Project Report A
TPG-4851 Expert in Team
Gullfaks Village 2010

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I. INTRODUCTION

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 of the Gullfaks Field.

There has been a downward trend in production from the Gullfaks license since the peak year 1994 when it totally produced more than 90,000 Sm^3/d. The start-up of the Gullfaks Satellites in October 1998 slowed the decline in production, but the total production profile for the license continues to show a downward trend. Following the start-up of the Gullfaks Satellites, oil production remained stable at approx. 60,000 Sm3/d for about one year. It flattened out at approx. 35,000 Sm3/d during the period between 2001 and 2004, but in 2005 it once again started to decline. As of November 2007, the oil production rate is approx. 25,000 Sm3/d.

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 GullfaksVillage 2010 shall focus on the Statfjord Fm., where the in-place volumes are 40.6 MSm3 of oil/condensate and 18.9 GSm3 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.

Initially each group will work with identical project (Project Part A) in order to get familiar and acquaint with the Gullfaks Sør Segment. The main purpose of Part A is to demonstrate an understanding of the challenges related to Improved Oil Recovery (IOR) from a subsea development like Gullfaks Sør. The students should to the extent possible use real data from the Gullfaks Sør Statfjord Fm.

Detail activities of Project A are as follows:

1) All students should be familiar with Eclipse reservoir simulation model provided by Statoil and each group should run the model, and plot and review relevant reservoir model based on Reference case data.
2) Each Group should make a new reservoir simulation run by adding four new oil producers and two new gas injectors to the model. Three of the producers are Multi-Lateral (MLT) wells. The new simulation is termed the extended case and will be compared with the Reference case.
3) Make an economic evaluation if the additional oil recovery from the extended case can be part of a reserve potential for a new drilling platform at Gullfaks Sør, or if a subsea alternative provides a better solution.

The content of this report is related to activities that conducted in Project A.

II. GENERAL DESCRIPTION OF GULLFAKS AREA

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 put on production in 1986, with subsea wells producing to the GF-A platform, the first of the 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 South, 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 MSm3. Recoverable oil reserves are currently estimated at 360 MSm3, of which approximately 330 MSm3 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 MSm3 of oil and 4 GSm3 of gas per year. Recoverable oil reserves are currently estimated at 50 MSm 3, of which approximately 27 MSm3 have been produced by the end of 2006. In addition gas volumes of 17 GSm3 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 satellites field has 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.

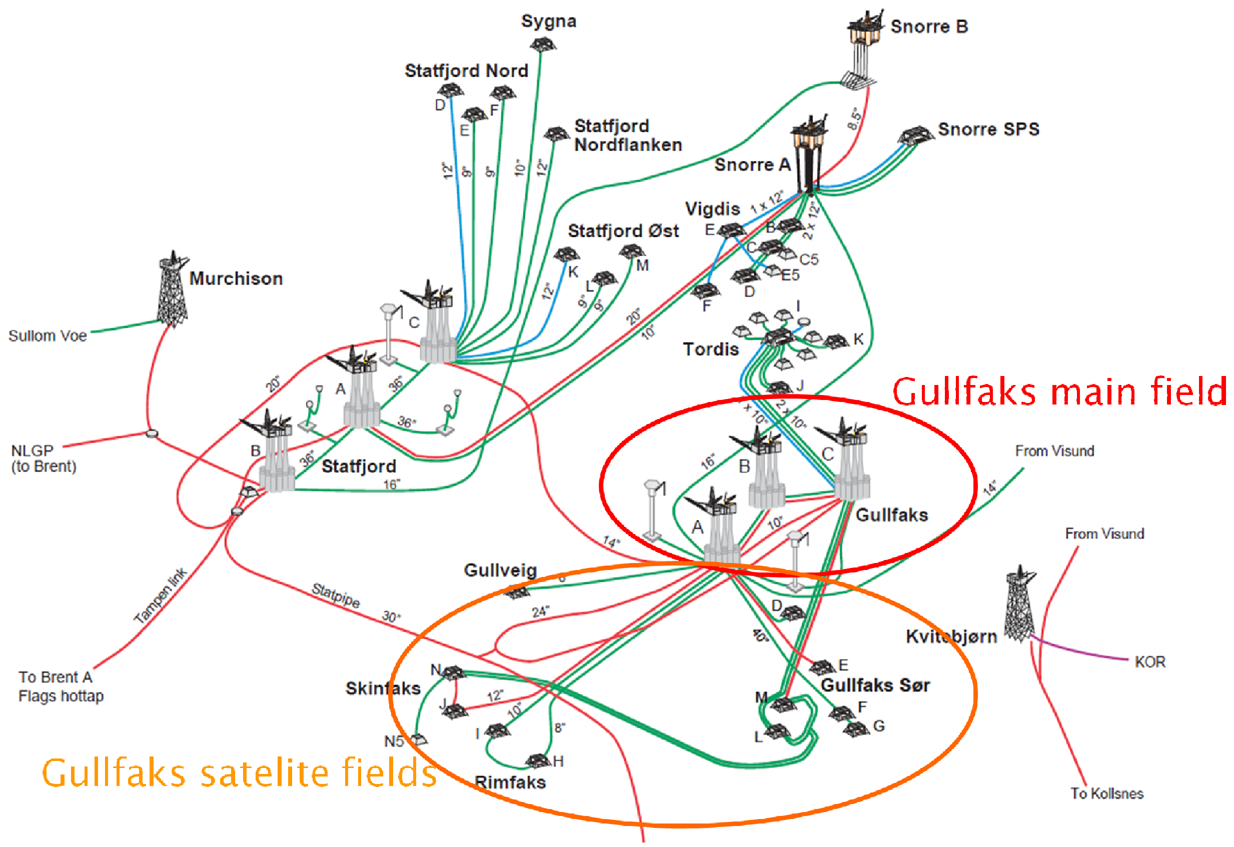


Figure 1 Gullfaks area

III. GENERAL DESCRIPTION OF GULLFAKS SØR

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...). We want 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.

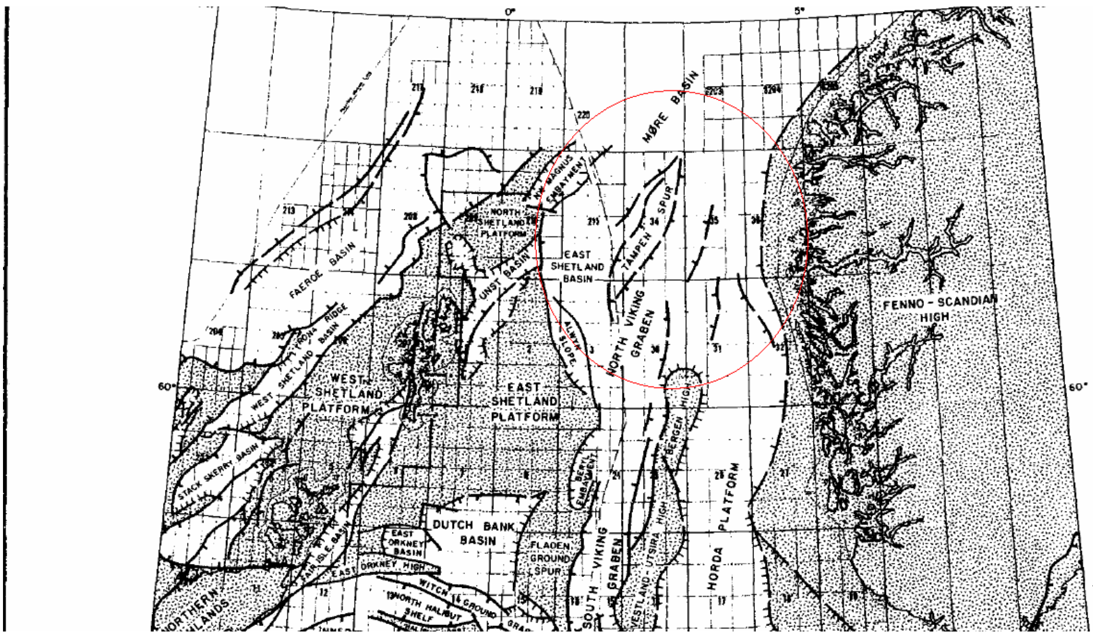
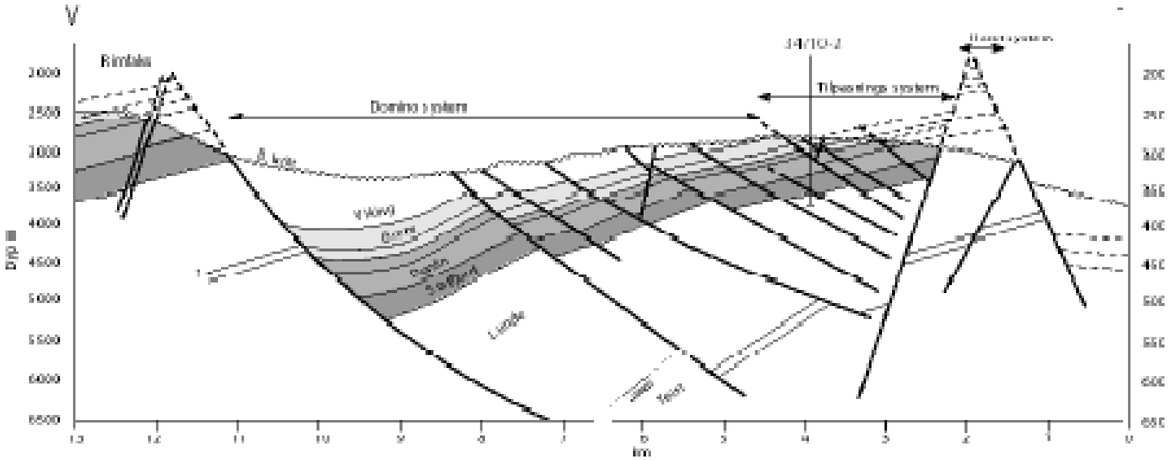


Figure 2 Structural elements of the North sea

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.



Figur 3 Gullfaks sør structure

Hydrocarbon system in Gullfaks Sør is shown in table below:

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

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. In the following section we are going to look into each of the members and describe 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.

We know from the production data that the pressure in the field 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.

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.

