Project Report
TPG-4851 Expert in Team
Gullfaks Village 2010

Group 5

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PREFACE

As early as 2000 *NTNU* and *Statoil* agreed on establishing an Experts in Team village at NTNU, where student groups are challenged to find new solutions to current problems related to the production in the Gullfaks Field.

In Gullfaks Village 2010, student groups are challenged to develop innovative recommendations that could increase the oil recovery by 10 % from Gullfaks Sør segment which is part of Gullfaks Satellite fields. It contains large oil volumes in both the Brent Group and the Statfjord Formation (Fm.). The Gullfaks Village 2010 shall focus on the Statfjord Formation.
This is the technical report presenting the results trying to enhance the oil recovery at Gullfaks Sør using different technologies for injection. Gas- , water- and WAG injection have all too some extent been tried out. Our biggest challenges have been to get to know the software and theory to be used, since none of us are reservoir engineers by heart. There have been a lot of work, but we have had fun doing it!

We would like to thank our supervisor at Statoil, Eli Gule, Jan Ivar Jensen and Jon Kleppe for giving us valuable feedback during the process. We would also like to thank Espen Rørvik, Ola T. Miljeteig, Christian Crescente and Bashir Hasanov for helping us out when our reservoir engineering skills was not sufficient.

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1 SUMMARY

The project is divided into two parts, Part A and Part B. In part A the main purpose was to demonstrate and understand the challenges related to Improved Oil Recovery (IOR) from a subsea development like Gullfaks Sør. The technology used in this part was gas injection. In addition an economical evaluation was made to evaluate the feasibility of this project.

In Part B the task was to improve the oil recovery at Gullfaks Sør with Water injection (WI) and Water alternating gas (WAG) by placing new injectors and producers. There have been done many cases with different well configuration and injection rates, trying to get the best possible result. These simulations were based on trial and error and the main objectives were to increase the oil production and to maintain a sustainable pressure in the reservoir.

The results from the WI simulations did show increased oil production compared to the Reference Case, but compared to the Extended Case (gas injection case, Part A) it is quite similar. The results from the WAG simulations show an increment in production of 10% compared with the best WI case. Based on these results from the production point of view, it is recommendable to implement WAG because it gives higher oil production, lower water cut and keeps the reservoir pressurized longer. Further economical analysis is required to take the decision for implementation.

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2 INTRODUCTION

The oil production on the Norwegian continental shelf and on the Gullfaks oil field is declining. Therefore there has been an increased focus on improved oil recovery (IOR). This project aims to find out whether water injection and/or water alternating gas injection as a technique for IOR is preferable for Statoil, when they are planning to expand with new wells on the Gullfaks Sør reservoir.

The project is divided into two parts; Part A and Part B. And the following chapters will introduce the parts separately.

In Part A each group worked with identical projects in order to get familiar and acquaint with the Gullfaks Sør segment. The main purpose is to demonstrate and understand the challenges related to Improved Oil Recovery (IOR) from a subsea development like Gullfaks Sør. The technology used in this part is gas injection.

In Part B each group has been given different assignments to solve. For this group the task has been to improve the oil recovery at Gullfaks Sør with Water injection and Water alternating gas (WAG) by placing new injectors and producers.

The biggest challenge met in this part of the assignment was on how the new injectors and producers should be placed in the field, and also getting to know the software to be used. There have been done many cases with different well configuration and injection rates, trying to get the best possible result.

The report contains an introduction to Gullfaks and Gullfaks Sør, followed by the results and discussions regarding task A and task B. In the end there is written a conclusion to summarize the task.

3 GENERAL DESCRIPTION OF GULLFAKS AREA

The following chapter contains a general description of the Gullfaks area.

3.1 Field Condition

Gullfaks is located in the Tampen area in the northern part of the North Sea. It was discovered in 1978 and the main field was put in production in 1986, with subsea wells producing to the GF-A platform, the first of three gravity base concrete platforms. Water depth is between 130 and 180 m. The GF-B and GF-C platforms were installed and started production in 1988 and 1990 respectively. GF-A and GF-C have integrated production and drilling, as well as water and gas injection facilities. GF-B has 1st stage separation only, with further fluid processing on GF-A and GF-C, and is without gas injection facilities. Following a three-stage separation process, the field gas production is exported by subsea pipeline to shore, where NGLs are removed, while the produced oil is stored offshore and exported by tankers, see Figure 1.

The field comprise of two main parts: the Gullfaks field (Gullfaks/GF) and the Gullfaks satellites (Gullfaks SAT/GF SAT). Gullfaks SAT consist of Gullfaks Sør, Rimfaks, Gullveig, Skinfaks and Gulltopp. Reservoir quality is generally very high, with permeability ranging from tens of mD to several Darcys depending on layer and location.

The Gullfaks main field is now on decline, and production is reduced by a third from the peak year 1994, when oil production exceeded 30 MSm^3. Recoverable oil reserves are currently estimated at 360 MSm^3, of which approximately 330 MSm^3 have been produced by the end of 2006. The uppermost Brent sequence contains roughly 80% of the reserves, with the deeper Cook and Statfjord formations contributing the remaining. The Gullfaks satellite production varies from field to field, but as a whole they are still at plateau producing 4 MSm^3 of oil and 4 GSm^3 of gas per year. Recoverable oil reserves are currently estimated at 50 MSm^3, of which approximately 27 MSm^3 have been produced by the end of 2006. In addition gas volumes of 17 GSm^3 have been produced to date.

The Gullfaks main field has been produced with pressure maintenance, mostly through water injection, but natural water influx has also contributed. Gas injection has been employed in the past to drain attic oil, but also to avoid reducing oil production during periods of restricted gas export. Gas flaring as a production control mechanism was eliminated in 1998. WAG injection is also being employed in parts of the field to improve vertical sweep. Large differences in reservoir quality between adjacent layers have in some parts of the field resulted in water override and inefficient vertical sweep. The dense fault pattern has necessitated close well spacing in some areas, which again; often combined with good internal reservoir quality, has resulted in rapid water and gas breakthrough in producers. A few wells are currently shut in due to high H_2S levels. Gullfaks satellite fields have been produced with pressure maintenance by gas for Rimfaks and to some extent Gullfaks Sør. Gullveig, Gulltopp and Skinfaks have water influx and are produced with natural depletion while Gimle will have water injection.

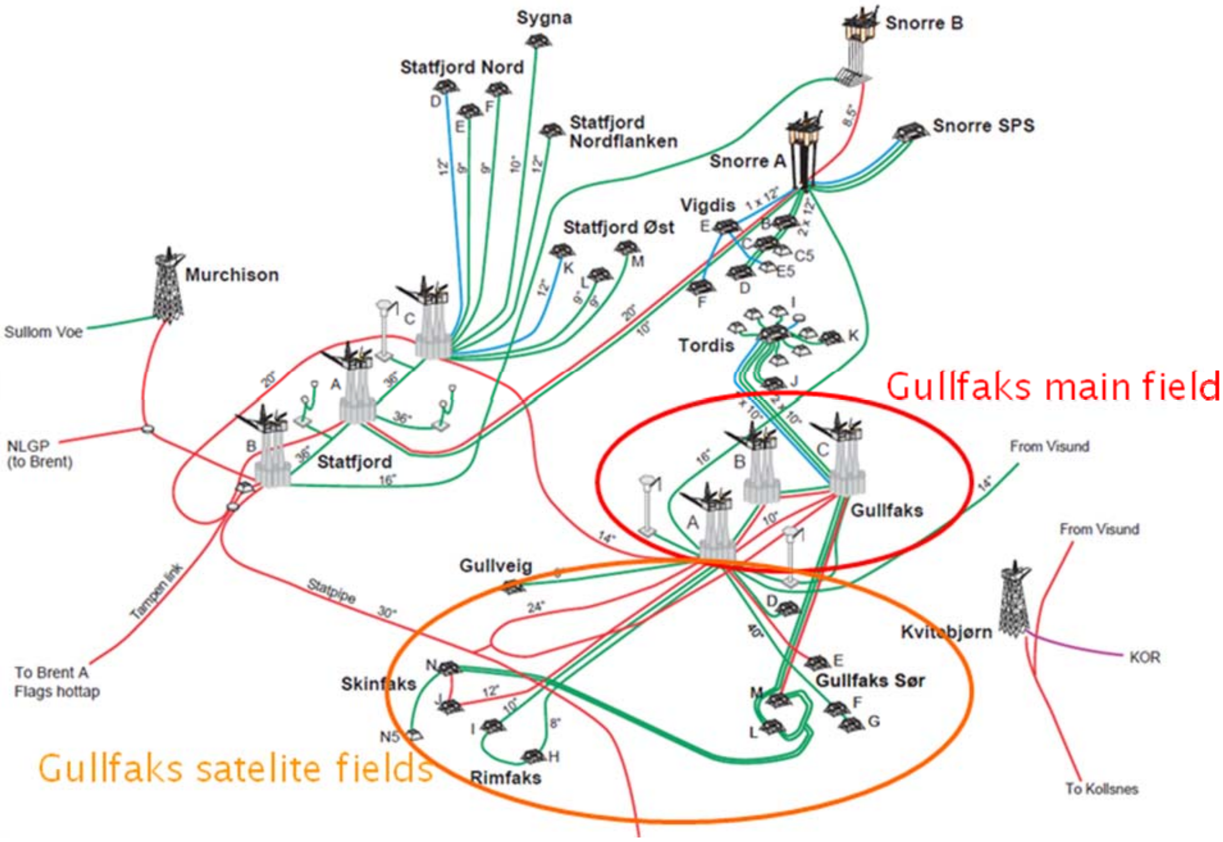


Figure 1 Gullfaks area

4 GENERAL DESCRIPTION OF GULLFAKS SØR [1], [2], [10]

The scope of this work, both in Part A and B, has been Gullfaks sør, Statfjord formation. In the following section there will be a closer introduction of the field and the formation worked on.

4.1 Geological History of the North Sea

The North-sea is a failed rift basin, which has been created through two rifting periods. It consists of several structural elements, see Figure 2. The group has chosen to focus on the creation of the Viking graben in the Northern-north-sea, which is where the Gullfaks sør field is located. The first rifting period took place in late-Permian - early Triassic when Pangea started to split up due to change from compression to extension. This provided us with tilted fault blocks in the Viking graben in a mainly North- South direction. This first period of rifting was followed by thermal subsidence of the basin. In the Middle-Jurassic the second rift period started, and listric faults were created in addition to reactivating of the old main faults. The early rifting was quite uniform and became more asymmetric in the later stages. The rifting direction went from being N-S oriented to have a more NØ-SW orientation, this caused already existing fault blocks to split up in smaller segments, and the rhomboid shaped fault blocks were created. The rotation of the fault blocks is towards the basin centre. When the rifting ended in Late-Jurassic- Early Cretaceous the lithosphere started cooling and the basin subsided because of this and deposition of the overlying sediments.

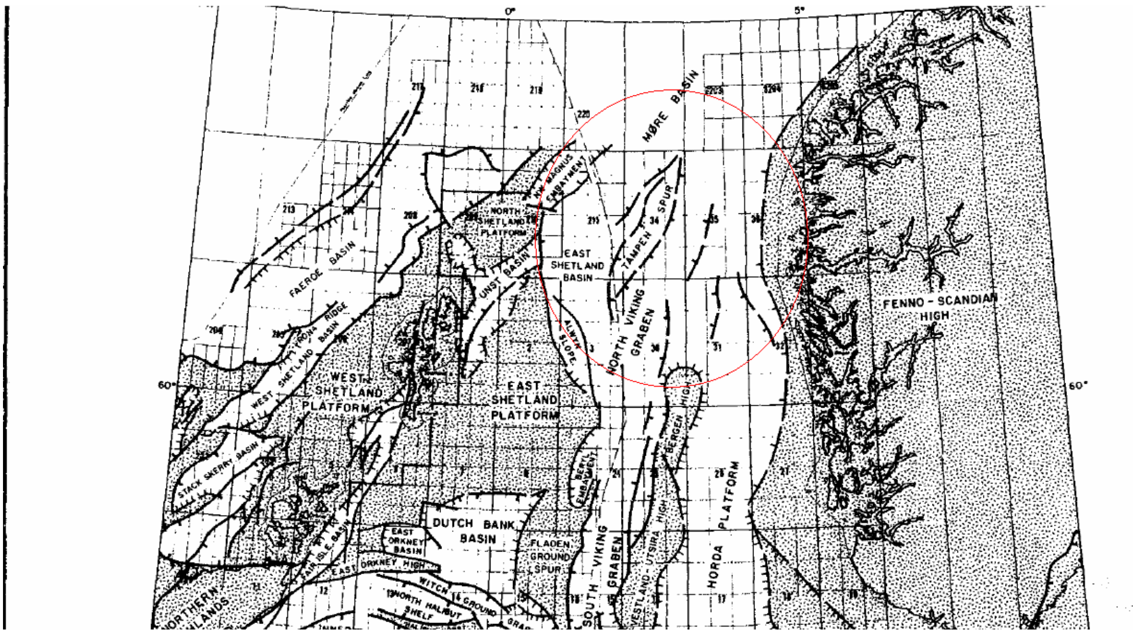


Figure 2 Structural elements of the North sea

4.2 Structural Geology of Gullfaks sør

The Gullfaks area is located on the western flank of the Viking graben, and the area is dominated by structures created in the latest rift period. The Gullfaks sør field is the deepest structural element of the Gullfaks satellites, and is a separate west rotated fault block. The field can be subdivided into three structural segments: the domino area, the transition area and the horst area, where the domino area makes up the west- and central parts of Gullfaks sør. This area consists of repeating east tilted fault blocks with layers tilting in a western direction. See Figure 3.

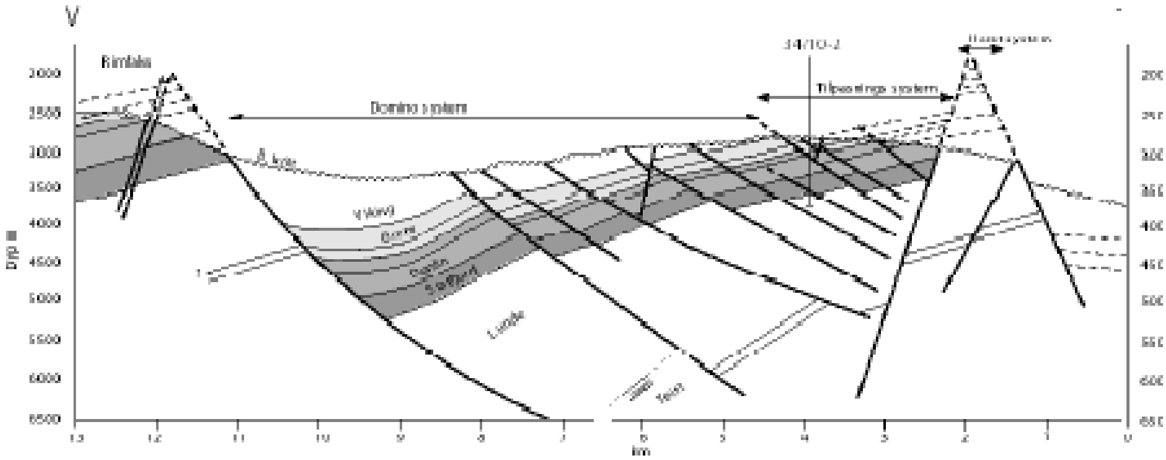


Figure 3 Gullfaks sør structure

Hydrocarbon system in Gullfaks Sør is shown in Table 1

Table 1 Hydrocarbon system in Gullfaks Sør

Reservoir	Gullfaks Sør
Brent Group	Oil with gas cap
Cook Formation	Hydrocarbons (Segment 23C)
Statfjord Formation	Oil with gas cap
Lunde Formation	Oil with gas cap

4.3 Reservoir Description of the Statfjord Formation

The lower part of the Statfjord formation was deposited on alluvial planes and in braided stream, while the upper part is deposited in a marine environment. This implies a transgression during the depositional period.

Statfjord is subdivided into three members: Raude, Eiriksson(1 and 2) and Nansen. The following section is focusing on each of the members and describing the rock and its reservoir quality.

Raude and Eiriksson 2:

Consists of alternating sand- and clay beddings with varying thickness and reservoir quality.

Nansen and Eiriksson 1:

Consists of massive, relative homogeneous high permeable (0.5-2D) sandstones inter bedded with shale and coal. Average thickness of the sand layers is approximately 5m, while average thickness of the shale is 2,5m.

The upper Statfjord (Nansen and Eirikson1) has an overall thickness in Gullfaks sør of 70-80m.

The lower Statfjord (Eiriksson2 and Raude) has an overall thickness in Gullfaks sør of 160-175m.

It is known from the production data that the pressure in the field has dropped quite rapidly, meaning there is poor communication between each segment. There has been found deformation band in connection with the faults, these minor faults has steps only on mm- cm scale, but that is enough to decrease the permeability and thereby the communication across faults.

4.4 Reservoir Quality

The quality of the sands is quite good, with permeability as follows:

- Good sands: 500-5000 mD
- Middle good sands: 100 – 500 mD
- Poor sands: 1-100 mD
- Net/gross 0.5 in the reservoir

The challenge is the connectivity internally between the sand bodies. The success of the pressure support depends upon the communication between the injected sand and the producing sand. Figure 4 shows a composite type log indicating the quality and variability of the various reservoirs.

4.5 Gullfaks Sør Statfjord – History

The in-place volumes in Gullfaks Sør are 40.6 MSm^3 of oil/condensate and 18.9 GSm^3 of gas. The field has produced 3.3 MSm^3 of oil/condensate to date - significantly less than the 12 MSm^3 anticipated in the Plan for field Development and Operation (PDO) from 1995. Gas production to date is 2.0 GSm^3 of which 0.2 GSm^3 has been re-injected. The field has been shut in since September 2008 due to low reservoir pressure. Gullfaks Sør Statfjord Fm. is shown on Figure 1 and it is produced by the E, F and G subsea templates tied back to the Gullfaks A platform.

Below is the history of Gullfaks Sør Statfjord:

- The Plan for Development and Operation (PDO) in Gullfaks Sør Statfjord was delivered in 1995. The field was planned to be produced by 7 wells with rates up to 2000 Sm^3/d and one injector, none of which were branch wells.
- In 1998, a new geological model came, and suggested a volume of 16.5 MSm^3 in reserves.
- In 1999, G-2 HT3 and F-4 T3H in production but it produce far less than expected (reserves downsized to ca. 5 MSm^3).
- In accordance to new/updated expectations, in 2001, G-3 T2H starts to produce oil.
- In 2002, Increase Oil Recovery (IOR) Project was started with recommendations that primary and secondary technology needed to increase oil recovery in Gullfaks Sør Statfjord is zone control (DIACS) and MLT with branch control respectively.
- Additional perforations of G-2 HT3 (03.-08.09.03) and F-4 H (21.-24.10.03) in lower Statfjord
- Drill new well G–1 H with DIACS (2003)

- Drill new well G–2 YH MLT with DIACS (2004)
- Drill new well F–2 YH MLT with DIACS (2004)
- Drill new well G-3YH, MLT with DIACS (2005)
- Drill new well E-1YH, gas injector (MLT) (2006).
  E-1 injecting for 8 months until a packer problem occured and injectivity lost.
- Field shut in (Oct 2008) to increase pressure and drill ability for remaining wells

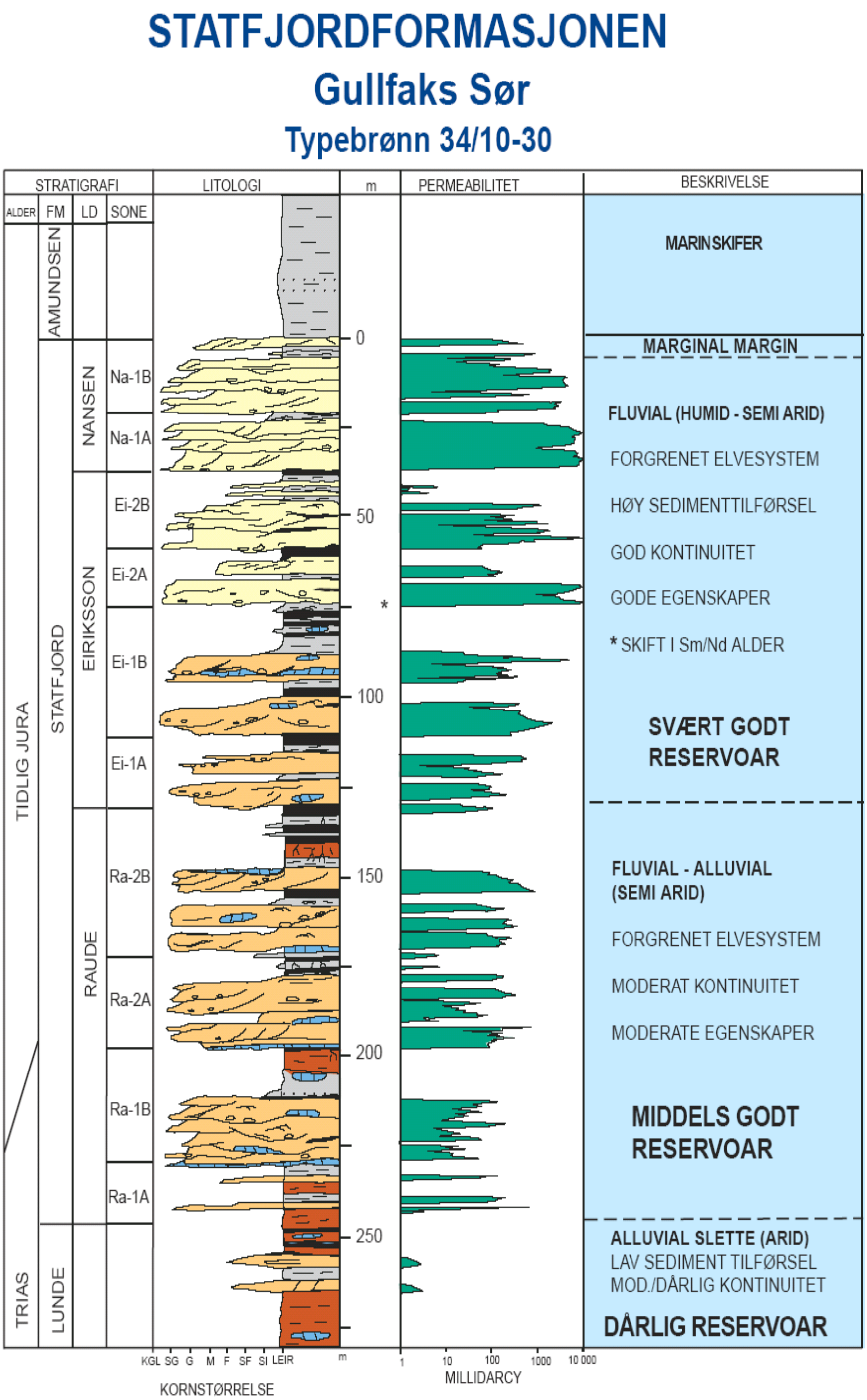


Figure 4 Composite log display of the Gullfaks Sør Reservoir

5 RESERVOIR SIMULATION – PART A

An Eclipse reservoir simulation model is provided by Statoil and each student group should run the model and plot and review the result. The simulations are conducted for Reference Case and Extended Case. Below are general information related to both cases.

5.1 Reference Case

- The simulation for Reference Case (base case) is started from 1998 until 2025 with 8 number of existing single wells i.e.: E-1 Y3H, F-2 ML, F-4 AT3H, G-1 H, G-2 ML, G-2 T3H, G-3 T2H, G-3 Y3HT4
- In addition to existing wells,
  - future wells G-4H and F-1 are included
  - future injectors E-2BH and E-3H are included
- 5 Wells producing from 2010:
  - F-2_ML, F-4AT3H, G-2_ML, G-4H and F-1
- Gas injection stopped on 1 October 2015
- G-4H and F-1 start oil rate lowered to 600 Sm3/d
- G-4H shut in after having produced 1.5 MSm3 oil in October 2017
- Blow down start from 2015 and the production is planned until1 January 2025
- The simulation is conducted for 3 formations in Statjford which are NANSEN-1B, NANSEN-1A, EIRIKSSON-2B, EIRIKSSON-2A, EIRIKSSON-1B, EIRIKSSON-1A, RAUDE -2B, RAUDE -2A, RAUDE -1B, RAUDE -1A.

5.2 Extended Case

- The simulation for Extended Case is started from 1999 until 2030
- Reference Case is used as basis (starting-point)
- In addition to existing wells, 6 new wells will be installed in 2015:
  - Installation of branched oil producers W2W3, W4W5, W6W7
  - Installation of single oil producer W1
  - Installation of injectors on existing E-template (GI-2, GI-4)
- Blow down start from 2025 and the production is planned until 1 January 2030

The position of the wells in the Extended Case simulation is shown on Figure 5.

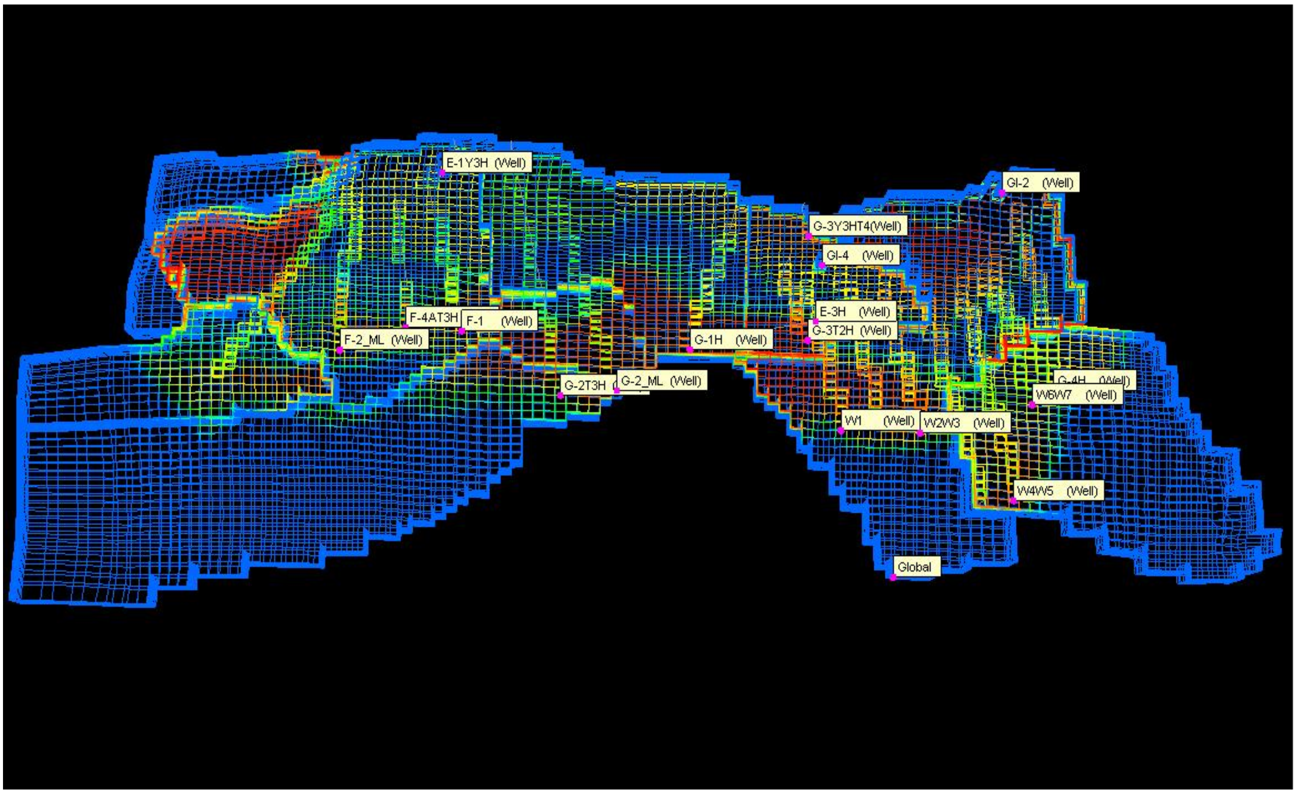


Figure 5 Position of the wells in the Extended Case simulation

6 SIMULATION RESULTS - PART A

The following chapter contains the results from the simulation of the Extended Case.

6.1 History matching in base case

This subchapter contains a comparison between the actual history data and the reference simulation.

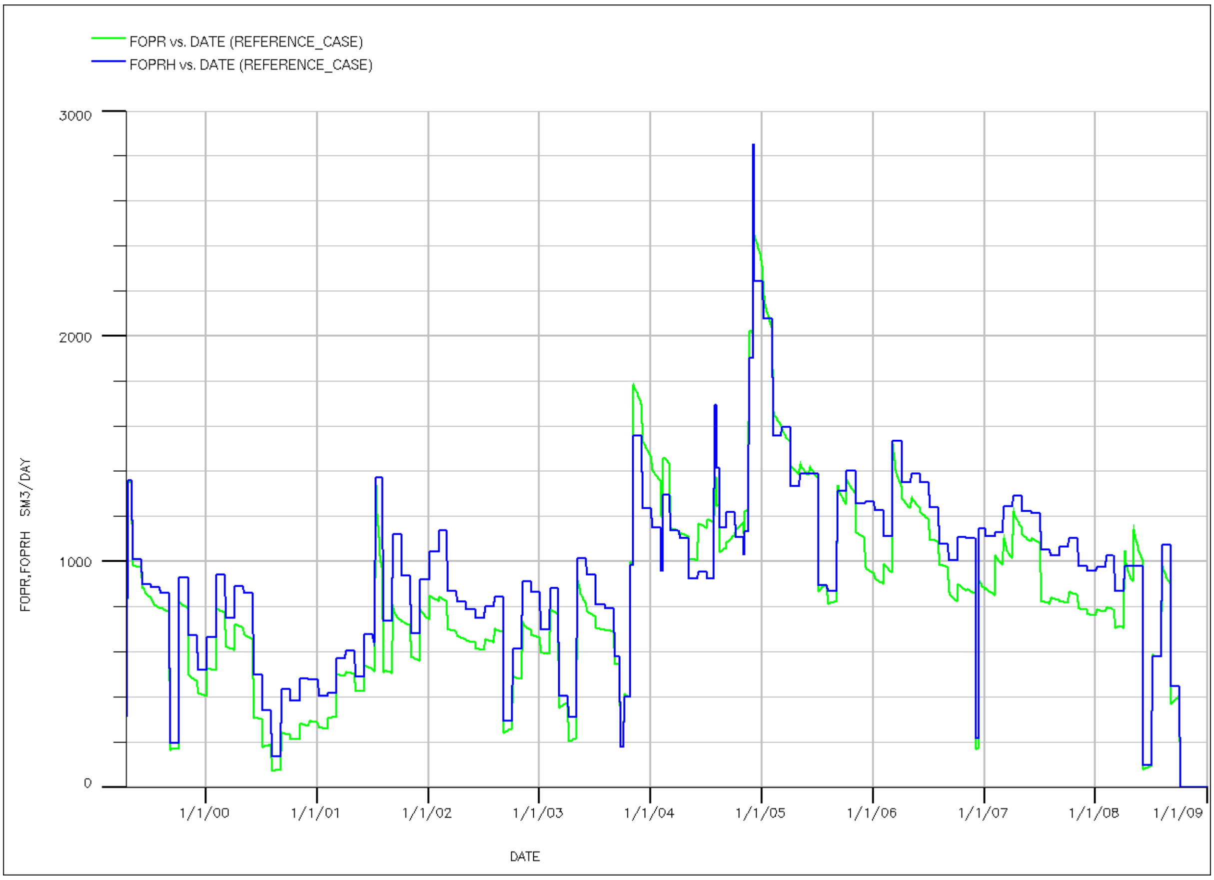


Figure 6 FOPR vs FOPRH

Figure 6 shows the matching between the real field oil production and the oil production simulated. The history matching for the field oil production is good. It has a good correlation, and hits the peaks well. History shows in general a higher oil production than the simulation gives. The blue line represents the history and the green line represents the simulation.

