Technical Report - Group 2

Gullfaks Village 2010

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Trondheim, 28.04.2010

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Contents

1 Introduction

This report is a part of the final report in the course Experts in Team at the Gullfaks village. Our main task was to improve the oil recovery at Gullfaks Sør. In this part A, the task was to run an Eclipse reservoir simulation of the Gullfaks Sør. The simulation and the information that we needed was given by Statoil. In the simulation we used the wells that already had been planned and drilled, as well as four new oil producers and two gas injectors. These two cases was named Reference_Case, which had no new wells, and GFS_Restart, which included the new wells. After running the simulation we interpreted the results and compared them with each other. The additional production that we got from the new wells was included in an economic evaluations. Based upon these economic evaluations, we came up with some recommendations on what Statoil should do at the Gullfaks Sør field.

Trondheim, 24.02.2010

2 Gullfaks Sør - The Field

2.1 Field history

Gullfaks Sør was discovered in 1978. It is located in the northern part of the North Sea, approximately 175 km northwest of Bergen. Gullfaks Sør is located in the blocks 34/10 and 33/12, just a bit south of the mainfield Gullfaks. When the field first was discovered, the initial plan was to produce oil and condensate. After some years there came a new plan, that also included production of gas from the Brent group. The production on Gullfaks Sør is done by eleven subsea templates, that are connected to the platforms Gullfaks A and C trough the Gullfaks Sør satellite. From here the oil and gas are processed, stored and then shipped into the mainland. The driving mechanism for production on the field is injection with gas. According to numbers from Statoil 2008, the total oil volume in Gullfaks Sør is 39.3 MSm3 and 2.9 MSm3 condensate. The total gas volume is 1.25 GSm3 and the water volume is 175.1 MSm3. The information also state that the Gullfaks Sør field had produced 3,3MSm3 of oil/condensate and 2,0 GSm3 gas. Since September 2008, the field has been shut in due to low pressure.

2.2 Geology

The geology in the North Sea today is a result of the two rifting periods that took place there for over 200 million years ago. The first rifting period was in Trias, and during this period about 3000 m of sediments from the mainland were deposited. These sediments were mostly deposited in the Central Graben that developed during the rifting. The second period of rifting was during the Jurassic. It lead to the development of a huge riftdome between the Central Graben, Viking Graben and the Morey-Firth Graben. Due to some uplift and erosion of this dome, a lot of clastic sediments were deposited in particular in the Viking Graben. Some of the sandstones and shales that are good reservoirs and source rocks today, were deposited in the Viking Graben at this time.

The Gullfaks Sør field is located at the west flank of the Viking Graben, and has a pretty complex structural geology. Gullfaks Sør is distinguished from the mainfield Gullfaks, by an east-trending fault. But the Gullfaks Sør itself has faults that are N-S trending, and these faults dip approximately 15 degrees to the west. One can divide both Gullfaks and Gullfaks Sør into three structural areas. The first and the largest one is a domino-area with a lot of rotated fault blocks. The second area is an adaptation zone with complex folding. The third area is a horst area with a lot of faults.

The geology of Gullfaks Sør is quite diverse, and the age range from Middle Jurassic to Upper Trias. The top reservoir is found at 2860 m true vertical depth, but the whole reservoir is between 2400 m and 3400 m below sea level. This makes Gullfaks Sør one of the deepest structures in the area. The oil-water contact is found at 3362 m below sea level, and gas-oil contact is found at 3224 m. The stratigraphical structure of the Gullfaks Sør can be divided into five main formations, the Lunde, Statfjord, Amundsen, Cook and Brent formations. The production has mainly been from the Statfjord and Brent formations.

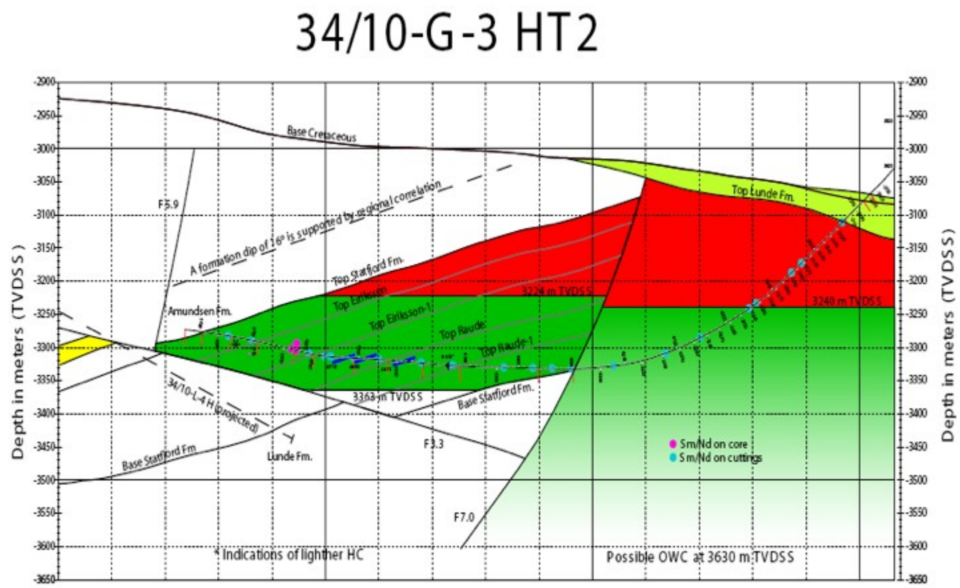

Figure 1: Cross-section of the Gullfaks Sør field showing the different formations

From figure 1, it is shown that the Brent formation is the one that is on the top of the Gullfaks Sør. The formation is dated back to middle Jurassic and consists manly of deltaic sandstone and shale deposits. It is difficult and dangerous to drill in the Brent formation due to large pressure differences trough out the formation. Hence the old wells has been drilled beneath the Brent formation and into the Statfjord formation. The next formation is the Cook formation, which is dated back to early Jurassic and it is 150 m thick. The Cook formation consists of sandstone, which is coarsening upwards. The Amundsen formation is from early Jurassic, and consists of marine shale. The most important formation in Gullfaks Sør is the Statfjord formation. It is subdivided into three layers. The first one, which occurs on the top of the formation, is Nansen. This layer is mostly sandstone from channel systems and fluvial deposits. The permeability and porosity in Nansen are very good. The next layer is Eiriksson, which has the same history of deposition, hence the same very good reservoir quality. Both of these layers are from early Jurassic. The last layer is Raude, which is dated back to Trias. This layer has deposits from both fluvial and alluvial environments, hence poorer permeability and porosity. In addition a lot of shale between the sandstone, makes the net to gross ratio poor. This is a moderate good reservoir. The last formation in the Gullfaks Sør is the Lunde formation from Trias. It consists of sediments from an alluvial flat, with low sedimentation rate. This makes Lunde a poor reservoir. One of the largest uncertainties today in Gullfaks Sør, is the connectivity between the sand bodies in the reservoir.

2.3 Petrophyscis

Permeability is defined as a measure of the ability of a porous material (often, a rock or unconsolidated material) to transmit fluids. For a rock to be considered as an exploitable hydrocarbon reservoir without stimulation, its permeability must be greater than approximately 100 milliDarcy (1 darcy 1012m2). Depending on the nature of the hydrocarbon - gas reservoirs with lower permeabilities are most times still exploitable because of the lower viscosity of gas with respect to oil. Rocks with permeabilities significantly lower than 100 mD can form efficient seals. In figure 2, one can see that the good reservoirs(Eiriksson and Nansen) has a permeability between 500 - 5000 mD. Raude has a permeability about 100-500mD and Lunde has a very poor permeability ranging from 1-100mD.

Porosity is defined as the relative amount of pore space between the minerals to the bulk volume of the reservoir , it is expressed as a fraction or in percentages. Porosities in potential reservoirs tend to range from 10 percent to 30 percent. The Statfjord formation in the Gullfaks-Sør field has been determined to have a porosity of about 20 percent.

The Gullfaks - Sør field is characterized by reasonably high reservoir pressure ranging from 114.4bar to 522.11bar in different areas of the field as can been seen from figure 3.