Gullfaks Sør Statfjord – History

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 Sm3/d and one injector, none of which were branch wells.
- In 1998, a new geological model came, and suggested a volume of 16.5 MSm3 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 MSm3).
- 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

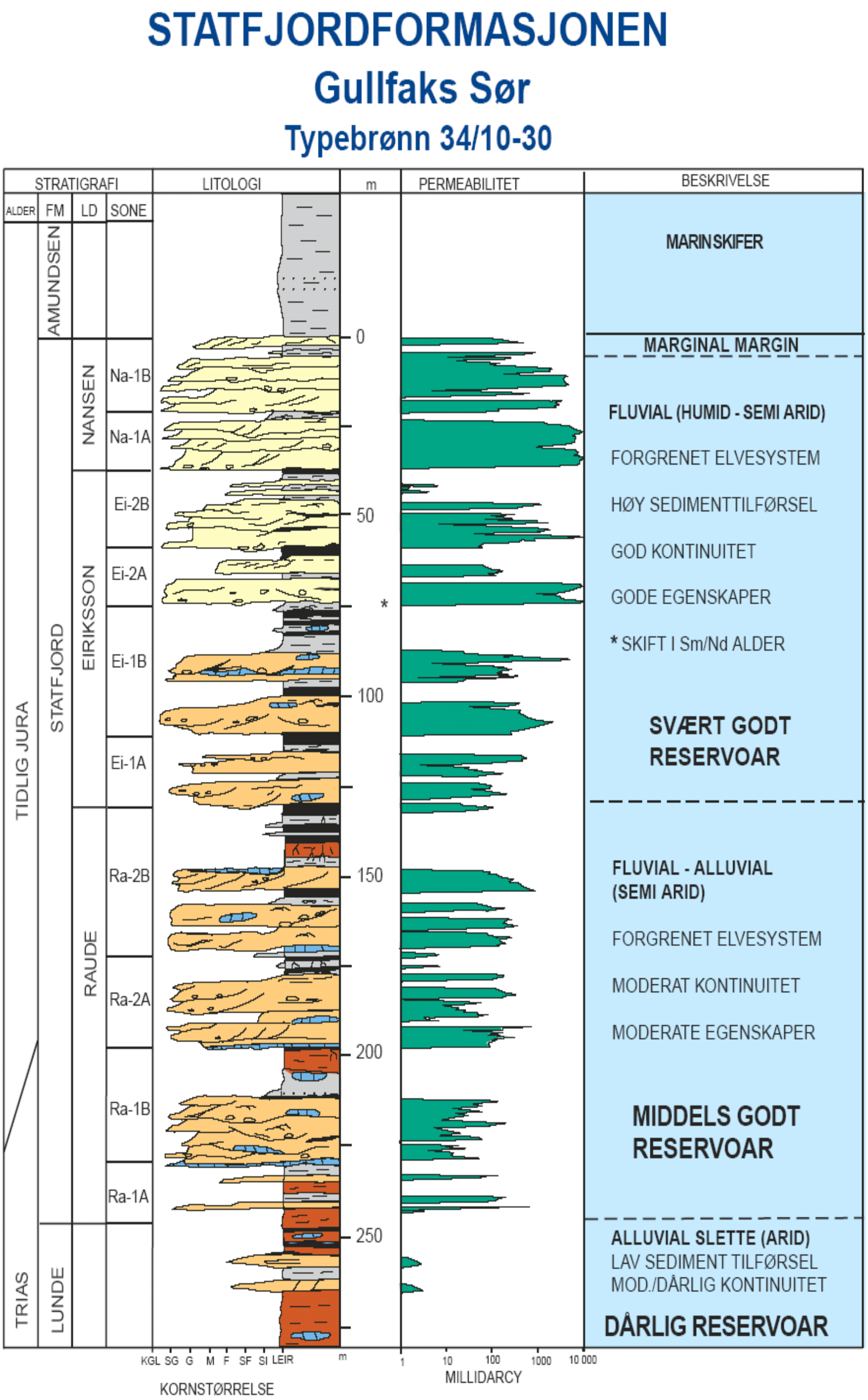


Figure 4 Composite log display of the Gullfaks Sør Reservoir

IV. RESERVOIR SIMULATION

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.

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.

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.

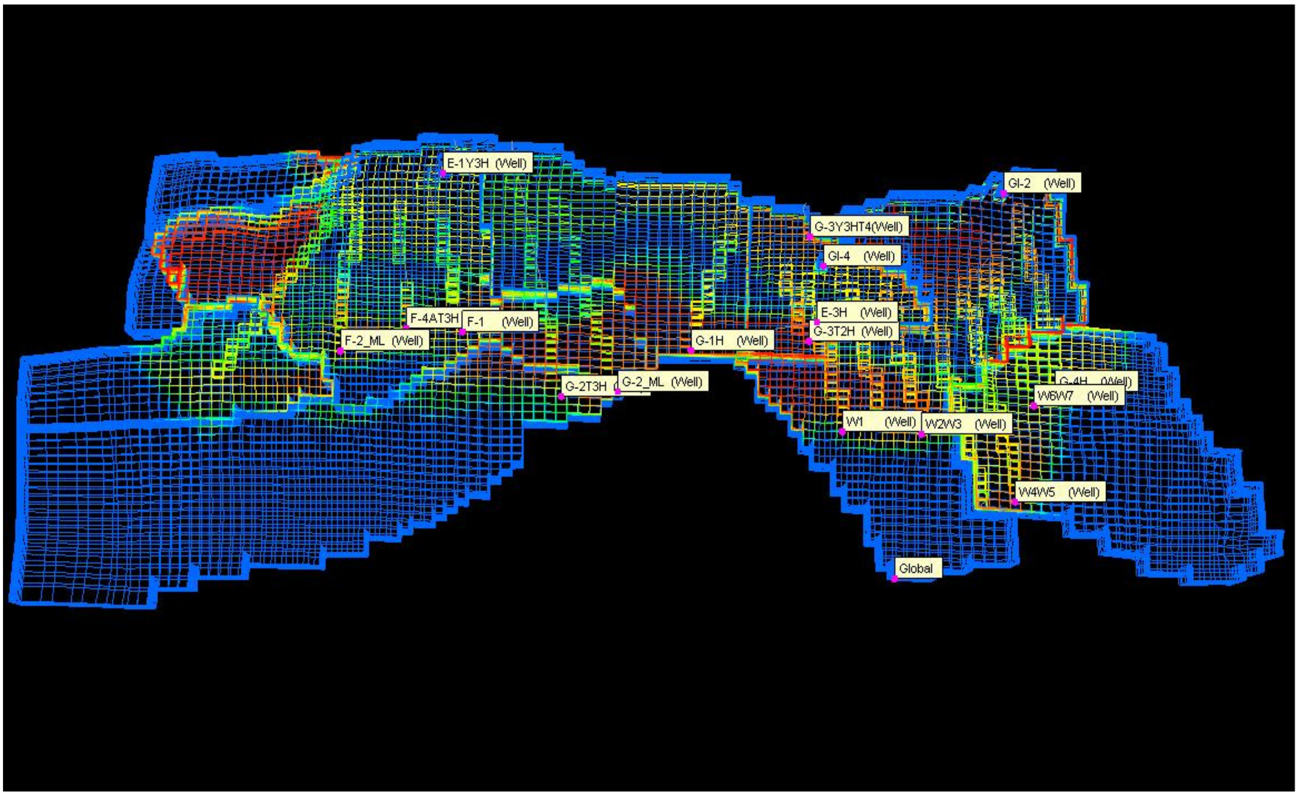


Figure 5 Position of the wells in the extended case simulation

V. SIMULATION RESULTS

The following chapter contains the results from the simulation.

Field in total

The total oil and gas production and total water cut follows under.

Total Oil Production in Field (FOPT)

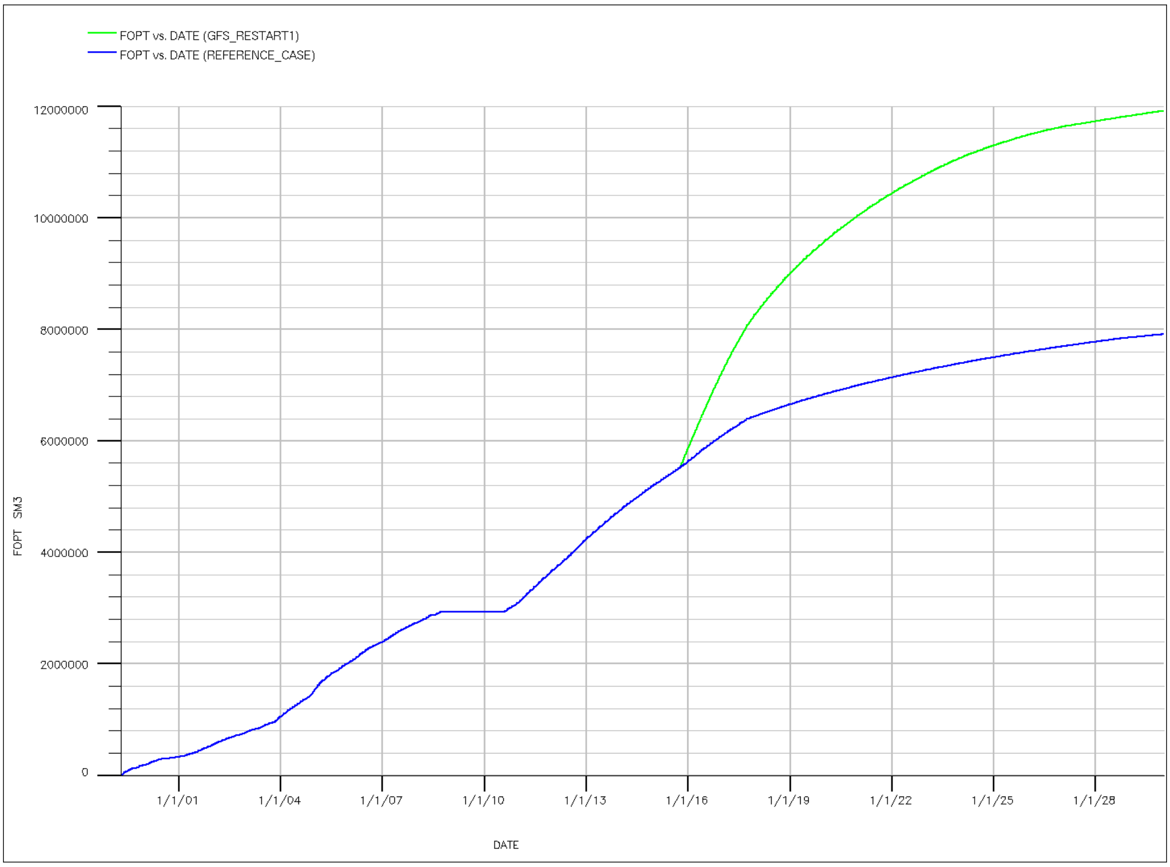


Figure 6 Field oil production total

Figure 6 shows that by adding 4 oil producers and 2 gas injector in 2015, we gain additional oil approximately 5 MSm3.

