND   DIR   Ro
    'A-39A'   46   81   44   44      'OPEN'  2*      0.178 3* 'Y' /
    'A-39A'   46   81   45   46      'OPEN'  2*      0.178  /
    'A-39A'   46   80   46   46      'OPEN'  2*      0.178 3* 'Y' /
    'A-39A'   47   80   46   46      'OPEN'  2*      0.178 3* 'X' /
/
WECON
'A-39A' 1* 1* 0.90 1* 1* CON N 2* 0.99 CON /
/

......

DATES
 1 'JUN' 2013 /
/
WELSPECS
'NW' 'H1' 37 74 1* 'OIL'/
/
COMPDAT
-- WELL I J K1 K2    Sat.  CF  DIAM   KH SKIN ND   DIR   Ro
'NW' 37 74 30 39 'OPEN' 2*  0.178/
/
WCONPROD
'NW' 'OPEN' 'LRAT' 3* 500 1* 50 /
/
WECON
'NW' 1* 1* 0.8 1* 1* CON N/
/

......

DATES
 1 'JAN' 2016 /
/
WELSPECS
'NWIW' 'H1' 36 78 1* 'WATER'/
/
COMPDAT
-- WELL I J K1 K2    Sat.  CF  DIAM   KH SKIN ND   DIR   Ro
'NWIW' 36 78 44 49 'OPEN' 2*  0.178/
/
WCONINJE
'NWIW'       'WATER'  1*      'RATE'     500       1*   310.000  3* /
/
WTEMP
'NWIW' 25 /
/

......
```

Case 5 SCHEDULE-file changes

```
......

DATES
 1 'JUN' 2012 /
/
COMPDAT
-- WELL        I    J    K1  K2            Sat.        CF       DIAM        KH
SKIN ND        DIR   Ro
     'B-37'   48   68   49   49      'OPEN'  2*     0.178 3* 'X' /
     'B-37'   48   68   48   48      'OPEN'  2*     0.178  /
     'B-37'   48   69   48   48      'OPEN'  2*     0.178  3* 'Y' /
     'B-37'   48   69   46   47      'OPEN'  2*     0.178  /
     'B-37'   47   69   46   46      'OPEN'  2*     0.178  3* 'X' /
     'B-37'   47   69   41   45      'OPEN'  2*     0.178  /
/
WECON
'B-37' 1* 1* 0.90 1* 1* CON N 2* 0.99 CON /
/

......

DATES
 1 'JUN' 2013 /
/
WELSPECS
'NW' 'H1' 37 74 1* 'OIL' /
/
COMPDAT
-- WELL I J K1 K2    Sat.  CF  DIAM   KH SKIN ND   DIR   Ro
'NW' 37 74 30 39 'OPEN' 2*  0.178/
/
WCONPROD
'NW' 'OPEN' 'LRAT' 3* 500 1* 50 /
/
WECON
'NW' 1* 1* 0.8 1* 1* CON N/
/

......

DATES
 1 'JAN' 2016 /
/
WELSPECS
'NWIW' 'H1' 36 78 1* 'WATER'/
/
COMPDAT
-- WELL I J K1 K2    Sat.  CF  DIAM   KH SKIN ND   DIR   Ro
'NWIW' 36 78 44 49 'OPEN' 2*  0.178/
/
WCONINJE
'NWIW'       'WATER'  1*      'RATE'     500       1*   310.000  3* /
/
WTEMP
'NWIW' 25 /
/

......
```

Case 6 SCHEDULE-file changes

```
......

DATES
 1 'JUN' 2013 /
/
WELSPECS
'NW' 'H1' 37 74 1* 'OIL'/
/
COMPDAT
-- WELL I J K1 K2    Sat.  CF  DIAM   KH SKIN ND   DIR   Ro
'NW' 37 74 30 39 'OPEN' 2*  0.178/
/
WCONPROD
'NW' 'OPEN' 'LRAT' 3* 500 1* 50 /
/
WECON
'NW' 1* 1* 0.8 1* 1* CON N/
/

DATES
 1 'JAN' 2014 /
/
WELSPECS
'NW2' 'H1' 42 81 1* 'OIL'/
/
COMPDAT
-- WELL I J K1 K2    Sat.  CF  DIAM   KH SKIN ND   DIR   Ro
'NW2' 42 81 38 49 'OPEN' 2*  0.178/
/
WCONPROD
'NW2' 'OPEN' 'LRAT' 3* 500 1* 50 /
/

DATES
 1 'JAN' 2015 /
/

DATES
 1 'JAN' 2016 /
/
WELSPECS
'NWIW' 'H1' 36 78 1* 'WATER'/
/
COMPDAT
-- WELL I J K1 K2    Sat.  CF  DIAM   KH SKIN ND   DIR   Ro
'NWIW' 36 78 44 49 'OPEN' 2*  0.178/
/
WCONINJE
'NWIW'       'WATER'  1*      'RATE'     500       1*   310.000  3* /
/
WTEMP
'NWIW' 25 /
/

......
```

Case 7 SCHEDULE-file changes

```
......