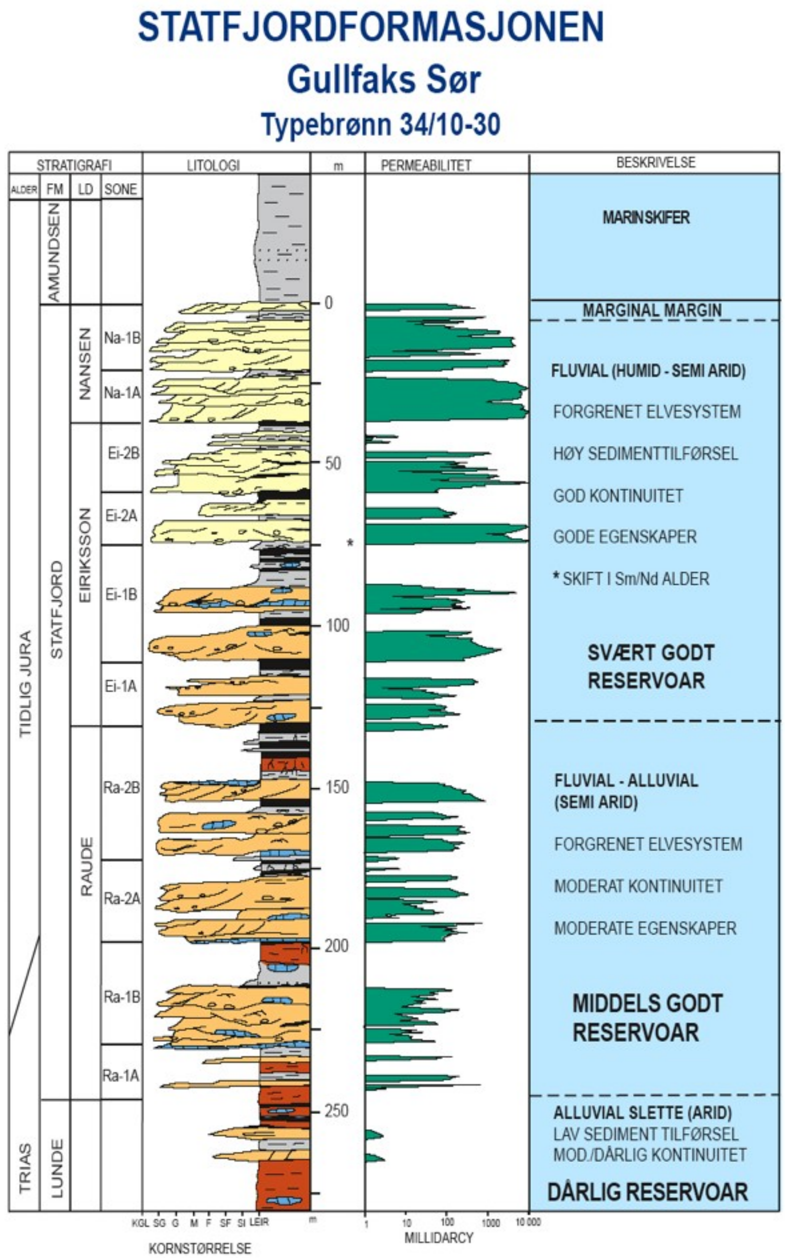

Figure 2: The Statfjord formation lithology log

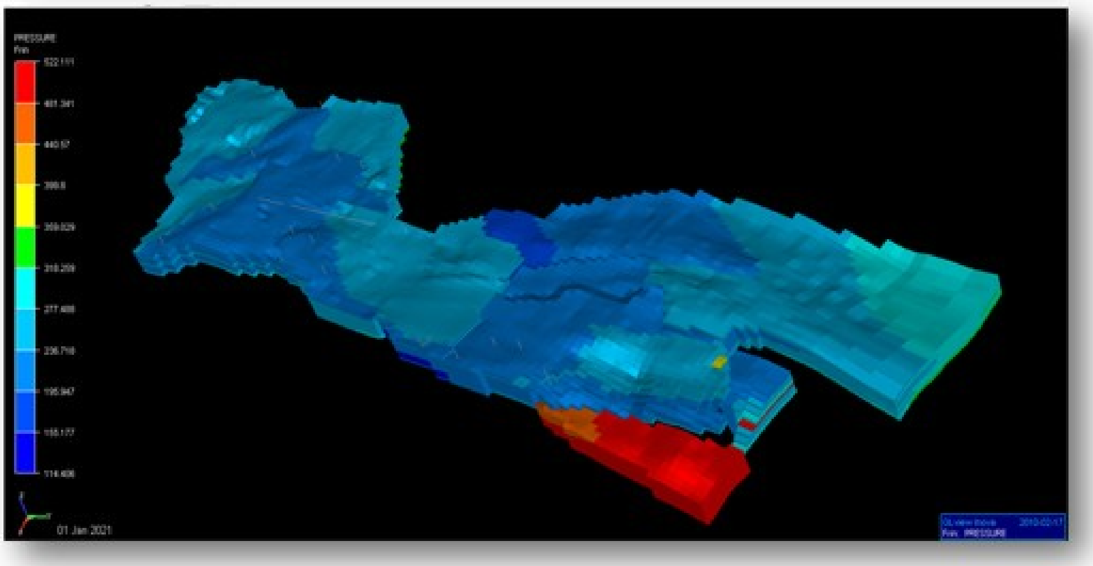

Figure 3: Distribution of pressure in the reservoir

3 Results from Eclipse

3.1 The new wells

To evaluate the Gullfaks field with new wells, the reservoir evaluation program Eclipse was used. By using of simulation results and plotting graphs afterwards, it was possible to get the relevant information about the field behaviour.

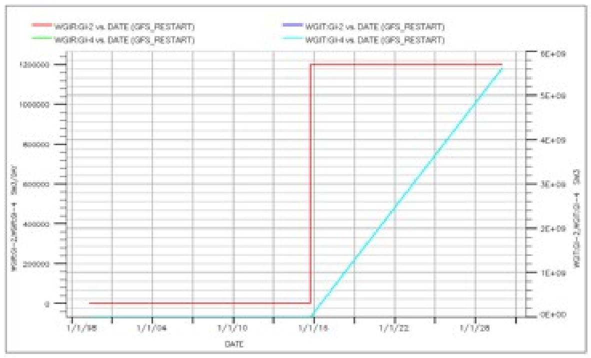

Figure 4: Gas Injection for Well GI-2 and GI-4

From figure 4, we can say gas injection will start from 02 October 2015 and it will continue till 01 January 2030 for both of gas injection wells GI-2 and GI-4. In case of both wells, gas injection rate is 1200000 Sm3/D. Total 5.6224799E+9 Sm3 gas will be injected for both of the wells to build up the pressure.

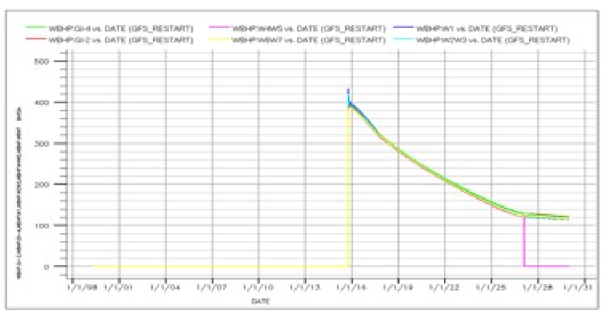

Figure 5: Bottom Hole Pressure for Two Injection Wells and Four Producing Wells

From figure 5 we can see the initial bottom hole pressure of gas injection well, GI-2 is 387.38501 bar and GI-4 is 426.10626 bar on 02 October 2015. Gradually BHP will be decreased and it will go down to be 120.83537 bar for GI-2 and 119.85867 bar for GI-4 on 01 January 2030. The initial bottom hole pressure of producing well, W1 is 432.73343 bar, W2W3 is 418.95245 bar, W4W5 is 383.28238 bar and W6W7 is 379.91541 bar on 02 October 2015.

Gradually BHP will be decreased and it will go down to be 113.50892 bar for W1, 113.99010 bar for W2W3, 114.73647 bar for W6W7 on 01 January 2030. BHP will go down to be 0.00000 bar for W4W5 on 10 February 2027. This mean that there will be no more oil production from the well W4W5 on that day.