Total Gas Production in Field (FGPT)

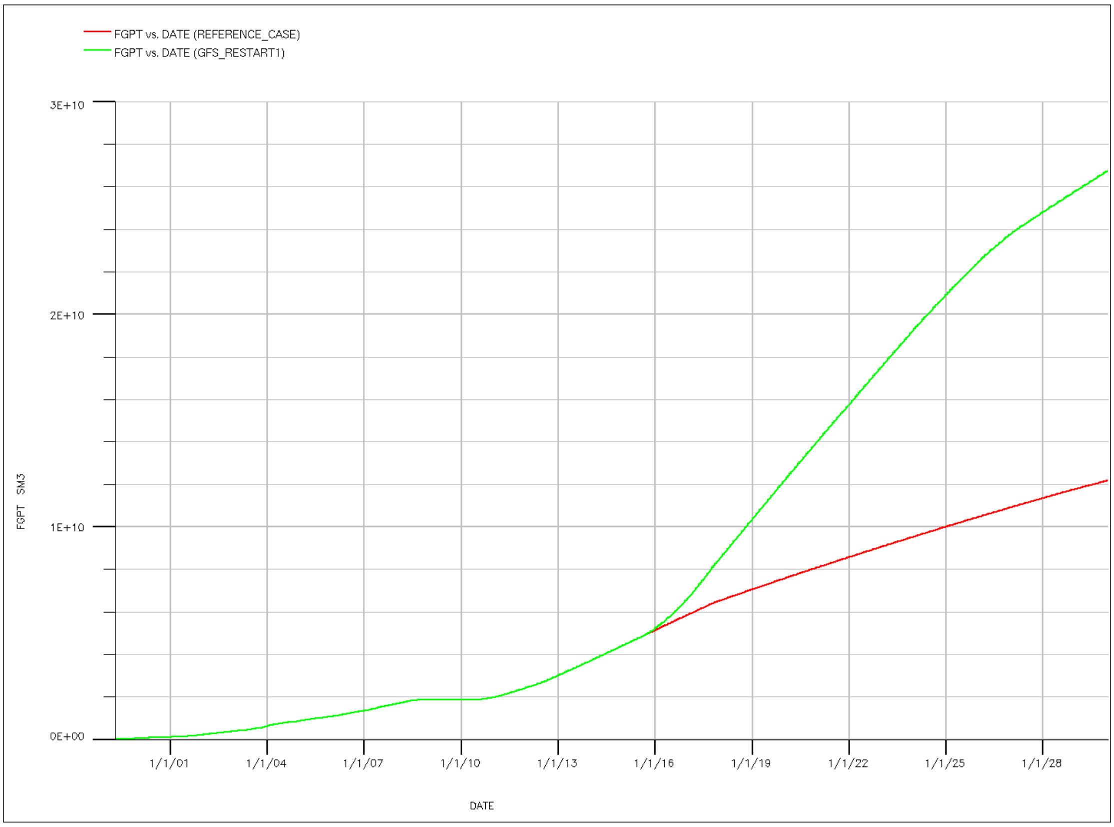


Figure 7 Field gas production total

Figure 7 shows that by adding 2 new gas injector in 2015, total gas production in 2030 increase from 12,1 billion Sm3 to 26,5 billion Sm3.

Total Water Cut Production in Field (FWCT)

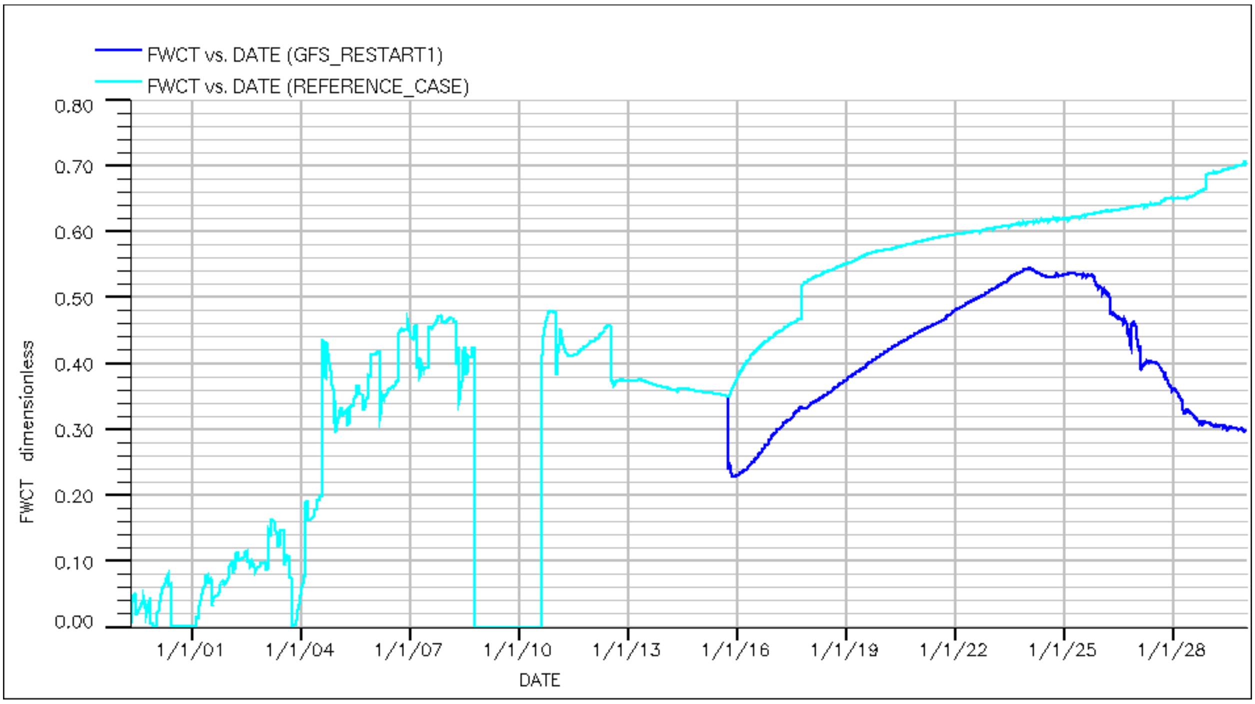


Figure 8 Field water cut total

Figure 8 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.

Field production

Field Production of reference Case

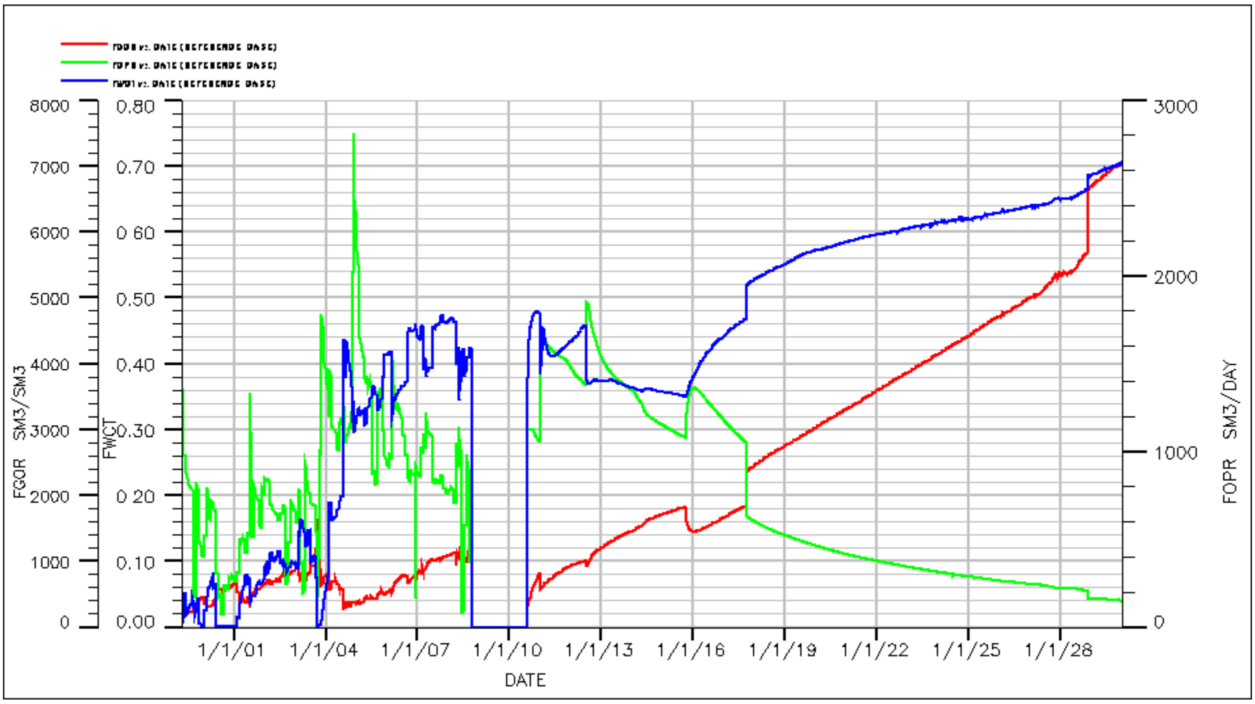


Figure 9 Field production from reference case

The green line shows the oil production, Blue one is water cut and the red line is gas to oil ratio. The date that we have supposed the new wells start to production is Oct-2015. Before this time, oil production has lots of turbulence due to reasons we are not going to cover here. But it is obvious that production has a decreasing rate and we expect high decrease in production after 2016. See Figure 9.

From 2001 to 2004, oil production is more than water cut but after 2004 this inverts. In period In 2010 and 2016, the oil production and water cut is almost the same but after that the gap increases significantly as the production of oil decreases and water cut increase.

The graph also shows that Gas to oil ratio increases with time.

Field Production of Extended Case

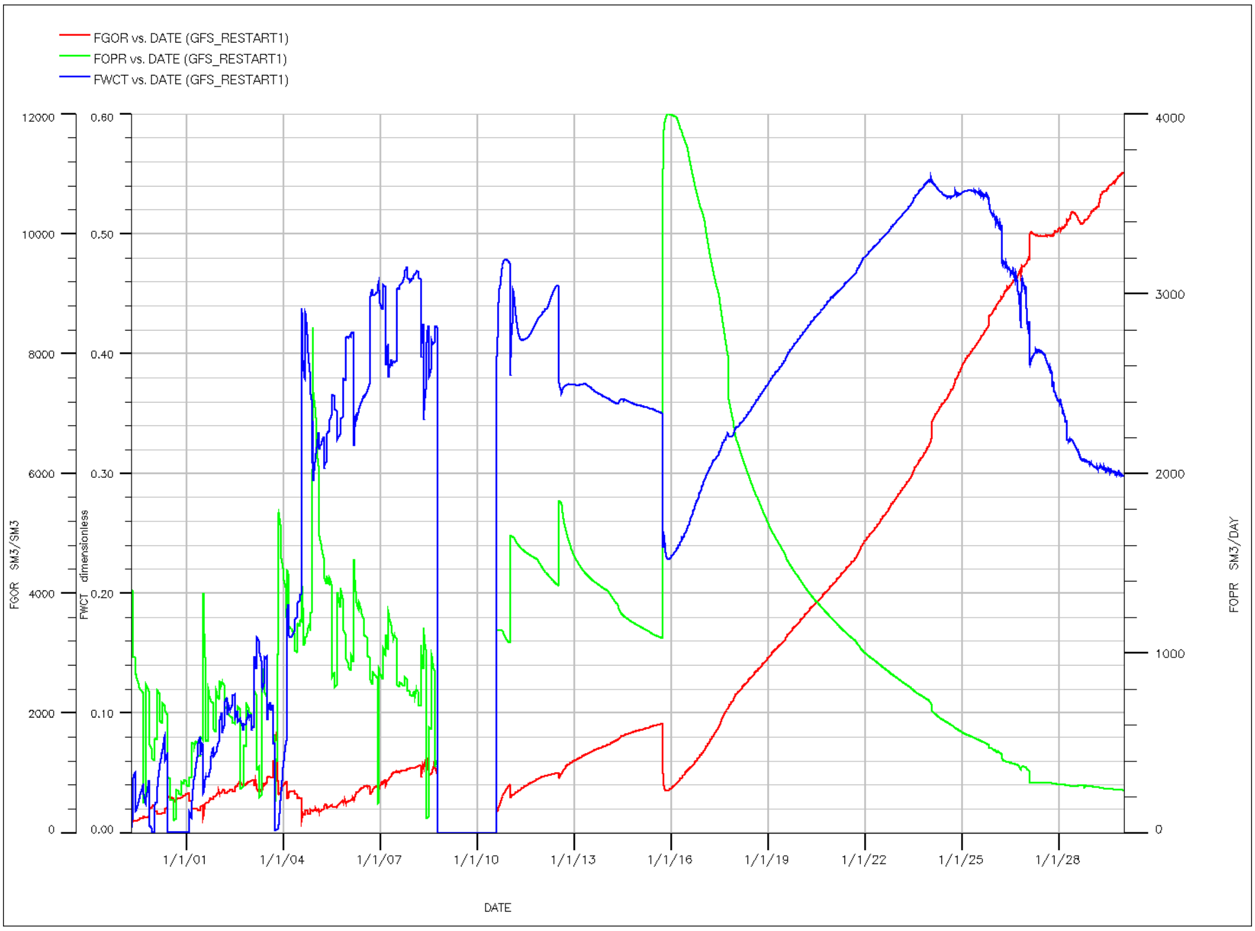


Figure 10 Field production from extended case

The date that the wells are supposed to come into production is Oct-2015. The production rate for oil has a significant increase at the date, and the water cut decreases at the same time. But this change is not a permanent one and it starts to change again. See Figure 10.