DATES
 1 'JUN' 2013 /
/
WELSPECS
'NW' 'H1' 37 74 1* 'OIL'/
/

COMPDAT
-- WELL I J K1 K2    Sat.  CF  DIAM   KH SKIN ND   DIR   Ro
'NW' 37 74 30 45 'OPEN' 2*  0.178/
/

WCONPROD
'NW' 'OPEN' 'LRAT' 3* 500 1* 50 /
/

WECON
'NW' 1* 1* 0.8 1* 1* CON N/
/

......

DATES
 1 'JAN' 2016 /
/
WELSPECS
'NW' 'H1' 37 74 1* 'WATER'/
/
COMPDAT
-- WELL I J K1 K2    Sat.  CF  DIAM   KH SKIN ND   DIR   Ro
'NW' 37 74 44 49 'OPEN' 2*  0.178/
/
WCONINJE
'NW'       'WATER'  1*      'RATE'     500       1*   310.000  3* /
/
WTEMP
'NW' 25 /
/

WELSPECS
'NW2' 'H1' 36 78 1* 'OIL'/
/
COMPDAT
-- WELL I J K1 K2    Sat.  CF  DIAM   KH SKIN ND   DIR   Ro
'NW2' 36 78 30 47 'OPEN' 2*  0.178/
/
WCONPROD
'NW2' 'OPEN' 'LRAT' 3* 500 1* 50 /
/
WECON
'NW2' 1* 1* 0.8 1* 1* CON N/
/

......
```

Case 8 SCHEDULE-file changes

```
......

DATES
 1 'JAN' 2013 /
/
WCONINJE
    'A-35'     'WATER'  1*      'RATE'   3000  1*   320.000  3* /
/
DATES
 1 'JUN' 2013 /
/
WELSPECS
'NW' 'H1' 37 74 1* 'OIL'/
/
COMPDAT
-- WELL I J K1 K2    Sat.  CF  DIAM   KH SKIN ND   DIR   Ro
'NW' 37 74 30 39 'OPEN' 2*  0.178/
/
WCONPROD
'NW' 'OPEN' 'LRAT' 3* 500 1* 50 /
/
WECON
'NW' 1* 1* 0.8 1* 1* CON N/
/

......
DATES
 1 'JAN' 2015 /
/
WELSPECS
'NW3' 'H1' 42 73 1* 'OIL'/
/
COMPDAT
-- WELL I J K1 K2    Sat.  CF  DIAM   KH SKIN ND   DIR   Ro
'NW3' 42 73 42 49 'OPEN' 2*  0.178/
/
WCONPROD
'NW3' 'OPEN' 'LRAT' 3* 500 1* 50 /
/
WECON
'NW3' 1* 1* 0.95 1* 1* CON N/
/

DATES
 1 'JAN' 2016 /
/
WELSPECS
'NWIW' 'H1' 36 78 1* 'WATER'/
/
COMPDAT
-- WELL I J K1 K2    Sat.  CF  DIAM   KH SKIN ND   DIR   Ro
'NWIW' 36 78 44 49 'OPEN' 2*  0.178/
/
WCONINJE
'NWIW'       'WATER'  1*      'RATE'     500       1*   310.000  3* /
/
WTEMP
'NWIW' 25 /
/

......
```

Case 9 SCHEDULE-file changes

```
......

DATES
 1 'JAN' 2013 /
/
WCONINJE
    'A-35'     'WATER'  1*      'RATE'   2600  1*   320.000  3* /
/

DATES
 1 'JUN' 2013 /
/
WELSPECS
'NW' 'H1' 37 74 1* 'OIL'/
/
COMPDAT
-- WELL I J K1 K2    Sat.  CF  DIAM   KH SKIN ND   DIR   Ro
'NW' 37 74 30 39 'OPEN' 2*  0.178/
/
WCONPROD
'NW' 'OPEN' 'LRAT' 3* 500 1* 50 /
/
WECON
'NW' 1* 1* 0.8 1* 1* CON N/
/

......

DATES
 1 'JAN' 2016 /
/
WELSPECS
'NWIW' 'H1' 36 78 1* 'WATER'/
/
COMPDAT
-- WELL I J K1 K2    Sat.  CF  DIAM   KH SKIN ND   DIR   Ro
'NWIW' 36 78 44 49 'OPEN' 2*  0.178/
/
WCONINJE
'NWIW'       'WATER'  1*      'RATE'     900       1*   310.000  3* /
/
WTEMP
'NWIW' 25 /
/

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