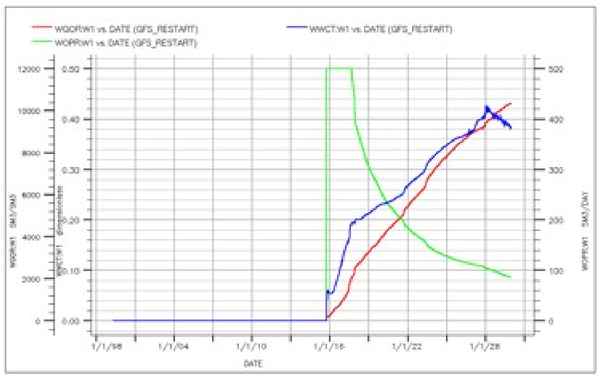

Figure 6: Gas Oil Ratio, Oil Production Rate and Water Cut for Producing Well, W1

By interpreting figure 6 we can say, the initial GOR is 187.65845 Sm3/Sm3 on 02 October 2015 and it will go up to be 10350.516 Sm3/Sm3 on 01 January 2030. This mean that gas production rate will be increased gradually than oil production rate. The initial oil production rate is 500 Sm3/D on 02 October 2015 and it will be constant till 03 September 2017. After that it will go down to be 85.450928 Sm3/D on 01 January 2030. The initial Water-Cut is 0.020448819 and it will be increased up to 0.42233464 on 31 January 2028, hence water production will be increased gradually. After that water-cut will be decreased from 0.42233464 to 0.38180426 on 01 January 2030.

Analyzing figure 7, we can say that the initial oil production rate (OPR) is 800 Sm3/D and it will be constant till 20 Jun 2017. After that OPR will go down gradually from 800 Sm3/D to 93. 707558 Sm3/D on 15 February 2027. Again OPR will be slightly increased up to 101.71559 Sm3/D on 13 August 2028. After that OPR will be decreased to 86.701073 Sm3/D on 01 January 2030. The initial GOR is 187.24797 Sm3/ Sm3. On 02 October 2015 and it will be increased to 10708.131 Sm3/ Sm3 on 05 February 2027. This mean that gas production will be increased during these years. After that GOR will be decreased to 9831.334 Sm3/ Sm3 on 05 February 2027. And again it will be increased to 11533.883 Sm3/ Sm3 on 01 January 2030. The initial water-cut is 0.056113884 and it will be increased abruptly to 0.25495565 on 09 August 2017. Hence during these years this well will produce more water. After that water-cut will be increased slowly to 0.31182933 on 31 May 2026. Again water-cut

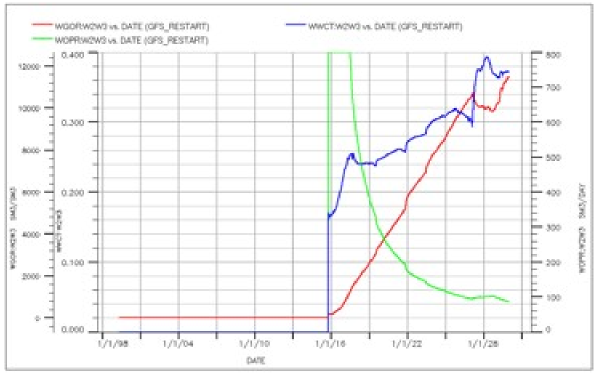

Figure 7: Gas Oil Ratio, Oil Production Rate and Water Cut for Producing Well, W2W3

will be increased abruptly to 0.39320382 and oil production will be decreased on 21 March 2028.

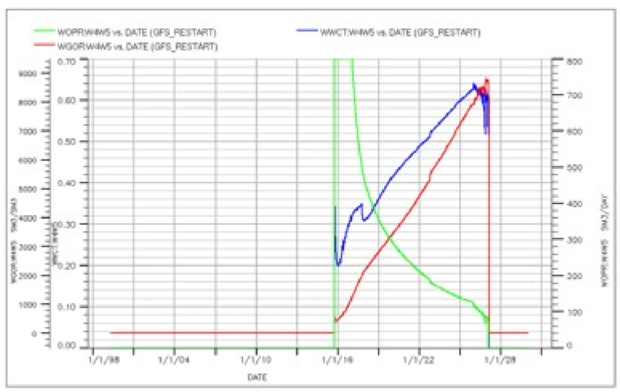

Figure 8: Gas Oil Ratio, Oil Production Rate and Water Cut for Producing Well, W4W5

From figure 8, we can say the initial GOR is 826.39404 Sm3/ Sm3 on 02 October 2015 and it will be increased to 8131.8071 Sm3/ Sm3 on 05 February 2027. After that it will go down to zero, that means there will be no more gas production. The initial oil production rate (OPR) is 800 Sm3/D and it will be constant till 11 January 2017. After that it will go down to be 2.3036892E-8 Sm3/D on 31 January 2027, there will be no more oil production after 31 January 2027. The initial water-cut is 0.35461435 on 02 October 2015 and it will be gradually increased up to 0.61189598 on 14 August 2026. After that it will be decreased to 0.055502843 on 05 February 2027, after this date the well will be closed because there will be no more oil production from this well.

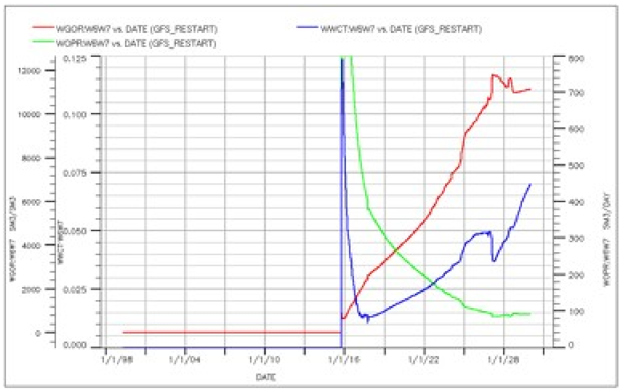

Figure 9: Gas Oil Ratio, Oil Production Rate and Water Cut for Producing Well, W6W7.

By analyzing the graphs in figure 9, we can explain that the initial GOR is 1512.8853 Sm3/ Sm3 on 02 October 2015 and it will be increased to 11635.893 Sm3/ Sm3 a lot of gas will be produced from this well. The initial oil production rate (OPR) is 800 Sm3/D and it will be constant till 29 Jun 2016. After this date it will go down to 89.642807 Sm3/D on 01 January 2030. The initial water-cut will be 0.1112828 and it will be decreased to 0.037029918 on 29 Jun 2016, oil production will be more than the water production at these periods. After that water cut will be increased to 0.069909818 on 01 January 2030, and more water will be produced.

By interpreting figure 10, we can say the total (cumulative) oil production (OPT) from well W1 will be 1039896.3 Sm3, from well W2W3 will be 1275609.5 Sm3, from well W6W7 will be 1111230.5 Sm3 on 01 January 2030 and from well W4W5 will be 1167215.5 Sm3 on 31 January 2027. After this there will be no more oil production from well W4W5. More oil will be produced from well W2W3.

By interpreting figure 11, we can say the total (cumulative) water production (WPT) from well W1 will be 327178.88 Sm3, from well W2W3 will be 429399.56 Sm3, from well W6W7 will be 39177.328 Sm3 on 01 January 2030 and from well W4W5 will be 793105.31 Sm3 on 31 January 2027. After this date there will be no more oil production and water production from well W4W5. More water will be produced from well W4W5.

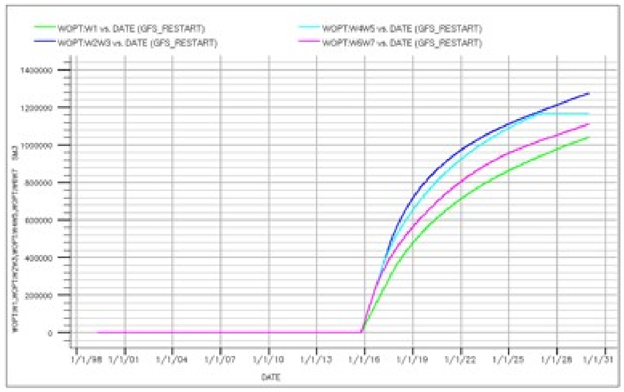

Figure 10: Total Oil Production for Producing Well - W1, W2W3, W4W5 and W6W7.

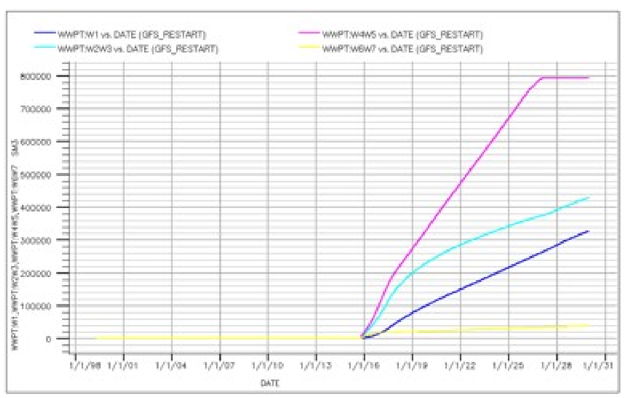

Figure 11: Total Water Production for Producing Well - W1, W2W3, W4W5 and W6W7.