The oil production starts to decrease in a high rate and water cut increases with a notable rate, and at the same time, Gas/Oil ratio increases.

History matching in base case

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

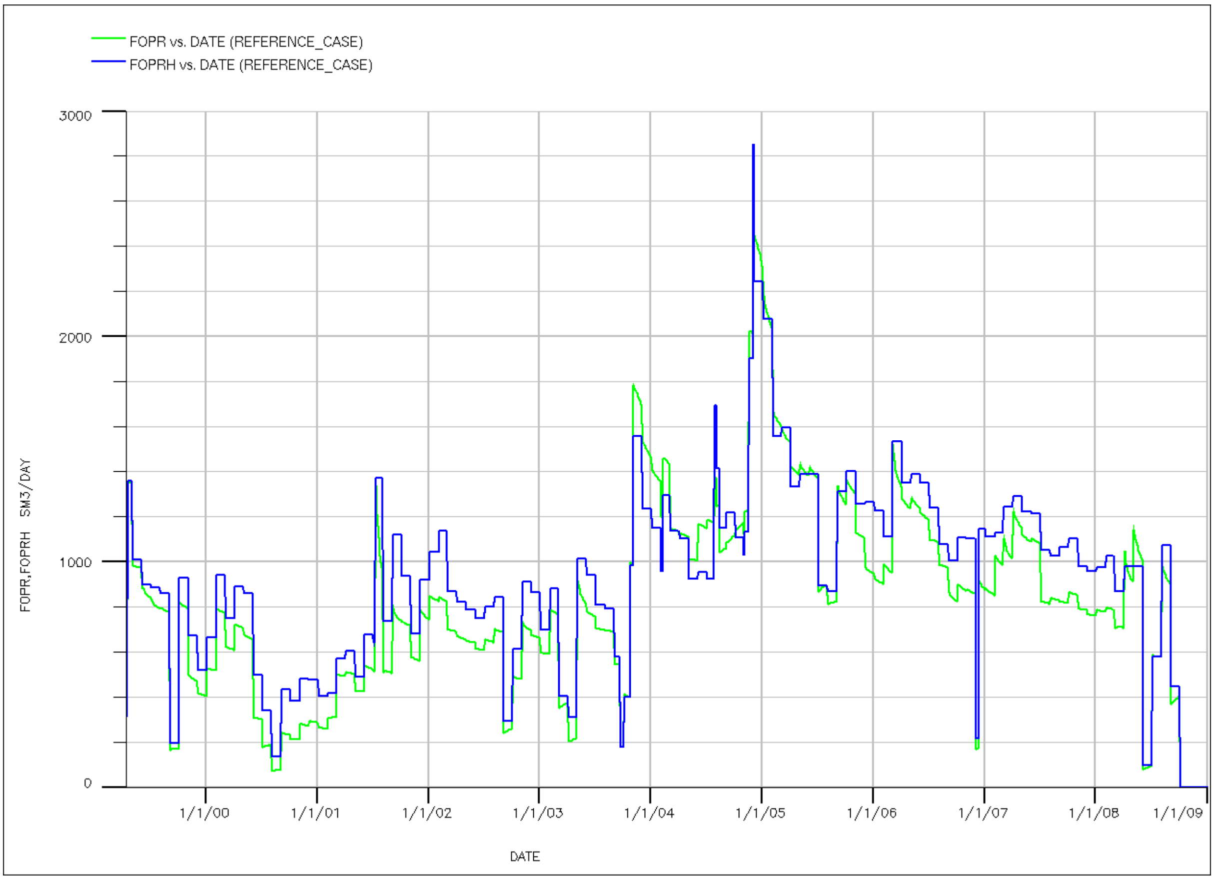


Figure 11 FOPR vs FOPRH

Figure 11 shows the matching between the real field oil production and the oil production simulated (reference case). 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.

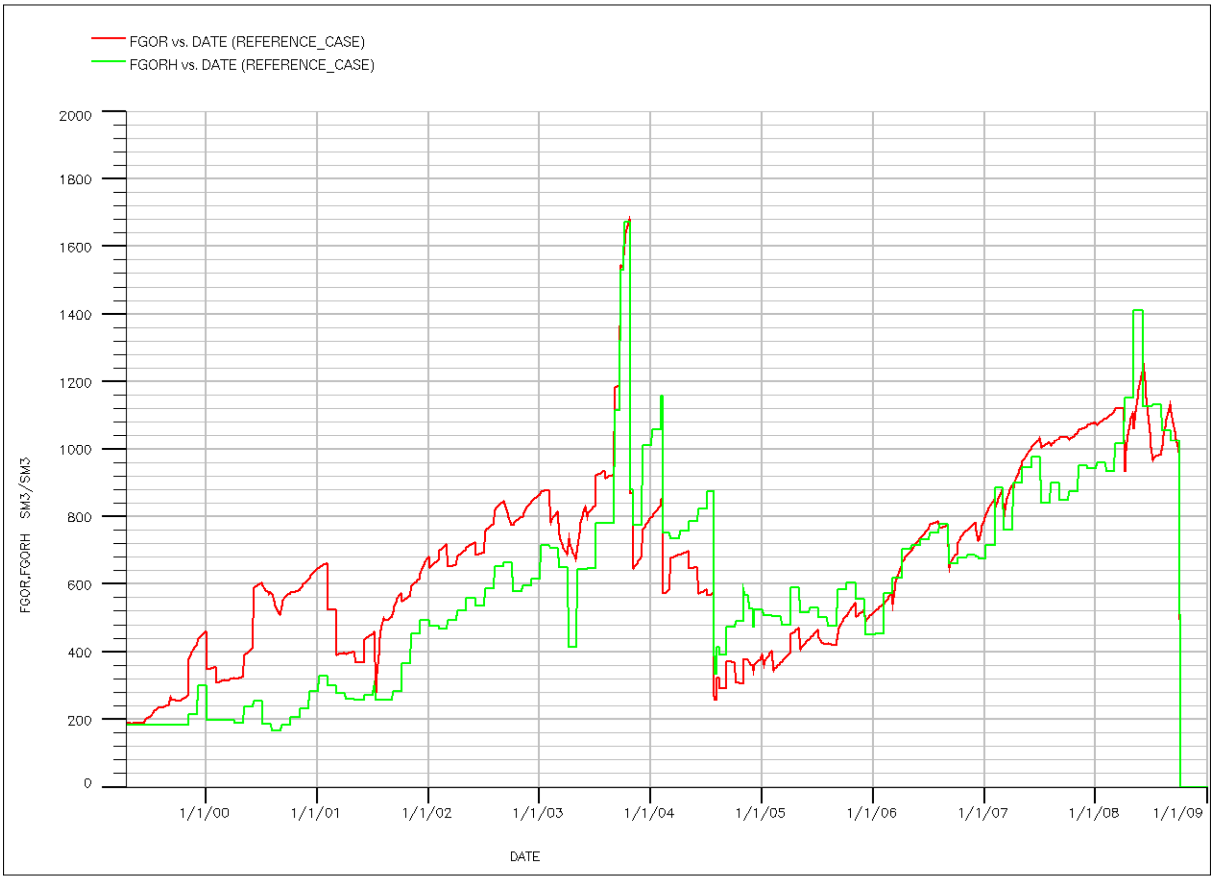


Figure 12 FGOR vs FGORH

Figure 12 shows the matching between the real gas-oil ratio and the gas-oil ratio from the reference case simulation. Field gas – oil ratio history 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 green line represents the simulation.

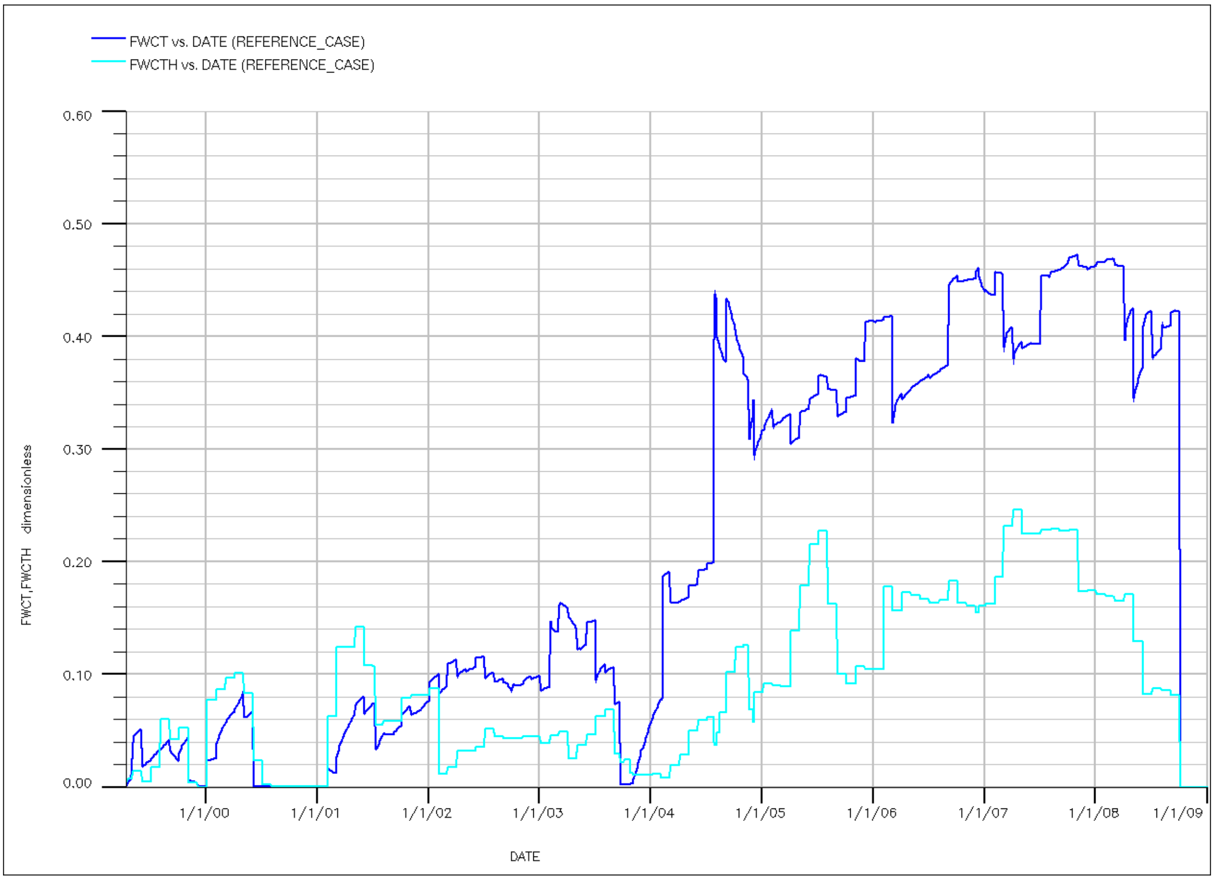


Figure 13 FWCT vs FWCTH

Figure 13 shows the actual water cut compared with water cut from the reference case simulation. The Field water cut simulation produces a lot more water 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.