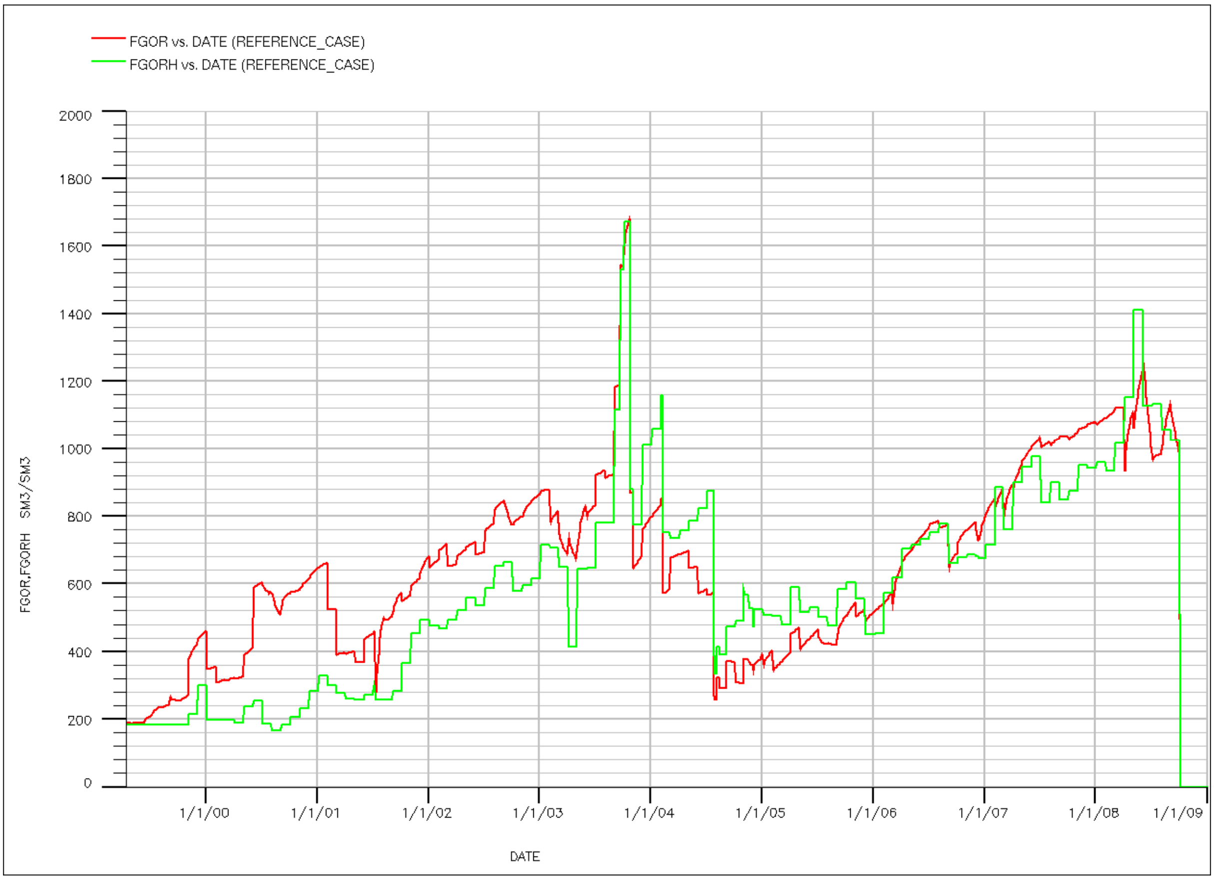


Figure 7 FGOR vs FGORH

Figure 7 shows the matching between the real gas-oil ratio and the gas-oil ratio from the Reference Case simulation. The matching shows a generally good correlation. The first half of the time period, the gas - oil ratio is higher for the simulation than the actual history. In the second part of the time period the FGOR is in average equal to the actual history. The green line represents the actual history and the red line represents the simulation.

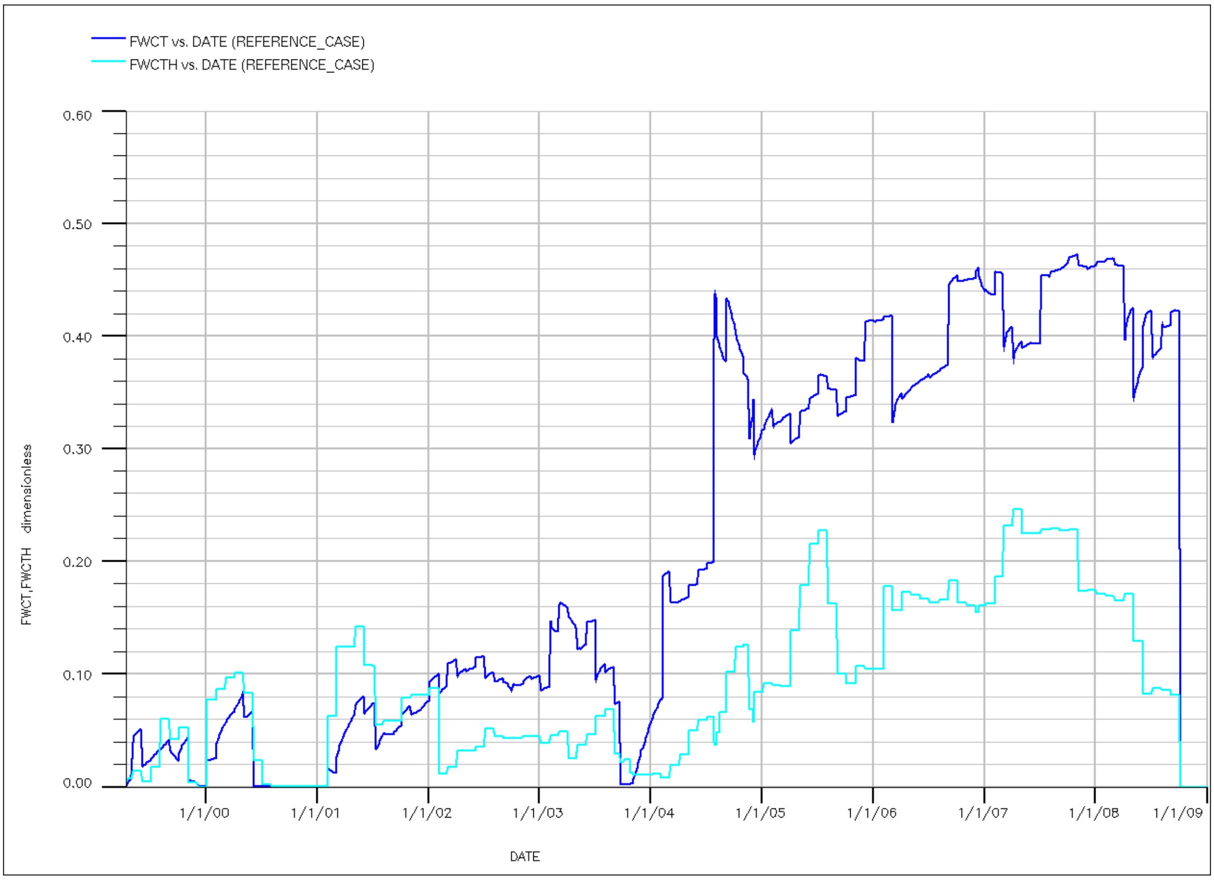


Figure 8 FWCT vs FWCTH

Figure 8 shows the actual water cut compared with water cut from the Reference Case simulation. The Field water cut from the simulation is much higher than the actual history shows. The difference between history and simulation increases throughout the time period. The sky blue line represents the actual history and the dark blue line represents the simulation.

6.2 Field production

The following sub chapter contains field production data for the Reference Case and the Extended Case.

6.2.1 Field data for Reference Case

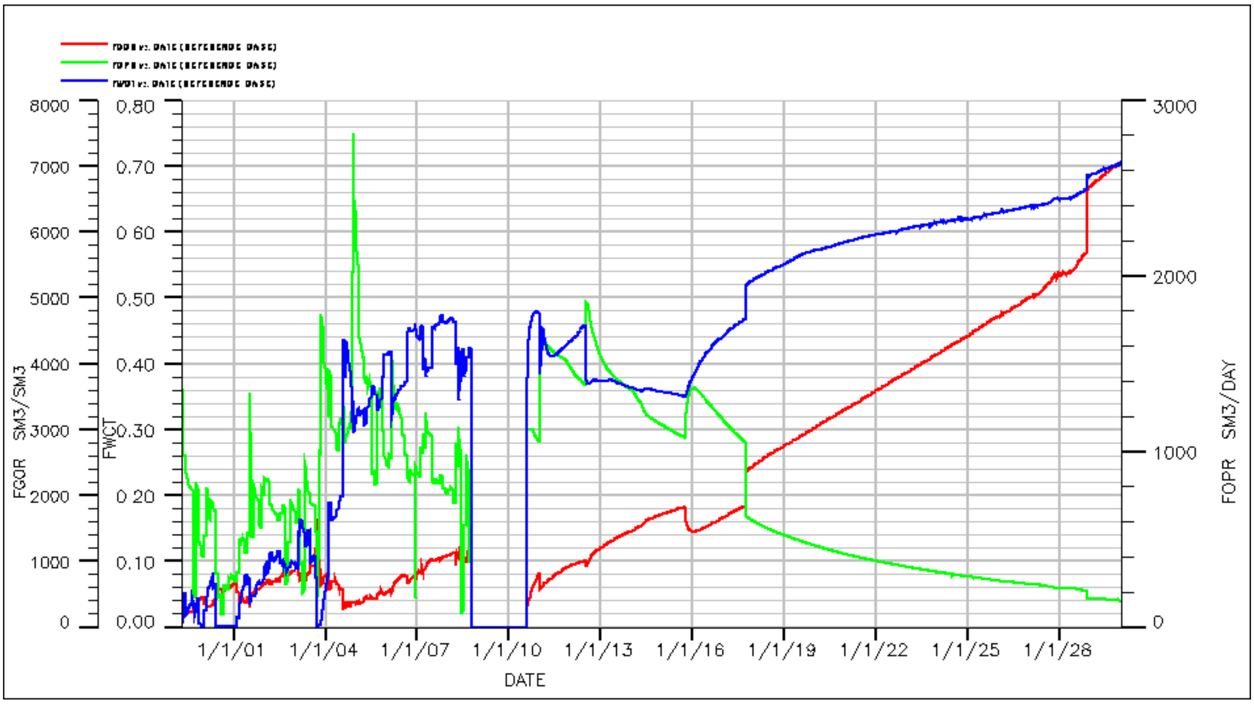


Figure 9 Field production rate from Reference Case

The green line shows the oil production, blue line is water cut and the red line is gas to oil ratio. The simulation results shows that the oil production has a decreasing trend, while both the water cut and GOR are increasing. This could probably be explained by the pressure drop in the field, causing more gas to dissolve from the oil. See Figure 9.

Before the Extended Case was simulated there was some thinking about what are reasonable results which can be expected from this case. The expectations were to get a jump in oil production from 1 October 2015, when the new wells are starting to produce. There will also expectations for the production to decrease after some time, but hopefully not down to the Reference Case level. There is also likely to believe that the water cut will be lower.

6.2.2 Field data for Extended Case

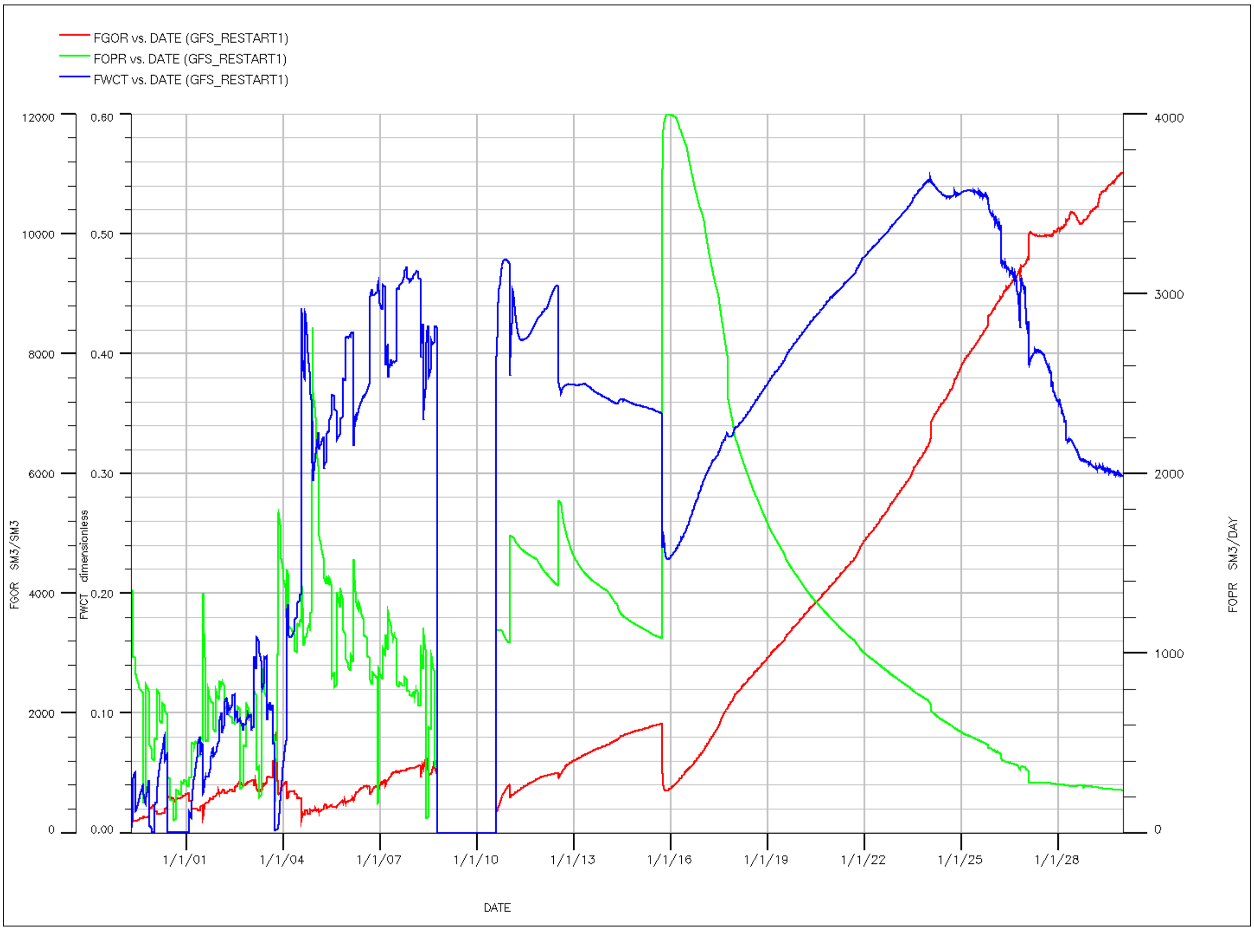


Figure 10 Field production rate from Extended Case

The date that the wells are supposed to come into production is Oct-2015. And as expected the production rate for oil has a significant increase at the date, and the water cut decreases at the same time. As expected the production will start to decrease and the water cut will increase. See Figure 10. Notice that the water cut will only increase up to 54% before it starts to decrease again around 2026. This is lower than the water cut for the Reference Case, where the water cut is between 60-80 % in the same time period.

As for the Reference Case the GOR will increase, this is probably an effect of pressure loss in the field.

6.3 Field in total

The total oil and gas production and total water cut follows under, comparing the Reference Case to the Extended Case.

6.3.1 Total Oil Production in Field (FOPT)

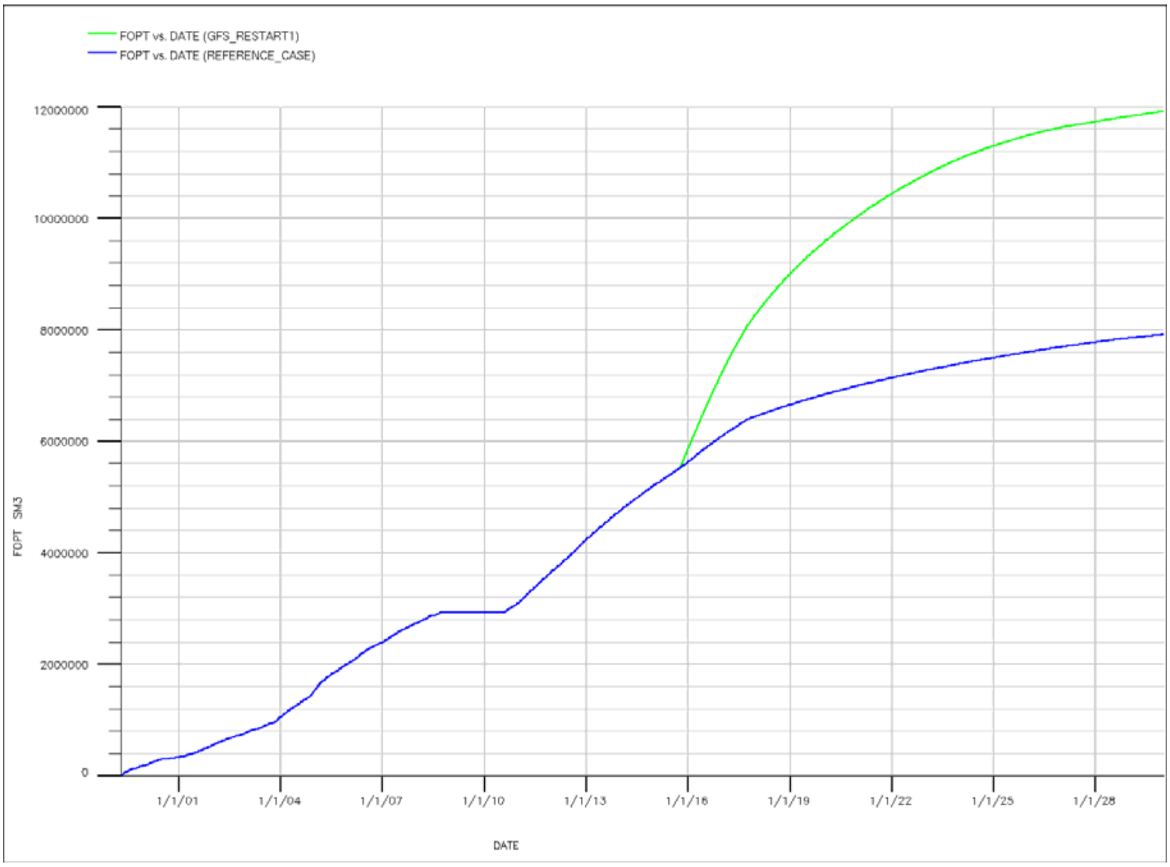


Figure 11 Field oil production total

Figure 11 shows that by adding 4 oil producers and 2 gas injector in 2015, there is a gain of approximately 5 MSm^3 additional oil.

6.3.2 Total Gas Production in Field (FGPT)

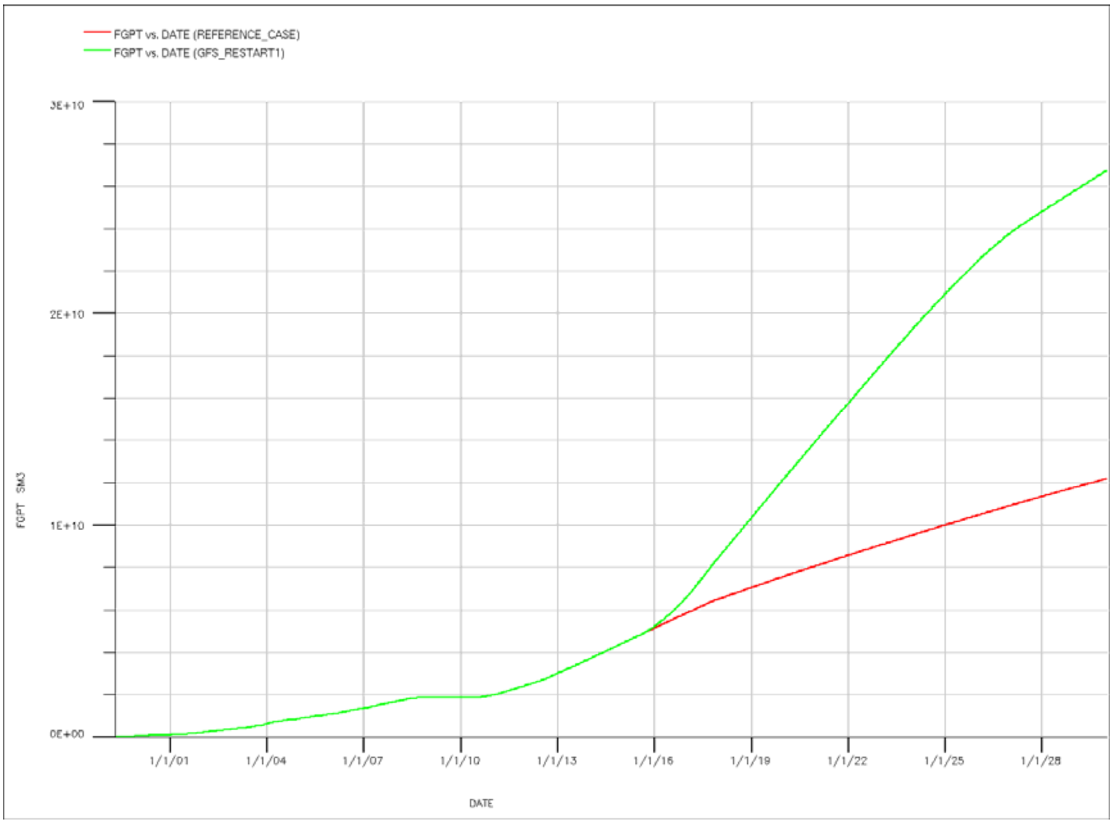


Figure 12 Field gas production total

Figure 12 shows that by adding 2 new gas injector in 2015, total gas production in 2030 increase from 12,1 billion Sm^3 to 26,5 billion Sm^3.

6.3.3 Total Water Cut in Field (FWCT)

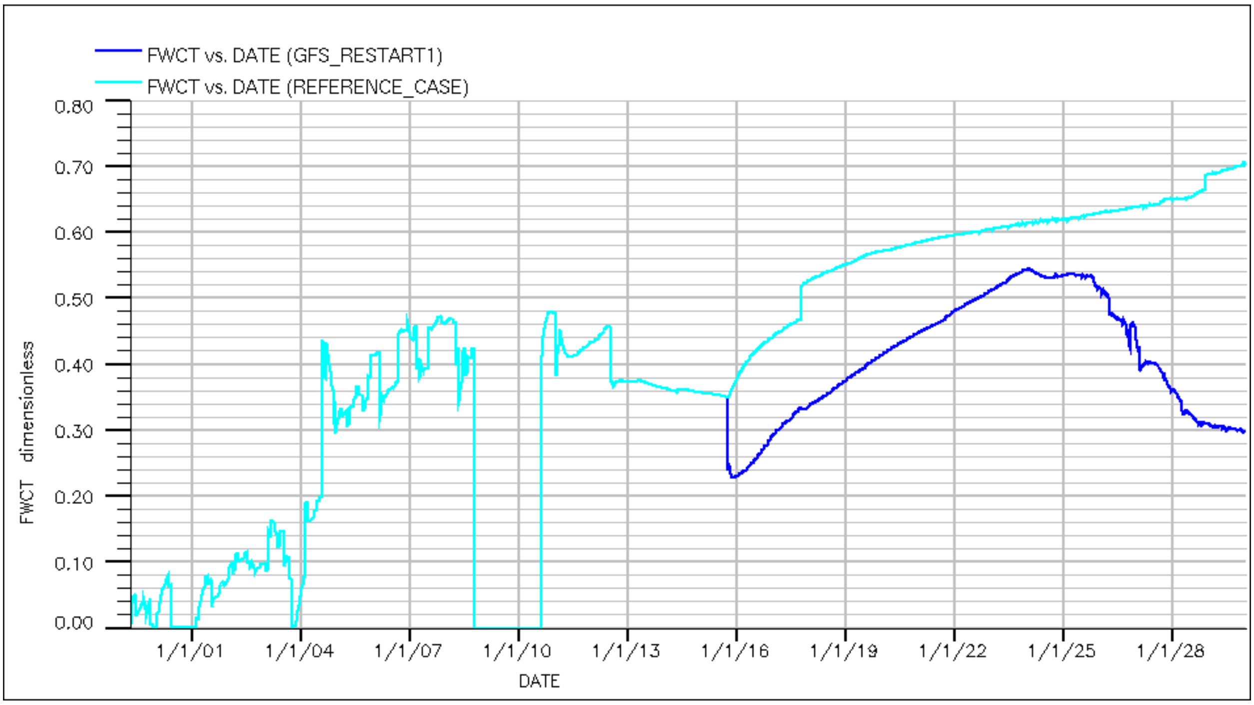


Figure 13 Field water cut total

Figure 13 shows the water cut in the Reference Case vs. Extended Case. The water cut is higher for the Reference Case than for the Extended Case. Notice the drop in water cut in 2015 when the 4 new wells are starting to produce.

6.4 Well production Reference Case vs. Extended Case

This sub chapter contains a comparison of oil and gas well production and water cut, between Reference Case and Extended Case.

6.4.1 Well oil production rate, Reference Case vs. Extended Case

The oil production trend for all the old wells in this comparison is similar. To illustrate the trend, one figure for the oil production is included. The blue line is the Reference Case, and the green line is the Extended Case.

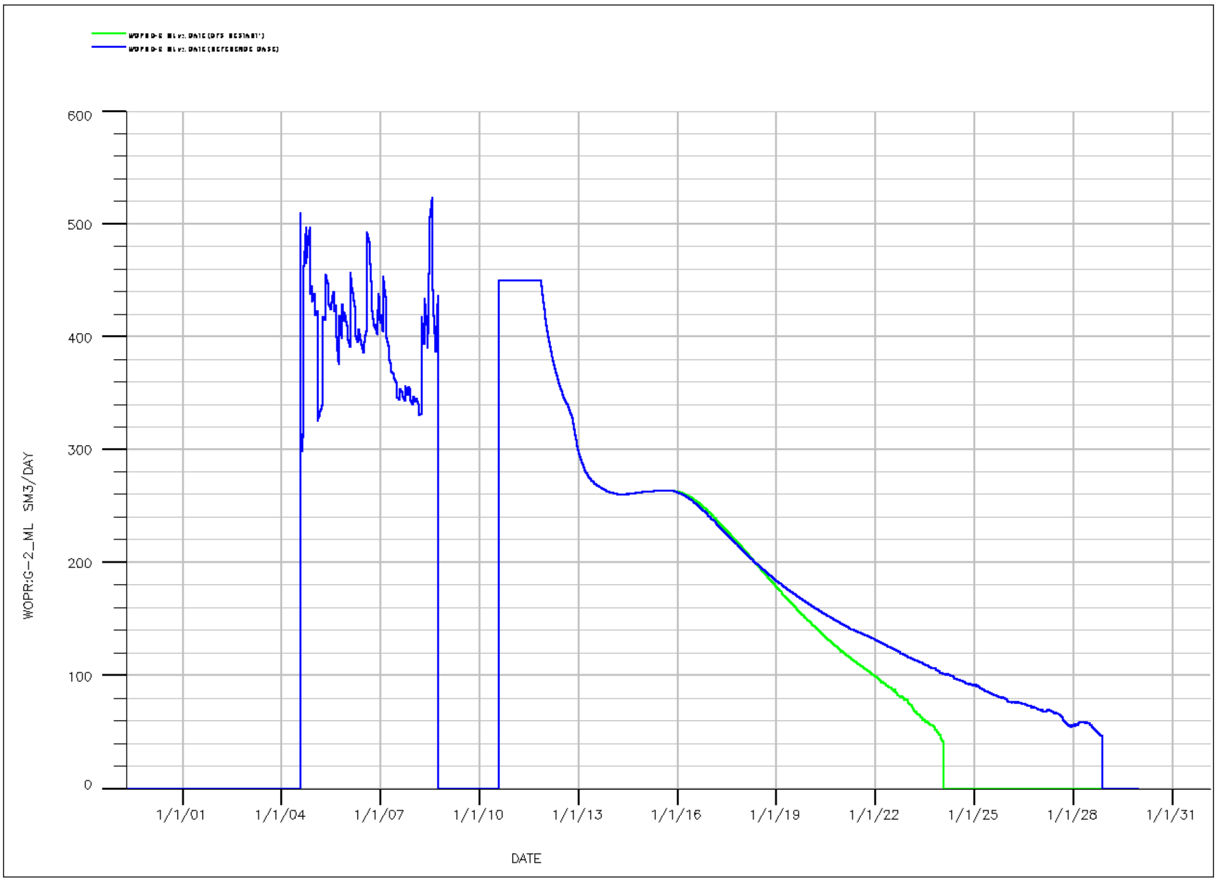


Figure 14 WOPR, G-2_ML reference vs. Extended Case

Figure 14 shows the oil production for well G-2_ML. It has a small period with higher production for the Extended Case than for the Reference Case. Then it decreases, faster than the production in the Reference Case and is eventually shut in. The shut in is done earlier for the Extended Case. Totally this well produces less oil in the Extended Case compared to the Reference Case. The reason for the more rapid decrease in oil production is probably because it is influenced by the new wells. The new wells are producing some of the oil that the old well would have produced if the new wells were not introduced.

Well gas production rate, Reference Case vs. Extended Case

The gas production trend for all the old wells in this comparison is equal. To illustrate this trend, one figure for the gas production is included. The green line is the Reference Case, and the red line is the Extended Case.

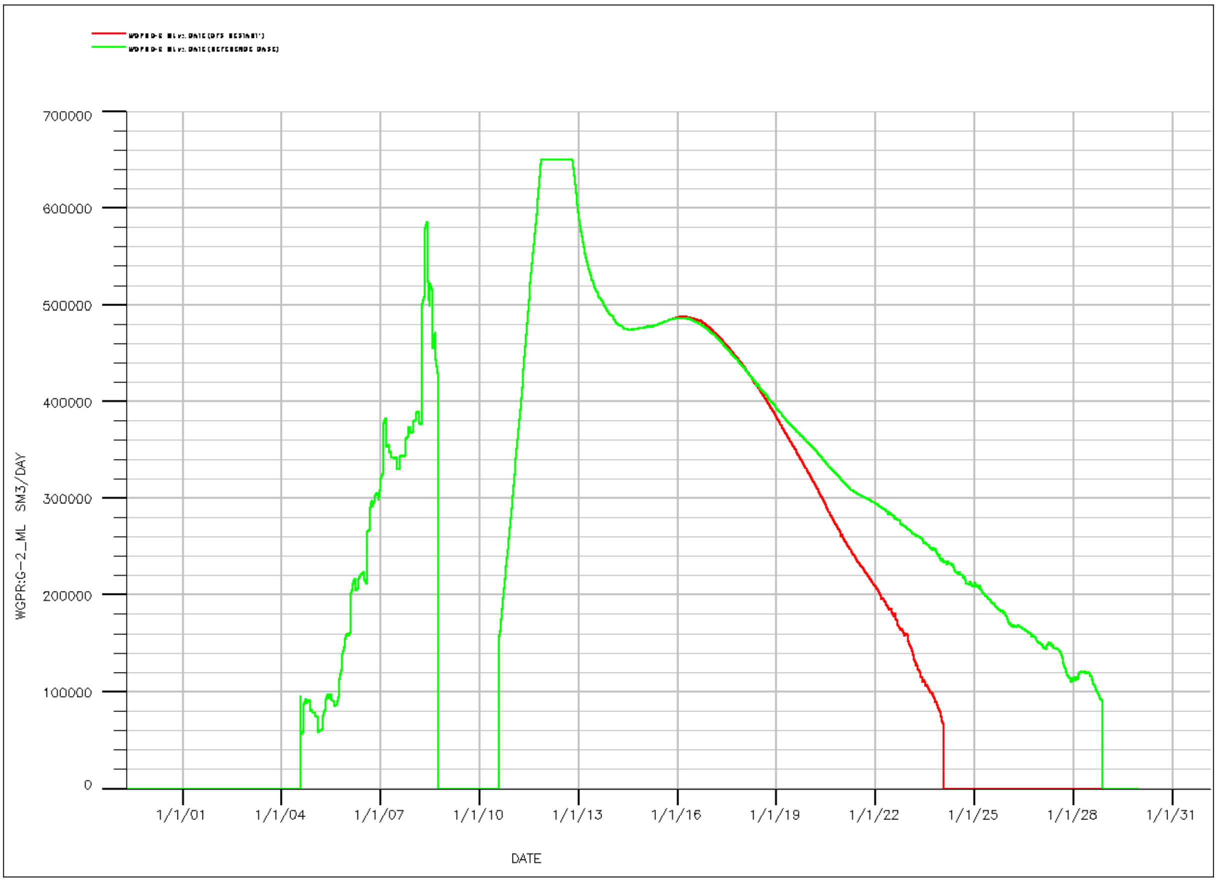


Figure 15 WGPR, G-2_ML reference vs. Extended Case

Figure 15 shows the gas production rate for well G-2_ML. It also has a small period where it is producing slightly more in the Extended Case than in the Reference Case. The production in the Extended Case is declining faster than in the Reference Case. In the end the well is shut in earlier in the Extended Case than for the Reference Case, and the gas production in total is also lower. The reason for the more rapid decrease in gas production is probably because it is influenced by the new wells. The new wells are producing some of the gas that the old well would have produced if the new wells were not introduced.

6.4.2 Well water cut, Reference Case vs. Extended Case

The water cut trend for all the old wells in this comparison is similar. To illustrate the trend, one figure for the water cut is included. The blue line is the Reference Case, and the sky blue line is the Extended Case.