3.2 The whole field

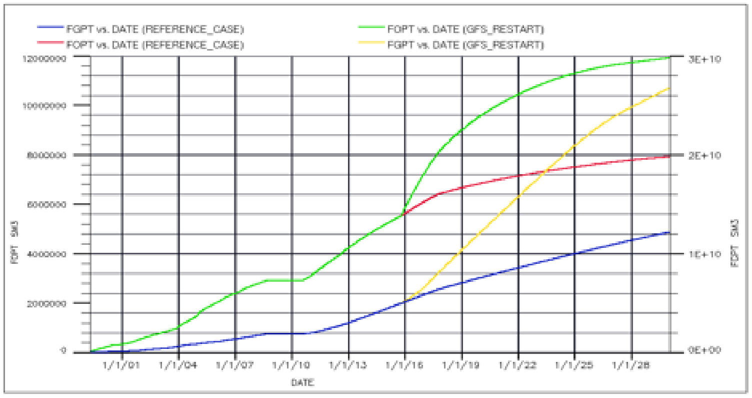

Figure 12: Total oil and gas production vs date

Let us start the interpretation of the field from the production side picture 12. After drilling and placing of the new wells, the amount of the total oil production increases starting at the end of the year 2015. As we can find from the graph, the total difference in oil produced would be 4 MSm3. It will grow up from 7.92 MSm3 to 11.92 MSm3. The total difference in gas produced would be 14.5 GSm3, it will grow up from 12.2 GSm3 to 26.7 GSm3. Big difference in gas production is occurring due to 2 gas injecting wells. Oil and gas will form the main income in the economical calculations. It is also very important to know that the money earned from the production would cover all the expenditures and make the project profitable.

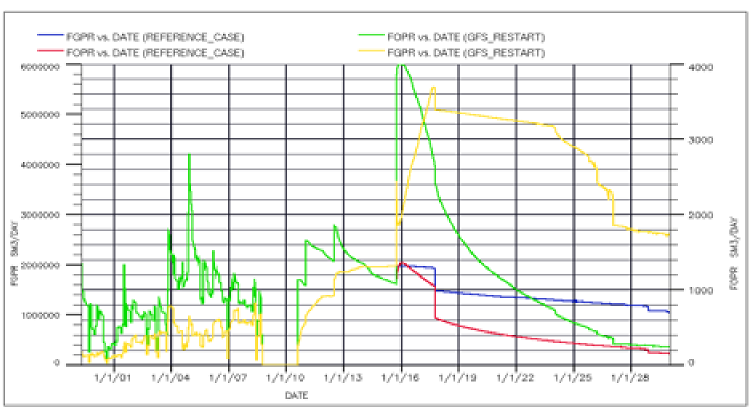

Figure 13: Production data of oil and gas vs date

Production data per each day, which represented on picture 13, can show that there is a big increase in oil production at the beginning of 2016. New wells helped to increase production from 1400 Sm3/day to 4000 Sm3/day in first months. During the next years the production is gradually decreasing and in the end gets to 250 Sm3/day (with new wells) and 150 Sm3/day (without new wells). As for the gas, as it was already discussed, there is an increase of production also and gas injection wells provide additional production of gas. New wells increase production from 1.97 MSm3/day to 3 - 5.53 MSm3/day in first months. During the next years the production is gradually decreasing, in the period of 2018 till 2024 the production changes slightly from 5.08 MSm3/day to 4.77 MSm3/day and in the end gets to 2.6 MSm3/day (with new wells) and 1.09 MSm3/day (without new wells).

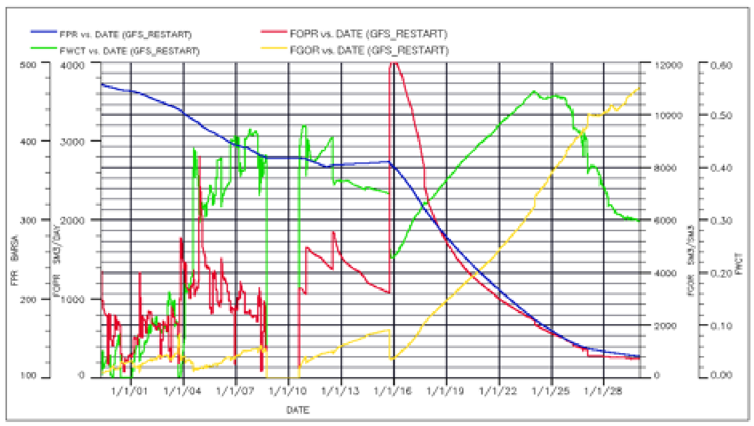

Figure 14: Reservoir parameters vs date (Restart Case)

Picture 14 shows the behavior of the main reservoir parameters. Looking at this picture, one could mention the gap in the period oct 2009 till aug 2010, this is due to putting the Statfjord formation on ice. The production was not profitable because it was far less than expected. At the beginning of the simulation (year 1999), you can see an initial reservoir pressure which is equal to nearly 470 bar. It is gradually decreases due to oil and gas production. The GOR (gas-oil ratio) is relatively low at the simulation start then there is a sharp increase at the end of 2015. It can be due to the new gas injection wells. The same increase could be mentioned in the production of oil after placing new wells. The WC (water cut) curve behaves in the same way. It decreases due to increase in oil production, but as the production continues the WC curve goes up again, but decreases after the middle of 2024 (this might happen due to closing of the well W4W5 in that period).

Before the simulation we had a reference case, in order to see what kind of changes we get with implementation of a new project. The data in graphical

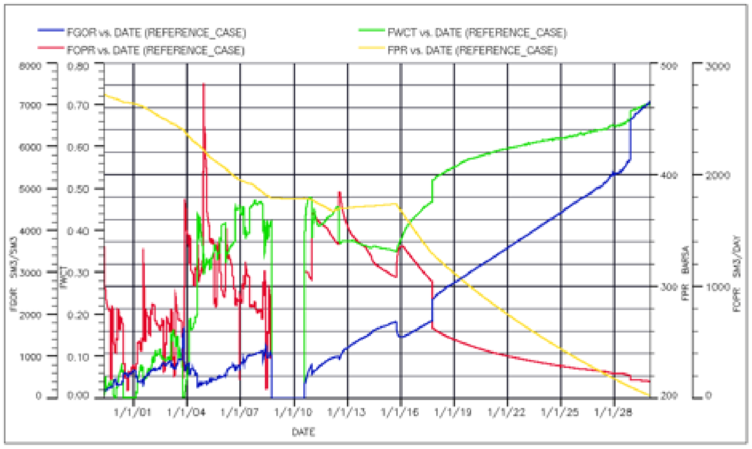

Figure 15: Reservoir parameters vs date (Reference Case)

form from the reference case is shown on the picture 15. It is good to mention the period after the end of 2015. As there were no new wells drilled, the oil production curve decreases and also the GOR is not that high then with the usage of gas injecting wells. To have a better interpretation of the difference in 2 cases, we made a new plot for comparison. As you can see from the picture 16, the GOR curves are different from each other. It was discussed previously that this is due to 2 new gas injecting wells. The GOR with new wells gets to 11059 Sm3/Sm3 at 2030, and the reference case GOR is 7085 Sm3/Sm3. For both cases GOR increases from 1800 Sm3/Sm3 from 2015.

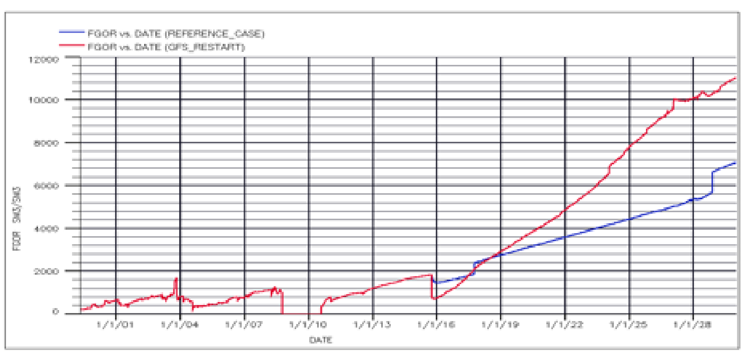

Figure 16: GOR vs date (Reference Case)

Other curves of interest could be pressure and water cut curves which presented on the picture 17. The pressure curve decreases due to depletion of the reservoir. The initial reservoir pressure is 473 bar and it decreases to 203 bar in the reference case and till 128 bar in the case with new wells. That difference can be explained in the way that more oil is recovered from the reservoir thus it gets to 128 bar in the end. The water cut curve behavior is described by the gradual increase because of increased water production through the life of the reservoir. The special interest is the WC curve with new wells. There is a sharp decrease in WC at the end of 2015 because of new wells production. It returned to 23 percent from 35 percent. The subsequent condition is the gradual increase up to 54 percent from 2015 till the beginning of 2024. Then the decrease in WC can be observed. As was mentioned before, it might be due to shutting down of the well W4W5. The decrease was from 54 percent to 30 percent from 2024 till the beginning of 2030. The reference case has the same gradual increase which is obvious due to oil production. The WC is increasing from 35 percent to 47 percent in the period from the end of 2015 till the end of 2018, and then the sharp jump to 52 percent is occurring, which can mean that one of the field wells had a water break through. After this there is an increase up to 71 percent at the beginning of the 2030.