Well production reference case vs. extended case

This subchapter contains a comparison of oil and gas well production and water cut, between reference case and extended case.

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.

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 the trend, one figure for the gas production is included. The green line is the reference case, and the red line is the extended case.

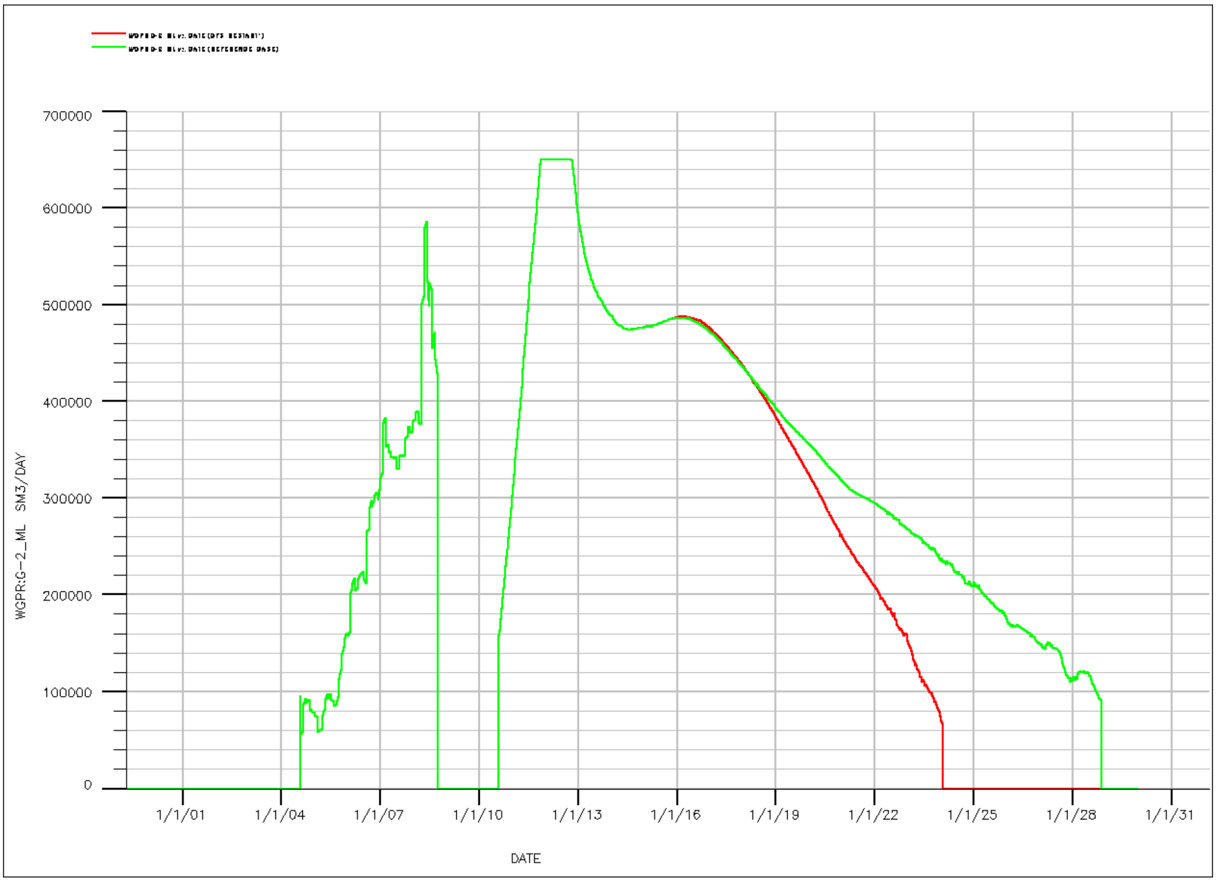


Figure 15 WGPR, G-2_ML reference vs. extended case

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.

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.

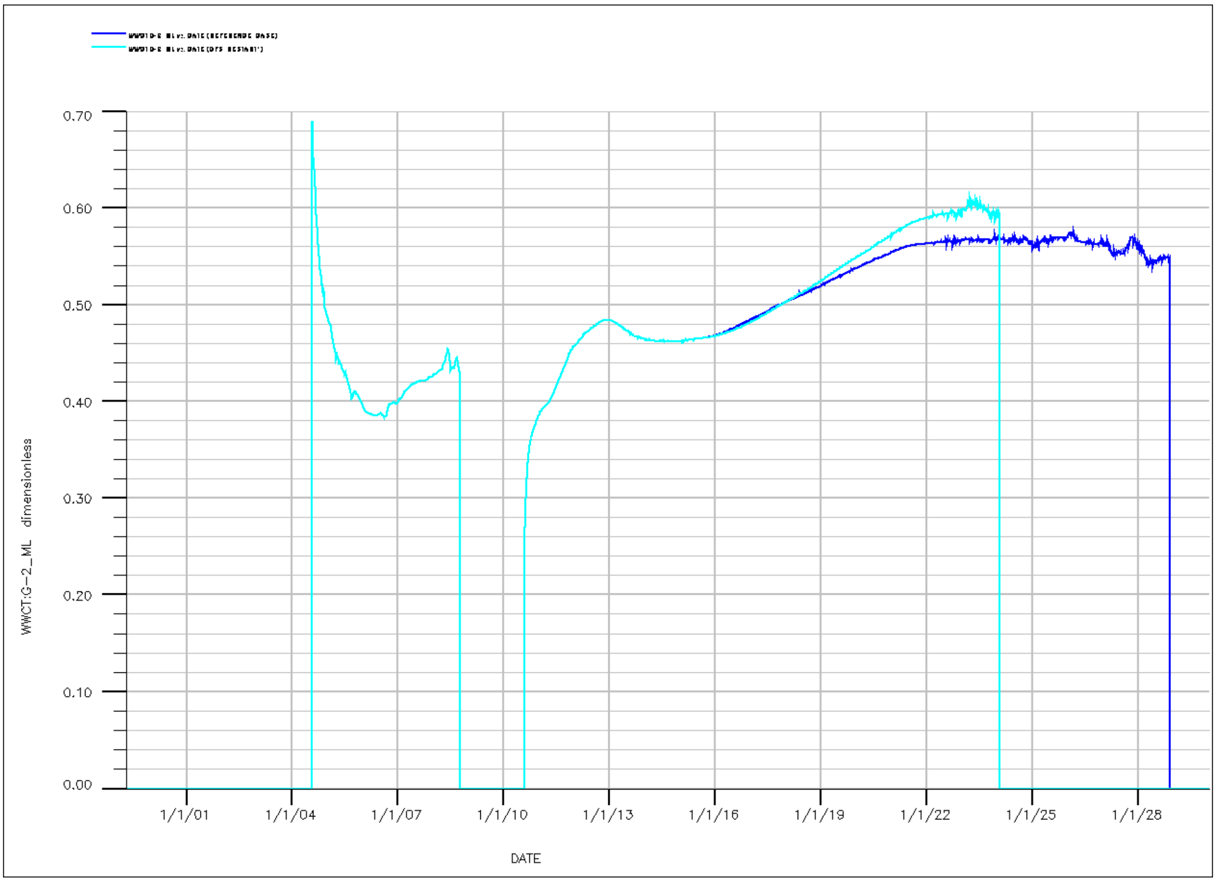


Figure 16 WWCT G-2_ML reference vs. extended case

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. The reason for the lower oil and gas production is because of the new wells production.

New Wells in extended case

Well W1

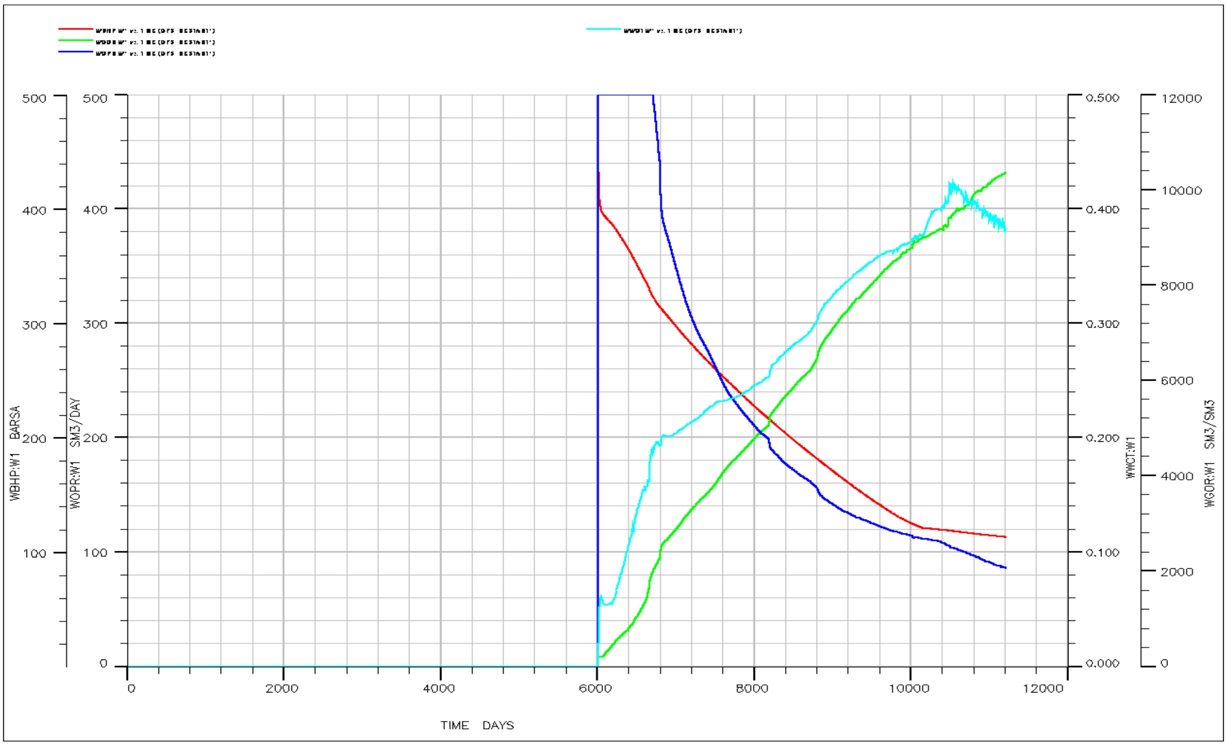


Figure 17 WOPR, WWCT, WGOR and WBH for W1

From Figure 17 we can see 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. This well should probably be shut in before reaching these levels because of the low production and drop in pressure (red line).