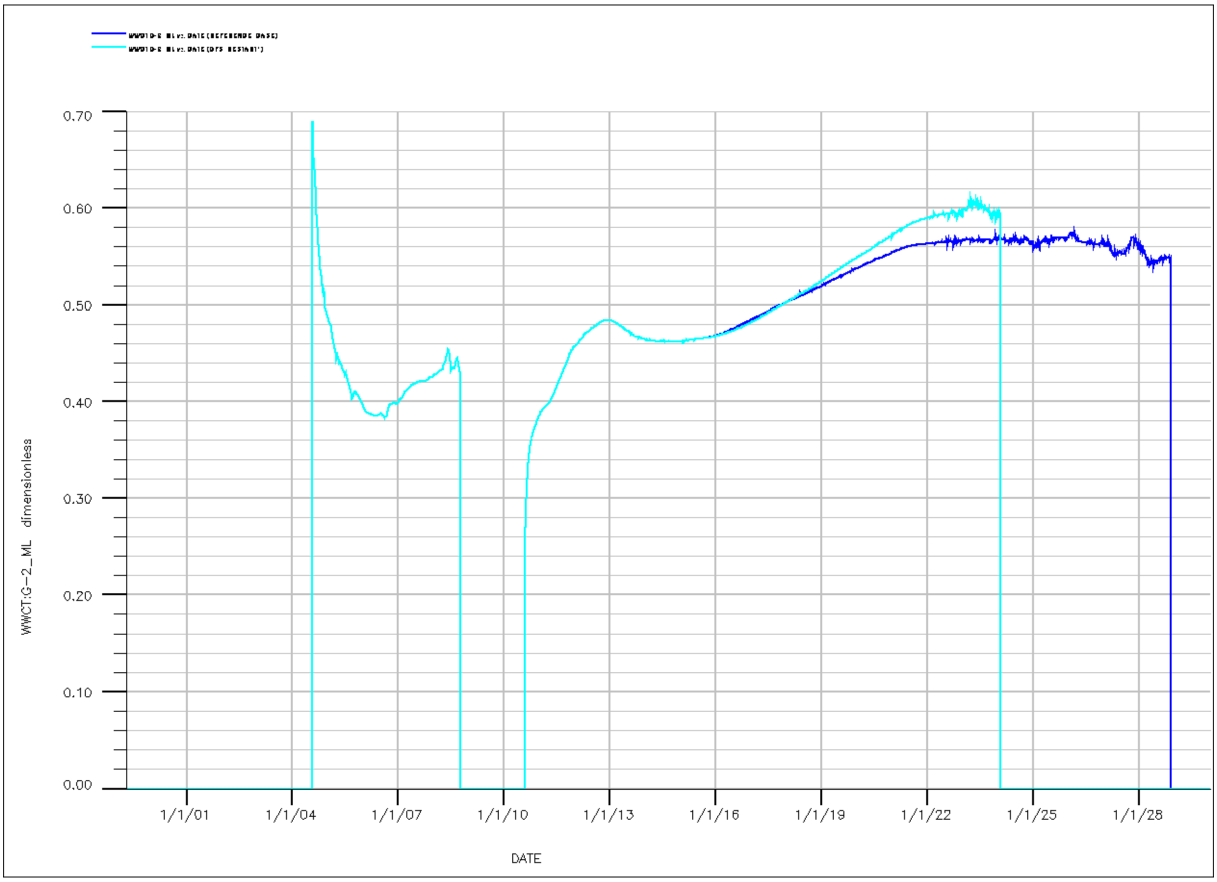


Figure 16 WWCT G-2_ML reference vs. Extended Case

Figure 16 shows the well water cut for well G-2_ML. The water cut is increasing faster for the Extended Case, and well is shut in earlier.

This trend follows for all the old wells. The oil production is lower, the gas production is lower, the water cut is higher and the majority of the wells are shut in earlier in the Extended Case compared to the Reference Case.

6.5 New Wells in Extended Case

The following sub chapter contains the most important parameters for the new production wells from the Extended Case.

6.5.1 Well W1

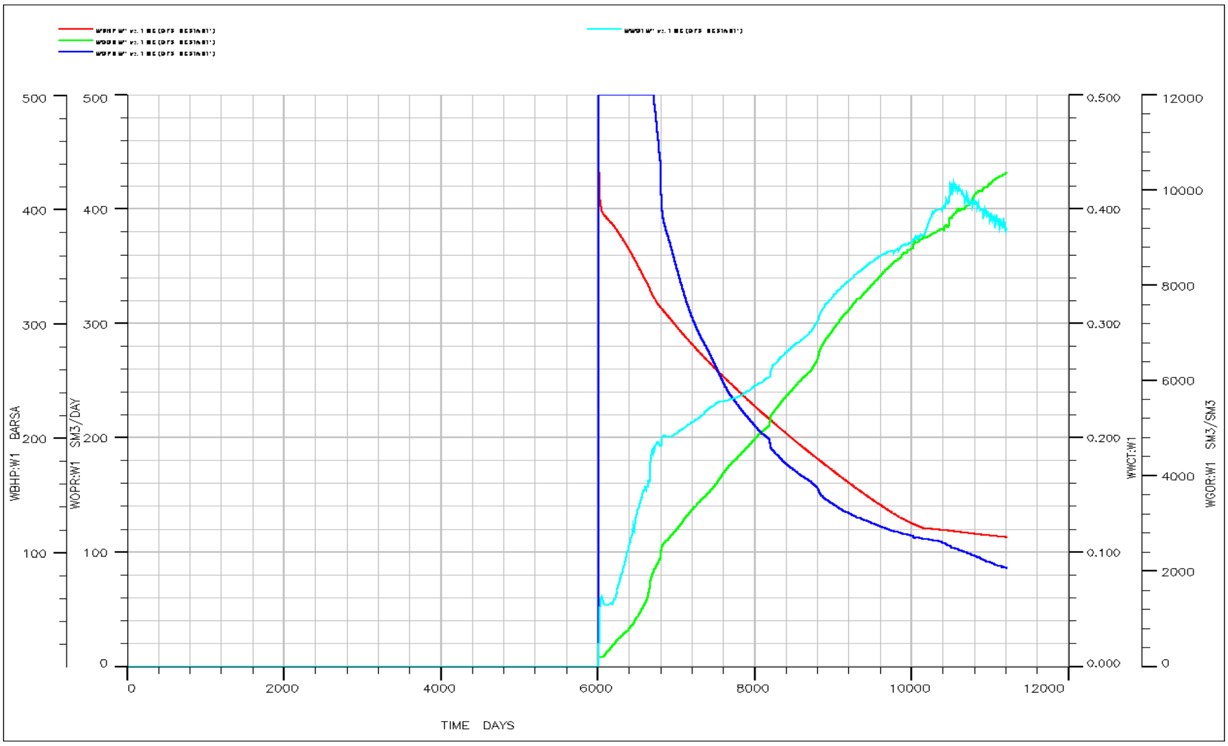


Figure 17 WOPR, WWCT, WGOR and WBH for W1

From Figure 17 it can be seen that the oil production, dark blue line, is kept steady for only a few years before it starts to decrease, quite rapidly. The water cut, light blue line, and the gas to oil, green line, ratio increases up to big levels. The water cut is over 40% at the most.

6.5.2 Well W2W3

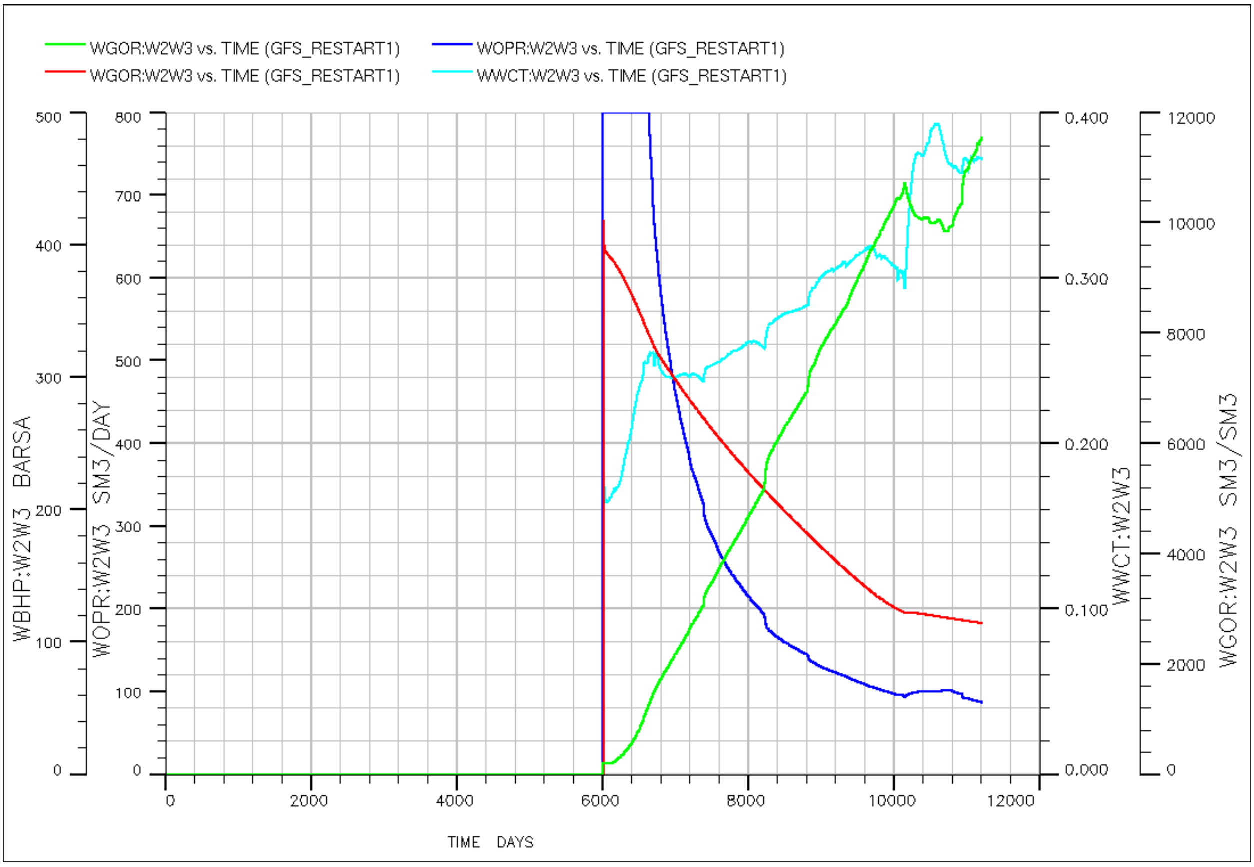


Figure 18 WOPR, WWCT, WGOR and WBHP for W2W3

For this well it can be seen that the production is only kept steady for a few years before it drops. Like well W1 this well has increased water cut in time and the GOR increases as well. See Figure 18.

6.5.3 Well W4W5

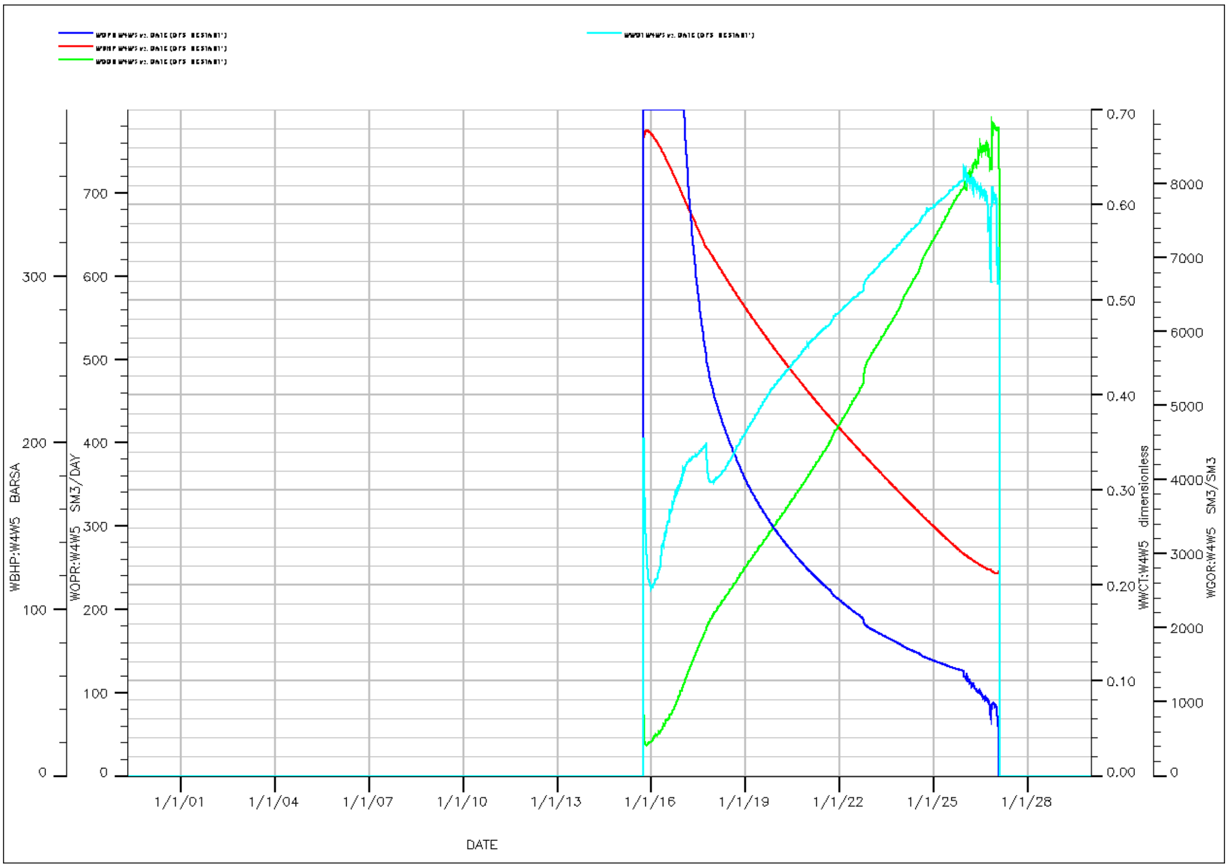


Figure 19 WOPR, WWCT, WGOR and WBHP for W4W5

As for the previous wells the production (dark blue line) starts to decrease shortly after production start. The pressure (red line) drops to zero around 2027, and the well is not able to produce any more. See Figure 19.

6.5.4 Well W6W7

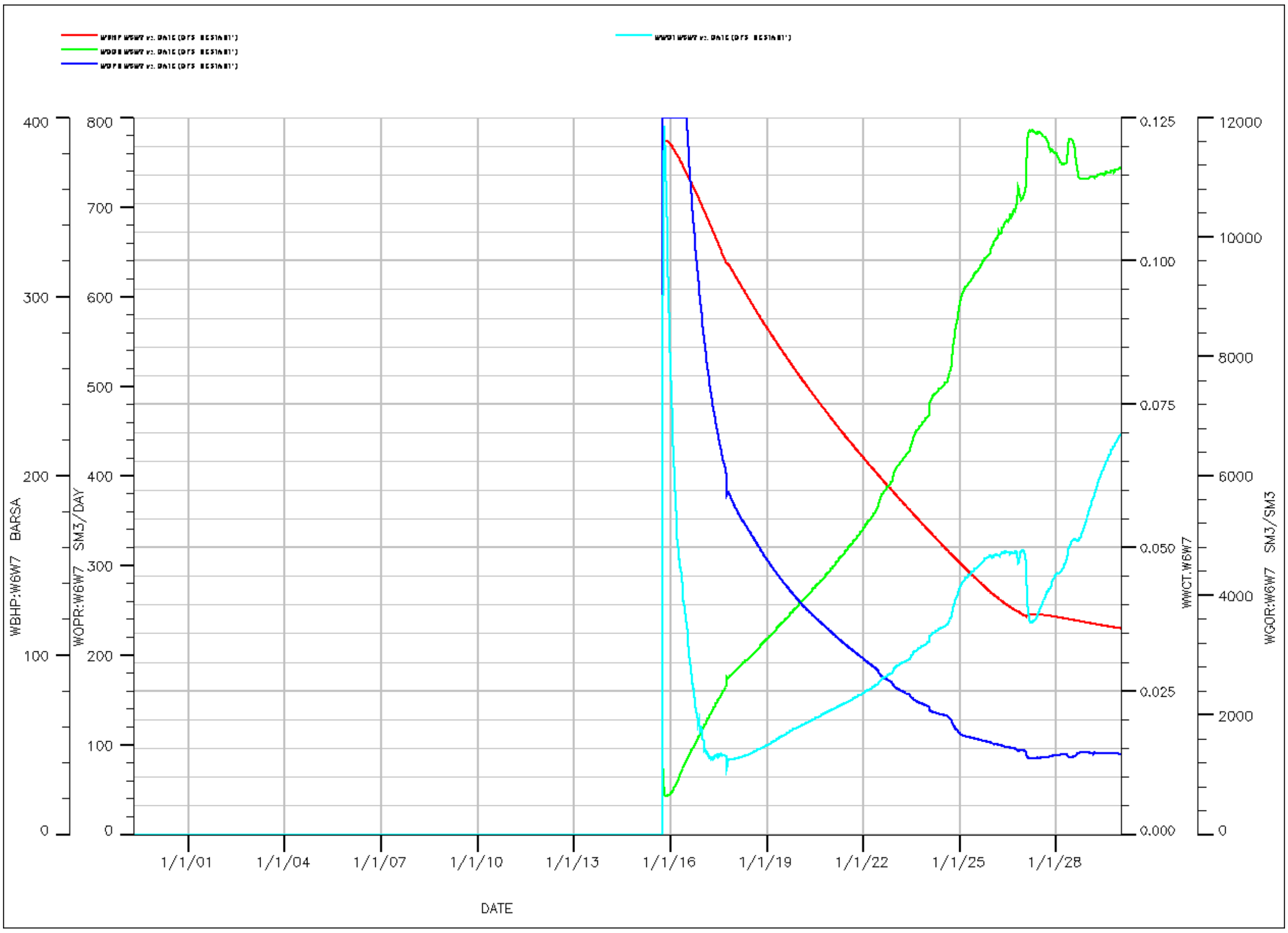


Figure 20 WOPR, WWCT, WGOR and WBHP for W6W7

This well has a shorter plateau production, dark blue line, than the other wells. Here, the water cut, light blue line, drops after some time before it starts to increase again. But the level of water cut never exceeds 12, 5%, which is much lower than for the rest of the new wells. As for all the other wells the GOR, green line, is increasing with time. See Figure 20.

In all the wells the pressure is decreasing with time.

Notice that the level of water cut is varying from each well from around 10% all the way up to over 60%. In all wells the GOR reaches quite high levels because of the pressure drop. The bubble point pressure in the field is around 220 Bars. The pressure in the wells is below this pressure at some point. This means that the gas is coming out of solution, and there will be more gas produced. This is probably the main reason for the decrease in oil production.

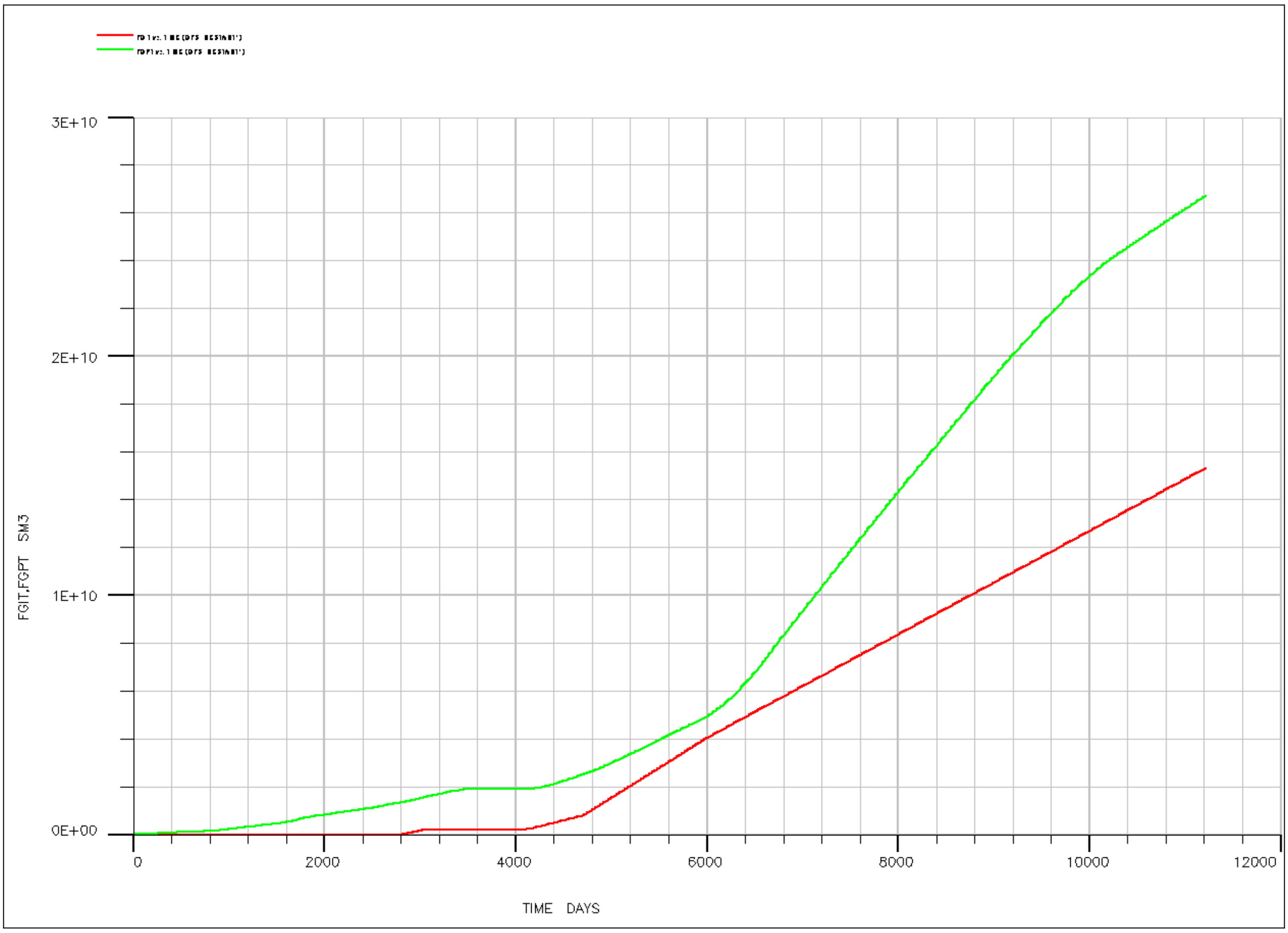


Figure 21 FGIT and FGPT

Figure 21 shows the total field gas production and how much gas injected into the field. The production of gas is increasing quite rapidly from around the same time as the oil production starts to drop. As discussed previously one reason for this may be the gas coming out of solution when the pressure falls below the bubble point. Another reason may be that the injected gas is moving straight to the wells and gets produced. To check this one can observe how the gas saturation changes with time in e.g. GL- view. This exceeds the scope of this assignment, and is therefore not included in this report.

7 ECONOMIC EVALUATION – PART A

The economic evaluation is based on the field data estimates, regarding the extra gas and oil produced from the new 4 wells and the gas injected from the new 2 injectors. The extra volumes of oil and gas were estimated using the results of the rates from eclipse simulation then an average rate per year was estimated and multiplied by 365 days, assuming that the field is producing during the entire year, then the extra volumes were found for both cases, oil and gas.

[QExtended Case (Sm3/d) – Qref case (Sm3/d)]*365d = Extra volume (Sm3)→in a year

For the gas sale there was assumed that:

Gas Sale (Gsm3) = Extra volume (Gsm3) – Volume injected for the new injectors (Gsm3)

The production of the new wells will start in the end of 2015.

When the volume of gas injected is bigger than the extra gas produced, it is assumed that the project must pay for the missing amount of gas needed, at standard gas prices.

7.1 Economic factors:

In order to calculate the net present value the following assumptions were made. See Table 2 Economical assumptions

Table 2 Economical assumptions

CASES	LOW	BASE	HIGH
GAS (NOK/Sm3)	1,2	2	2,8
OIL ($/bbl)	45	75	105
Discount Rate (%)	10	8	5
Oil price development (%)	5	10	15
Gas price development (%)	5	10	15

Exchange rate: 6 NOK/USD

For the Oil and gas prices it is considered → High/Low cases: +/- 40 %

7.2 Main Calculations

- The oil revenues are calculated with the following formula:

Revenues from oil = oil produced (sm3)*oil price(nok/sm3)*(1+oil price development)^project year

- The Gas revenues:

Revenues from gas=(gas produced-gas injected) (Gsm3)*gas price(nok/sm3)*1000000000*(1+gas price development)^project year

- Capex

Capital expenditures, are made in order to create future benefits, the capital cost estimates covers the costs from the time of issue for approval of the PDO up to and including the production start-up.

This includes: Platform costs, Subsea installations, Oil and gas Export system, Drilling and Completion and miscellaneous (PDO and conceptual engineering, soil investigations and insurance in construction period).

- Opex

Operational expenditure, is an ongoing cost for running a system, this includes costs of: Offshore (manning, chemicals, maintenance, well and subsea maintenance, inspection, platform services), Logistics (supply vessels, helicopters, and base), CO2 Duty, Onshore support, Insurance, Licence overhead.

- Net cash flow

Net cash flow = Revenues form Gas + Revenues from oil – CAPEX – OPEX

- Net present value

Is an indicator of the future cash inflows that the project will yield

NPV = Net cash flow/(1+discount rate)^project year

7.3 Evaluation

There are many options for drilling the wells. In this task two options were evaluated in 3 different scenarios: low base, base case and high case:

Option 1 → Drill the new wells from a ship to the subsea templates and tie back to Gullfaks A platform.

Option 2→ Drill the new wells from a new platform.

7.3.1 Option 1

To make the calculations for the economic evaluation, the CAPEX and the OPEX are assumed for the base case, see Table 3 and Table 4, for high case it is -40% and for low case +40%.

Table 3 CAPEX assumptions, option 1

ELEMENT	COST (MNOK)
Production Unit (new installations in platform A)	1035
Subsea pipeline	3500
Drilling ad Completion (DRILEX)	1035 (172,5MNOK/well)
Total	**5570**

Table 4 OPEX assumptions, option 1

ELEMENT	COST (MNOK)
Field/onshore (offshore and onshore operations)	3190
Oil and Gas Transportation	1411(0,3NOK/Sm3 Gas ; 15NOK/Bbl Oil)
CO_2 Duty	280
Total	**4881**

7.3.2 Option 2

To make the calculations for the economic evaluation, the CAPEX and the OPEX is assumed for the base case, see Table 5 and Table 6, for high case it is -40% and for low case +40%.

Table 5 CAPEX assumptions, option 2

ELEMENT	COST (MNOK)
Production Unit (new platform)	11000
Subsea pipeline	2100
Drilling ad Completion (DRILEX)	1500 (250MNOK/well)
Total	**14600**

Table 6 OPEX assumptions, option 2

ELEMENT	COST (MNOK)
Field/onshore (offshore and onshore operations)	6320
Oil and Gas Transportation	1411 (0,3NOK/Sm3 Gas ; 15NOK/Bbl Oil)
CO2 Duty	280
Total	**8011**

7.4 Results

This subchapter contains the results from the economical evaluation.

7.4.1 Option 1

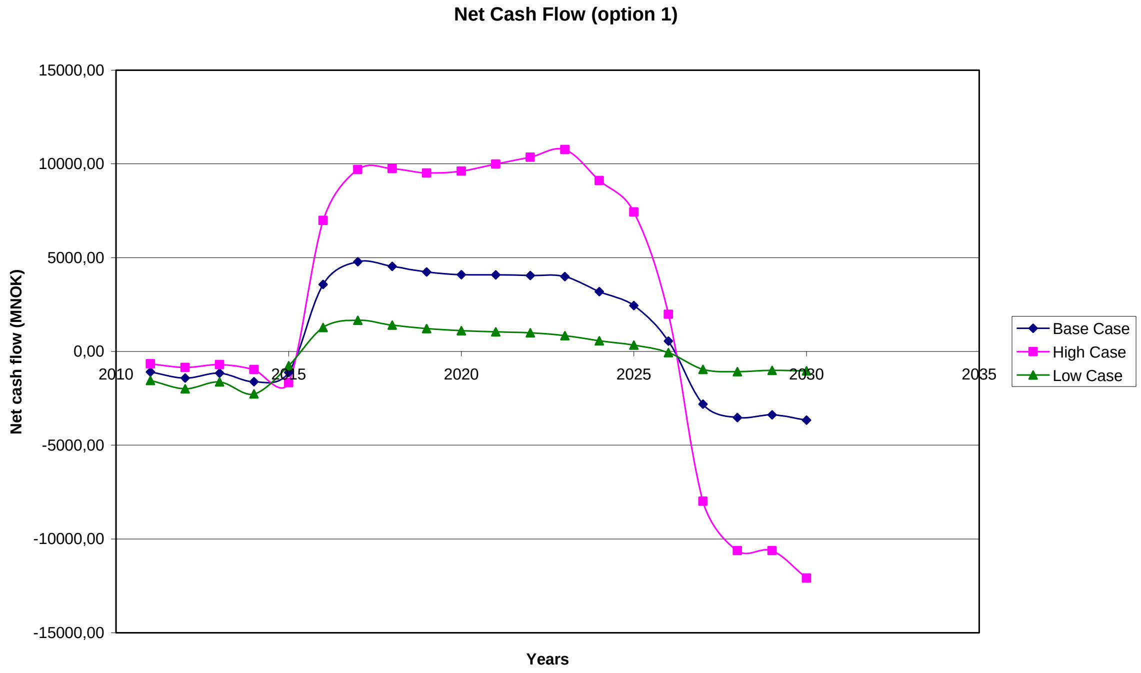


Figure 22 Net cash flow, option 1

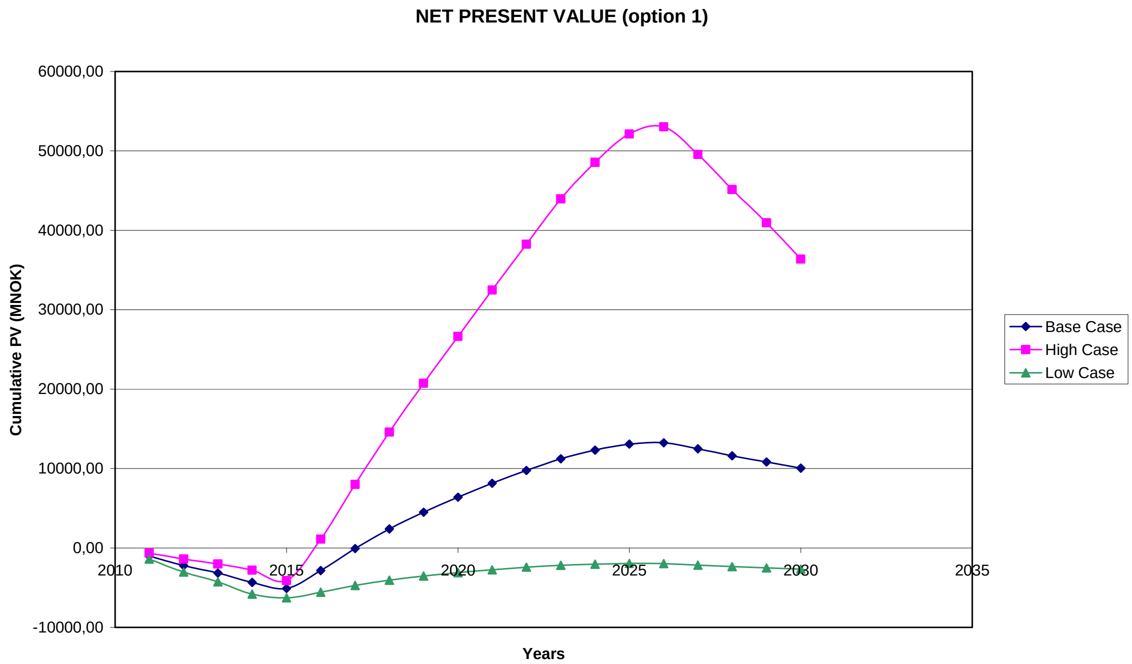


Figure 23 Net present value, option 1

From Figure 22 and Figure 23, there can be seen that the low case are having losses and the base case and the high case are having earnings, but after 2025 the losses will increase. Based on the assumptions made the production should be shut down in 2025 so the maximum earnings are achieved