From Eclipse we also get information about the recovery factor. Before we introduced the new wells, the recovery factory in 2015 was 12,77 %, and after introducing the new wells this factor increased with 15 % up to 28,3 %. This recovery factor is both for oil and wet gas. This can be seen from figure 18. This is very good, and shows that the new wells are a good contribution to the Gullfaks Sør.

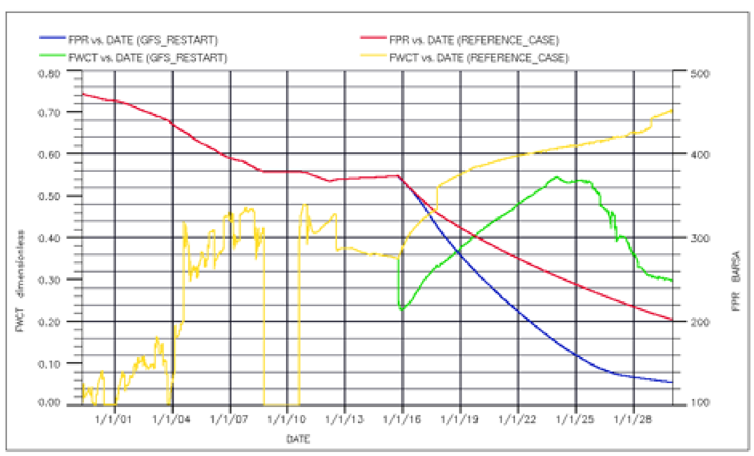

Figure 17: GOR vs date (Reference Case)

Figure 18: Recovery factor for both oil and wet gas

4 Economic evaluations and recommendations

For this part A an economical evaluation of further development of the Gullfaks Sør field should be done, the main goal was to see if the increased production and income could support a new production unit, or if a subsea solution was a better alternative. It is important to know that no cost data has been provided and we have made or own assumptions on CAPEX and OPEX. Estimating these cost over a period of time are quite complicated and time consuming. Therefore the calculations are simplified to some extent, giving a high amount of uncertainties.
The method of evaluation is calculating the net present value, from now on referred to as NPV, for the subsea alternative and the new production unit alternative. The criterion is that the NPV should be positive if the project is worth doing and with a discount rate of 8 %.

The uncertainties are dealt with using three different cases:

- A base oil/gas price case
- A high oil/gas price case
- A low oil/gas price case

The expected net present value is calculated from these three cases. The oil and gas price and the probability distribution for the different cases are taken from the background material handed out for GullfaksVillage 2009, which states an oil price of 75 USD/bbl and gas price of 2 NOK/Sm3 from 2014 and on. These values are used as the base case with the high/low prices +/- 40% of the base case. The probability distribution is 60% for base case, 20% for both high case and low case. Uncertainties in estimating CAPEX/OPEX are dealt in the same way using the same probability distribution and the costs are +/- 40% for the high case and low case respectively for each of the oil/gas price cases.

Estimation of income

For the estimation of income, increased production data are taken from Eclipse for both oil and gas production[1]. The amount of gas reinjected is also taken from Eclipse and the remaining gas production assumed sold.

Estimation of OPEX

The operational cost is estimated in a simplified way. Ten years ago an assumption of 10 USD/bbl was a recognized assumption[2]. We have therefore chosen to use 15 USD/bbl of produced oil for estimation of OPEX. The same operational costs are used for both alternatives. So the operational costs will not reflect on the differences in investment costs, but in general give an indication if the alternative is feasible or not.

[1] See chapter 3.2 for graphs and data

[2] See appendix for source references

4.1 Subsea alternative

For the subsea alternative it is assumed that there is a remaining capacity on the three existing platforms and also the infrastructure can handle the increased production.

Capital Expenses (CAPEX)

For the base case an investment cost of 700 million NOK are assumed per complete subsea well. Six wells make it 4,2 billion NOK[3]. An additional 1,8 billion NOK are assumed necessary for connecting of all six wells to the existing infrastructure. Outphasing cost for removing all the gear is assumed to be 10% of the initial investment. In the NPV calculations, 6 billion NOK are divided equally on three years assuming start up in 2013 and outphasing costs at the end year 2029.

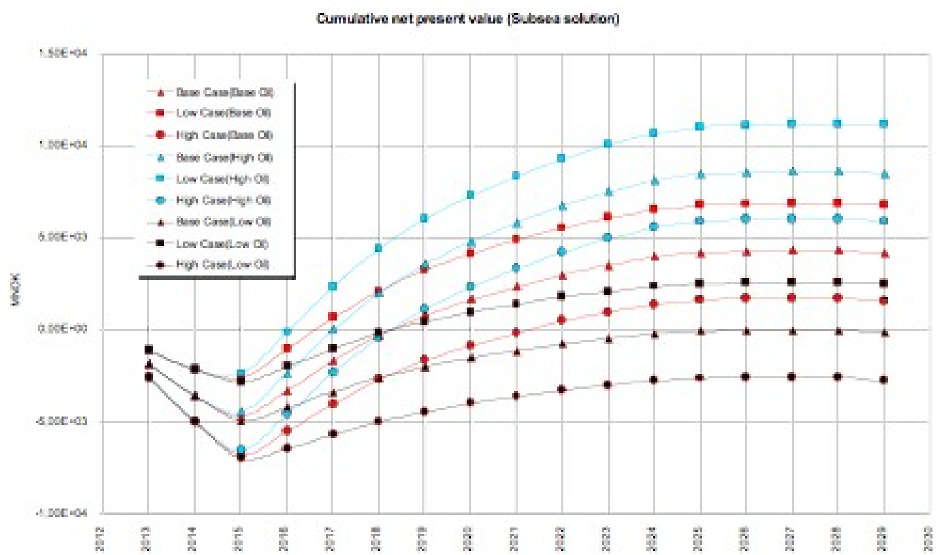

Figure 19: Cumulative net present value

Net present value calculations

Figure 19 illustrates cumulative net present value for all the cases for a subsea solution. For more detailed data on the NPV calculation it is referred to appendix A-C.

Expected net present value

The subsea alternative gives a positive E(NPV) of 4,232 billion NOK which indicates that this alternative may be worth doing and developing.

[3]See appendix for source reference

Expected Net Present Value - Subsea Solution

Oilprice	Prob.	Capex/Opex	NPV	Prob.
Base Case	0,6			
		Base	4,230E+09	0,6
		Low	6,860E+09	0,2
		High	1,600E+09	0,2
E(NPV - Base)				4,230E+09
Low Case	0,2			
		Base	-8,940E+07	0,6
		Low	2,540E+09	0,2
		High	-2,720E+09	0,2
E(NPV - Low)				-8,964E+07
High Case	0,2			
		Base	8,560E+09	0,6
		Low	1,120E+10	0,2
		High	5,930E+09	0,2
E(NPV - High)				8,562E+09
E(NPV)				4,232E+09

Figure 20: Expected net present value

4.2 New production unit alternative

For a new production unit different possibilities are considered. However a concrete platform like the three existing platforms is considered to be too expensive today. And a production unit with good storage capabilities are assumed preferable, hence the NPV calculations are based on an FPSO solution.

Capital expenses

For estimation of capital expenses the Skarv/Idun field is considered. This field have similarities to the Gullfaks Sør development, using an FPSO but includes more wells and 80km of piping. This project is estimated to cost 19,7 billion NOK[4]. For the development of the Gullfaks Sør field only six wells are planned and less piping is needed to connect to existing transport network, hence a total installation cost is estimated to be 14 billion NOK and outfacing costs are assumed to be 180 million NOK at the base case.

Net present value calculations

Figure 21 illustrates cumulative net present value for all the cases for a new production unit. For more detailed data on the NPV calculation it is referred to appendix D-F.