Well W2W3

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

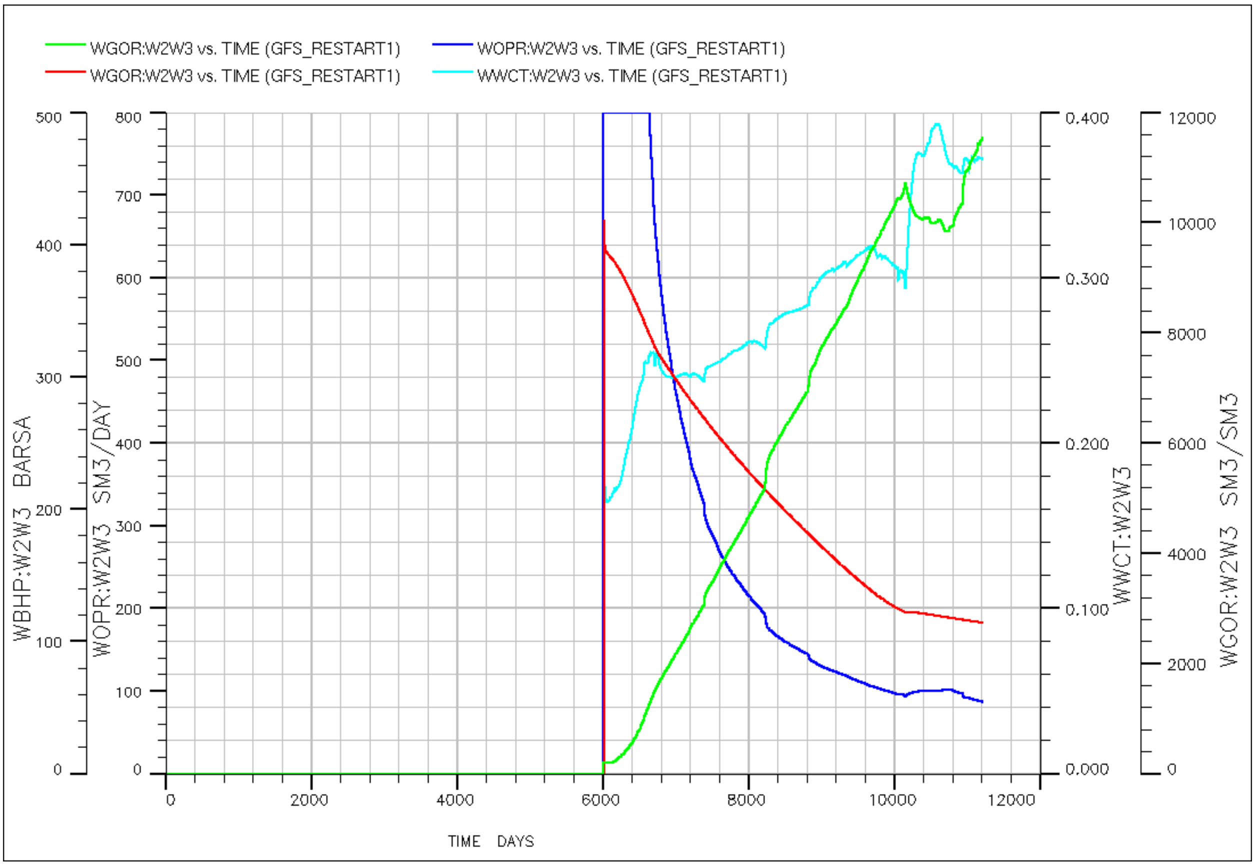


Figure 18 WOPR, WWCT, WGOR and WBHP for W2W3

Well W4W5

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

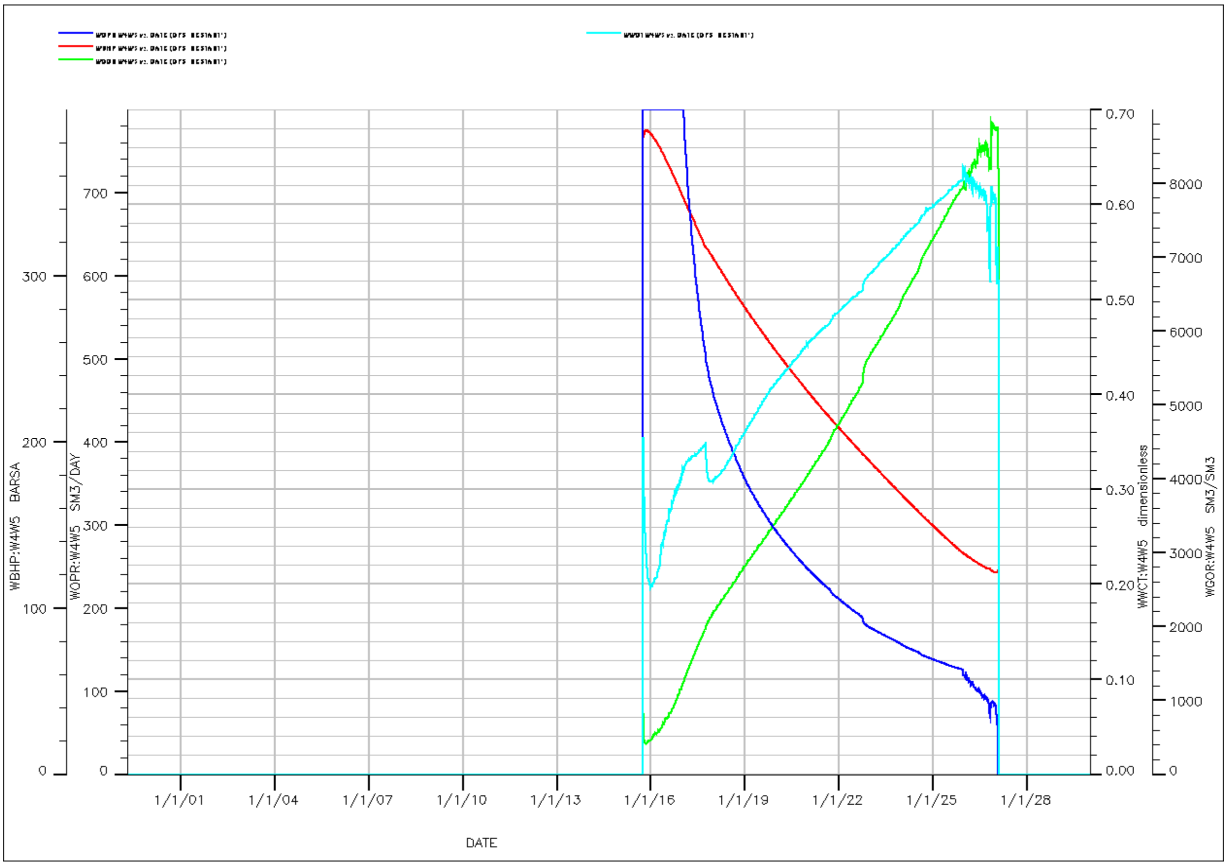


Figure 19 WOPR, WWCT, WGOR and WBHP for W4W5

Well W6W7

This well has a shorter plateau production (dark blue line) than the other wells. Here we can see that the water cut (light blue line) drops after some while 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.

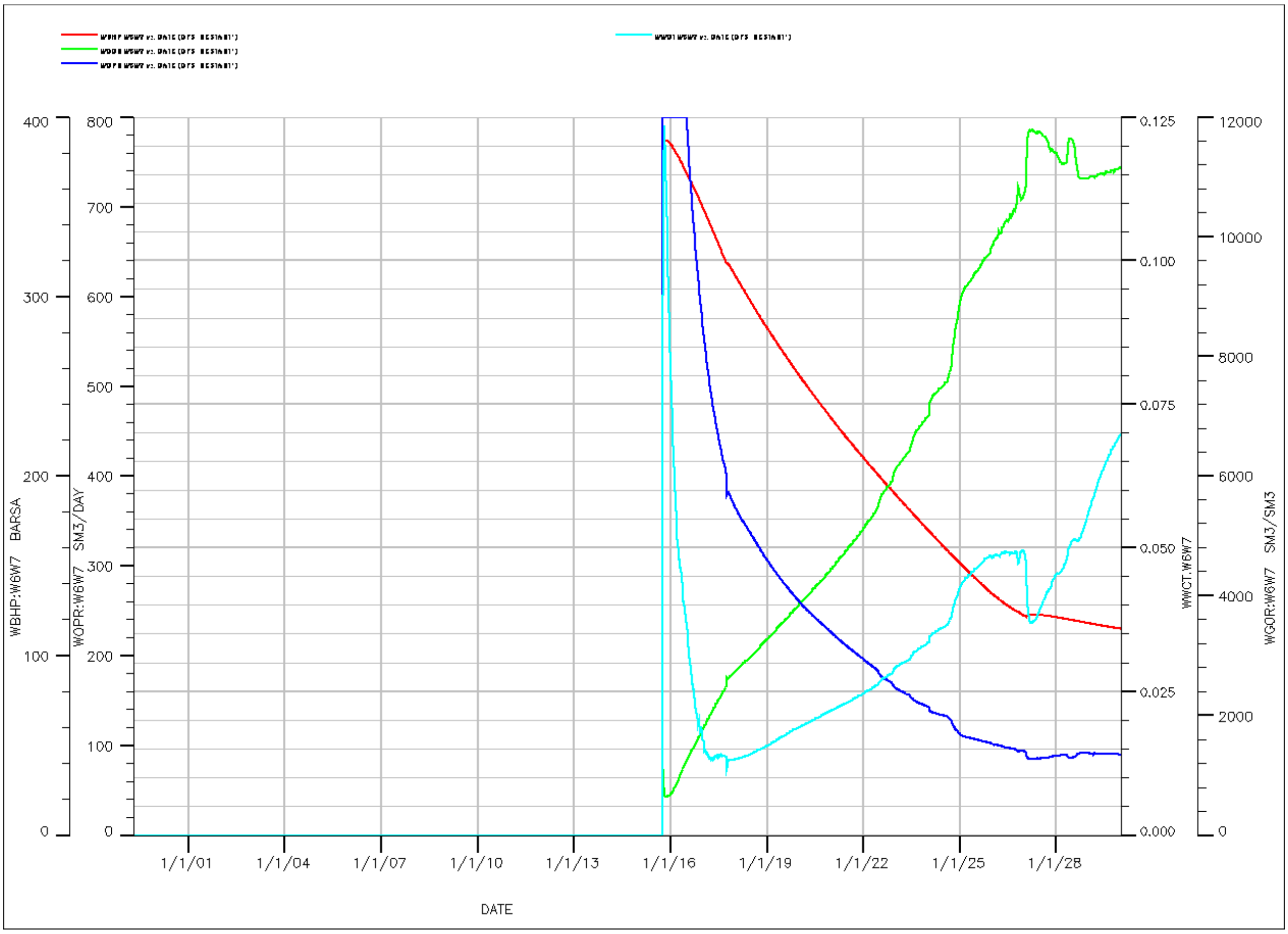


Figure 20 WOPR, WWCT, WGOR and WBHP for W6W7

In all the wells the pressure is decreasing with time.