7.4.2 Option 2

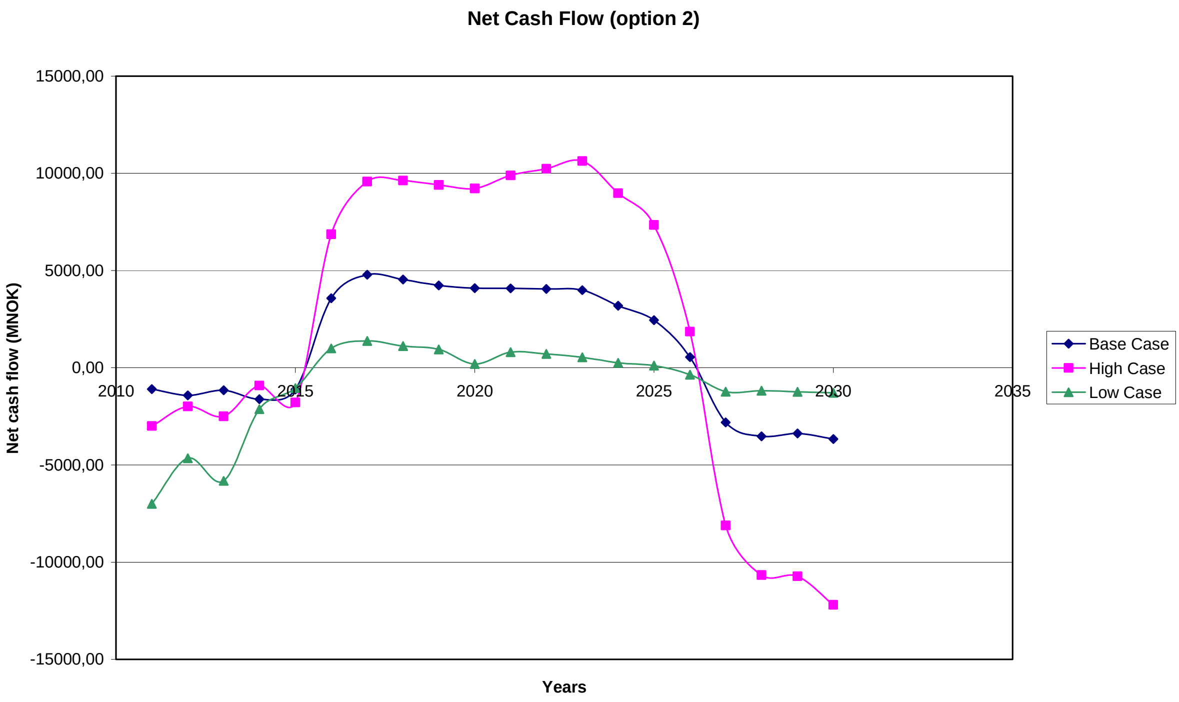


Figure 24 Net cash flow, option 2

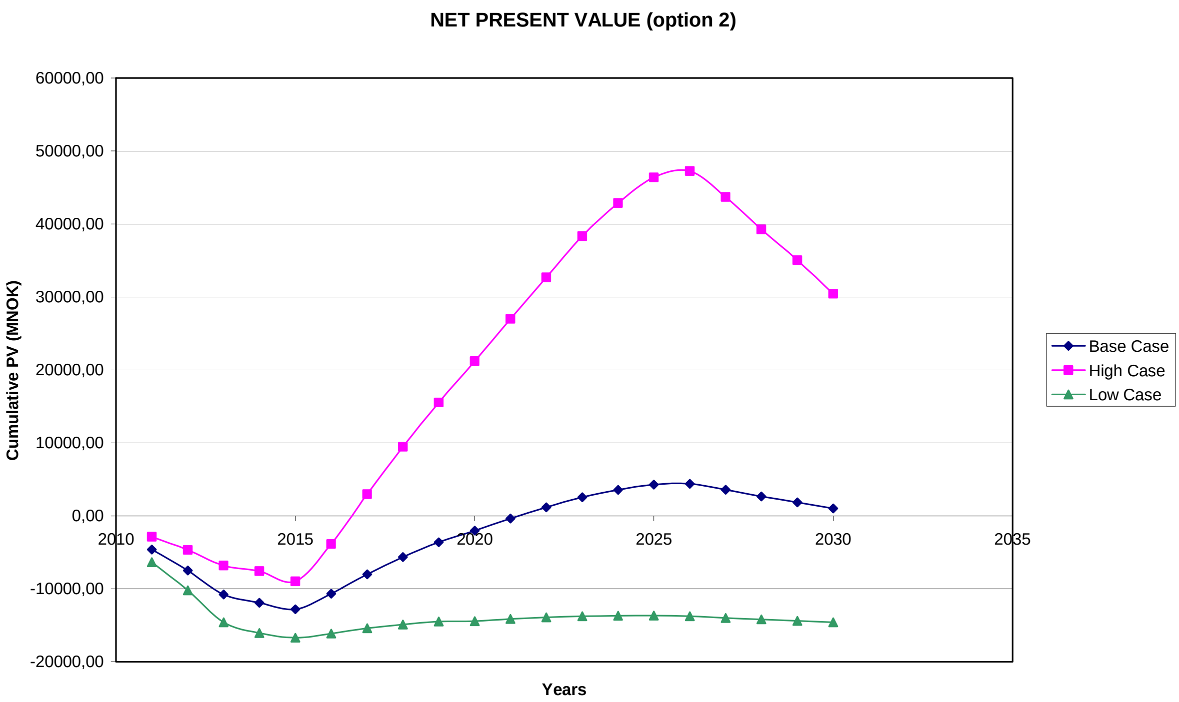


Figure 25 Net present value, option 2

From Figure 24 and Figure 25 it can be observed that in the low case there are losses and for the base case the earnings are very low compared with option 1, the high case gets high revenues, but considering the base case as the most probable then option 1 represents the best option. See Appendix A for more details.

7.5 Sensitivity Analysis

As many assumptions were made, it is necessary to perform a sensitivity analysis which studies how the variation (uncertainty) in the input affects the output. In this case the *ceteris paribus* approach was used to observe how the effect of a single independent variable on a dependent variable can be isolated, for example if only the oil price changes, how is the net present value affected.

7.5.1 Option 1

Using the base case the following parameters shown in Table 7 were changed independently and as a result the % NPV changed. In the sensitivity spider plot the oil price is the factor that influences the most in the change of NPV and the well cost influences the least. See Figure 26.

Table 7 Sensitivity results 1

	CASES		
PARAMETERS	**LOW**	**BASE**	**HIGH**
Oil price	45	75	105
% change	-40,00 %	0 %	40,00 %
NPV	4648,39	10039,56	15430,73
% change	-53,7 %	0,0 %	53,7 %
Gas price	1,200	2	2,800
% change	-40,00 %	0 %	40,00 %
NPV	8772,06	10039,56	11307,06
% change	-12,63 %	0,00 %	12,63 %
Discount rate	0,1	0,08	0,05
% change	25,00 %	0,00 %	-37,50 %
NPV	8257,76	10039,56	13228,24
% change	-17,75 %	0,00 %	31,76 %
Well cost	1449	1035	621
% change	40 %	0 %	-40 %
NPV	9704,5	10039,56	10374,62
% change	-3,3 %	0,0 %	3,3 %

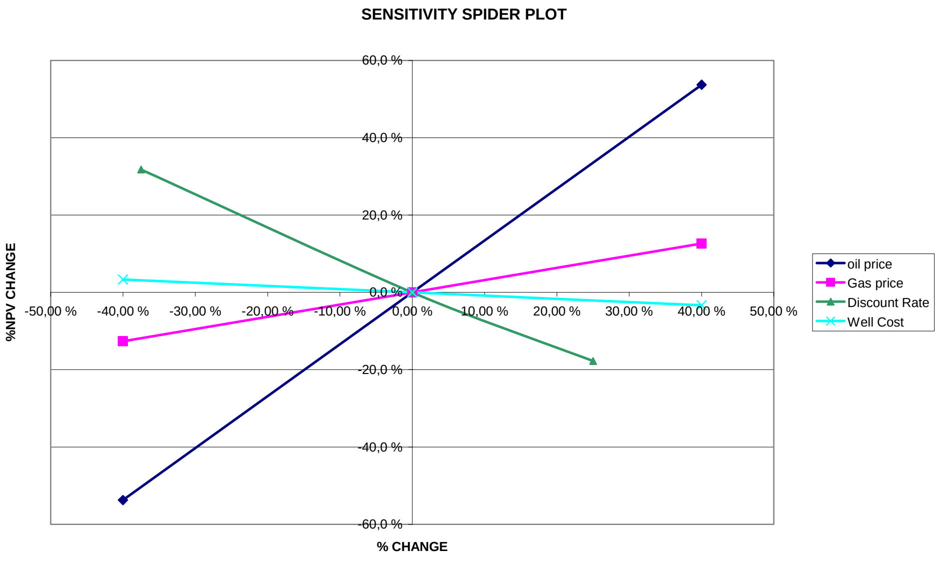


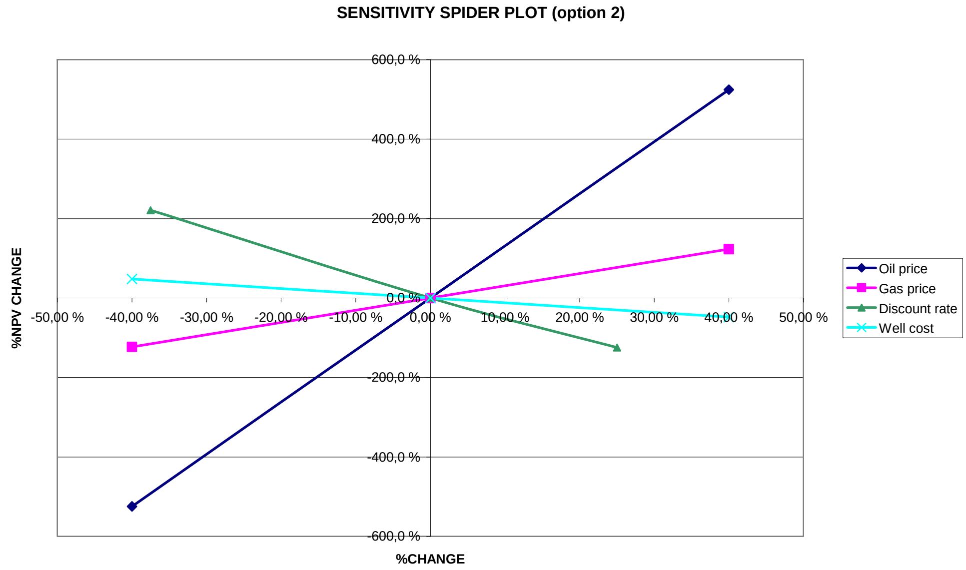
Figure 26 Sensitivity spider plot, option 1

7.5.2 Option 2

Using the base case the parameters shown in Table 8 were changed independently and as a result the % NPV changed. In the sensitivity spider plot the oil price is the factor that influences the most in the change of NPV, as the earnings (NPV) in the base case are not that high. Then if the oil price increases in 40% the NPV increases in 524,3%. The well cost (including only drilex) influences the least.

Table 8 Sensitivity results 2

	CASES		
PARAMETERS	**LOW**	**BASE**	**HIGH**
Oil price	45	75	105
% change	-40,00 %	0 %	40,00 %
NPV	-4362,95	1028,22	6419,39
% change	-524,3 %	0,0 %	524,3 %
Gas price	1,200	2	2,800
% change	-40,00 %	0 %	40,00 %
NPV	-239,28	1028,22	2295,72
% change	-123,27 %	0,00 %	123,27 %
Discount rate	0,1	0,08	0,05
% change	25,00 %	0,00 %	-37,50 %
NPV	-252,87	1028,22	3299,72
% change	-124,59 %	0,00 %	220,92 %
Well cost	2100	1500	900
% change	40 %	0 %	-40 %
NPV	533,4	1028,22	1523,03
% change	-48,1 %	0,0 %	48,1 %



Figur 27 Sensitivity spider plot, option 2

8 PHYSICS BEHIND WI AND WAG

This chapter contains a basic description of water injection and water alternating gas injection.

8.1 Water injection (WI) [3]

Hydrocarbon Reservoirs consist of natural rock formations that are saturated with hydrocarbons and water. Due to their location under the earth, and their high temperature, they are often subjected to high pressure, which is exploited when hydrocarbons are recovered. Water is injected for two reasons: 1. For pressure support of the reservoir (also known as voidage replacement). 2. To sweep or displace the oil from the reservoir, and push it towards an oil production well.

Normally only 30% of the oil in a reservoir can be extracted, but water injection increases that percentage (known as the recovery factor), and maintains the production rate of a reservoir over a longer period of time.

The water used for water injection is usually some sort of brine, but it can also be made up of other sources that are treated. For example, in some reservoirs water is produced with the hydrocarbons, removed from the production and re-injected into the formation.

It is important that the water being injected works within the formation. Filtration and processing of the water that will be injected are sometimes necessary to ensure that no materials clog the well pores and that bacteria is not permitted to grow. In an effort to reduce any corrosion within the reservoir, oxygen is often removed from the water, as well.

While production wells can be converted into injection wells, water-injection wells are also drilled specifically for this purpose. Water is then pumped into the reservoir, or gravity can help to push the liquid into the formation. This solution positions water tanks on hills or somewhere above the well, and the water simply is fed into the wellbore.

There are a number of techniques for determining where the water-injection wells should be drilled, as well as established patterns for water-injection wells in relation to production wells. One popular pattern, called the five-spot pattern, involves drilling four water-injection wells in a square around a production well. This is repeated around each production well on the reservoir, resulting in four production wells surrounding each water-injection well, as well.

Other drilling techniques include the seven-spot pattern, which has six water-injection wells surrounding a production well, and the inverted seven-spot pattern, which describes six production wells surrounding one water-injection well.

Also, wells can be drilled in line patterns, rather than spot patterns, where a direct line or staggered line of production wells is followed by a similar line of water-injection wells, and so on. In an edge waterflood, water-injection wells are drilled along the outside borders of the field, and water is injected, with production flowing toward the production wells in the center of the reservoir.

8.2 Water alternating gas injection (WAG) [8]

WAG is an enhanced oil recovery process whereby water and gas are alternately injected for periods of time to provide better sweep efficiency and reduce gas channelling from injector to producer. The water and gas is supposed to follow the same route through the reservoir.

The idea behind the WAG is that gravitational forces ensures that the water runs oil out of the reservoir bottom parts, while the gas drive oil out of the upper parts. Three-phase gas, oil and water flow is better at displacing residual oil in the pore system than two-phase flow. WAG thus improves the efficiency of both microscopic and macroscopic displacement. The challenge is to achieve sufficient sweep in the reservoirs.

WAG is a well established technology in Statoil, and they have used this in several fields, including Gullfaks. IOR potential using the WAG vs. conventional water injection is considered to be around 5 to 10%. Gas costs constitute a large proportion of the total cost, except in cases where there is a surplus of gas from production.

Variants include injecting gas as a supplement to water or vice versa, primarily to reach other parts of the reservoir. In the case of supplementary water injection, it also saves on valuable injection gas.

A distinction can often be drawn between miscible and immiscible WAG injection, and the water and gas can be injected simultaneously (SWAG) rather than intermittently.

Adding a foaming agent to the injection water can also improve the gas sweep.

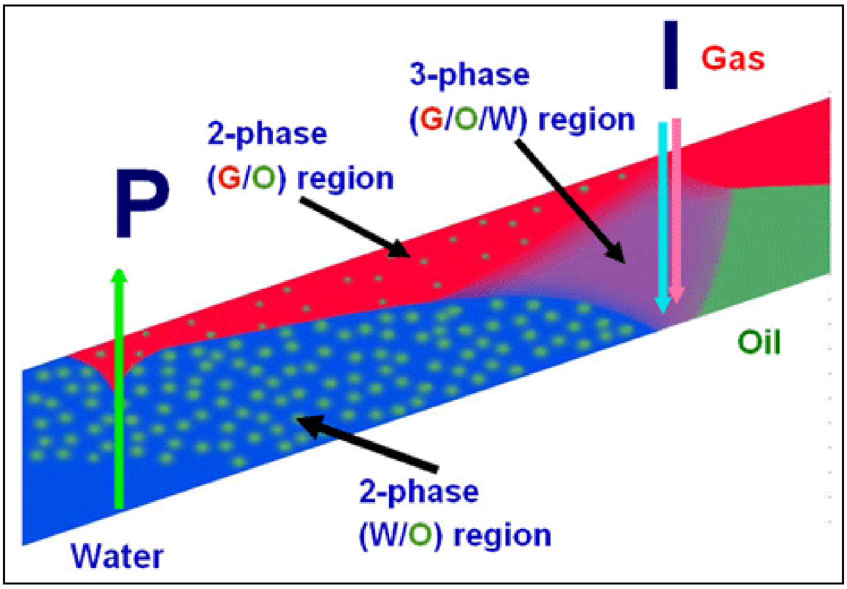


Figure 28 Segregated flow during up-dip WAG injection.

The WAG injection process aims to squeeze more oil out of the reservoirs. It is well known that remaining (residual) oil in the flooded rock may be lowest when three phases – oil, water and gas – have been achieved in this volume.

Water injection alone tends to sweep the lower parts of a reservoir, while gas injected alone sweeps more of the upper parts of a reservoir owing to gravitational forces.

9 STATOIL'S EXPERIENCE AT THE GULLFAKS MAIN FIELD [4]

This chapter presents some of Statoil's experiences using WAG injection at the Gullfaks main field.

Gullfaks Field

- Discovered: 1978
- Production start: 1986
- STOOIP: 600 MSm3
- Reserves: 360 MSm3
- Produced to date: 340 MSm3
- Main field drive mechanism: WI
- Satellite fields drive: GI/depletion

Water-alternating-gas (WAG)

- Start of injection: March 1991 in lower Brent, well A-11.
- Second well was A-12 in lower Brent, January 1993.
- Since then, gas has been injected in several WI-wells:
    - Lower Brent: C-10, A-35, A41B
    - Upper Brent: A-27A, A-25A, A-25B and C-17
    - Statfjord: C-21, C-4 and C-13
    - Cook: C-18, A-17A, C-1

Gas is injected both in WI-wells and in other wells on GFA/GFC.

Table 9 Injected gas and water

	Gas injected, MSm3	Water injected, MSm3
All GFA/GFC wells	14 547	444
GFA/GFC WAG wells	6 784	343

Injections have been performed in 15 wells on Gullfaks since the first WAG pilot in A-11. This has contributed to improved oil recovery of about 10 MSm^3. The scope of WAG is limited due to availability of injection gas. Gullfaks had a gas sale agreement, but the limited transport capacity and less gas sale in low gas-demand season provided opportunity to inject some gas for increased oil recovery without high economic consequence. WAG injection on Gullfaks is mostly concentrated in the Brent and Statfjord Formation. The water flooding in the Lower Brent Formations is relatively less effective due to well-known Etive-Rannoch override where water flows rapidly through the lower part of Etive and upper part of Rannoch. Gravitational segregation of injection gas gives better sweep in the areas not contacted by water. WAG on Gullfaks also helps to maintain oil production during low gas export period and reduces CO2 tax and storage cost. The injection gas is not miscible with the Gullfaks oil. The main mechanisms of incremental oil recovery by WAG are: (1) draining of attic oil, (2) sweeping of other areas not contacted by water, (3) reduction in water cut and gas lifting of high water-cut wells.

Gullfaks gas injection rates in WI-wells (Initial rates):

- A-11 and A-12: 1.5 Mill. Sm^3/d gas, 5 000 Sm^3/d water
- A-27A: 2-2.5 Mill. Sm^3/d gas, 9 000 Sm^3/d water
- A-25A: 1-1.5 Mill. Sm^3/d gas, 6 000 Sm^3/d water
- C-10: 2-2.5 Mill. Sm^3/d gas, 12 000 Sm^3/d water
- C-21: 2-3 Mill. Sm^3/d gas, 11 000 Sm^3/d water
- C-3 and C-14: 1.5-2 Mill. Sm^3/d gas, 10 000 Sm^3/d water
- A-25B: 0.5-1 Mill. Sm^3/d gas
- C-17: 1.5 -2.3 Mill. Sm^3/d gas, 10000 Sm^3/d water

Later the rates are smaller due to less need of volume.

Cook-wells show lower injectivity in the gas phase than expected from the water injection.

Table 10 Amount of gas and water injected in wells until 15-3-2009

Well	Formation	Gas injected, MSm^3	Water injected, MSm^3
A-11	Lower Brent	1 472	20,2
A-12	Lower Brent	258	26,4
A-35	Lower Brent	96	9,2
A-41B	Lower Brent	53	8,2
C-10	Lower Brent	475	45,5
A-25/A27	Upper Brent	2 247	59,4
C-17	Upper Brent	242	45,0
C-21T2	Statfjord	1 209	38,9
C-4/C-13	Statfjord	672	75,0
A-17	Cook	27	12,0
C-18	Cook	32	2,1
C-1	Cook	1	1
TOTAL		6 784	343

WAG contribution to improved oil recovery is 10 MSm^3.

Table 11 Gas volume injected, produced back, left in reservoir and estimated increased recovery

Well	Injected by 15.03.09 MSm³	Gas back produced MSm³	Gas left in reservoir MSm³	Estimated increased recovery, MSm³
A-11	1472	1049(71%)	423	1,6
A-12	258	17(7%)	241	0,3
A-25A/ A-27A/ A-25B	2247	1595(71%)	651	2,9
C-4/ C-13	672	133(20%)	539	1,2
C-21T2	1209	629(52%)	580	1,3
C-10	475	57(12%)	418	0,5
Total	6333	3480(55%)	2853	7,8

A-11 WAG pilot in G1/G2 segment

- Lower Brent
- Rannoch fm 50-90 m thick
- Etive fm 14-40m thick
- Upper Brent, 200m thick
- Uncertain communication through faults
- WCT > 50% in the production wells

Field observations:

- A-11 injection
- WI started in November 1987
- WAG started in March 1991
- Gas breakthrough:
    - Well A-19 in July 1991
    - Well A-10 in April 1992
    - Well A-13 in August 1992
    - Well A-14 in December 1994
- Reduced water cut after gas breakthrough

Summary of WAG in A-11:

- Injected volume: 1472 Mill. Sm³
- Backflow through producers: 1049 Mill. Sm³ gas (71% of injected volume)
- Left in reservoir: 423 Mill. Sm³ of gas, corresponding to 1,6 MRm³
- Estimated increased oil recovery: App. 1,6 MSm³
- Saturation logs shows gas cap in Etive in A-10 and A-14

Monthly gas injection volume, well A-11

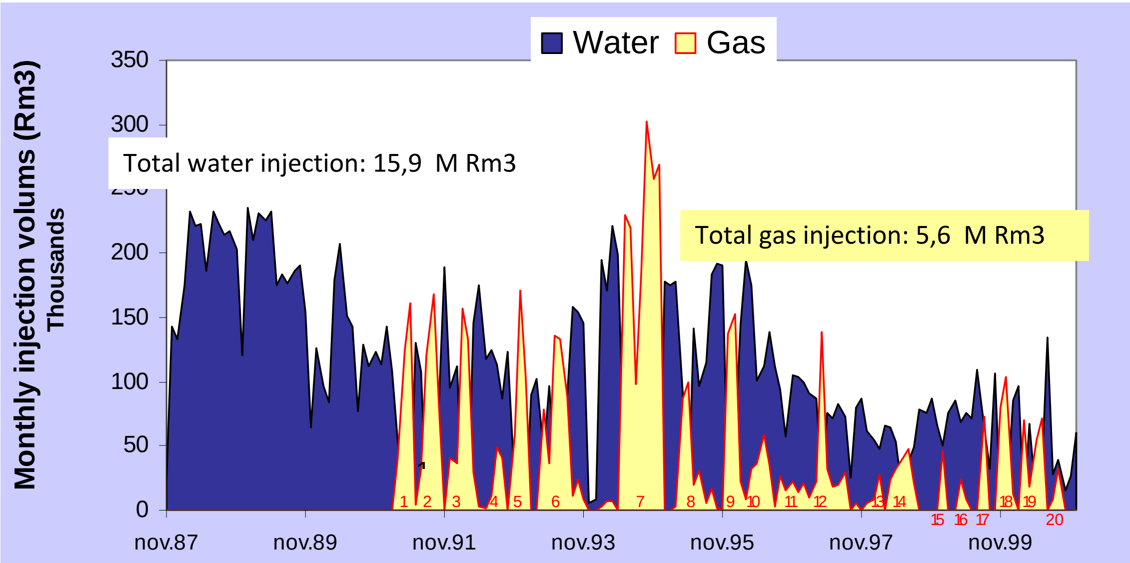


Figure 29 Total water and gas injection

10 SIMULATION

This chapter contains the simulations and results done in part B of the project. First the water injection is presented, then water alternating gas injection and in the end there is done a comparison of the two methods.

10.1 WI Simulation

The simulations were made with Eclipse, and in order to place the new wells in the simulation ECLPOST was used, with the well path in UTM coordinates and the type of well (water injectors or producer). Communication between the segments of the reservoir was studied by the animations in 3D of the flow in the Extended Case, then the strategy for the location of the producers was to place then near from the high oil saturation areas and near the gas oil contact to try to avoid the early water breakthrough, because the fluid to be injected is water then the gas and oil layers are moved up, and for the injectors the strategy was to inject in the water layers. The locations of the wells was chosen basically by trial and error, then after 11 cases the best result from the production point of view that we could find is still 0,2% less in total production than the Extended Case.

One of the major problems faced during the simulations was to keep the pressure in the reservoir, several attempts were made by changing the locations of the injectors and the producers and by changing the rates of injection and production, another problem was the high production of water up to 98% in water cut.

10.1.1 Sensitivity

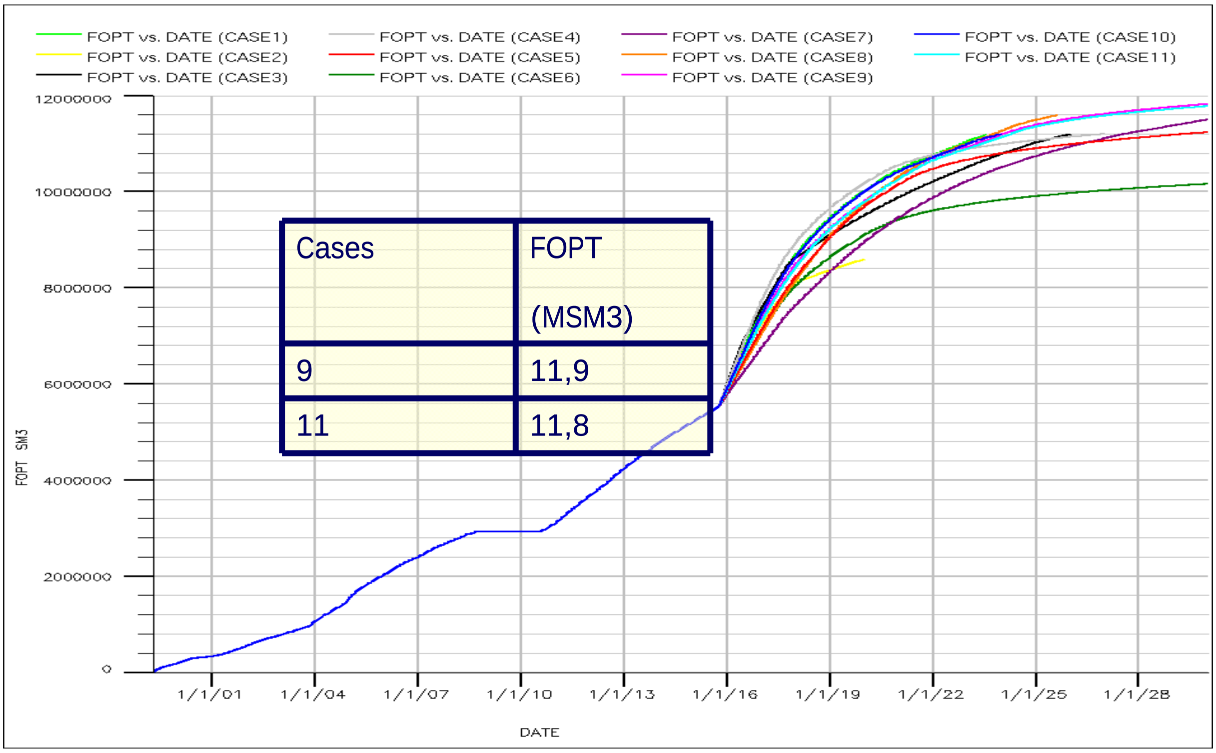


Figure 30 Comparison of total oil production (WI cases)

In Figure 30 the comparison of the total oil produced in the eleven cases can be observed. In some of the cases the simulation was stopped before 2030 because the pressure was too low and the producer could not work any longer. The two best cases are case 9 and case 11, and both cases have the same configuration in terms of well locations. A sensitivity analysis was performed by changing injection and production rates to improve case 9. The production is slightly lower in case 11, but is still considered as the best case taking all parameters in to consideration. The simulation results for this case will be presented in a separate sub chapter.

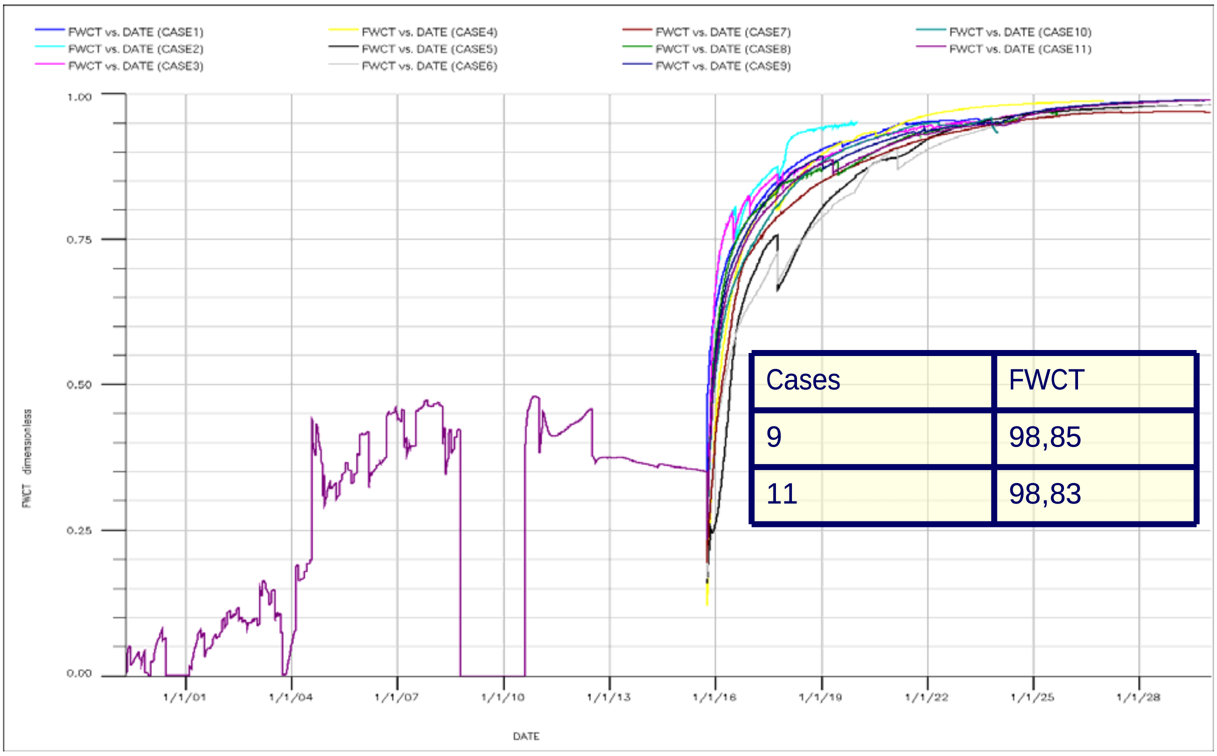


Figure 31 Water cut comparison (WI cases)

Figure 31 shows the water cut for the WI cases, it can be seen that the water cut is very high in all the cases, after the first year it is higher than 75% for all of them, and higher than 95% in the end of the simulation (year 2030). Several unsuccessful attempts were made to try to control the water produced in the reservoir by changing the injection rate and the separation of the injector from the producers but this did not influence the water cut. This is one of the cons of using water injection as an IOR method to exploit Gulfaks sør. Polymers might be considered to improve the mobility ratio to be more favourable for oil, but more importantly the production rates need to be adjusted to avoid that the pressure around the wells falls below the bubble point pressure.

Pressure support of the reservoir is one main purpose for injecting water, in case 4, seven injectors were placed in the aquifer (3 in the north and 4 in the south) to keep the reservoir pressurized. Figure 32 shows the reservoir pressure in 2015 to the left and 2030 to the right. The field pressure in 2015 is around 380 Bars and in 2030 the field pressure have dropped to around 150 Bars in high saturated zone (blue area), which is bellow the bubble point. In the water zone (green area), the pressure is around 400 Bars. This demonstrates that the water injection is pressurizing the low oil saturation zone in the reservoir, and can not support the pressure in the high oil saturation zone where the producer wells are located, which is a clear indication of no communication between these two zones along the line which divides them (a sealing fault). After this unsuccessful simulation another case was made; this time injectors were located inside the high oil saturation zone but the Figure 33 shows the same situation as case 4. The Figure 34 shows the comparison of the pressures between 2015 and 2030 for the case 11, which is the best case from the production point of view, and it can be seen that the pressure drops by 2030. This shows several attempts to keep the pressure in the reservoir, but this method (water injection) seems to be unable to support the pressure in the reservoir.