[4]See appendix for source reference

Expected net present value

The E(NPV) for a new production is negative with 2,848 billion NOK which indicates that the increased production is from these six wells alone can not support building of a new production unit.

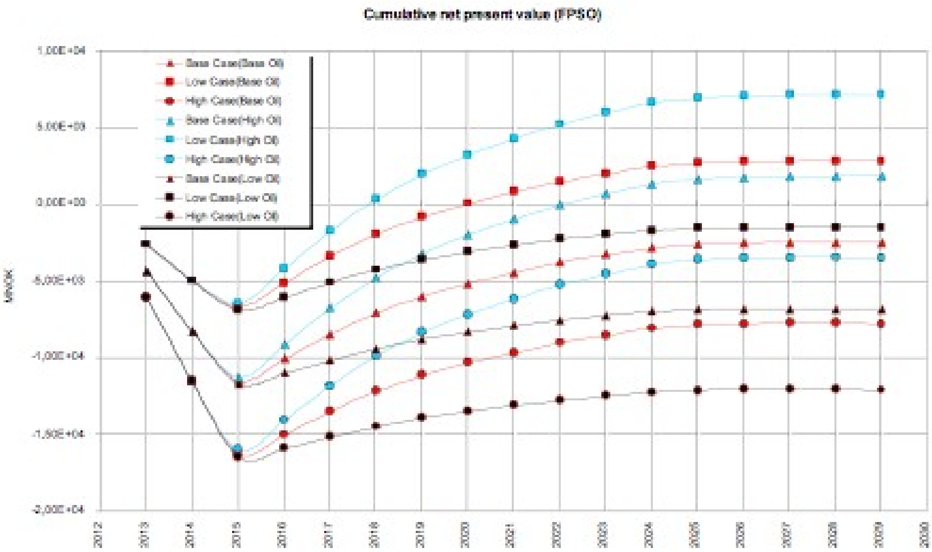

Figure 21: Cumulative net present value

Expected Net Present Value - New Production Unit Solution				
Oilprice	Prob.	Capex/Opex	NPV	Prob.
Base Case	0,6			
		Base	-2,460E+09	0,6
		Low	2,850E+09	0,2
		High	-7,750E+09	0,2
E(NPV - Base)				-2,456E+09
Low Case	0,2			
		Base	-8,940E+07	0,6
		Low	2,540E+09	0,2
		High	-2,720E+09	0,2
E(NPV - Low)				-8,964E+07
High Case	0,2			
		Base	-6,780E+09	0,6
		Low	-1,470E+09	0,2
		High	-1,210E+10	0,2
E(NPV - High)				-6,782E+09
E(NPV)				-2,848E+09

Figure 22: Expected net present value

5 Conclusions

In this report we have become very familiar with the Gullfaks Sør reservoir. We have gained knowledge about it's complexity and the difficulties tied to the Brent formation.

From the reservoir simulation we can see that by adding new producer wells and gas injectors, the gas production will be much higher than the oil production. The oil production will increase some in the first months of 2016, but after this it will decrease rapidly. The total oil production will be 11.92 MSm3, and out of this is 4 MSm3 due to the new well.The gas production will follow the same trend, but with smaller changes in production. The total production will be 26.7 GSm3, and from this is 14.5 GMSm3 due to the new wells. When comparing the Reference_Case with the GFS_Restart, one can see that it is profitable to make these new wells, because both oil- and gas production will increase some, compared with no new wells at all. This is shown by the fact that the recovery factor has increased to 28,3 % from 12,77 %.

From an economic point of view, it is clear that the enhanced oil- and gas recovery will give more income. When comparing the different production alternatives and their costs, it is quite clear that the subsea alternative connected to the existing platform is the best one. The expected net present value for this is 4,2 billion NOK, while expected net present value for the new production unit (FPSO) is -2.8 billion NOK. As long as the expected net present value is positive, the project should be considered done.

We could also have considered a jacket-strucutre and a jack-up, but since we misunderstood the water depth we did not consider it. We became aware of this after all the economic evaluations were done. If we get the time after the part B is done, we can make some new calculations on this and put them in the whole report due in April.

6 Appendix

Source references

- Researcher Jan Ivar Jensen at Department of Petroleum Engineering and Applied Geophysics NTNU
- Professor Sigbjørn Sangesland at Department of Petroleum Engineering and Applied Geophysics NTNU
- ConsecvenceEvaluation06 - Concequence Evaluation of the Skarv/Idun field, Nord-Trndelag Fylkeskommune, 2006
- http://www.ntfk.no/bibliotek/saker/2006/FR/FR06157.htm
- Documents and presentations given by Statoil

APPENDIX A - Economical calculations for subsea completion at base oil price.

BASE CASE (CAPEX, OPEX)

Oil price	75	USD/Bbl	2830.414847	NOK/Sm^3
Gas price	2	NOK/Sm^3		
Interest rate	0.09			
Exchange rate	6	NOK/USD		
Discount rate	0.08			
Opex	15	USD/Bbl	566.0829693	NOK/Sm^3

	Time	Oil production(Oil Sale)	Gas production, excl. fuel	Gas Injection	Gas Sale	Discount factor	Income from Oil (Discounted)	Income from Gas (Discounted)	CAPEX	OPEX	CAPEX (discounted amount)	OPEX (discounted amount)	NPV	Net Cash Flow	Cumulative PV Cash Flow
	year	Msm3	Gsm3	Gsm3	Gsm3		NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK
1	2013	0	0	0	0	0.92	0.00E+00	0.00E+00	-2.00E+09	0.00E+00	-1.84E+09	0.00E+00	-1.84E+09	-2.00E+09	-1.84E+09
2	2014	0	0	0	0	0.85	0.00E+00	0.00E+00	-2.00E+09	0.00E+00	-1.69E+09	0.00E+00	-1.69E+09	-2.00E+09	-3.53E+09
3	2015	0.26	0.0915	0.209	0	0.78	5.73E+08	0.00E+00	-2.00E+09	-1.47E+08	-1.56E+09	-1.15E+08	-1.10E+09	-1.41E+09	-4.63E+09
4	2016	0.86	0.6925	0.767	0	0.72	1.74E+09	0.00E+00		-4.87E+08	0.00E+00	-3.49E+08	1.40E+09	1.95E+09	-3.24E+09
5	2017	0.73	1.196	0.804	0.392	0.66	1.36E+09	5.17E+08		-4.13E+08	0.00E+00	-2.72E+08	1.61E+09	2.44E+09	-1.63E+09
6	2018	0.5	1.33	0.76	0.57	0.61	8.58E+08	6.91E+08		-2.83E+08	0.00E+00	-1.72E+08	1.38E+09	2.27E+09	-2.53E+08
7	2019	0.42	1.31	0.81	0.5	0.56	6.63E+08	5.58E+08		-2.38E+08	0.00E+00	-1.33E+08	1.09E+09	1.95E+09	8.36E+08
8	2020	0.26	1.3	0.76	0.54	0.51	3.78E+08	5.54E+08		-1.47E+08	0.00E+00	-7.55E+07	8.56E+08	1.67E+09	1.69E+09
9	2021	0.29	1.23	0.81	0.42	0.47	3.88E+08	3.97E+08		-1.64E+08	0.00E+00	-7.75E+07	7.07E+08	1.50E+09	2.40E+09
10	2022	0.18	1.35	0.8	0.55	0.43	2.21E+08	4.78E+08		-1.02E+08	0.00E+00	-4.43E+07	6.55E+08	1.51E+09	3.05E+09
11	2023	0.16	1.26	0.8	0.46	0.40	1.81E+08	3.68E+08		-9.06E+07	0.00E+00	-3.62E+07	5.12E+08	1.28E+09	3.57E+09
12	2024	0.13	1.22	0.77	0.45	0.37	1.35E+08	3.31E+08		-7.36E+07	0.00E+00	-2.71E+07	4.39E+08	1.19E+09	4.01E+09
13	2025	0.08	1.05	0.8	0.25	0.34	7.66E+07	1.69E+08		-4.53E+07	0.00E+00	-1.53E+07	2.30E+08	6.81E+08	4.24E+09
14	2026	0.03	0.85	0.76	0.09	0.31	2.64E+07	5.60E+07		-1.70E+07	0.00E+00	-5.28E+06	7.72E+07	2.48E+08	4.31E+09
15	2027	0.05	0.58	0.83	0	0.29	4.05E+07	0.00E+00		-2.83E+07	0.00E+00	-8.10E+06	3.24E+07	1.13E+08	4.35E+09
16	2028	0.01	0.59	0.82	0	0.26	7.46E+06	0.00E+00		-5.66E+06	0.00E+00	-1.49E+06	5.96E+06	2.26E+07	4.35E+09
17	2029	0.05	0.59	0.72	0	0.24	3.43E+07	0.00E+00	-6.00E+08	-2.83E+07	-1.45E+08	-6.86E+06	-1.18E+08	-4.87E+08	4.23E+09
TOTAL:		4.01	14.64	11.22	4.222		6.69E+09	4.12E+09	-6.60E+09	-2.27E+09	-5.24E+09	-1.34E+09	4.23E+09	1.09E+10	