We 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. We see that the pressure in the wells is below this pressure at some point. This means that the gas is coming out of solution, and we will get more gas produced. This is probably the main reasons for the decrease in oil production.

Figure 21 shows the total field gas production and how much gas we have 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 what we were supposed to look into in this assignment, and is therefore not included in this report.

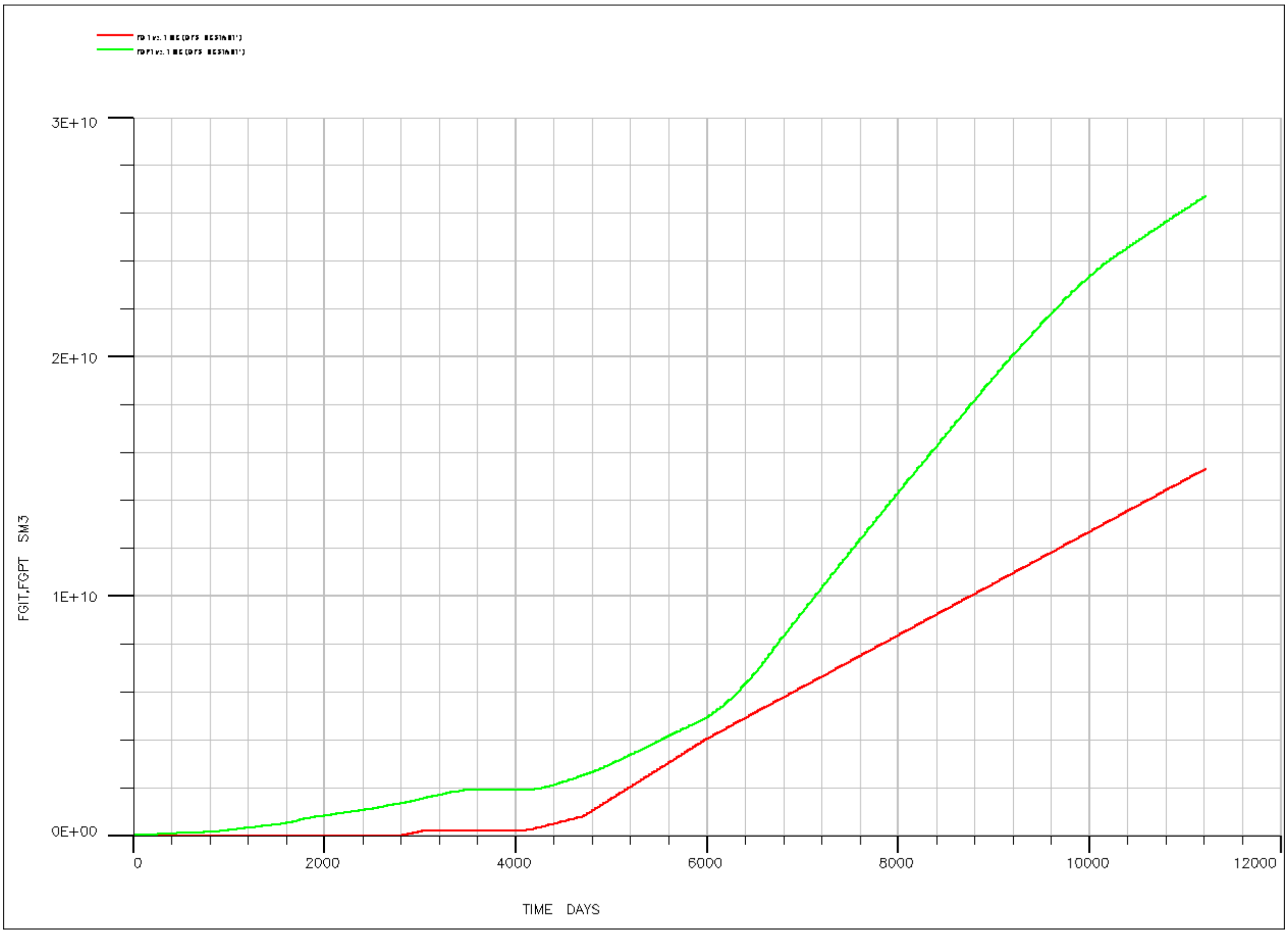


Figure 21 FGIT and FGPT

VI. VI. ECONOMIC EVALUATION

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):

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

For the gas sale 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, is assumed as that the project must pay for the missing amount of gas needed.

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 %

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

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.

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 assumed 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 assumed 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**

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 assumed 2

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

Table 6 OPEX assumed 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**

Results

Option 1

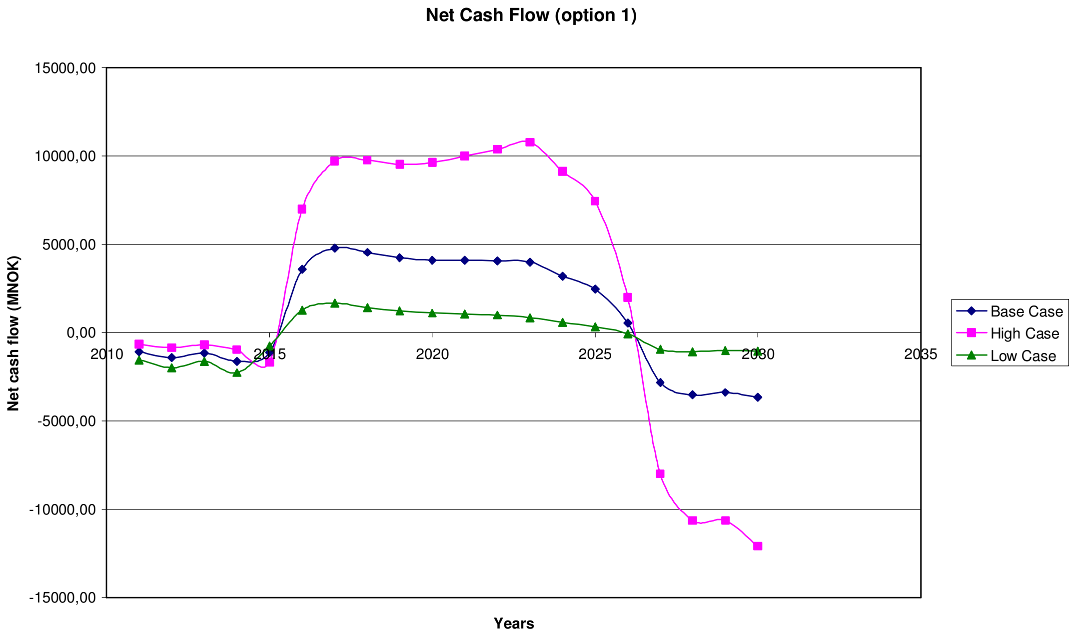


Figure 22 Net cash flow 1

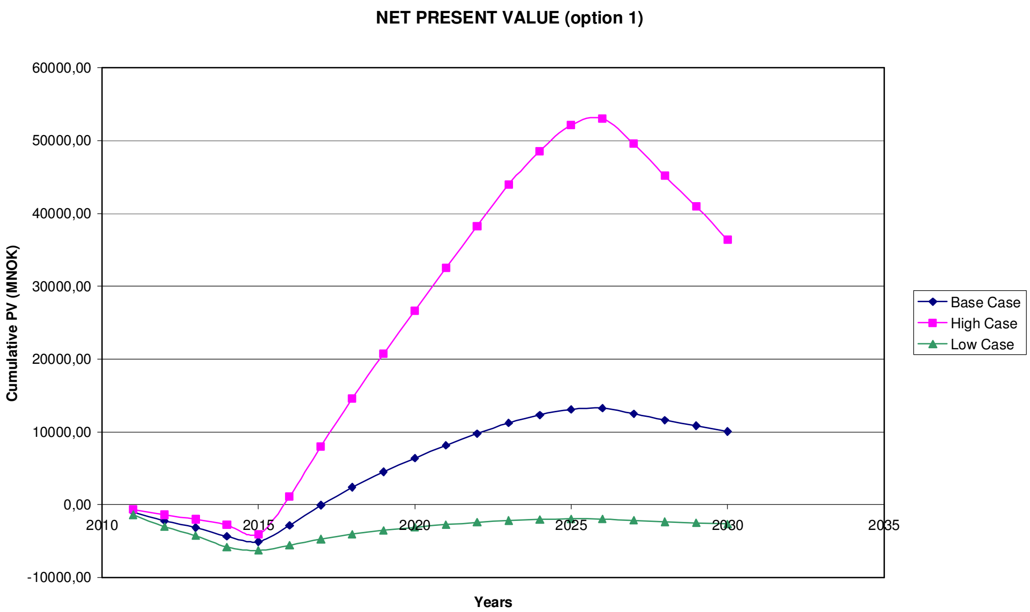


Figure 23 Net present value 1

From these two plots we can observe that in the low case we get losses and for the base case and the high case we get 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