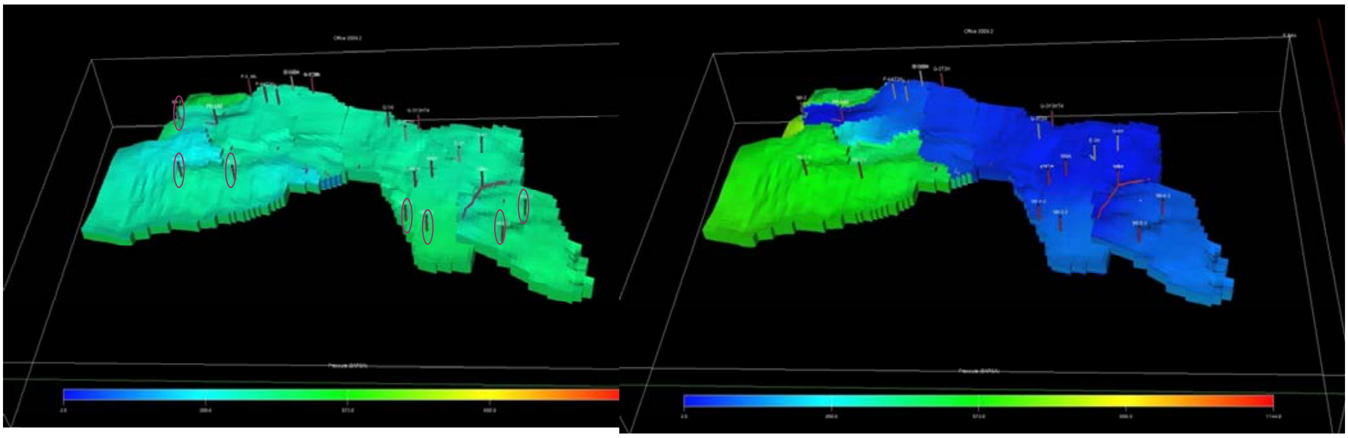


Figure 32 Comparison of pressure 2015 and 2030 (case 4)

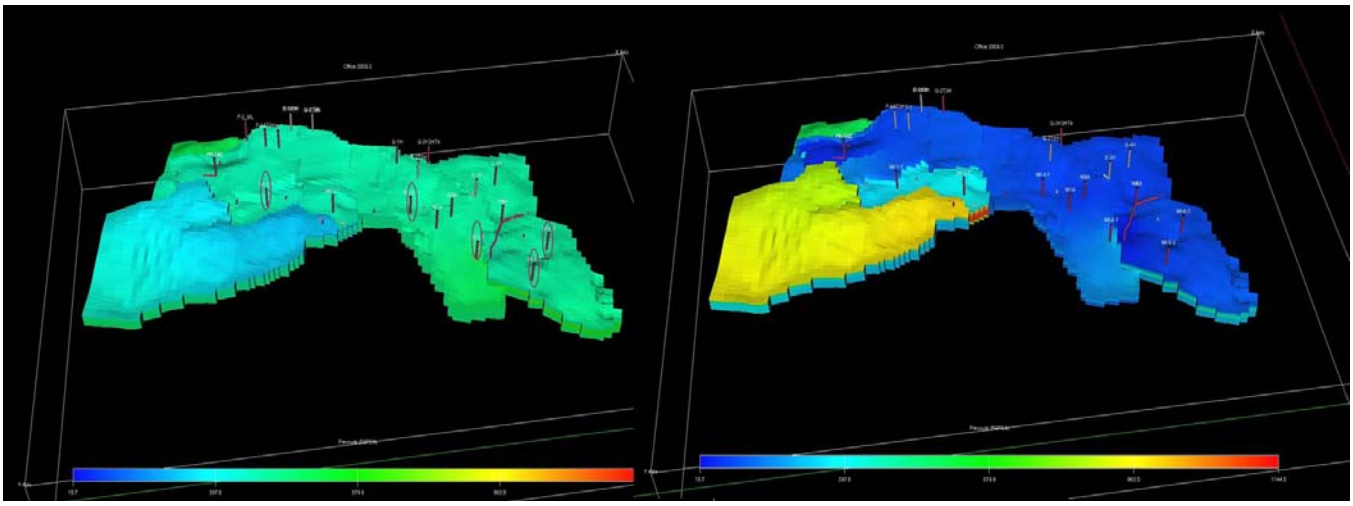


Figure 33 Comparison of pressure 2015 and 2030 (case 7)

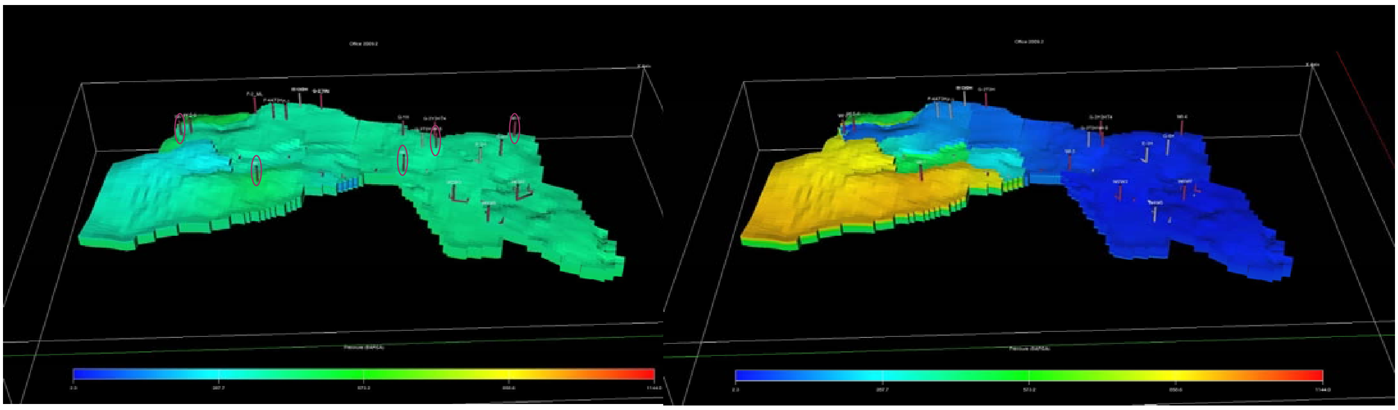


Figure 34 Comparison of pressure 2015 and 2030 (case 11)

10.1.2 WI Case 11

From the production point of view this is the best case obtained from the simulations of water injection (WI). This case includes the same producer wells as Reference Case and Extended Case, and 1 extra producer in the north segment A5.

Table 12 Oil rate target for the producers case 11

PRODUCER WELLS	SEGMENT LOCATION	OIL RATE TARGET
W-5-6	A5	300.000 Sm3/D
W2W3	A2	900.000 Sm3/D
W4W5	A2	600.000 Sm3/D
W6W7	A2	1000.000 Sm3/D

For the water injectors the strategy was to keep the reservoir pressurized as long as possible. The best results were obtained locating water injectors (WI-4 and WI-5) in the same position as the gas injectors of the Extended Case (GI-2 and GI-4). The water injectors were extended in order to inject in the water zone. In addition three more injectors were added, two in the north and one in the south.

Table 13 Injection rate data for the producers case 11

WATER INJECTORS	INJECTION RATE
WI-1	4000 Sm3/D
WI-2	4000 Sm3/D
WI-3	4000 Sm3/D
WI-4	4000 Sm3/D
WI-5	4000 Sm3/D

Figure 35 shows the configuration use in this case; new producers (red circles), and water injectors (violet circles).

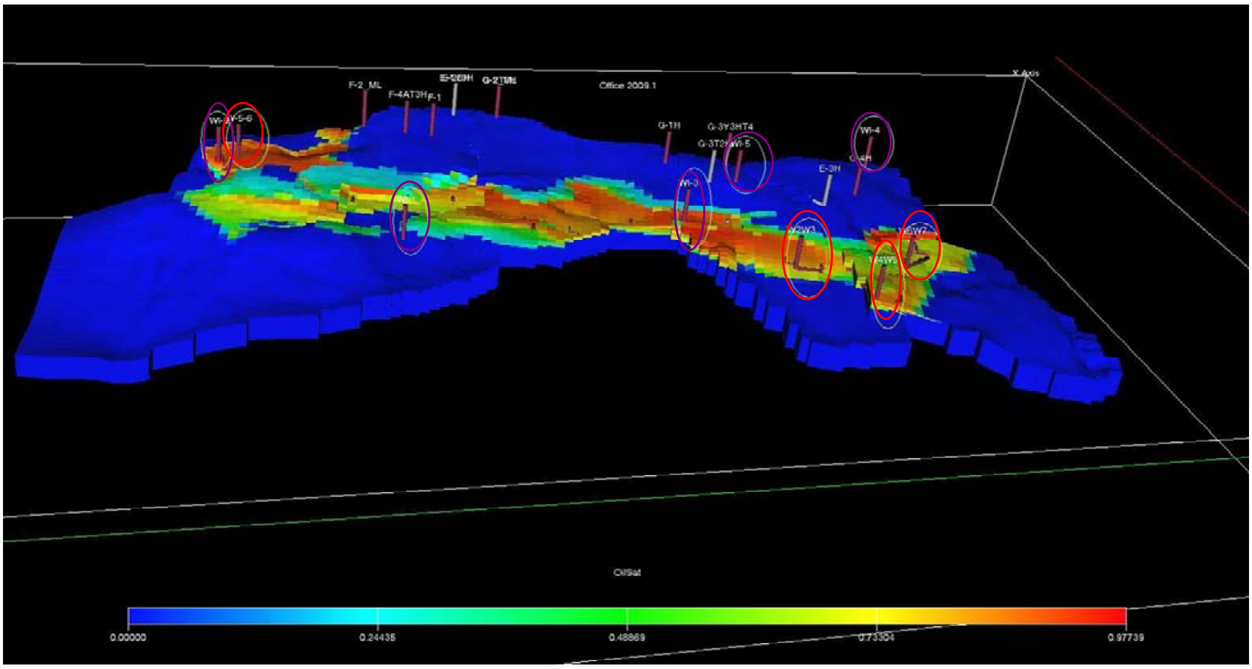


Figure 35 Configuration of producers wells and injectors

10.1.3 Results

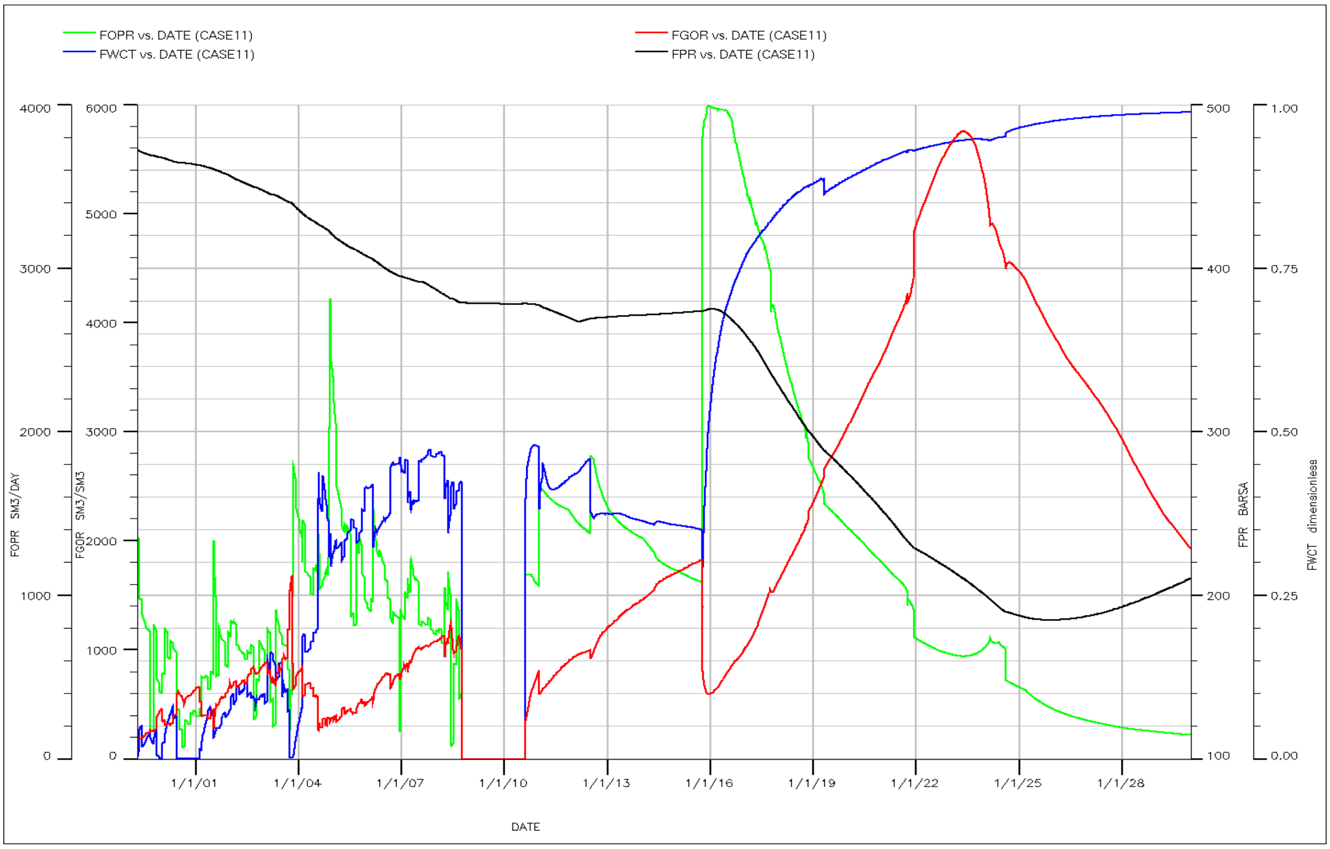


Figure 36 FOPR,FPR, FWCT and FGOR from case 11

In 2015, with the 5 new injectors and the 4 new producers, the rate of oil production increases dramatically (figure 36). The water cut increases quite rapidly, which could be a sign of water fingering. The pressure is dropping very quickly after the new wells start producing and injecting.

Measures such as lowering the water injection rate and reducing the oil production rate were taken in the simulation but this problem persisted; adding polymers to improve the mobility ratio (in favour of the oil) can help reduce the water cut, and could therefore improve the sweep efficiency.

The abrupt drop in GOR at the initiation of the new wells is probably an indication that the pressure around the wellbores has dropped below the bubble point. This means that the gas in the oil around the producers will come out of solution. Since a critical gas saturation is necessary to start moving this free oil, the GOR will be lowered, while this saturation is achieved. However, this critical saturation appears to be achieved rather quickly, as the GOR starts increasing almost immediately after the drop. The GOR then continues to increase, as the oil rate decreases, having a very steep increase around 2022, which is more or less when the field pressure reaches the bubble point pressure. The GOR then reaches a maximum, where it starts to decrease. This turning point coincides with a turning point for the pressure. At this point probably the gas is starting to run out, as both the GOR and the oil production rate are decreasing simultaneously. The pressure starts to increase at this point, because total produced fluids are decreasing and the injected fluids are still being injected at a constant rate. An additional consequence of the release of gas due to the pressure dropping below the bubble point around the wells would be the increase of the viscosity and density of the oil. This is most likely one of the main factors for the rapid increase of the water cut and its final level, as increasing the oils viscosity will turn the mobility ratio even more in favor of the water.

All these things considered we see the potential for improving the model. From a strictly reservoir engineering perspective, we could prolong the life of the reservoir and increase the sweep and the final recovery by decreasing even more both the production and the injection rates. Additionally it has become very clear that the pressure around the producing wells needs to be controlled, something that will with no doubt improve considerably the performance of case 11.

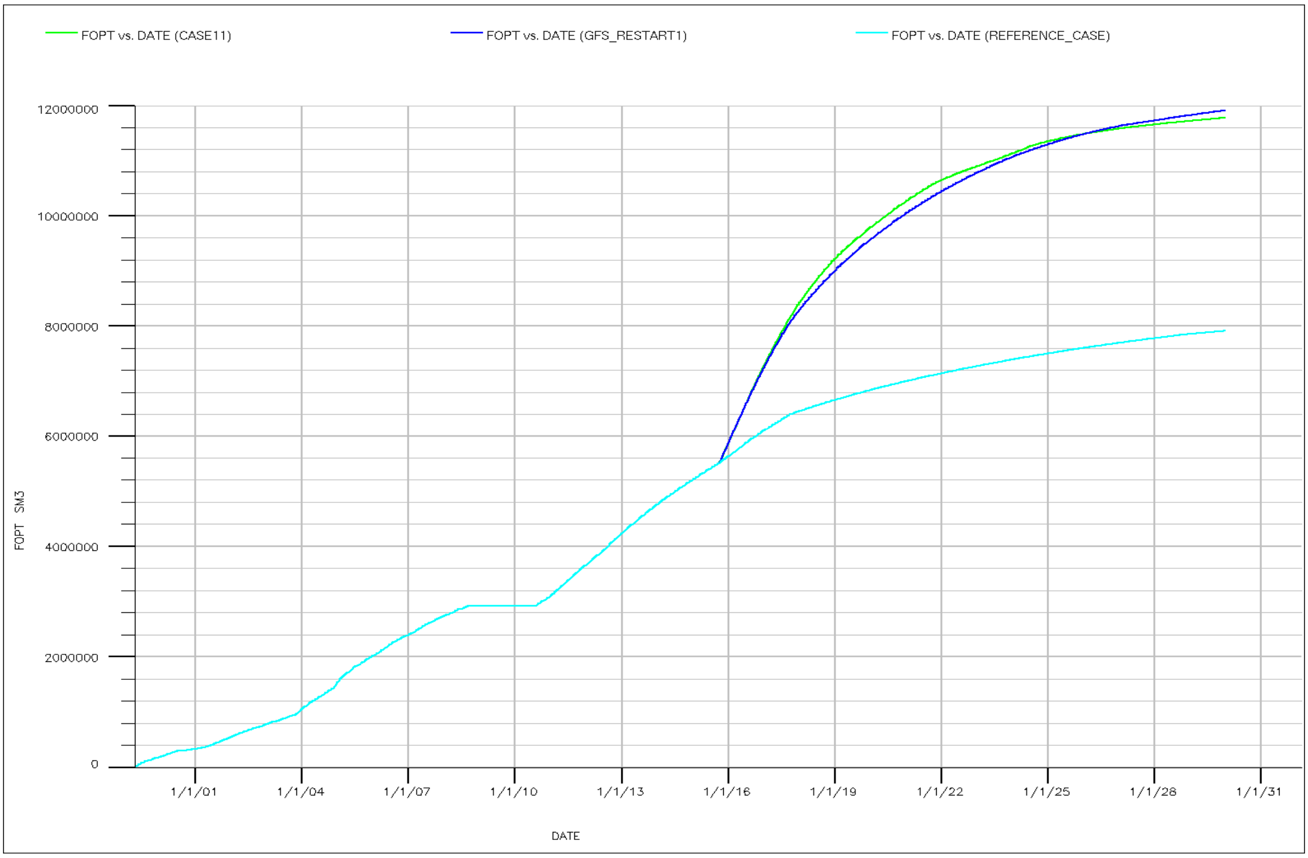


Figure 37 Difference in total oil production case 11, Extended Case and Reference Case

From Figure 37, it can be seen that the oil recovery in WI case 11 and Extended Case are a long way larger than the Reference Case, and the recovery in the Extended Case (gas injection) is 0,2% higher than WI case 11 (water injection).

Table 14 Recovery factor for Reference Case, Extended Case and case 1

Cases	FOPT(Sm3)	RF (STOOIP=42227633 Sm3)
Reference	7911706	0,187359
Restart	11911919	0,282088
11	11817941	0,279863

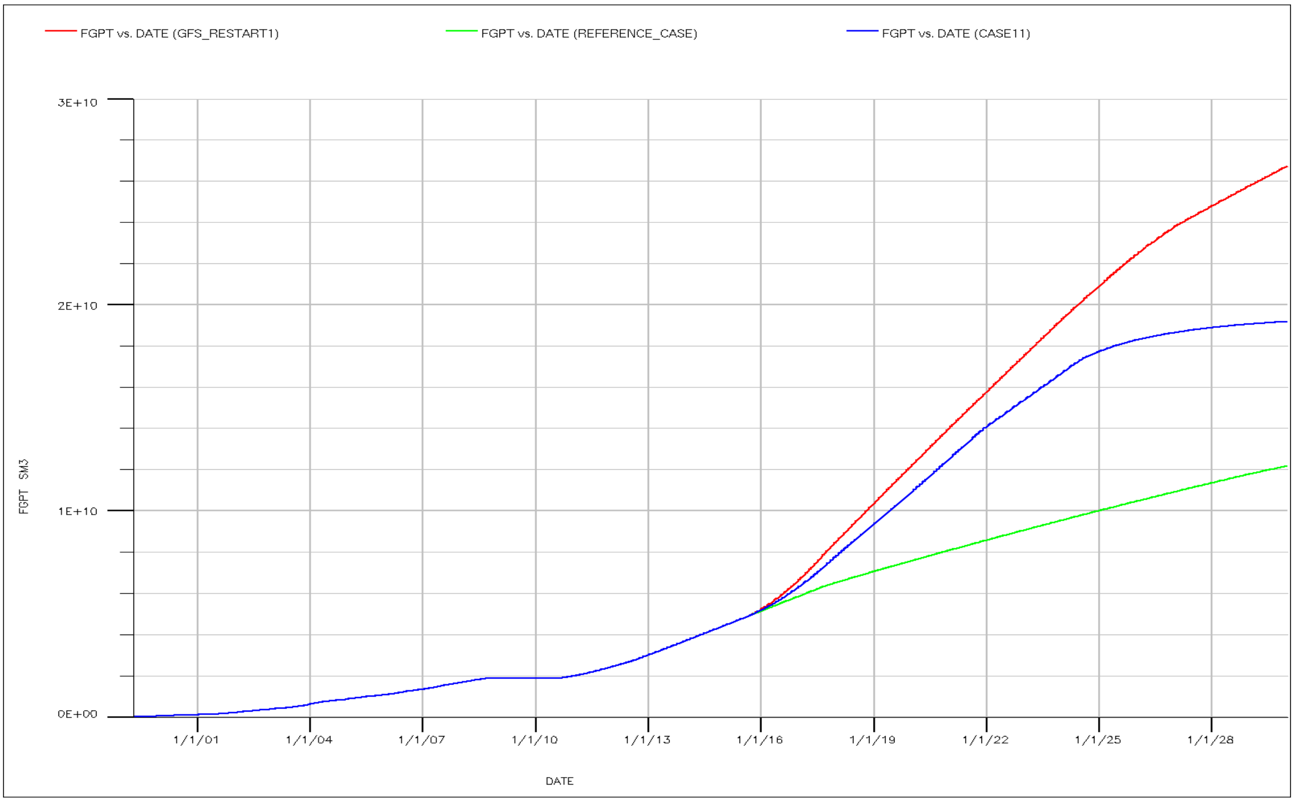


Figure 38 Total gas produced for Extended Case, Reference Case and case 11

The Figure 38 shows that Extended Case produces larger amount of gas as is expected from gas injection. The produced gas can be reinjected, and after oil production is uneconomical, a considerable amount of the injected gas can then be produced for sale or injection elsewhere.

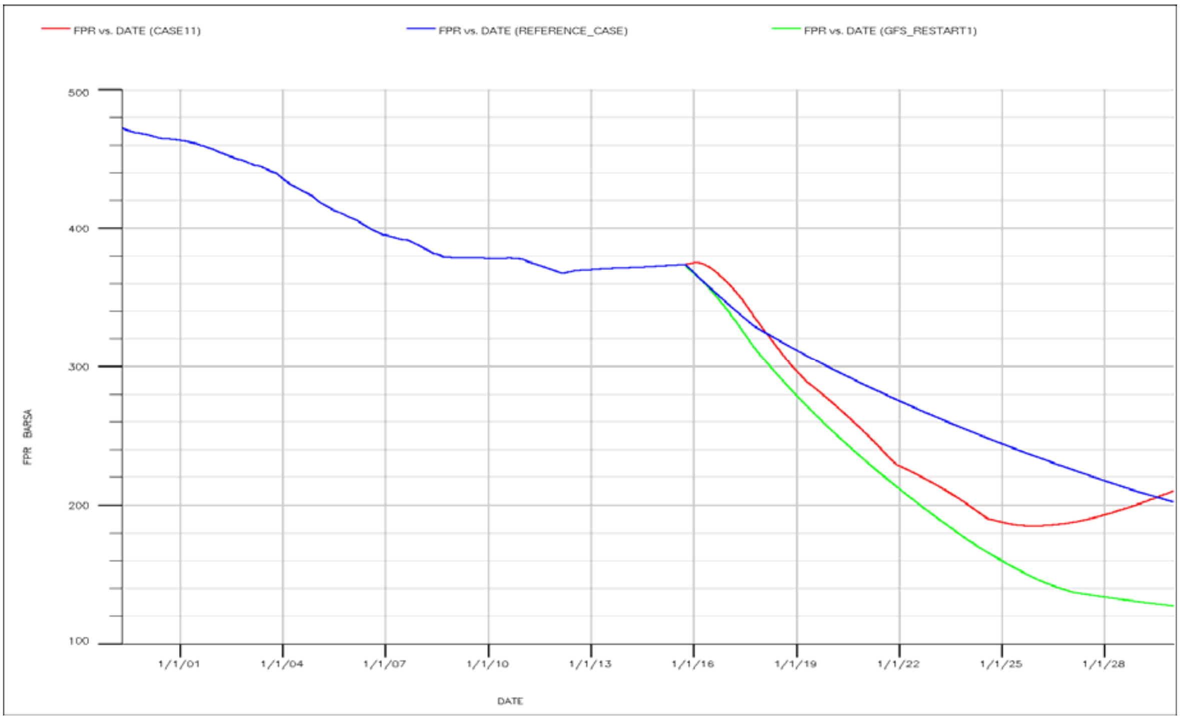


Figure 39 Field pressure for Extended Case, Reference Case and case 1

Figure 39, in this figure we can see how the field pressure drops below bubble point by 2028 for the reference case, by 2023 for case 11 and by 2021 for the extended case. After this the field can still be produced as an oil field as long as the economics are favorable, and then finally it could be changed into a gas reservoir, to recover the gas left in the reservoir. However, it is important to avoid "early" release of gas around the producer wells.

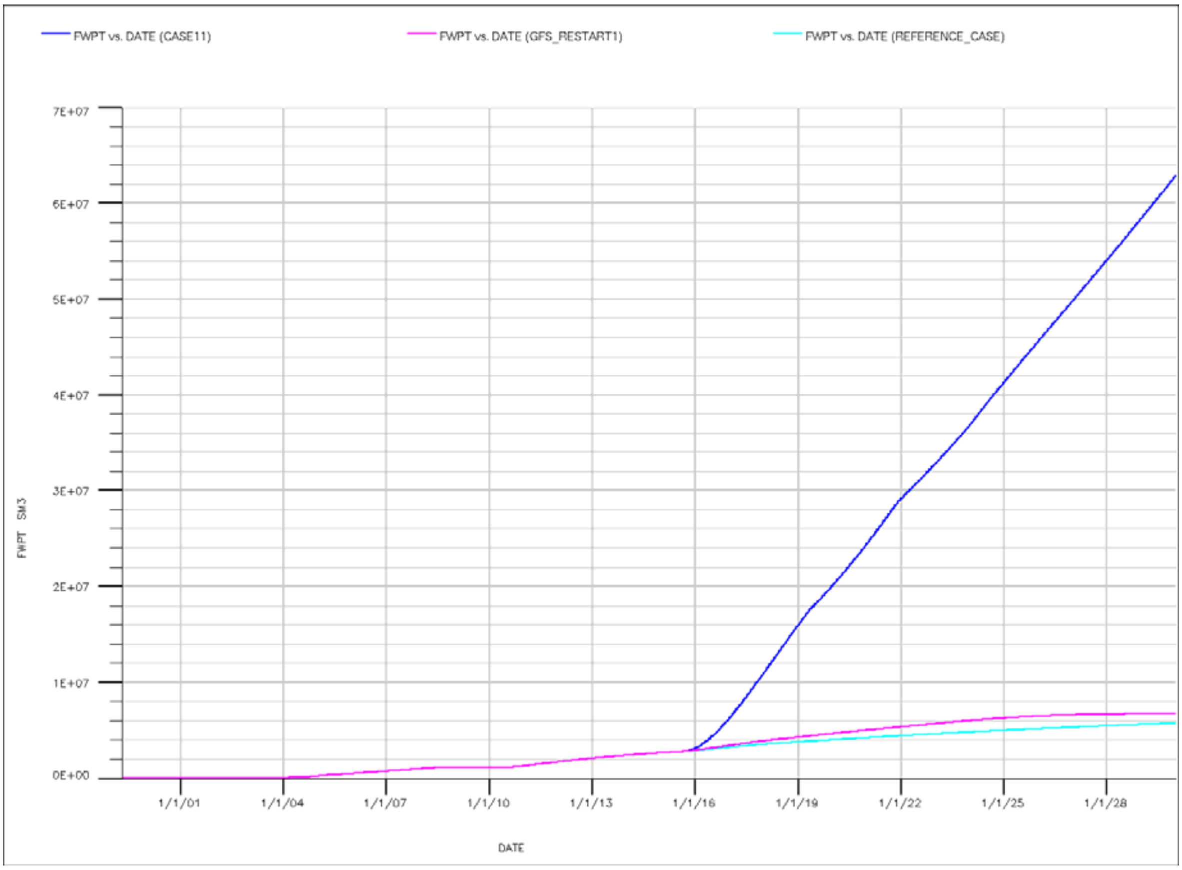


Figure 40 Water cut for case 11, reference and Extended Case

Figure 40 shows an extremely high water production (case 11), this is due to the quick water break through caused by the large aquifer and the high injection rate, and the previously discussed issue with the pressure drop around the producers causing the release of gas, and the increase of viscosity of the oil.

10.2 WAG injection

To do the WAG- simulation gas- and water injectors were placed in the same positions. The cycling between water and gas were done by using the WCYCLE keyword in eclipse.

The simulations were done from October 2015 up to 2030.

The restrictions on injection rates given by Statoil are:

- Max. 4000 Sm^3 water/d
- Max. 6 000 000 Sm^3 gas/d

WAG – Case 1

In this case the same well configuration as in WI case 11 has been used, only replacing the water injectors with "WAG- injectors" as described above.

Table 15 Injection data for WAG case 1

WELL	Gas injection rate [Sm3/d]	Water injection rate[Sm3/d]
WI-1/GI-1	1200000	4000
WI-2/GI-2W	1200000	4000
WI-3/GI-3	1200000	4000
WI-4/GI-4W	1200000	1000
WI-5/GI-5	1200000	4000

In this case water and gas were injected with the same rate in all wells. See Table 15. The injection cycle used in the simulation was: 60 days of water and 60 days of gas.

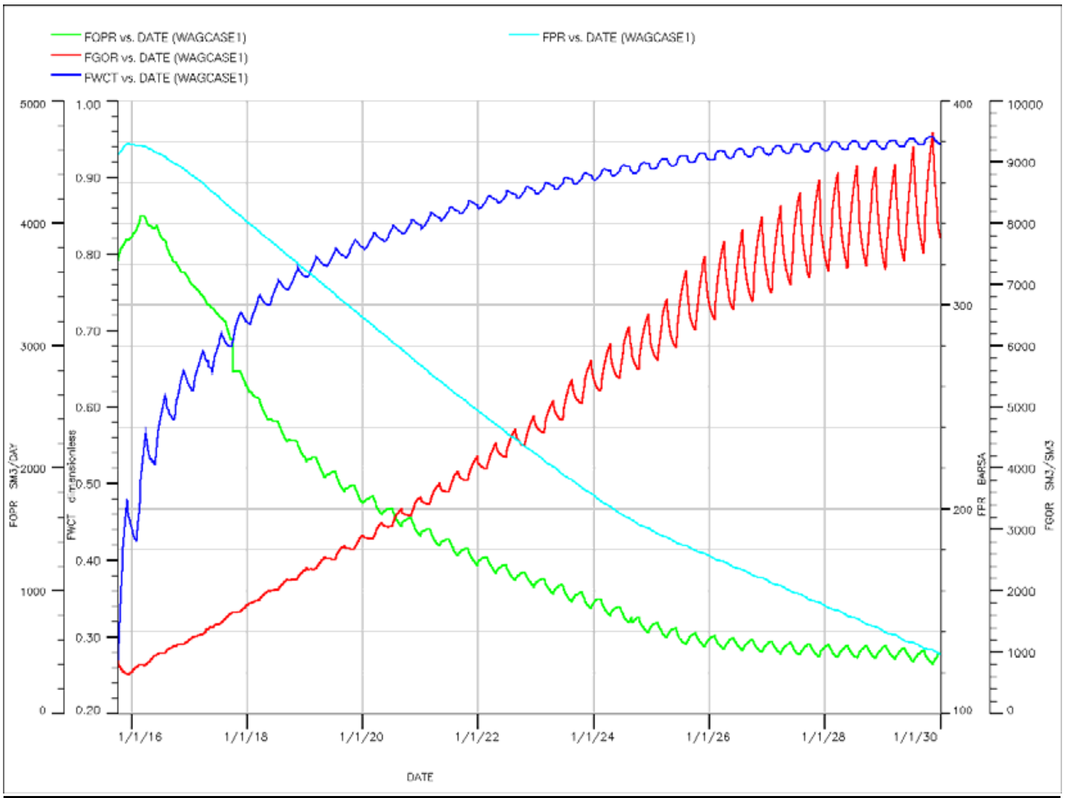


Figure 41 FOPR,FPR, FWCT and FGOR from WAG case 1.