LOW CASE (CAPEX, OPEX)

Oil price	75	USD/Bbl	2830.414847	NOK/Sm^3
Gas price	2	NOK/Sm^3		
Interest rate	0.09			
Exchange rate	6	NOK/USD		
Discount rate	0.08			
Opex	9	USD/Bbl	339.6497816	NOK/Sm^3

	Time	Oil production(Oil Sale)	Gas production, excl. fuel	Gas Injection	Gas Sale	Discount factor	Income from Oil (Discounted)	Income from Gas (Discounted)	CAPEX	OPEX	CAPEX (discounted amount)	OPEX (discounted amount)	NPV	Net Cash Flow	Cumulative PV Cash Flow
	year	Msm3	Gsm3	Gsm3	Gsm3		NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK
1	2013	0	0	0	0	0.92	0.00E+00	0.00E+00	-1.20E+09	0.00E+00	-1.10E+09	0.00E+00	-1.10E+09	-1.20E+09	-1.10E+09
2	2014	0	0	0	0	0.85	0.00E+00	0.00E+00	-1.20E+09	0.00E+00	-1.02E+09	0.00E+00	-1.02E+09	-1.20E+09	-2.12E+09
3	2015	0.26	0.0915	0.209	0	0.78	5.73E+08	0.00E+00	-1.20E+09	-8.83E+07	-9.34E+08	-6.88E+07	-4.30E+08	-5.52E+08	-2.55E+09
4	2016	0.86	0.6925	0.767	0	0.72	1.74E+09	0.00E+00		-2.92E+08	0.00E+00	-2.09E+08	1.53E+09	2.14E+09	-1.02E+09
5	2017	0.73	1.196	0.804	0.392	0.66	1.36E+09	5.17E+08		-2.48E+08	0.00E+00	-1.63E+08	1.72E+09	2.60E+09	7.00E+08
6	2018	0.5	1.33	0.76	0.57	0.61	8.58E+08	6.91E+08		-1.70E+08	0.00E+00	-1.03E+08	1.45E+09	2.39E+09	2.15E+09
7	2019	0.42	1.31	0.81	0.5	0.56	6.63E+08	5.58E+08		-1.43E+08	0.00E+00	-7.96E+07	1.14E+09	2.05E+09	3.29E+09
8	2020	0.26	1.3	0.76	0.54	0.51	3.78E+08	5.54E+08		-8.83E+07	0.00E+00	-4.53E+07	8.87E+08	1.73E+09	4.17E+09
9	2021	0.29	1.23	0.81	0.42	0.47	3.88E+08	3.97E+08		-9.85E+07	0.00E+00	-4.65E+07	7.38E+08	1.56E+09	4.91E+09
10	2022	0.18	1.35	0.8	0.55	0.43	2.21E+08	4.78E+08		-6.11E+07	0.00E+00	-2.66E+07	6.73E+08	1.55E+09	5.58E+09
11	2023	0.16	1.26	0.8	0.46	0.40	1.81E+08	3.68E+08		-5.43E+07	0.00E+00	-2.17E+07	5.27E+08	1.32E+09	6.11E+09
12	2024	0.13	1.22	0.77	0.45	0.37	1.35E+08	3.31E+08		-4.42E+07	0.00E+00	-1.62E+07	4.50E+08	1.22E+09	6.56E+09
13	2025	0.08	1.05	0.8	0.25	0.34	7.66E+07	1.69E+08		-2.72E+07	0.00E+00	-9.19E+06	2.37E+08	6.99E+08	6.80E+09
14	2026	0.03	0.85	0.76	0.09	0.31	2.64E+07	5.60E+07		-1.02E+07	0.00E+00	-3.17E+06	7.93E+07	2.55E+08	6.88E+09
15	2027	0.05	0.58	0.83	0	0.29	4.05E+07	0.00E+00		-1.70E+07	0.00E+00	-4.86E+06	3.57E+07	1.25E+08	6.91E+09
16	2028	0.01	0.59	0.82	0	0.26	7.46E+06	0.00E+00		-3.40E+06	0.00E+00	-8.95E+05	6.56E+06	2.49E+07	6.92E+09
17	2029	0.05	0.59	0.72	0	0.24	3.43E+07	0.00E+00	-3.60E+08	-1.70E+07	-8.72E+07	-4.12E+06	-5.71E+07	-2.35E+08	6.86E+09
TOTAL:		4.01	14.64	11.22	4.222		6.69E+09	4.12E+09	-3.96E+09	-1.36E+09	-3.14E+09	-8.03E+08	6.86E+09	1.45E+10	

HIGH CASE (CAPEX, OPEX)

Oil price	75	USD/Bbl	2830.414847	NOK/Sm^3
Gas price	2	NOK/Sm^3		
Interest rate	0.09			
Exchange rate	6	NOK/USD		
Discount rate	0.08			
Opex	21	USD/Bbl	792.5161571	NOK/Sm^3

	Time	Oil production(Oil Sale)	Gas production, excl. fuel	Gas Injection	Gas Sale	Discount factor	Income from Oil (Discounted)	Income from Gas (Discounted)	CAPEX	OPEX	CAPEX (discounted amount)	OPEX (discounted amount)	NPV	Net Cash Flow	Cumulative PV Cash Flow
	year	Msm3	Gsm3	Gsm3	Gsm3		NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK
1	2013	0	0	0	0	0.92	0.00E+00	0.00E+00	-2.80E+09	0.00E+00	-2.58E+09	0.00E+00	-2.58E+09	-2.80E+09	-2.58E+09
2	2014	0	0	0	0	0.85	0.00E+00	0.00E+00	-2.80E+09	0.00E+00	-2.37E+09	0.00E+00	-2.37E+09	-2.80E+09	-4.95E+09
3	2015	0.26	0.0915	0.209	0	0.78	5.73E+08	0.00E+00	-2.80E+09	-2.06E+08	-2.18E+09	-1.60E+08	-1.77E+09	-2.27E+09	-6.71E+09
4	2016	0.86	0.6925	0.767	0	0.72	1.74E+09	0.00E+00		-6.82E+08	0.00E+00	-4.88E+08	1.26E+09	1.75E+09	-5.46E+09
5	2017	0.73	1.196	0.804	0.392	0.66	1.36E+09	5.17E+08		-5.79E+08	0.00E+00	-3.81E+08	1.50E+09	2.27E+09	-3.96E+09
6	2018	0.5	1.33	0.76	0.57	0.61	8.58E+08	6.91E+08		-3.96E+08	0.00E+00	-2.40E+08	1.31E+09	2.16E+09	-2.65E+09
7	2019	0.42	1.31	0.81	0.5	0.56	6.63E+08	5.58E+08		-3.33E+08	0.00E+00	-1.86E+08	1.04E+09	1.86E+09	-1.62E+09
8	2020	0.26	1.3	0.76	0.54	0.51	3.78E+08	5.54E+08		-2.06E+08	0.00E+00	-1.06E+08	8.26E+08	1.61E+09	-7.90E+08
9	2021	0.29	1.23	0.81	0.42	0.47	3.88E+08	3.97E+08		-2.30E+08	0.00E+00	-1.09E+08	6.76E+08	1.43E+09	-1.15E+08
10	2022	0.18	1.35	0.8	0.55	0.43	2.21E+08	4.78E+08		-1.43E+08	0.00E+00	-6.20E+07	6.37E+08	1.47E+09	5.23E+08
11	2023	0.16	1.26	0.8	0.46	0.40	1.81E+08	3.68E+08		-1.27E+08	0.00E+00	-5.07E+07	4.98E+08	1.25E+09	1.02E+09
12	2024	0.13	1.22	0.77	0.45	0.37	1.35E+08	3.31E+08		-1.03E+08	0.00E+00	-3.79E+07	4.28E+08	1.16E+09	1.45E+09
13	2025	0.08	1.05	0.8	0.25	0.34	7.66E+07	1.69E+08		-6.34E+07	0.00E+00	-2.14E+07	2.24E+08	6.63E+08	1.67E+09
14	2026	0.03	0.85	0.76	0.09	0.31	2.64E+07	5.60E+07		-2.38E+07	0.00E+00	-7.40E+06	7.50E+07	2.41E+08	1.75E+09
15	2027	0.05	0.58	0.83	0	0.29	4.05E+07	0.00E+00		-3.96E+07	0.00E+00	-1.13E+07	2.92E+07	1.02E+08	1.78E+09
16	2028	0.01	0.59	0.82	0	0.26	7.46E+06	0.00E+00		-7.93E+06	0.00E+00	-2.09E+06	5.37E+06	2.04E+07	1.78E+09
17	2029	0.05	0.59	0.72	0	0.24	3.43E+07	0.00E+00	-8.40E+08	-3.96E+07	-2.04E+08	-9.60E+06	-1.79E+08	-7.38E+08	1.60E+09
TOTAL:		4.01	14.64	11.22	4.222		6.69E+09	4.12E+09	-9.24E+09	-3.18E+09	-7.33E+09	-1.87E+09	1.60E+09	7.38E+09	

APPENDIX B - Economical calculations for subsea completion at high oil price.