Option 2

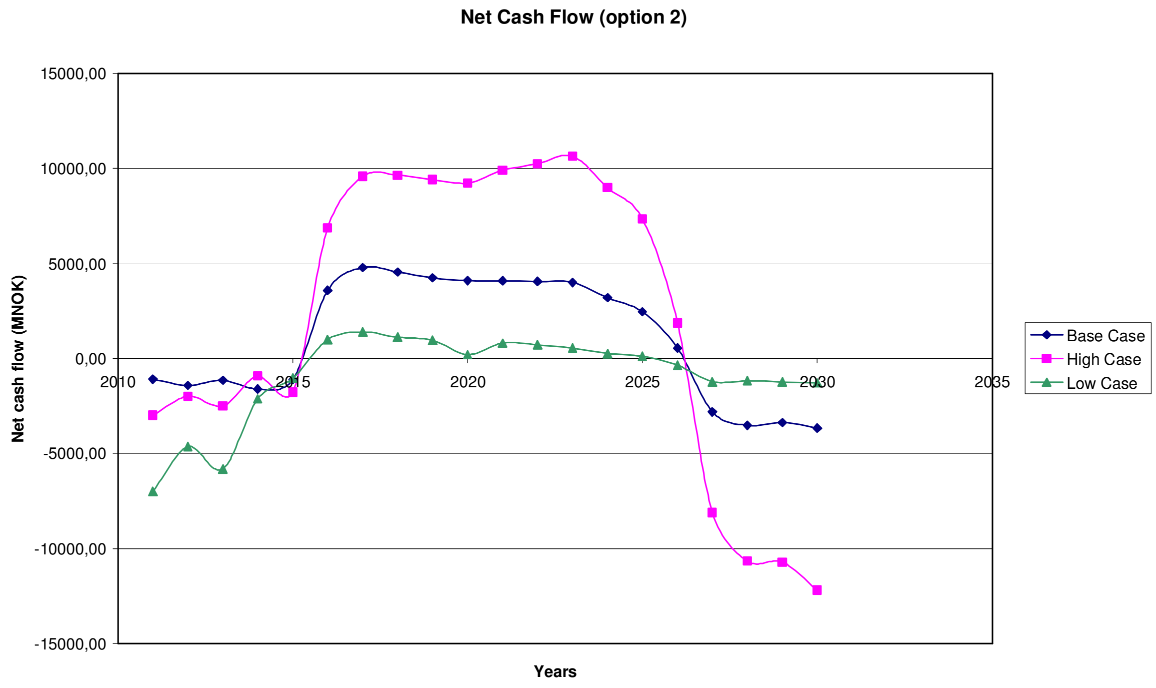


Figure 24 Net cash flow 2

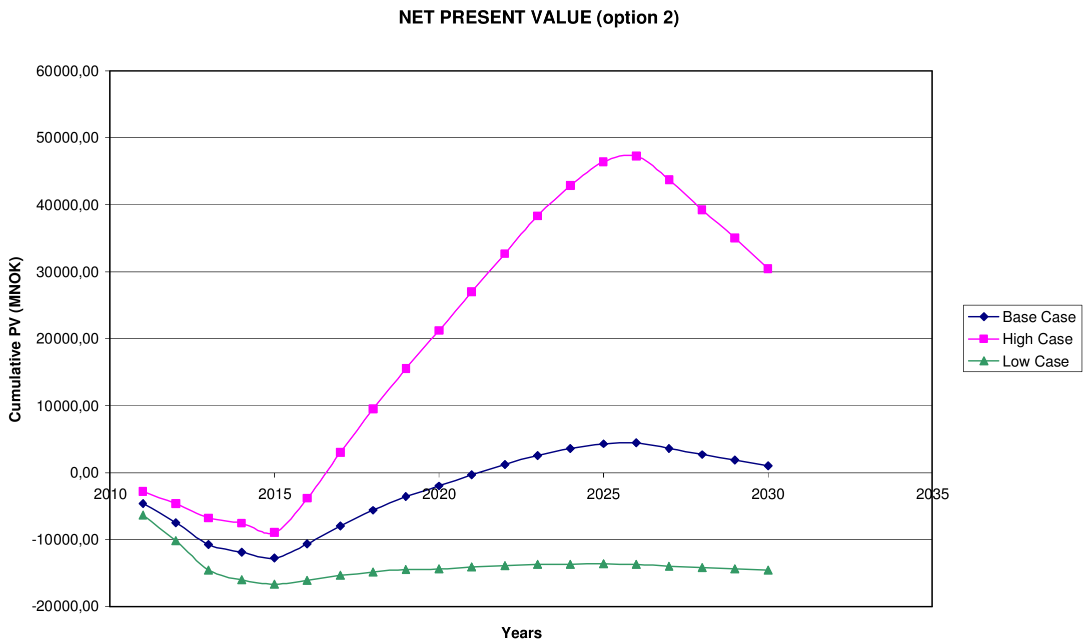


Figure 25 Net present value

From these plots it can be observed that in the low case we get losses and for the base case the earnings are very low compared with option 1, for the high case we get high revenues, but considering the base case as the most probable then option 1 represents the best option. In Appendix A we can observe the detailed results.

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.

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.

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 %

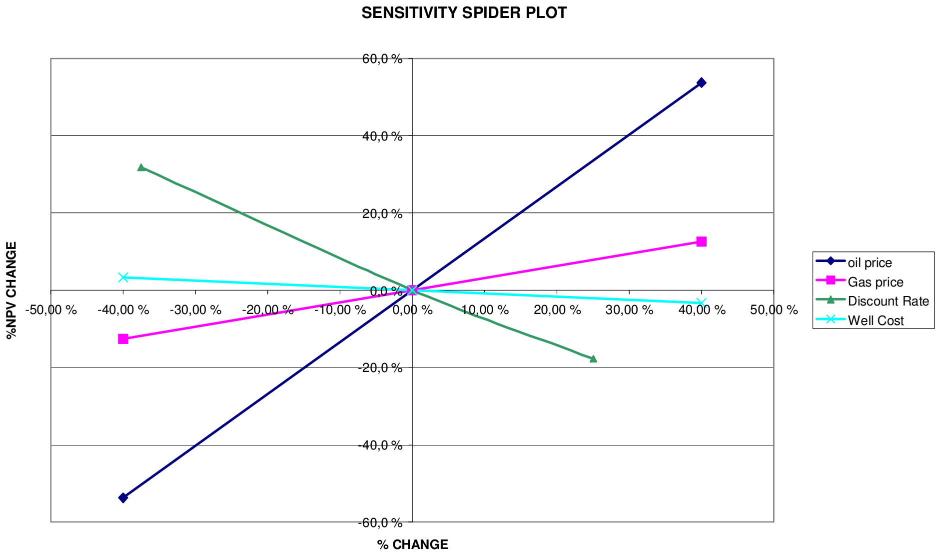


Figure 26 Sensitivity spider plot 1

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 %

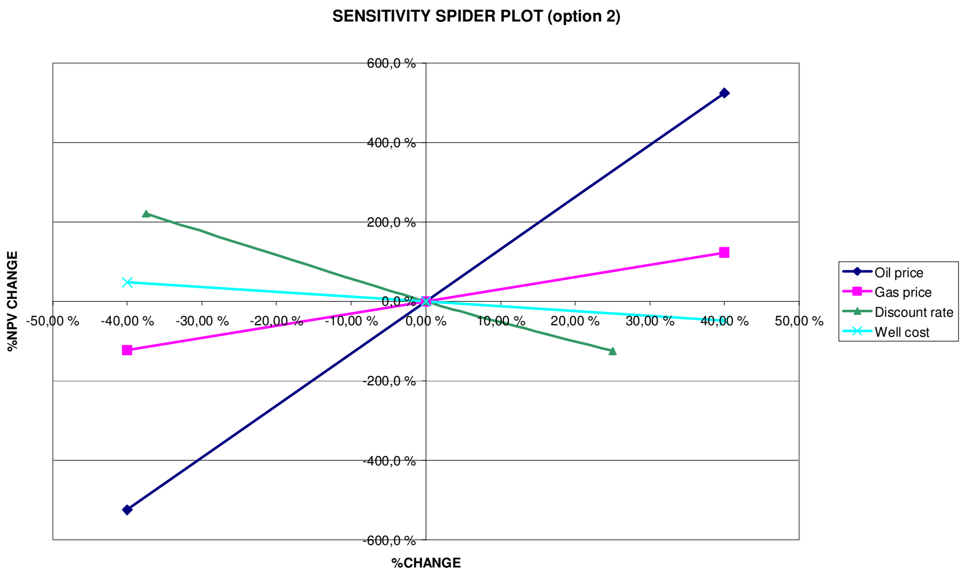


Figure 27 Sensitivity plot 2

VII. CONCLUSION

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 we note the big increase in production when the new wells start producing, but 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 we studied two options for drilling the new wells, 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. We had limited our study 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.

VIII. REFERENCES

Gullfaks - Reservoir management plan 2002

Gullfaks - Reservoir management plan 2004

IX. 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	4424114863,87	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			

YEAR	YEAR	Oil production	Gas production	Gas Injection	Gas Sale	Revenue from Oil	Revenue from Gas
PROJECT	CALENDER	sm3	Gsm3	Gsm3	Gsm3	NOK	NOK
1	2011	0	0	0	0	0,00	0,00
2	2012	0	0	0	0	0,00	0,00
3	2013	0	0	0	0	0,00	0,00
4	2014	0	0	0	0	0,00	0,00
5	2015	235978,2552	0,272652617	0,876	-0,603347383	511469617,64	-924049368,55
6	2016	909266,316	0,701911246	0,876	-0,174088754	2069322867,94	-279954696,55
7	2017	693888,994	1,230293397	0,876	0,354293397	1658121888,70	598231666,50
8	2018	509591,9232	1,326605867	0,876	0,450605867	1278610564,40	798900109,55
9	2019	390104,364	1,317799843	0,876	0,441799843	1027746153,68	822451875,25
10	2020	311488,8068	1,306576365	0,876	0,430576365	861661712,53	841636232,92
11	2021	257187,607	1,297960683	0,876	0,421960683	747022507,47	866035157,23
12	2022	208676,7992	1,287235966	0,876	0,411235966	636424830,18	886224852,73
13	2023	170946,384	1,274039047	0,876	0,398039047	547421898,28	900674383,99
14	2024	118191,7592	1,180563852	0,876	0,304563852	397409956,54	723618714,57
15	2025	87701,04675	1,087712446	0,876	0,211712446	309631846,56	528161964,68
16	2026	53051,3585	0,881072646	0,876	0,005072646	196664808,91	13287540,83
17	2027	18103,62965	0,588433791	0,876	-0,287566209	70466889,34	-790928421,75
18	2028	18761,0254	0,545238539	0,876	-0,330761461	76677035,65	-955220274,00
19	2029	32325,2428	0,565872459	0,876	-0,310127541	138720242,01	-940412220,37
20	2030	32330,5831	0,568356517	0,876	-0,307643483	145680317,29	-979523698,27
	TOTAL	**4047594,095**	**15,43232528**	**14,016**	**1,416325282**	**10673053137,13**	**2109133818,77**

YEAR	YEAR	CAPEX+40% Production unit	Subsea Pipeline	Drillex	OPEX+40% Field/onshore	Oil/Gas transportation	CO2 duty	Net Cash Flow	PV cash flow	Cumulative PV Cash Flow
PROJECT	CALENDER	NOK	NOK	NOK	NOK	NOK	NOK	MNOK	MNOK	MNOK
1	2011	-420000000	-700000000	-420000000	0	0	0	-1540,00	-1400,00	-1400,00
2	2012	-280000000	-1400000000	-280000000	-28000000	0	0	-1988,00	-1642,98	-3042,98
3	2013	-280000000	-1120000000	-140000000	-84000000	0	0	-1624,00	-1220,14	-4263,11
4	2014	-259000000	-1400000000	-560000000	-42000000	0	0	-2261,00	-1544,29	-5807,40
5	2015	0	0	0	-280000000	-31170367,72	-42000000	-765,75	-475,47	-6282,87
6	2016	0	0	0	-350000000	-120104987,7	-42000000	1277,26	720,98	-5561,89
7	2017	0	0	0	-322000000	-240459024	-28000000	1665,89	854,87	-4707,03
8	2018	0	0	0	-392000000	-256566461,3	-28000000	1400,94	653,55	-4053,47
9	2019	0	0	0	-364000000	-237084819,6	-28000000	1221,11	517,87	-3535,60
10	2020	-70000000	0	0	-280000000	-221986629,8	-28000000	1103,31	425,37	-3110,23
11	2021	0	0	-49000000	-280000000	-211195398	-28000000	1044,86	366,22	-2744,01
12	2022	0	0	0	-308000000	-200283224	-21000000	993,37	316,52	-2427,49
13	2023	0	-140000000	0	-252000000	-189756707,4	-21000000	845,34	244,86	-2182,63
14	2024	0	-140000000	0	-252000000	-143528767,5	-21000000	564,50	148,65	-2033,98
15	2025	-140000000	0	0	-238000000	-100503658,7	-21000000	338,29	80,98	-1952,99
16	2026	0	0	0	-238000000	-9138065,388	-21000000	-58,19	-12,66	-1965,66
17	2027	0	0	0	-210000000	-2391308,44	-21000000	-953,85	-188,71	-2154,37
18	2028	0	0	0	-182000000	-2478143,845	-14000000	-1077,02	-193,71	-2348,08
19	2029	0	0	0	-182000000	-4269841,321	-14000000	-1001,96	-163,83	-2511,91
20	2030	0	0	0	-182000000	-4270546,722	-14000000	-1034,11	-153,71	-2665,63
	TOTAL	**-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**			