Figure 41 shows the Field oil production rate, Field water cut, Field Gas to oil ratio and Field pressure. The water cut is extremely high (~95% in 2030), but we are still having a reasonable production of oil. During the whole production period the pressure drops from 500 Bars to nearly 100 Bars, that is a total pressure loss of 400 Bars. This means that the injection being done is not helping much to maintain the pressure in the field, which again can keep the production going for many more years. Also note the oscillation of the curves due to alternating water and gas injection. Since the pressure has dropped to far beneath the bubble point (220 bars) there is a lot of gas coming out of solution and therefore an increasing trend in the Gas to oil ratio (GOR). Figure 42 is showing the pressure in the field in 2015 vs. the pressure in 2030.

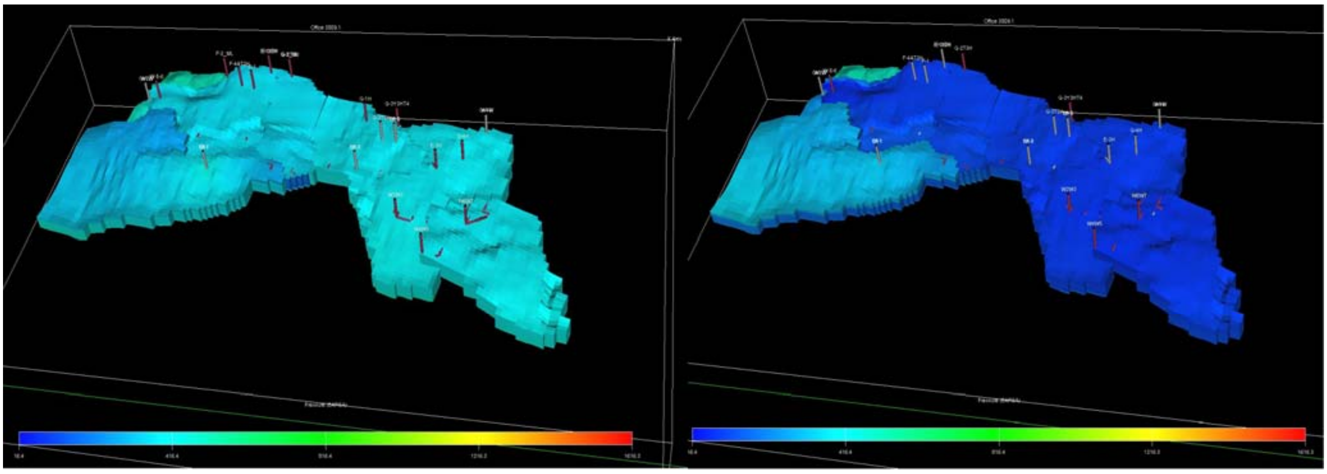


Figure 42 Pressure distribution in field. Left: 2015, Right: 2030

There is extremely high water cut after only a short time of injection (Figure 41). This could possible mean that the injectors are placed too close to the producers, or that the injectors are perforated in a zone with higher permeability than the surroundings, leading to a quick water break through. In injector wells WI-4/GI-4W and WI-5/GI-5 we notice that the bottom hole pressure (BHP) drops during the injection period, even though the injection is with constant rate (Figure 43). This is a clear indication that the water and gas which are being injected are going straight to the producers, and are not doing what they are thought for. These injectors should therefore bee placed differently in order to improve the result.

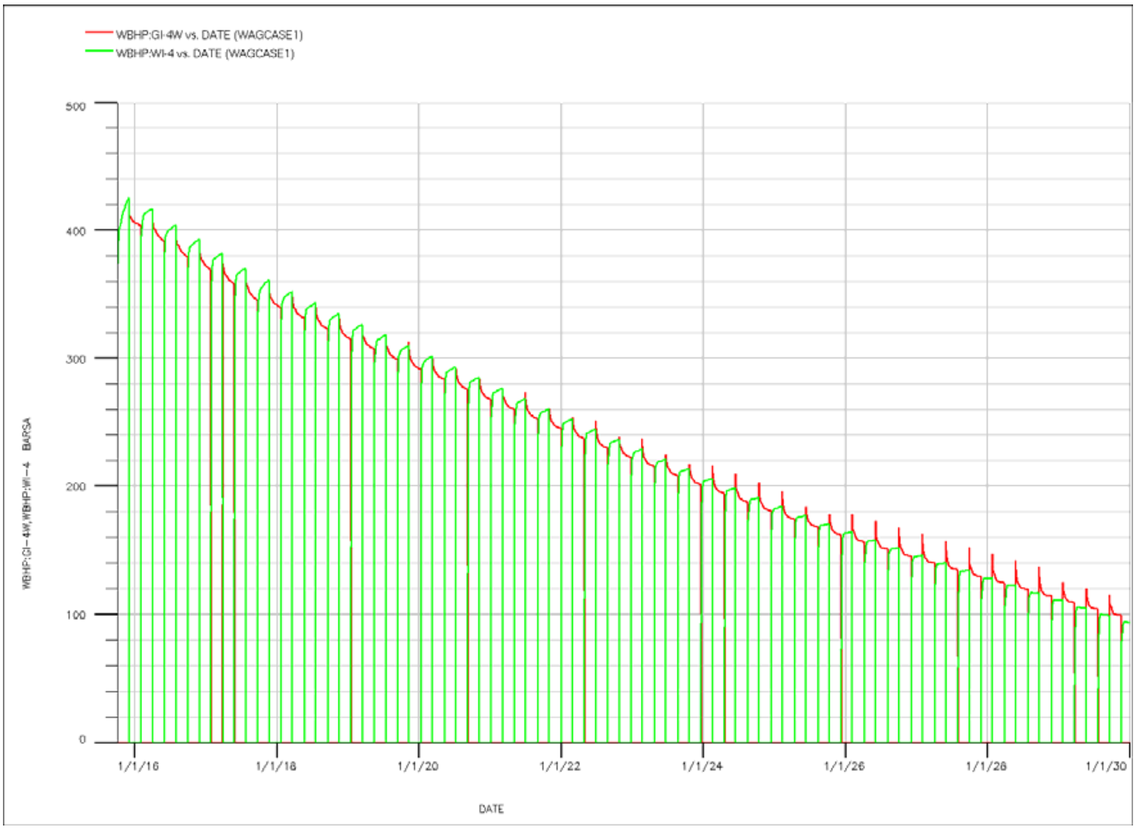


Figure 43 BHP in injector well WI-4/GI-4W

The pressure in the injectors shows a difference between when water and gas are being injected (Figure 43 and Figure 44). This implies that the injection rates used are not optimal. A quick calculation showed that the injected volumes are not the same at reservoir conditions. The injected volume of water is larger than that of gas. The wanted thing is to keep the pressure in the injector well, as stable as possible. This can be done by injecting the same volume of both phases.

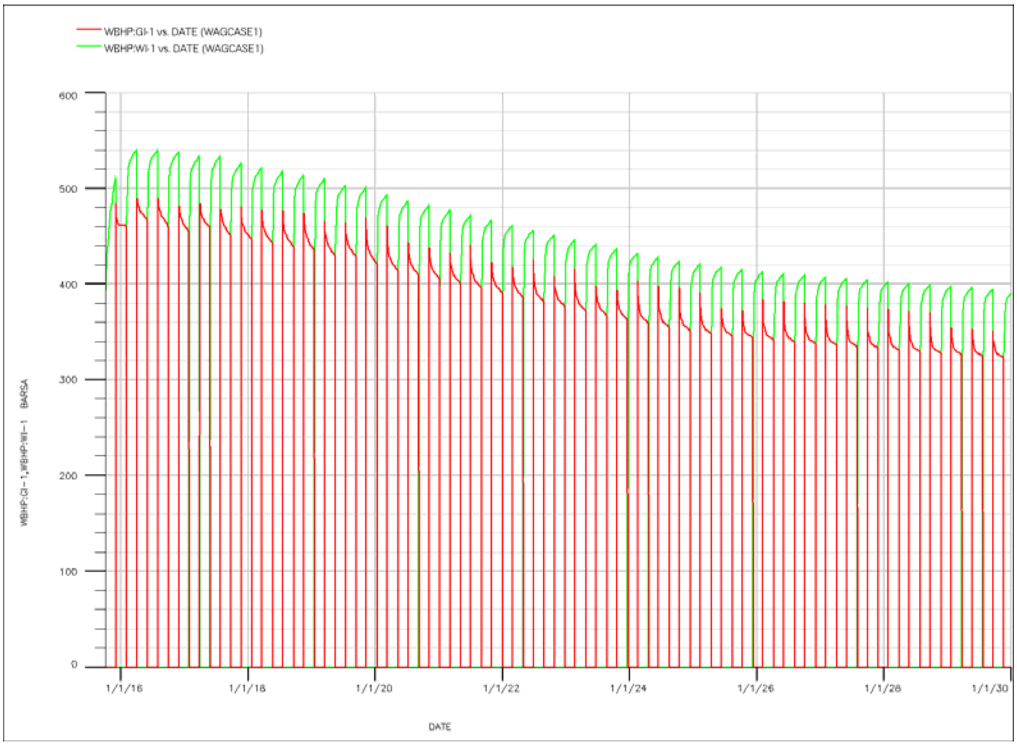


Figure 44 Pressure difference between injected phases in injector well WI-1/GI-1.

10.2.1 WAG - case 6

In the first WAG case there was a major problem with the pressure drop in the field. In WAG case 1 the maximum rates of injection given by Statoil is used. To manage the problem with different volumes being injected a reduction of the water injection rate were tried. This did not change the results at all. Then the injection rate of gas was increased with 0.5 mill Sm^3/d total in the field. This means that in this case 0.5 million Sm^3/d more than the limit given are being injected.

Table 16 Injection data for WAG case 6

WELL	Gas injection rate [Sm3/d]	Water injection rate[Sm3/d]
WI-1/GI-1	1300000	4000
WI-2/GI-2W	1300000	4000
WI-3/GI-3	1300000	4000
WI-4/GI-4W	1300000	1000
WI-5/GI-5	1300000	4000

The simulation was run with the same cycling as for the WAG case 1: 60 days of water followed by 60 days of gas.

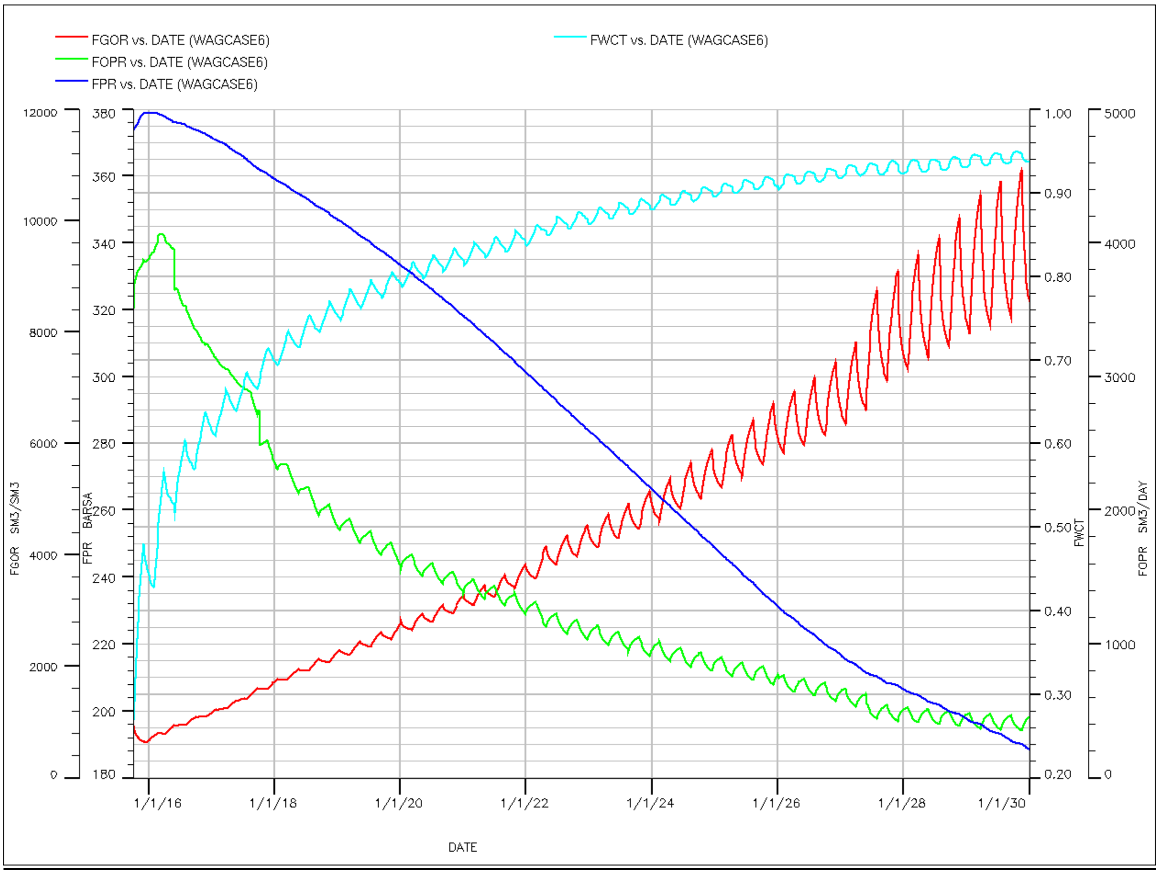


Figure 45 FOPR, FPR, FWCT and FGOR for WAG case 6

The results show that the field pressure is declining in this case as well, but here the minimum pressure is 190 Bars (Figure 45). This means that increasing the gas injection rate with 0.1 mill Sm^3/d in each well was successful from the pressure point of view. Figure 47 show the comparison of field pressure in the two cases. The results also show that the total water- and gas production have been reduced compared to WAG case 1 (Figure 48 and Figure 49). On the other hand the total oil production is less than for the WAG case 1 (Figure 50).

Despite the fact of smaller total production compared with the WAG case 1, this case gives a better total result. Being able to maintain the field pressure better by changing the injection rates of gas can extend the total life time of the field by years; remember there was still some oil production when the pressure was near 100 Bars in WAG case 1. The fact that there are less water and gas being produced is also a contributor and a reason for comparing WAG case 6 to the best WI case.

Table 17 Differences between Wag case 1 and WAG case 6.

	Total Oil production [Sm3]	Total water production [Sm3]	Total gas production [Sm3]	Min pressure [Bar]
WAG case 1	13200000	4.2E7	3.8E10	130
WAG case 6	12900000	3.8E7	3.7E10	190
Difference	2.3 %	10.7 %	3.6 %	60

The problems with the injector wells WI-4/GI-4W and WI-5/GI-5 mentioned under WAG case 1 is still a problem in this case. These injectors should be replaced.

There is still not being injecting the same volume of water and gas. Figure 46 shows the BHP of injector well WI-1/GI-1, and there is still a pressure difference between the two injected phases, but all in all there is a more stable trend compared to the situation in WAG case 1.

This case was run to see if a change in the gas injection rate had a positive effect on the result, because of the limitation given by Statoil. As shown by the simulation result this small change has a major effect, especially on the field pressure. It could therefore be a good idea, if possible, to increase the gas injection rate even further so the injected volumes are the same.

Figure 46 BHP in injector well WI-1/GI-1 WAG case 6

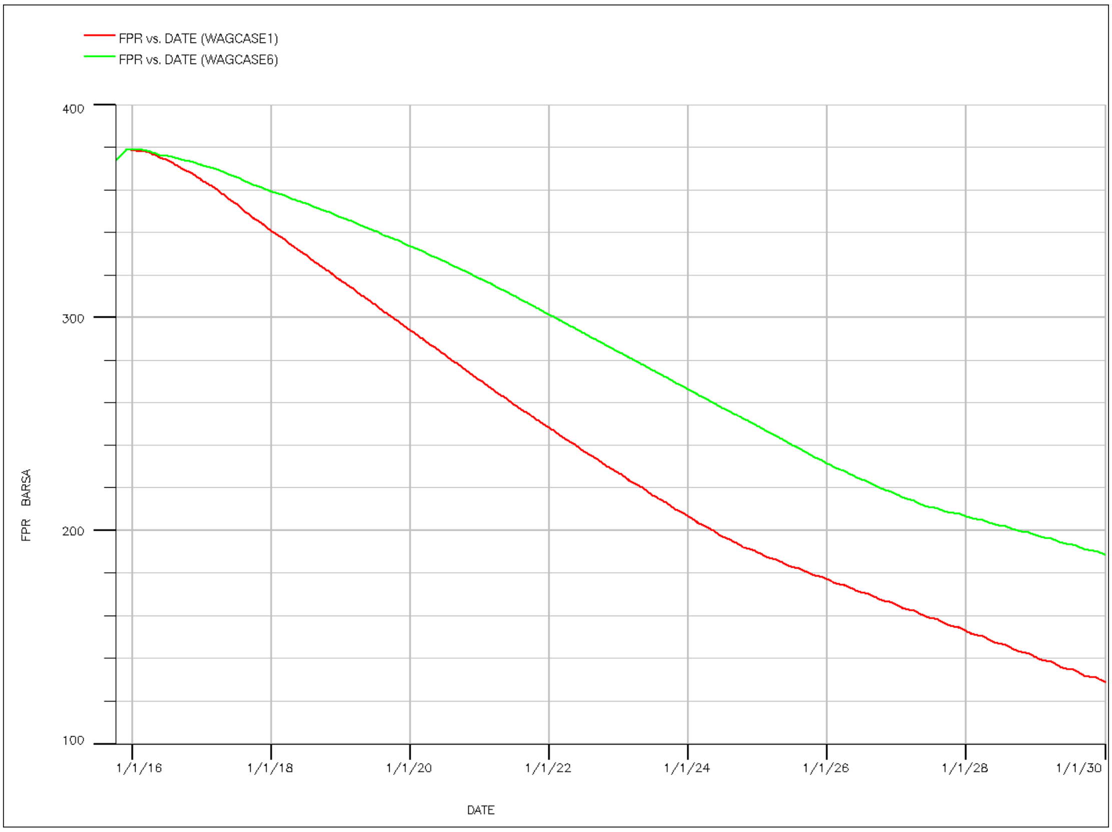


Figure 47 Difference in FPR WAG case 1 and WAG case 6

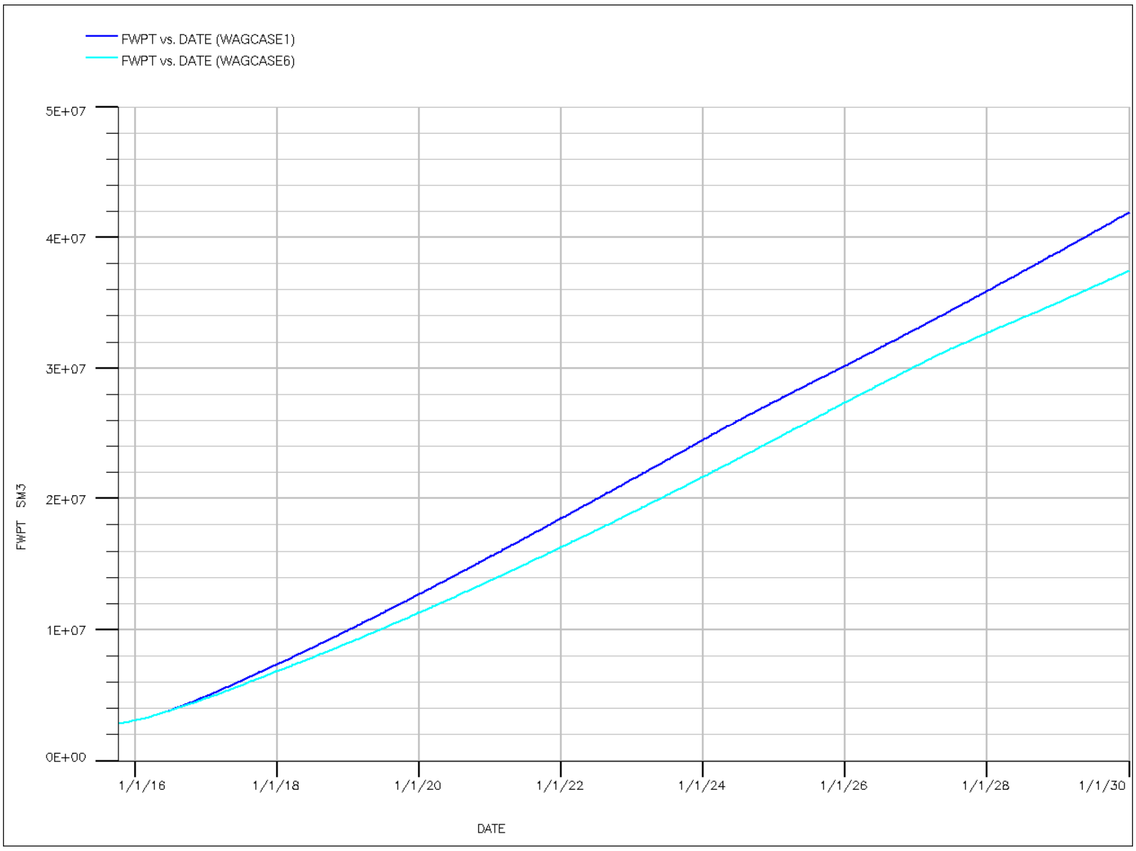


Figure 48 Difference in water production WAG case 1 and WAG case 6.

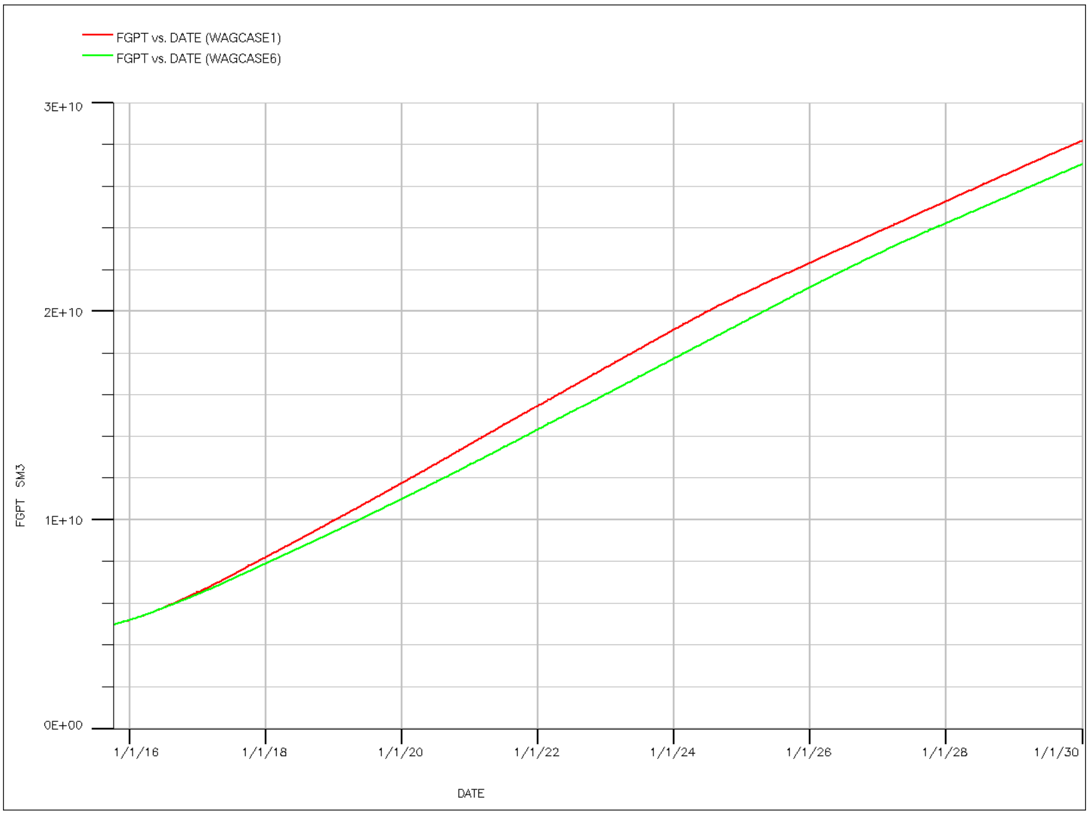


Figure 49 Difference in Gas production WAG case 1 and WAG case 6.

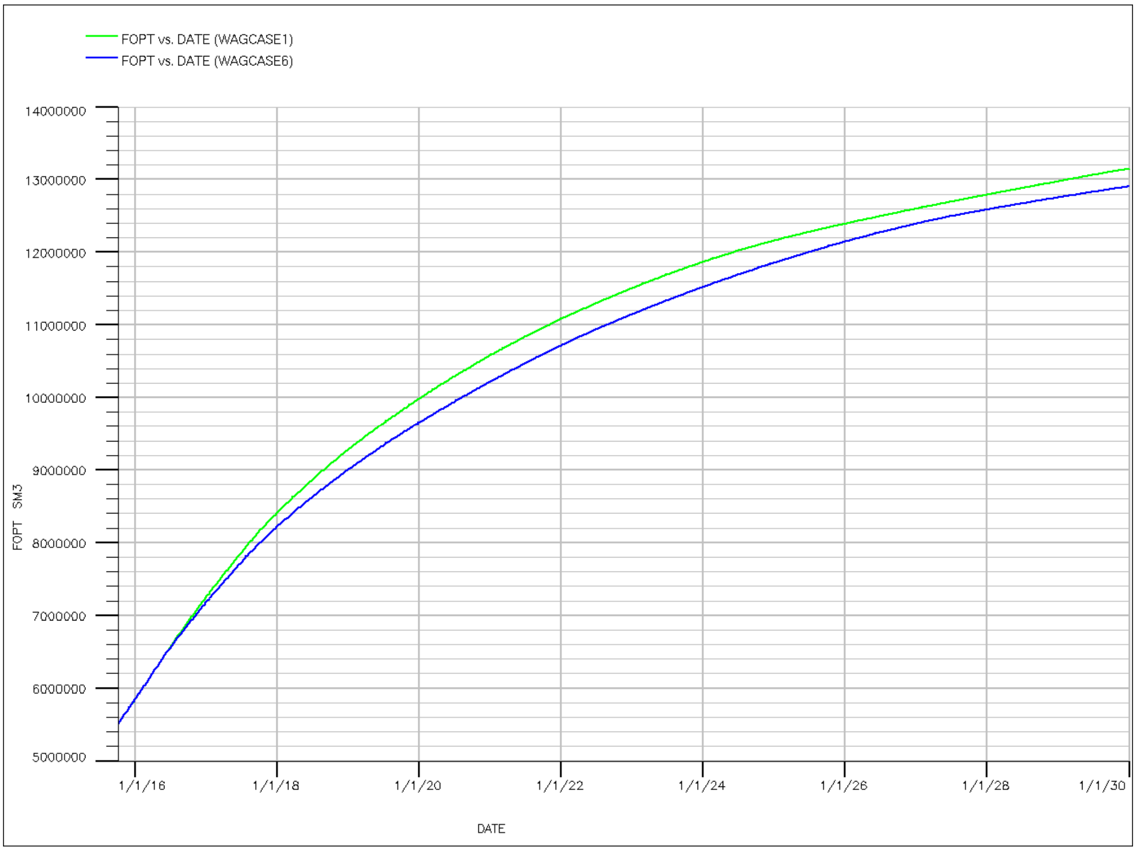


Figure 50 Difference in total oil production WAG case 1 and WAG case 6.

11 COMPARISON WAG CASE 6 AND WI CASE 11

When comparing the results from the best WI case and WAG case, the WAG case is producing approximately 8% more than the WI case. (Table 18Table 18: Total Oil production, and Water cut; Reference Case, WI case 11 and WAG case 6.) This is what we should expect to get according to the theory.

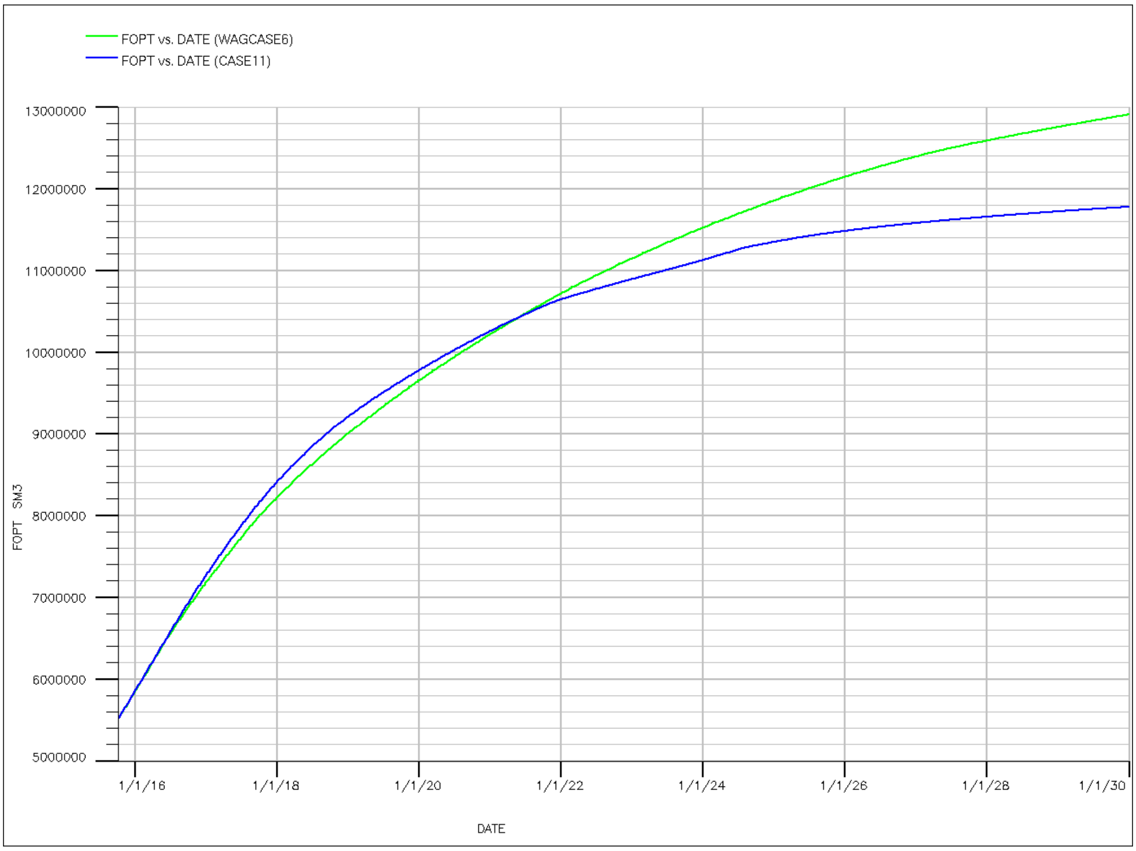


Figure 51: Total Oil production for WI case 11 and WAG case 6.

Table 18: Total Oil production, and Water cut; Reference Case, WI case 11 and WAG case 6.

Case	Total Oil production [Sm3]	Recovery factor	Max Water cut
Reference Case	8000000	0.19	0.7
WI case 11	11817941	0.28	0.98
WAG case 6	12932515	0.31	0.95

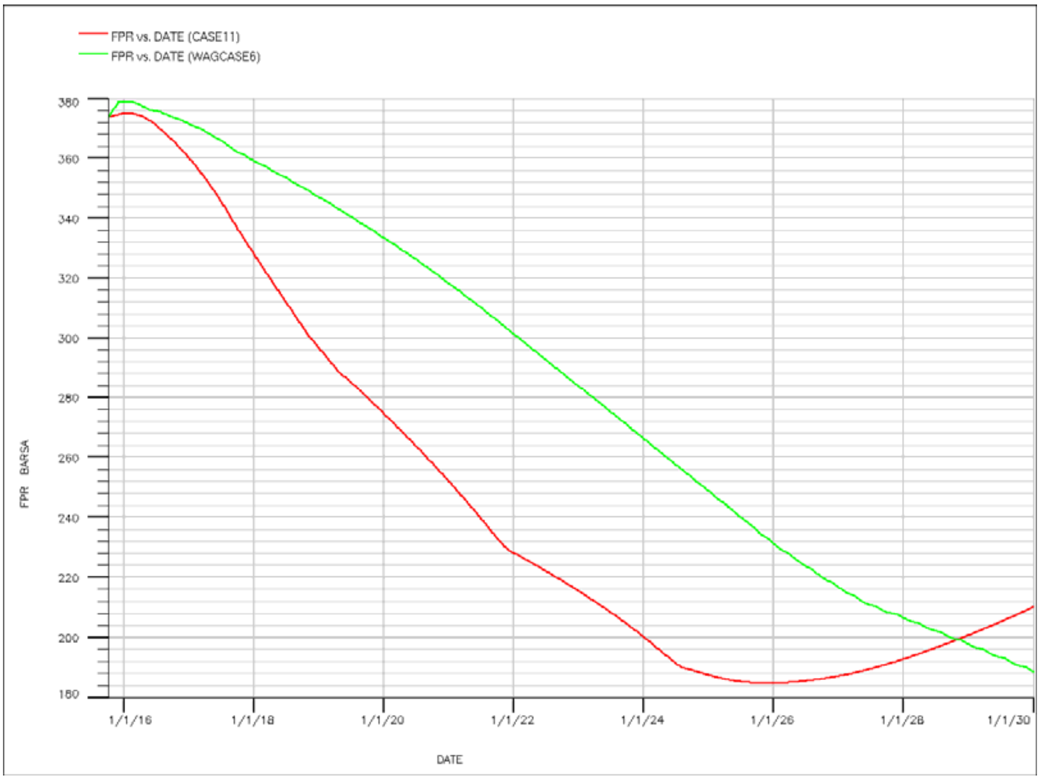


Figure 52 Field pressure for WAG case 6 and WI case 11

The pressure in the field is dropping in both cases. See Figure 52. But the pressure in WAG case 6 is at a higher level and more stable than for the WI case 11. The main purpose with injection is to give pressure support to the reservoir. The results show that a WAG injection is more successful in this matter than WI.

The total water production is lower using WAG injection compared to WI (Figure 53), but the gas production is at a higher level (Figure 54) This could be explained by the previous mentioned problem with injected fluids going straight to producers from injectors WI-4/GI-4W and WI-5/GI-5.

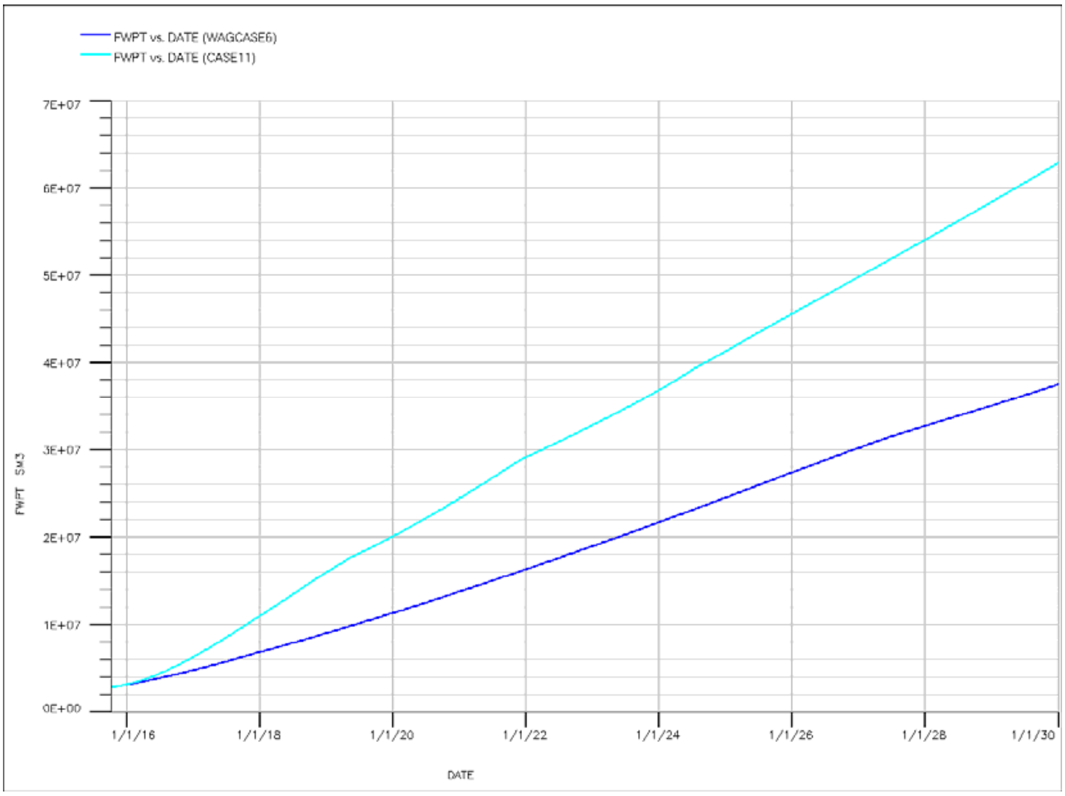


Figure 53 Total water production WAG case 6 and WI case 11

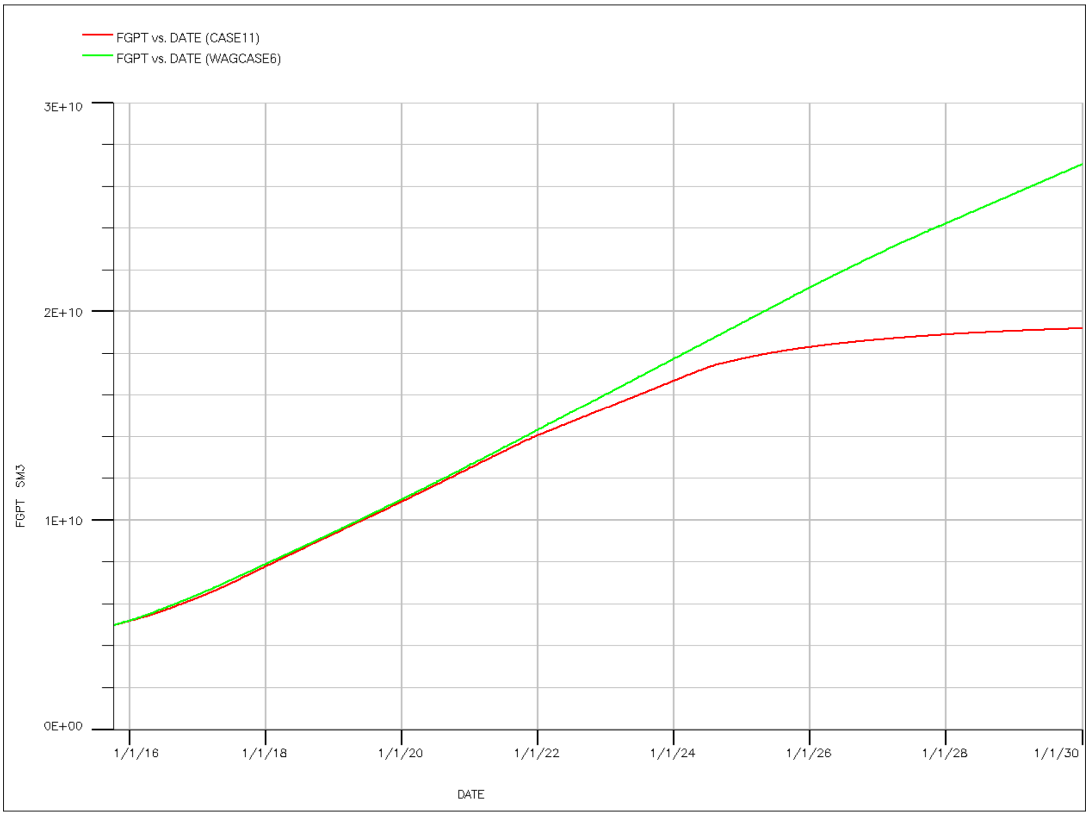


Figure 54 Total gas production WAG case 6 and WI case 11.

12 CONCLUSION

12.1 Part A

History matching for the oil production rate and gas production rate is overall quite good. However for the water cut the model gives overestimated results. When comparing the Reference Case with the Extended Case there is a big increase in production when the new wells start producing. Within a year the production already starts to decrease. This is the same trend for the new wells, W1, W2W3, W4W5 and W6W7. All the wells have the same expected behaviour with pressure drop, increase in GOR and water cut. One well, W6W7, stands out with a lower water cut than the rest. The production in this well is decreasing with the same amount as the others; this leads us into believing the main reason for the decrease is the pressure drop and the increase in gas production.

For the economical evaluation two options for drilling the new wells were studied, a subsea solution and a platform solution. Based on our assumptions the Subsea solution is the most profitable. There are a lot of uncertainties in our calculations, but in the sensitivity analysis we isolated some of the variables so we can see the effect of each one in the NPV. The study was limited to only two options, but there are more options that could be considered for drilling the wells, for example an extended reach well if the platform/templates capacity and the distance between the platform and well target allows.

The economic evaluation indicates that by 2025 the project will yield losses because the cost of operation and injecting gas becomes higher than the value of the produced hydrocarbons, by this time a new strategy should be implemented, for example the field strategy could be changed to gas production by depletion if the economic evaluation is favourable, this strategy is planned for the late life of the Statfjord field

12.2 Part B

The results from different simulations, have shown that a Water Alternating Gas (WAG) injection will give a higher recovery factor at Gullfaks Sør than with a conventional water injection. The field pressure will also be maintained better. Therefore a WAG solution is recommended strictly from a production point of view.

One of the cons of using WAG injection is the high water cut, which is up to 95%.

In WAG case 6, the pressure will drop in every production well from 2015. One reason could be that the production oil rate target is too high. A solution to keep the pressure more stable is to put other restrictions on the production rate, than them being used in the WAG cases. This in addition to optimize the injection rates could probably help to get more pressure support from the injected fluids.

There have also only been run simulations with 60/60 days cycling. This is not necessary the best alternating cycle. There should be done simulations with longer injection periods and with different periods for water and gas to see which effects it has on the result.

As mentioned the positioning of both injector and producer wells could be optimized further. The perforation in the wells should also be looked at closer, since there are indications of injecting water into a “thief zone”.

Since it is so important to keep the pressure in the field, the possibility of closing the field for production to build up the pressure, as done in October 2008, should be considered. A shut in should be done before reaching the bubble point pressure.

All these things considered, show potential for improving the recovery from Gullfaks Sør using WAG. However without an economical evaluation it will not be clear how much the benefits of an improved sweep will be.

13 REFERENCES

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14 APPENDIX

APPENDIX A.1

Option 1(base case): Drilling from a ship to the subsea template

Oil price	75	USD/Bbl	2830,41495 NOK/Sm^3
Gas price	2	NOK/Sm^3	
Oil price development	0,1		
Gas price development	0,1		
Exchange rate	6	NOK/USD	
Discount rate	0,08		

								CAPEX			OPEX					
YEAR	YEAR	Oil production	Gas production	Gas Injection	Gas Sale	Revenue from Oil	Revenue from Gas	Production unit	Subsea Pipeline	Drillex	Field/onshore	Oil/Gas transportation	CO2 duty	Net Cash Flow	PV cash flow	Cumulative PV Cash Flow
PROJECT	CALENDER	sm3	Gsm3	Gsm3	Gsm3	NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK	MNOK	MNOK	MNOK
1	2011	0	0	0	0	0,00	0,00	-300000000	-500000000	-300000000	0	0	0	-1100,00	-1018,52	-1018,52
2	2012	0	0	0	0	0,00	0,00	-200000000	-1000000000	-200000000	-20000000	0	0	-1420,00	-1217,42	-2235,94
3	2013	0	0	0	0	0,00	0,00	-200000000	-800000000	-100000000	-60000000	0	0	-1160,00	-920,85	-3156,79
4	2014	0	0	0	0	0,00	0,00	-185000000	-1000000000	-400000000	-30000000	0	0	-1615,00	-1187,07	-4343,86
5	2015	235978,2552	0,272652617	0,876	-0,603347383	1075686011,22	-1943393986,97	0	0	0	-200000000	-22264548,37	-30000000	-1119,97	-762,23	-5106,09
6	2016	909266,316	0,701911246	0,876	-0,174088754	4559291115,90	-616817694,62	0	0	0	-250000000	-85789276,92	-30000000	3576,68	2253,92	-2852,18
7	2017	693888,994	1,230293397	0,876	0,354293397	3827268267,86	1380835202,54	0	0	0	-230000000	-171756445,7	-20000000	4786,35	2792,79	-59,39
8	2018	509591,9232	1,326605867	0,876	0,450605867	3091819463,13	1931827388,71	0	0	0	-280000000	-183261758,1	-20000000	4540,39	2453,03	2393,64
9	2019	390104,364	1,317799843	0,876	0,441799843	2603544976,32	2083481840,74	0	0	0	-260000000	-169346299,7	-20000000	4237,68	2119,90	4513,54
10	2020	311488,8068	1,306576365	0,876	0,430576365	2286753783,09	2233608400,65	-50000000	0	0	-200000000	-158561878,4	-20000000	4091,80	1895,30	6408,83
11	2021	257187,607	1,297960683	0,876	0,421960683	2076919594,73	2407806150,14	0	0	-35000000	-200000000	-150853855,7	-20000000	4078,87	1749,36	8158,19
12	2022	208676,7992	1,287235966	0,876	0,411235966	1853687400,42	2581269248,98	0	0	0	-220000000	-143059445,7	-15000000	4056,90	1611,05	9769,24
13	2023	170946,384	1,274039047	0,876	0,398039047	1670378667,96	2748277484,94	0	-100000000	0	-180000000	-135540505,3	-15000000	3988,12	1466,42	11235,66
14	2024	118191,7592	1,180563852	0,876	0,304563852	1270383657,89	2313161445,54	0	-100000000	0	-180000000	-102520548,2	-15000000	3186,02	1084,72	12320,38
15	2025	87701,04675	1,087712446	0,876	0,211712446	1036919791,22	1768750857,57	-100000000	0	0	-170000000	-71788327,65	-15000000	2448,88	771,99	13092,37
16	2026	53051,3585	0,881072646	0,876	0,005072646	689969004,71	46617345,38	0	0	0	-170000000	-6527189,563	-15000000	545,06	159,10	13251,47
17	2027	18103,62965	0,588433791	0,876	-0,287566209	258995020,16	-2906989714,60	0	0	0	-150000000	-1708077,457	-15000000	-2814,70	-760,73	12490,74
18	2028	18761,0254	0,545238539	0,876	-0,330761461	295239875,69	-3678012752,82	0	0	0	-130000000	-1770102,747	-10000000	-3524,54	-882,01	11608,73
19	2029	32325,2428	0,565872459	0,876	-0,310127541	559568067,72	-3793423666,07	0	0	0	-130000000	-3049886,658	-10000000	-3376,91	-782,47	10826,26
20	2030	32330,5831	0,568356517	0,876	-0,307643483	615626562,44	-4139343038,21	0	0	0	-130000000	-3050390,515	-10000000	-3666,77	-786,70	10039,56
	TOTAL	**4047594,095**	**15,43232528**	**14,016**	**1,416325282**	**27772051260,46**	**2417654511,91**	**-1035000000**	**-3500000000,00**	**-1035000000,00**	**-3190000000,00**	**-1410848536,78**	**-280000000,00**			

Appendix A.2
Option 1 (high case): Drilling from a ship to the subsea templates

Oil price	105	USD/Bbl	3962,58093	NOK/Sm^3
Gas price	2,8	NOK/Sm^3		
oil price development	0,15			
gas price development	0,15			
exchange rate	6	NOK/USD		
discount rate	0,05			

								CAPEX-40%			OPEX-40%					
YEAR	YEAR	Oil production	Gas production	Gas Injection	Gas Sale	Revenue from Oil	Revenue from Gas	Production unit	Subsea Pipeline	Drillex	Field/onshore	Oil/Gas transportation	CO2 duty	Net Cash Flow	PV cash flow	Cumulative PV Cash Flow
PROJECT	CALENDER	sm3	Gsm3	Gsm3	Gsm3	NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK	MNOK	MNOK	MNOK
1	2011	0	0	0	0	0,00	0,00	-180000000	-300000000	-180000000	0	0	0	-660,00	-628,57	-628,57
2	2012	0	0	0	0	0,00	0,00	-120000000	-600000000	-120000000	-12000000	0	0	-852,00	-772,79	-1401,36
3	2013	0	0	0	0	0,00	0,00	-120000000	-480000000	-60000000	-36000000	0	0	-696,00	-601,23	-2002,59
4	2014	0	0	0	0	0,00	0,00	-111000000	-600000000	-240000000	-18000000	0	0	-969,00	-797,20	-2799,79
5	2015	235978,2552	0,272652617	0,876	-0,603347383	1880785779,81	-3397931865,92	0	0	0	-120000000	-13358729,02	-18000000	-1668,50	-1307,32	-4107,11
6	2016	909266,316	0,701911246	0,876	-0,174088754	8334053616,53	-1127498027,20	0	0	0	-150000000	-51473566,15	-18000000	6987,08	5213,87	1106,76
7	2017	693888,994	1,230293397	0,876	0,354293397	7313967508,45	2638796943,16	0	0	0	-138000000	-103053867,4	-12000000	9699,71	6893,40	8000,16
8	2018	509591,9232	1,326605867	0,876	0,450605867	6177082532,15	3859558218,15	0	0	0	-168000000	-109957054,8	-12000000	9746,68	6596,94	14597,10
9	2019	390104,364	1,317799843	0,876	0,441799843	5438003928,14	4351752144,57	0	0	0	-156000000	-101607779,8	-12000000	9520,15	6136,77	20733,88
10	2020	311488,8068	1,306576365	0,876	0,430576365	4993430318,85	4877380324,35	-30000000	0	0	-120000000	-95137127,06	-12000000	9613,67	5901,96	26635,84
11	2021	257187,607	1,297960683	0,876	0,421960683	4741376321,90	5496753507,92	0	0	-21000000	-120000000	-90512313,44	-12000000	9994,62	5843,65	32479,48
12	2022	208676,7992	1,287235966	0,876	0,411235966	4424114883,87	6160602753,82	0	0	0	-132000000	-85835667,44	-9000000	10357,88	5767,66	38247,14
13	2023	170946,384	1,274039047	0,876	0,398039047	4167829922,39	6857339210,84	0	-60000000	0	-108000000	-81324303,17	-9000000	10766,84	5709,89	43957,03
14	2024	118191,7592	1,180563852	0,876	0,304563852	3313867248,08	6034011777,68	0	-60000000	0	-108000000	-61512328,92	-9000000	9109,37	4600,85	48557,88
15	2025	87701,04675	1,087712446	0,876	0,211712446	2827811962,53	4823608225,17	-60000000	0	0	-102000000	-43072996,59	-9000000	7437,35	3577,49	52135,37
16	2026	53051,3585	0,881072646	0,876	0,005072646	1967161881,38	132910122,37	0	0	0	-102000000	-3916313,738	-9000000	1985,16	909,42	53044,79
17	2027	18103,62965	0,588433791	0,876	-0,287566209	771981846,36	-8664812496,45	0	0	0	-90000000	-1024846,474	-9000000	-7992,86	-3487,26	49557,53
18	2028	18761,0254	0,545238539	0,876	-0,330761461	920016980,34	-11461304739,23	0	0	0	-78000000	-1062061,648	-6000000	-10626,35	-4415,47	45142,07
19	2029	32325,2428	0,565872459	0,876	-0,310127541	1822967421,94	-12358260164,91	0	0	0	-78000000	-1829931,995	-6000000	-10621,12	-4203,14	40938,93
20	2030	32330,5831	0,568356517	0,876	-0,307643483	2096758873,60	-14098164010,17	0	0	0	-78000000	-1830234,309	-6000000	-12087,24	-4555,55	36383,38
	TOTAL	**4047594,095**	**15,43232528**	**14,016**	**1,416325282**	**61191211026,32**	**-5875258075,84**	**-621000000**	**-2100000000,00**	**-621000000,0**	**-1914000000,0**	**-846509122,07**	**-168000000,00**			

Appendix A.3

Option 1(low case): Drilling from a ship to the subsea template

Oil price	45	USD/Bbl	1698,24897 NOK/Sm^3
Gas price	1,2	NOK/Sm^3	
oil price development	0,05		
gas price development	0,05		
exchange rate	6	NOK/USD	
discount rate	0,1		

								CAPEX+40%			OPEX+40%					
YEAR	YEAR	Oil production	Gas production	Gas Injection	Gas Sale	Revenue from Oil	Revenue from Gas	Production unit	Subsea Pipeline	Drillex	Field/onshore	Oil/Gas transportation	CO2 duty	Net Cash Flow	PV cash flow	Cumulative PV Cash Flow
PROJECT	CALENDER	sm3	Gsm3	Gsm3	Gsm3	NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK	MNOK	MNOK	MNOK
1	2011	0	0	0	0	0,00	0,00	-420000000	-700000000	-420000000	0	0	0	-1540,00	-1400,00	-1400,00
2	2012	0	0	0	0	0,00	0,00	-280000000	-1400000000	-280000000	-28000000	0	0	-1988,00	-1642,98	-3042,98
3	2013	0	0	0	0	0,00	0,00	-280000000	-1120000000	-140000000	-84000000	0	0	-1624,00	-1220,14	-4263,11
4	2014	0	0	0	0	0,00	0,00	-259000000	-1400000000	-560000000	-42000000	0	0	-2261,00	-1544,29	-5807,40
5	2015	235978,2552	0,272652617	0,876	-0,603347383	511469617,64	-924049368,55	0	0	0	-280000000	-31170367,72	-42000000	-765,75	-475,47	-6282,87
6	2016	909266,316	0,701911246	0,876	-0,174088754	2069322867,94	-279954696,55	0	0	0	-350000000	-120104987,7	-42000000	1277,26	720,98	-5561,89
7	2017	693888,994	1,230293397	0,876	0,354293397	1658121888,70	598231666,50	0	0	0	-322000000	-240459024	-28000000	1665,89	854,87	-4707,03
8	2018	509591,9232	1,326605867	0,876	0,450605867	1278610564,40	798900109,55	0	0	0	-392000000	-256566461,3	-28000000	1400,94	653,55	-4053,47
9	2019	390104,364	1,317799843	0,876	0,441799843	1027746153,68	822451875,25	0	0	0	-364000000	-237084819,6	-28000000	1221,11	517,87	-3535,60
10	2020	311488,8068	1,306576365	0,876	0,430576365	861661712,53	841636232,92	-70000000	0	0	-280000000	-221986629,8	-28000000	1103,31	425,37	-3110,23
11	2021	257187,607	1,297960683	0,876	0,421960683	747022507,47	866035157,23	0	0	-49000000	-280000000	-211195398	-28000000	1044,86	366,22	-2744,01
12	2022	208676,7992	1,287235966	0,876	0,411235966	636424830,18	886224852,73	0	0	0	-308000000	-200283224	-21000000	993,37	316,52	-2427,49
13	2023	170946,384	1,274039047	0,876	0,398039047	547421898,28	900674383,99	0	-140000000	0	-252000000	-189756707,4	-21000000	845,34	244,86	-2182,63
14	2024	118191,7592	1,180563852	0,876	0,304563852	397409956,54	723618714,57	0	-140000000	0	-252000000	-143528767,5	-21000000	564,50	148,65	-2033,98
15	2025	87701,04675	1,087712446	0,876	0,211712446	309631846,56	528161964,68	-140000000	0	0	-238000000	-100503658,7	-21000000	338,29	80,98	-1952,99
16	2026	53051,3585	0,881072646	0,876	0,005072646	196664808,91	13287540,83	0	0	0	-238000000	-9138065,388	-21000000	-58,19	-12,66	-1965,66
17	2027	18103,62965	0,588433791	0,876	-0,287566209	70466889,34	-790928421,75	0	0	0	-210000000	-2391308,44	-21000000	-953,85	-188,71	-2154,37
18	2028	18761,0254	0,545238539	0,876	-0,330761461	76677035,65	-955220274,00	0	0	0	-182000000	-2478143,845	-14000000	-1077,02	-193,71	-2348,08
19	2029	32325,2428	0,565872459	0,876	-0,310127541	138720242,01	-940412220,37	0	0	0	-182000000	-4269841,321	-14000000	-1001,96	-163,83	-2511,91
20	2030	32330,5831	0,568356517	0,876	-0,307643483	145680317,29	-979523698,27	0	0	0	-182000000	-4270546,722	-14000000	-1034,11	-153,71	-2665,63
	TOTAL	**4047594,095**	**15,43232528**	**14,016**	**1,416325282**	**10673053137,13**	**2109133818,77**	**-1449000000**	**-4900000000,00**	**-1449000000,00**	**-4466000000,00**	**-1975187951,49**	**-392000000,00**			

APPENDIX A.4

Option 2(base case): Drilling from a New Platform

Oil price	75	USD/Bbl
Gas price	2	NOK/Sm^3
oil price development	0,1	
gas price development	0,1	
exchange rate	6	NOK/USD
discount rate	0,08	

								CAPEX			OPEX					
YEAR	YEAR	Oil production	Gas production	Gas Injection	Gas Sale	Revenue from Oil	Revenue from Gas	Production unit	Subsea Pipeline	Drillex	Field/onshore	Oil/Gas transportation	CO2 duty	Net Cash Flow	PV cash flow	Cumulative PV Cash Flow
PROJECT	CALENDER	sm3	Gsm3	Gsm3	Gsm3	NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK	MNOK	MNOK	MNOK
1	2011	0	0	0	0	0,00	0,00	-4000000000	-500000000	-500000000	0	0	0	-5000,00	-4629,63	-4629,63
2	2012	0	0	0	0	0,00	0,00	-3000000000	-100000000	-200000000	-20000000	0	0	-3320,00	-2846,36	-7475,99
3	2013	0	0	0	0	0,00	0,00	-3000000000	-800000000	-300000000	-60000000	0	0	-4160,00	-3302,34	-10778,34
4	2014	0	0	0	0	0,00	0,00	-500000000	-500000000	-490000000	-30000000	0	0	-1520,00	-1117,25	-11895,58
5	2015	235978,2552	0,272652617	0,876	-0,603347383	1075686011,22	-1943393986,97	0	0	0	-400000000	-22264548,37	-30000000	-1319,97	-898,35	-12793,93
6	2016	909266,316	0,701911246	0,876	-0,174088754	4559291115,90	-616817694,62	0	0	0	-450000000	-85789276,92	-30000000	3376,68	2127,88	-10666,05
7	2017	693888,994	1,230293397	0,876	0,354293397	3827268267,86	1380835202,54	0	0	0	-430000000	-171756445,7	-20000000	4586,35	2676,09	-7989,96
8	2018	509591,9232	1,326605867	0,876	0,450605867	3091819463,13	1931827388,71	0	0	0	-480000000	-183261758,1	-20000000	4340,39	2344,98	-5644,98
9	2019	390104,364	1,317799843	0,876	0,441799843	2603544976,32	2083481840,74	0	0	0	-460000000	-169346299,7	-20000000	4037,68	2019,85	-3625,14
10	2020	311488,8068	1,306576365	0,876	0,430576365	2286753783,09	2233608400,65	-500000000	0	0	-400000000	-158561878,4	-20000000	3441,80	1594,22	-2030,92
11	2021	257187,607	1,297960683	0,876	0,421960683	2076919594,73	2407806150,14	0	0	-10000000	-400000000	-150853855,7	-20000000	3903,87	1674,30	-356,62
12	2022	208676,7992	1,287235966	0,876	0,411235966	1853687400,42	2581269248,98	0	0	0	-420000000	-143059445,7	-15000000	3856,90	1531,63	1175,01
13	2023	170946,384	1,274039047	0,876	0,398039047	1670378667,96	2748277484,94	0	-100000000	0	-400000000	-135540505,3	-15000000	3768,12	1385,53	2560,54
14	2024	118191,7592	1,180563852	0,876	0,304563852	1270383657,89	2313161445,54	0	-100000000	0	-400000000	-102520548,2	-15000000	2966,02	1009,82	3570,35
15	2025	87701,04675	1,087712446	0,876	0,211712446	1036919791,22	1768750857,57	0	0	0	-430000000	-71788327,65	-15000000	2288,88	721,55	4291,91
16	2026	53051,3585	0,881072646	0,876	0,005072646	689969004,71	46617345,38	0	0	0	-380000000	-6527189,563	-15000000	335,06	97,80	4389,71
17	2027	18103,62965	0,588433791	0,876	-0,287566209	258995020,16	-2906989714,60	0	0	0	-350000000	-1708077,457	-15000000	-3014,70	-814,78	3574,93
18	2028	18761,0254	0,545238539	0,876	-0,330761461	295239875,69	-3678012752,82	0	0	0	-200000000	-1770102,747	-10000000	-3594,54	-899,53	2675,40
19	2029	32325,2428	0,565872459	0,876	-0,310127541	559568067,72	-3793423666,07	0	0	0	-300000000	-3049886,658	-10000000	-3546,91	-821,86	1853,53
20	2030	32330,5831	0,568356517	0,876	-0,307643483	615626562,44	-4139343038,21	0	0	0	-310000000	-3050390,515	-10000000	-3846,77	-825,32	1028,22
	TOTAL	**4047594,09**	**15,43232528**	**14,016**	**1,416325282**	**27772051260,46**	**2417654511,91**	**-11000000000**	**-2100000000,**	**-1500000000,0**	**-6320000000,0**	**-1410848536,78**	**-280000000,**			

APPENDIX A.5

Option 2 (high case): Drilling from a New Platform

Oil price	105	USD/Bbl	3962,58093
Gas price	2,8	NOK/Sm^3	
oil price development	0,15		
gas price development	0,15		
exchange rate	6	NOK/USD	
discount rate	0,05		

								CAPEX-40%			OPEX-40%					
YEAR	YEAR	Oil production	Gas production	Gas Injection	Gas Sale	Revenue from Oil	Revenue from Gas	Production unit	Subsea Pipeline	Drillex	Field/onshore	Oil/Gas transportation	CO2 duty	Net Cash Flow	PV cash flow	Cumulative PV Cash Flow
PROJECT	CALENDER	sm3	Gsm3	Gsm3	Gsm3	NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK	MNOK	MNOK	MNOK
1	2011	0	0	0	0	0,00	0,00	-2400000000	-300000000	-300000000	0	0	0	-3000,00	-2857,14	-2857,14
2	2012	0	0	0	0	0,00	0,00	-1800000000	-60000000	-120000000	-12000000	0	0	-1992,00	-1806,80	-4663,95
3	2013	0	0	0	0	0,00	0,00	-1800000000	-480000000	-180000000	-36000000	0	0	-2496,00	-2156,14	-6820,08
4	2014	0	0	0	0	0,00	0,00	-300000000	-300000000	-294000000	-18000000	0	0	-912,00	-750,30	-7570,39
5	2015	235978,2552	0,272652617	0,876	-0,603347383	1880785779,81	-3397931865,92	0	0	0	-240000000	-13358729,02	-18000000	-1788,50	-1401,34	-8971,73
6	2016	909266,316	0,701911246	0,876	-0,174088754	8334053616,53	-1127498027,20	0	0	0	-270000000	-51473566,15	-18000000	6867,08	5124,32	-3847,41
7	2017	693888,994	1,230293397	0,876	0,354293397	7313967508,45	2638796943,16	0	0	0	-258000000	-103053867,4	-12000000	9579,71	6808,12	2960,71
8	2018	509591,9232	1,326605867	0,876	0,450605867	6177082532,15	3859558218,15	0	0	0	-288000000	-109957054,8	-12000000	9626,68	6515,72	9476,43
9	2019	390104,364	1,317799843	0,876	0,441799843	5438003928,14	4351752144,57	0	0	0	-276000000	-101607779,8	-12000000	9400,15	6059,42	15535,85
10	2020	311488,8068	1,306576365	0,876	0,430576365	4993430318,85	4877380324,35	-300000000	0	0	-240000000	-95137127,06	-12000000	9223,67	5662,54	21198,39
11	2021	257187,607	1,297960683	0,876	0,421960683	4741376321,90	5496753507,92	0	0	-6000000	-240000000	-90512313,44	-12000000	9889,62	5782,25	26980,64
12	2022	208676,7992	1,287235966	0,876	0,411235966	4424114883,87	6160602753,82	0	0	0	-252000000	-85835667,44	-9000000	10237,88	5700,84	32681,48
13	2023	170946,384	1,274039047	0,876	0,398039047	4167829922,39	6857339210,84	0	-60000000	0	-240000000	-81324303,17	-9000000	10634,84	5639,89	38321,36
14	2024	118191,7592	1,180563852	0,876	0,304563852	3313867248,08	6034011777,68	0	-60000000	0	-240000000	-61512328,92	-9000000	8977,37	4534,18	42855,54
15	2025	87701,04675	1,087712446	0,876	0,211712446	2827811962,53	4823608225,17	0	0	0	-258000000	-43072996,59	-9000000	7341,35	3531,31	46386,86
16	2026	53051,3585	0,881072646	0,876	0,005072646	1967161881,38	132910122,37	0	0	0	-228000000	-3916313,738	-9000000	1859,16	851,70	47238,56
17	2027	18103,62965	0,588433791	0,876	-0,287566209	771981846,36	-8664812496,45	0	0	0	-210000000	-1024846,474	-9000000	-8112,86	-3539,61	43698,95
18	2028	18761,0254	0,545238539	0,876	-0,330761461	920016980,34	-11461304739,23	0	0	0	-120000000	-1062061,648	-6000000	-10668,35	-4432,92	39266,03
19	2029	32325,2428	0,565872459	0,876	-0,310127541	1822967421,94	-12358260164,91	0	0	0	-180000000	-1829931,995	-6000000	-10723,12	-4243,50	35022,52
20	2030	32330,5831	0,568356517	0,876	-0,307643483	2096758873,60	-14098164010,17	0	0	0	-186000000	-1830234,309	-6000000	-12195,24	-4596,26	30426,27
	TOTAL	**4047594,095**	**15,43232528**	**14,016**	**1,416325282**	**61191211026,32**	**-5875258075,84**	**-6600000000**	**-1260000000,00**	**-900000000,00**	**-3792000000,00**	**-846509122,07**	**-168000000,00**			

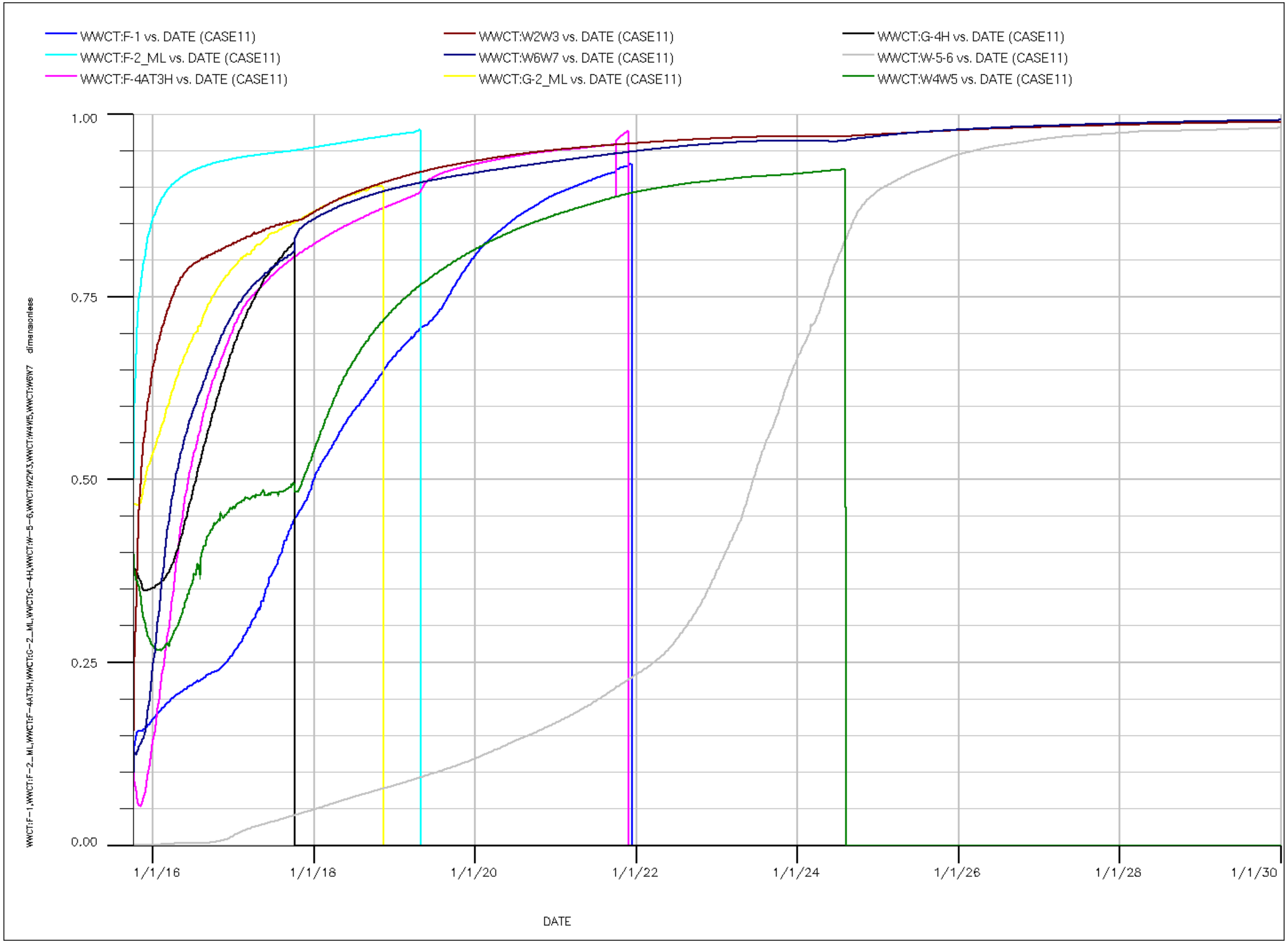
APPENDIX A.6

Option 2 (low case): Drilling from a New Platform

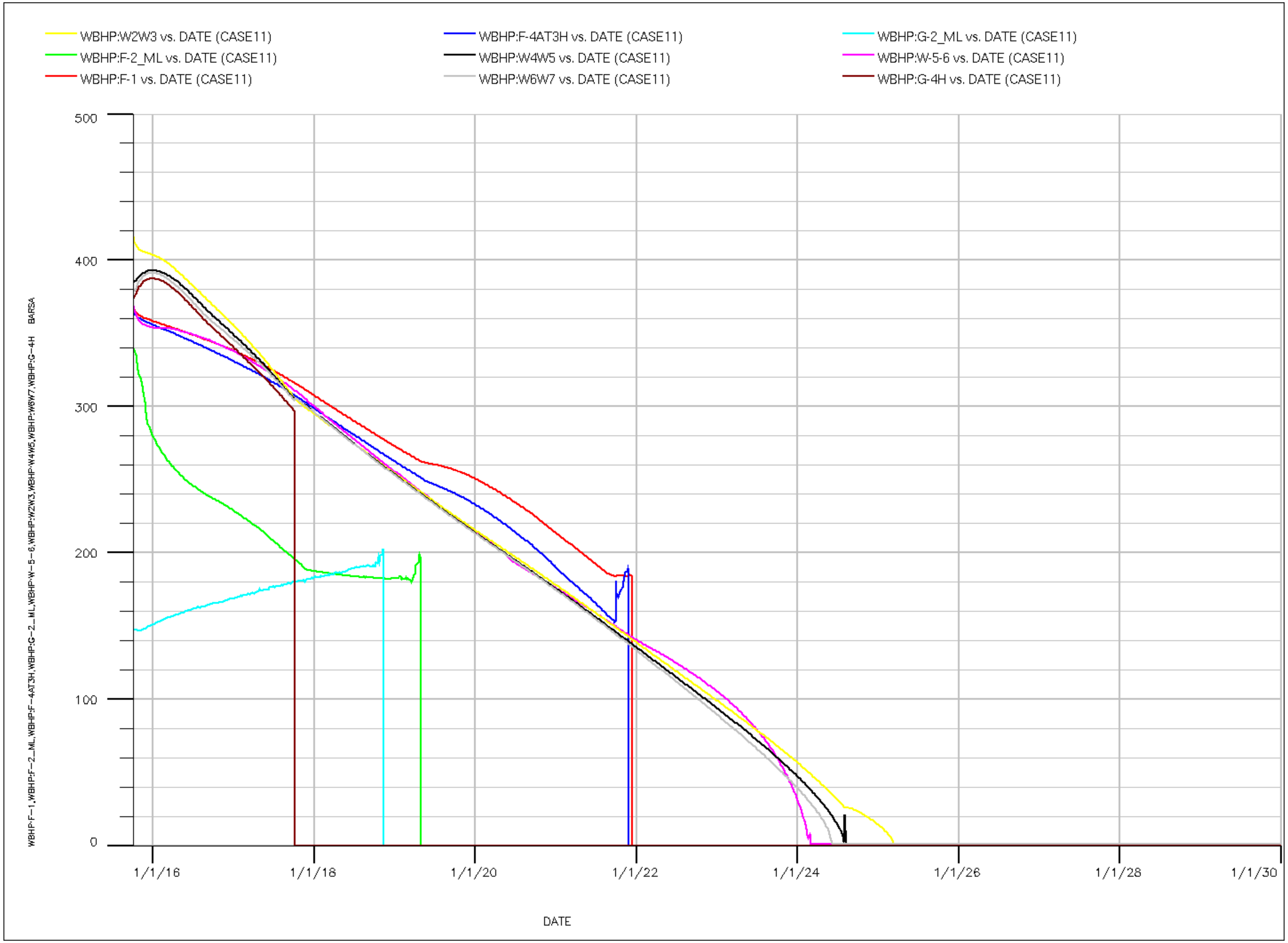
Oil price	45	USD/Bbl	1698,24897
Gas price	1,2	NOK/Sm^3	
oil price development	0,05		
gas price development	0,05		
exchange rate	6	NOK/USD	
discount rate	0,1		

								CAPEX+40%			OPEX+40%					
YEAR	YEAR	Oil production	Gas production	Gas Injection	Gas Sale	Revenue from Oil	Revenue from Gas	Production unit	Subsea Pipeline	Drillex	Field/onshore	Oil/Gas transportation	CO2 duty	Net Cash Flow	PV cash flow	Cumulative PV Cash Flow
PROJECT	CALENDER	sm3	Gsm3	Gsm3	Gsm3	NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK	MNOK	MNOK	MNOK
1	2011	0	0	0	0	0,00	0,00	-5600000000	-700000000	-700000000	0	0	0	-7000,00	-6363,64	-6363,64
2	2012	0	0	0	0	0,00	0,00	-4200000000	-140000000	-280000000	-28000000	0	0	-4648,00	-3841,32	-10204,96
3	2013	0	0	0	0	0,00	0,00	-4200000000	-1120000000	-420000000	-84000000	0	0	-5824,00	-4375,66	-14580,62
4	2014	0	0	0	0	0,00	0,00	-700000000	-700000000	-686000000	-42000000	0	0	-2128,00	-1453,45	-16034,07
5	2015	235978,2552	0,272652617	0,876	-0,603347383	511469617,64	-924049368,55	0	0	0	-560000000	-31170367,72	-42000000	-1045,75	-649,33	-16683,40
6	2016	909266,316	0,701911246	0,876	-0,174088754	2069322867,94	-279954696,55	0	0	0	-630000000	-120104987,7	-42000000	997,26	562,93	-16120,47
7	2017	693888,994	1,230293397	0,876	0,354293397	1658121888,70	598231666,50	0	0	0	-602000000	-240459024	-28000000	1385,89	711,18	-15409,29
8	2018	509591,9232	1,326605867	0,876	0,450605867	1278610564,40	798900109,55	0	0	0	-672000000	-256566461,3	-28000000	1120,94	522,93	-14886,36
9	2019	390104,364	1,317799843	0,876	0,441799843	1027746153,68	822451875,25	0	0	0	-644000000	-237084819,6	-28000000	941,11	399,12	-14487,23
10	2020	311488,8068	1,306576365	0,876	0,430576365	861661712,53	841636232,92	-700000000	0	0	-560000000	-221986629,8	-28000000	193,31	74,53	-14412,70
11	2021	257187,607	1,297960683	0,876	0,421960683	747022507,47	866035157,23	0	0	-14000000	-560000000	-211195398	-28000000	799,86	280,35	-14132,36
12	2022	208676,7992	1,287235966	0,876	0,411235966	636424830,18	886224852,73	0	0	0	-588000000	-200283224	-21000000	713,37	227,30	-13905,06
13	2023	170946,384	1,274039047	0,876	0,398039047	547421898,28	900674383,99	0	-140000000	0	-560000000	-189756707,4	-21000000	537,34	155,65	-13749,41
14	2024	118191,7592	1,180563852	0,876	0,304563852	397409956,54	723618714,57	0	-140000000	0	-560000000	-143528767,5	-21000000	256,50	67,54	-13681,86
15	2025	87701,04675	1,087712446	0,876	0,211712446	309631846,56	528161964,68	0	0	0	-602000000	-100503658,7	-21000000	114,29	27,36	-13654,50
16	2026	53051,3585	0,881072646	0,876	0,005072646	196664808,91	13287540,83	0	0	0	-532000000	-9138065,388	-21000000	-352,19	-76,65	-13731,15
17	2027	18103,62965	0,588433791	0,876	-0,287566209	70466889,34	-790928421,75	0	0	0	-490000000	-2391308,44	-21000000	-1233,85	-244,11	-13975,26
18	2028	18761,0254	0,545238539	0,876	-0,330761461	76677035,65	-955220274,00	0	0	0	-280000000	-2478143,845	-14000000	-1175,02	-211,34	-14186,60
19	2029	32325,2428	0,565872459	0,876	-0,310127541	138720242,01	-940412220,37	0	0	0	-420000000	-4269841,321	-14000000	-1239,96	-202,74	-14389,34
20	2030	32330,5831	0,568356517	0,876	-0,307643483	145680317,29	-979523698,27	0	0	0	-434000000	-4270546,722	-14000000	-1286,11	-191,17	-14580,51
	TOTAL	**4047594,095**	**15,43232528**	**14,016**	**1,416325282**	**10673053137,13**	**2109133818,77**	**-15400000000**	**-2940000000,0**	**-2100000000,0**	**-8848000000,**	**-1975187951,49**	**-392000000,0**			

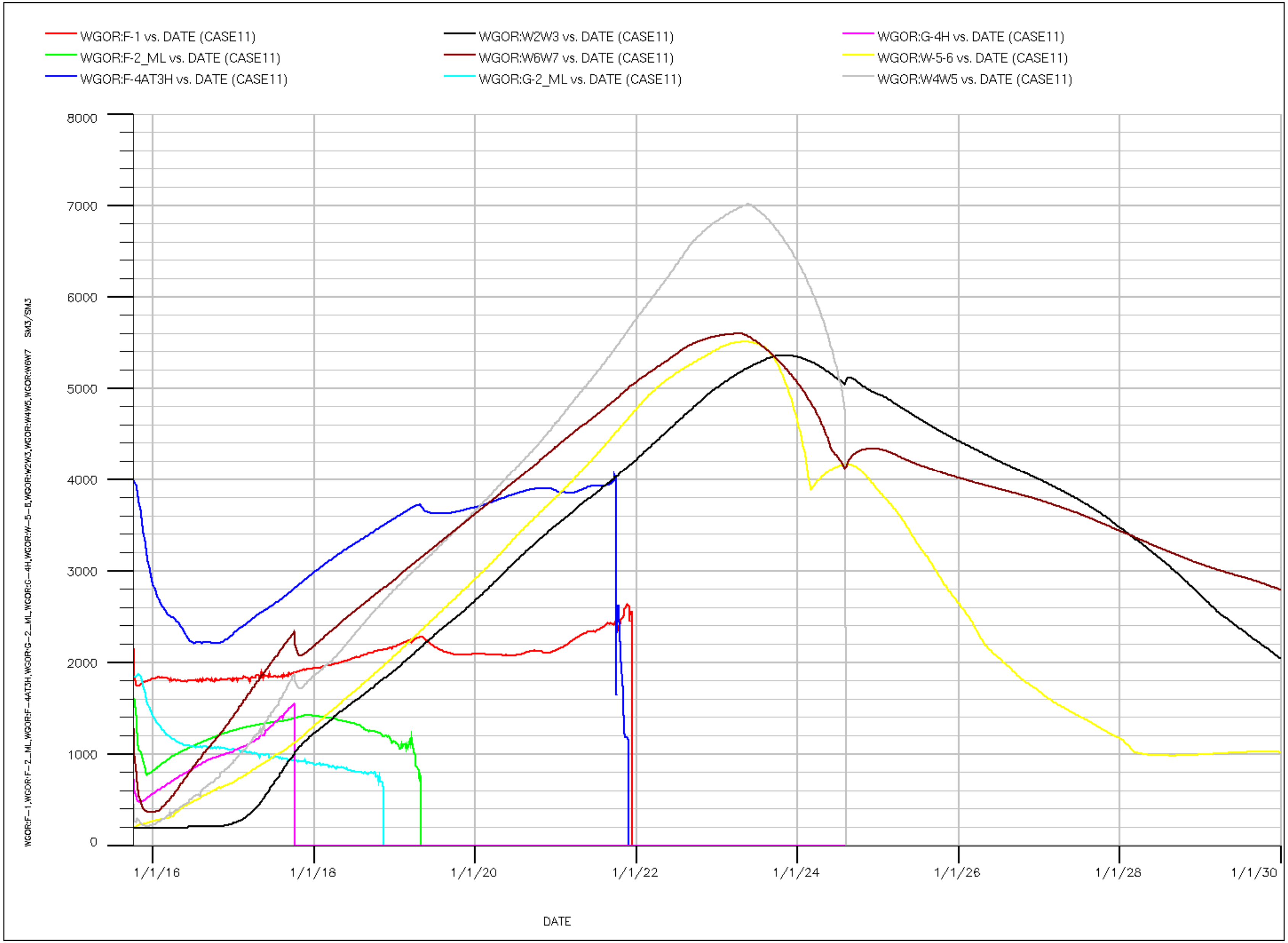
Appendix B.1 WI case 11, WWCT producer wells



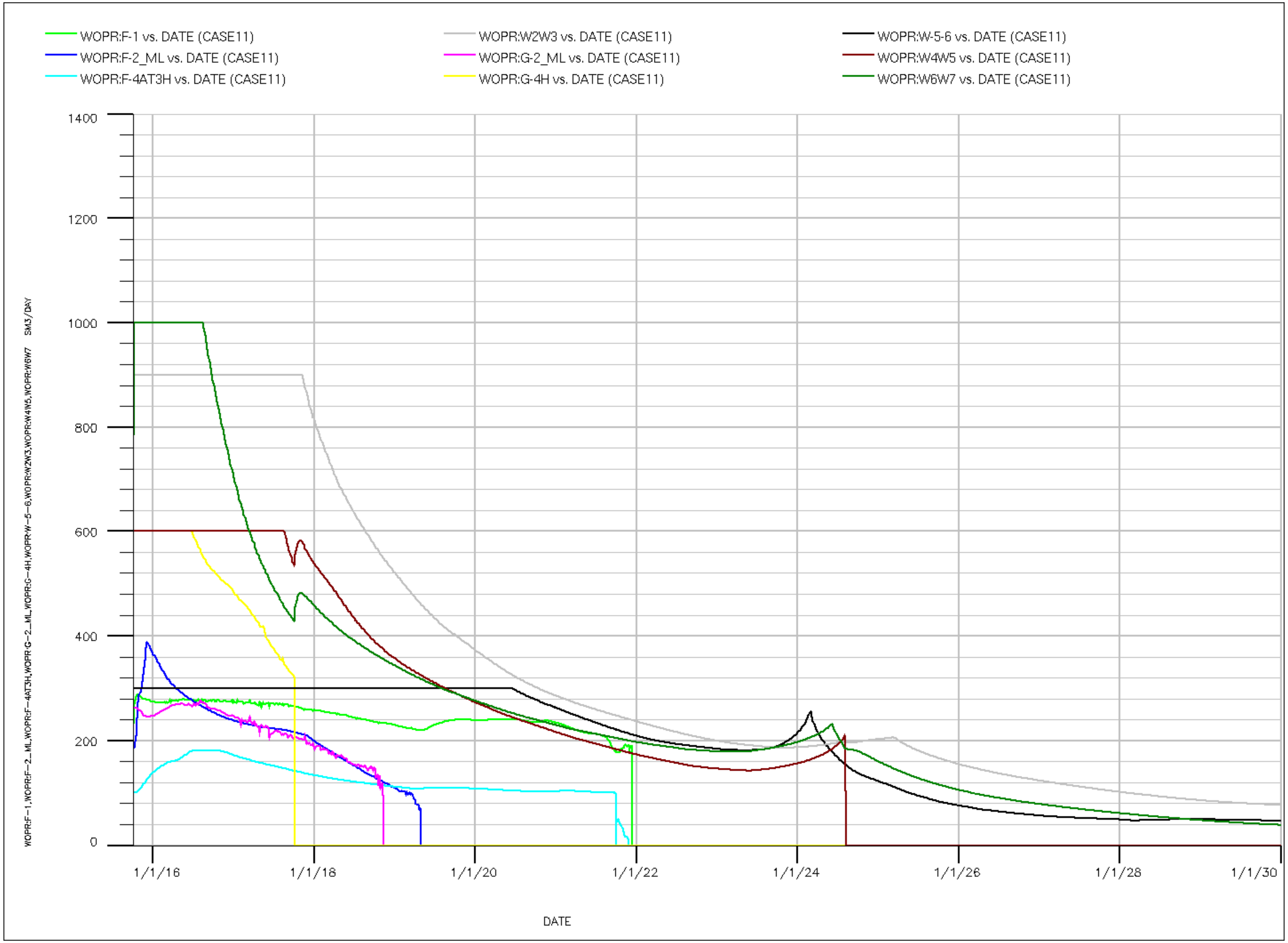
AppendixB.2 WI case 11, BHP producer wells



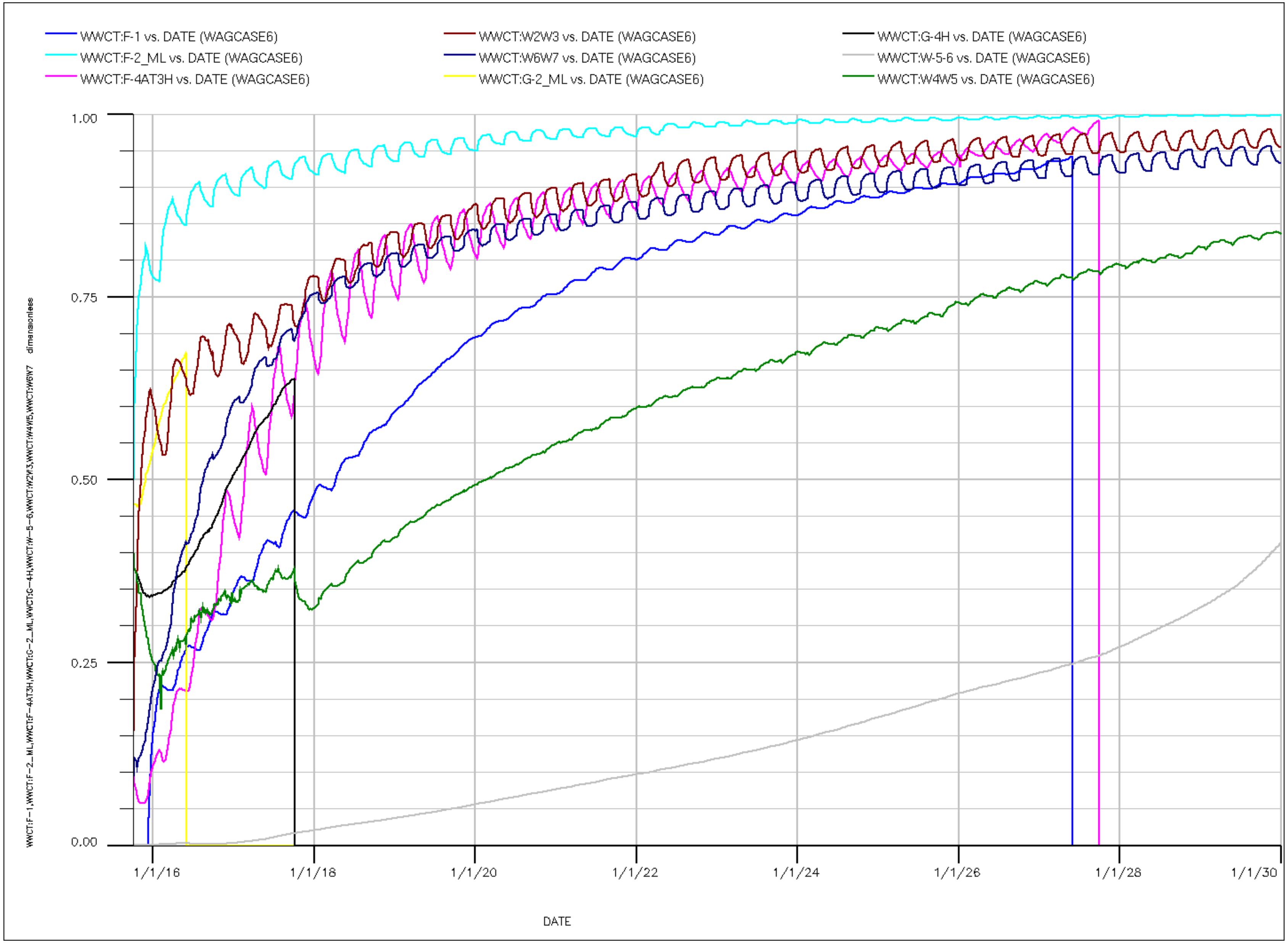
AppendixB.3 WI case 11, WGOR producer wells



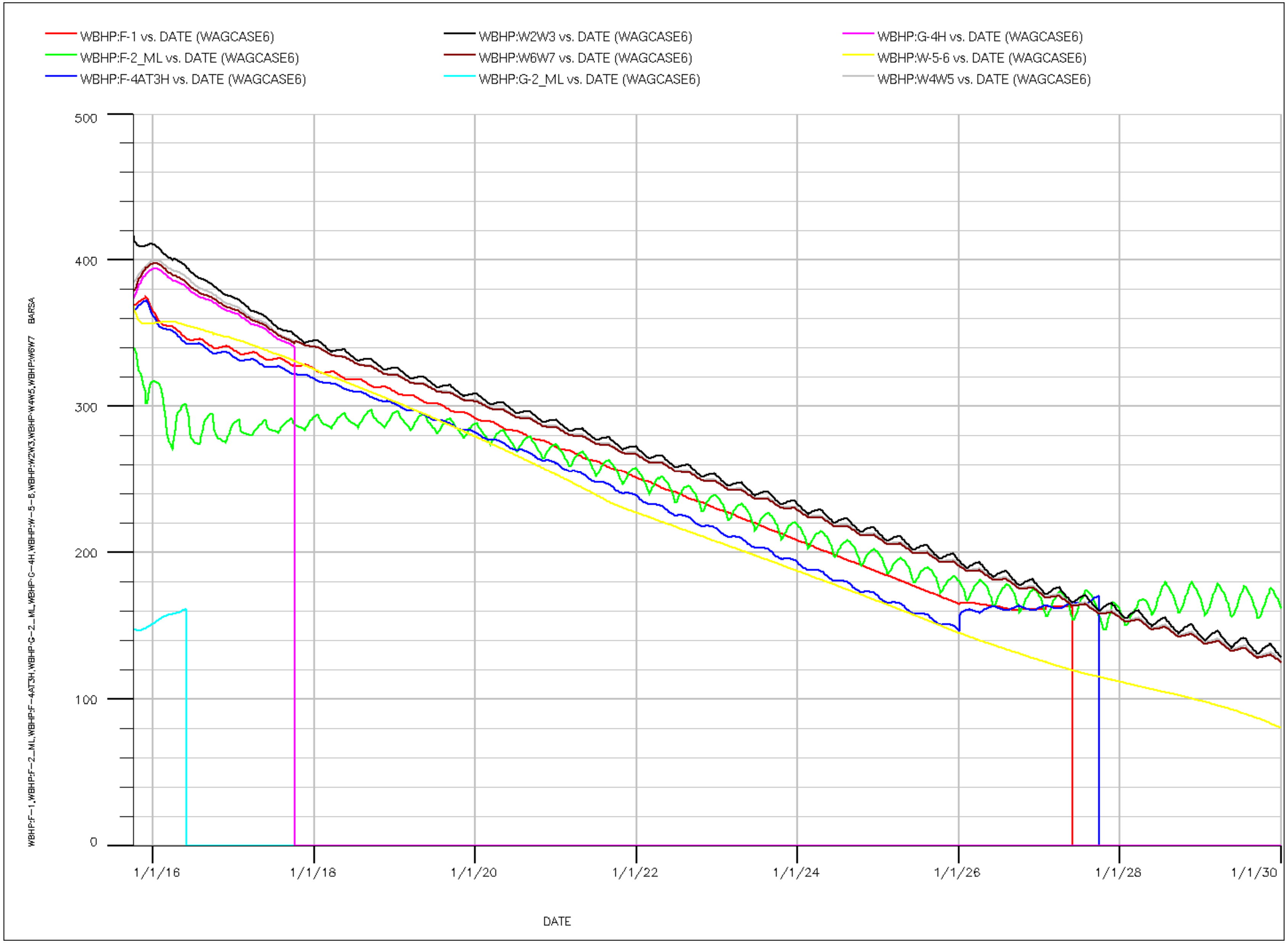
Appendix B.4 WI case 11, WOPR producer wells



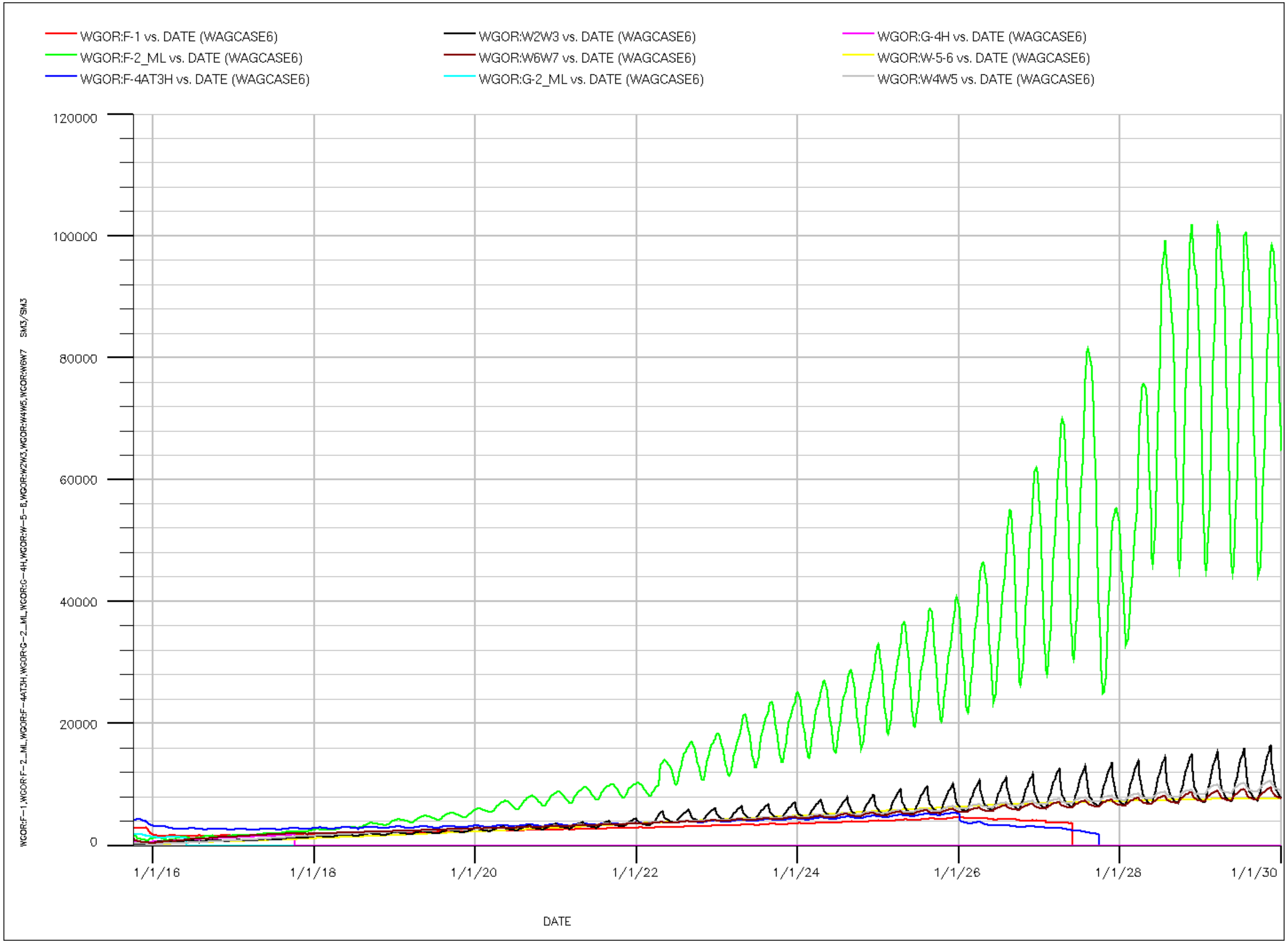
AppendixC.1 WAG case 6, WWCT producer wells



Appendix C.2 WAG case 6, WBHP producer wells



AppendixC.3 WAG case 6, WGOR producer wells



AppendixC.4 WAG case 6, WOPR producer wells