BASE CASE (CAPEX, OPEX)

Oil price	105	USD/Bbl	3962.580785	NOK/Sm^3
Gas price	2.8	NOK/Sm^3		
Interest rate	0.09			
Exchange rate	6	NOK/USD		
Discount rate	0.08			
Opex	15	USD/Bbl	566.0829693	NOK/Sm^3

	Time	Oil production(Oil Sale)	Gas production, excl. fuel	Gas Injection	Gas Sale	Discount factor	Income from Oil (Discounted)	Income from Gas (Discounted)	CAPEX	OPEX	CAPEX (discounted amount)	OPEX (discounted amount)	NPV	Net Cash Flow	Cumulative PV Cash Flow
	year	Msm3	Gsm3	Gsm3	Gsm3		NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK
1	2013	0	0	0	0	0.92	0.00E+00	0.00E+00	-2.00E+09	0.00E+00	-1.84E+09	0.00E+00	-1.84E+09	-2.00E+09	-1.84E+09
2	2014	0	0	0	0	0.85	0.00E+00	0.00E+00	-2.00E+09	0.00E+00	-1.69E+09	0.00E+00	-1.69E+09	-2.00E+09	-3.53E+09
3	2015	0.26	0.0915	0.209	0	0.78	8.02E+08	0.00E+00	-2.00E+09	-1.47E+08	-1.56E+09	-1.15E+08	-8.70E+08	-1.12E+09	-4.40E+09
4	2016	0.86	0.6925	0.767	0	0.72	2.44E+09	0.00E+00		-4.87E+08	0.00E+00	-3.49E+08	2.09E+09	2.92E+09	-2.31E+09
5	2017	0.73	1.196	0.804	0.392	0.66	1.91E+09	7.23E+08		-4.13E+08	0.00E+00	-2.72E+08	2.36E+09	3.58E+09	4.76E+07
6	2018	0.5	1.33	0.76	0.57	0.61	1.20E+09	9.68E+08		-2.83E+08	0.00E+00	-1.72E+08	2.00E+09	3.29E+09	2.05E+09
7	2019	0.42	1.31	0.81	0.5	0.56	9.28E+08	7.81E+08		-2.38E+08	0.00E+00	-1.33E+08	1.58E+09	2.83E+09	3.62E+09
8	2020	0.26	1.3	0.76	0.54	0.51	5.29E+08	7.76E+08		-1.47E+08	0.00E+00	-7.55E+07	1.23E+09	2.40E+09	4.85E+09
9	2021	0.29	1.23	0.81	0.42	0.47	5.43E+08	5.55E+08		-1.64E+08	0.00E+00	-7.75E+07	1.02E+09	2.16E+09	5.87E+09
10	2022	0.18	1.35	0.8	0.55	0.43	3.10E+08	6.69E+08		-1.02E+08	0.00E+00	-4.43E+07	9.35E+08	2.15E+09	6.81E+09
11	2023	0.16	1.26	0.8	0.46	0.40	2.53E+08	5.15E+08		-9.06E+07	0.00E+00	-3.62E+07	7.32E+08	1.83E+09	7.54E+09
12	2024	0.13	1.22	0.77	0.45	0.37	1.89E+08	4.63E+08		-7.36E+07	0.00E+00	-2.71E+07	6.26E+08	1.70E+09	8.16E+09
13	2025	0.08	1.05	0.8	0.25	0.34	1.07E+08	2.37E+08		-4.53E+07	0.00E+00	-1.53E+07	3.29E+08	9.72E+08	8.49E+09
14	2026	0.03	0.85	0.76	0.09	0.31	3.70E+07	7.84E+07		-1.70E+07	0.00E+00	-5.28E+06	1.10E+08	3.54E+08	8.60E+09
15	2027	0.05	0.58	0.83	0	0.29	5.67E+07	0.00E+00		-2.83E+07	0.00E+00	-8.10E+06	4.86E+07	1.70E+08	8.65E+09
16	2028	0.01	0.59	0.82	0	0.26	1.04E+07	0.00E+00		-5.66E+06	0.00E+00	-1.49E+06	8.95E+06	3.40E+07	8.66E+09
17	2029	0.05	0.59	0.72	0	0.24	4.80E+07	0.00E+00	-6.00E+08	-2.83E+07	-1.45E+08	-6.86E+06	-1.04E+08	-4.30E+08	8.56E+09
TOTAL:		4.01	14.64	11.22	4.222		9.36E+09	5.77E+09	-6.60E+09	-2.27E+09	-5.24E+09	-1.34E+09	8.56E+09	1.88E+10	

LOW CASE (CAPEX, OPEX)

Oil price	105	USD/Bbl	3962.580785	NOK/Sm^3
Gas price	2.8	NOK/Sm^3		
Interest rate	0.09			
Exchange rate	6	NOK/USD		
Discount rate	0.08			
Opex	9	USD/Bbl	339.6497816	NOK/Sm^3

	Time	Oil production(Oil Sale)	Gas production, excl. fuel	Gas Injection	Gas Sale	Discount factor	Income from Oil (Discounted)	Income from Gas (Discounted)	CAPEX	OPEX	CAPEX (discounted amount)	OPEX (discounted amount)	NPV	Net Cash Flow	Cumulative PV Cash Flow
	year	Msm3	Gsm3	Gsm3	Gsm3		NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK
1	2013	0	0	0	0	0.92	0.00E+00	0.00E+00	-1.20E+09	0.00E+00	-1.10E+09	0.00E+00	-1.10E+09	-1.20E+09	-1.10E+09
2	2014	0	0	0	0	0.85	0.00E+00	0.00E+00	-1.20E+09	0.00E+00	-1.02E+09	0.00E+00	-1.02E+09	-1.20E+09	-2.12E+09
3	2015	0.26	0.0915	0.209	0	0.78	8.02E+08	0.00E+00	-1.20E+09	-8.83E+07	-9.34E+08	-6.88E+07	-2.01E+08	-2.58E+08	-2.32E+09
4	2016	0.86	0.6925	0.767	0	0.72	2.44E+09	0.00E+00		-2.92E+08	0.00E+00	-2.09E+08	2.23E+09	3.12E+09	-8.85E+07
5	2017	0.73	1.196	0.804	0.392	0.66	1.91E+09	7.23E+08		-2.48E+08	0.00E+00	-1.63E+08	2.47E+09	3.74E+09	2.38E+09
6	2018	0.5	1.33	0.76	0.57	0.61	1.20E+09	9.68E+08		-1.70E+08	0.00E+00	-1.03E+08	2.07E+09	3.41E+09	4.44E+09
7	2019	0.42	1.31	0.81	0.5	0.56	9.28E+08	7.81E+08		-1.43E+08	0.00E+00	-7.96E+07	1.63E+09	2.92E+09	6.07E+09
8	2020	0.26	1.3	0.76	0.54	0.51	5.29E+08	7.76E+08		-8.83E+07	0.00E+00	-4.53E+07	1.26E+09	2.45E+09	7.33E+09
9	2021	0.29	1.23	0.81	0.42	0.47	5.43E+08	5.55E+08		-9.85E+07	0.00E+00	-4.65E+07	1.05E+09	2.23E+09	8.38E+09
10	2022	0.18	1.35	0.8	0.55	0.43	3.10E+08	6.69E+08		-6.11E+07	0.00E+00	-2.66E+07	9.52E+08	2.19E+09	9.34E+09
11	2023	0.16	1.26	0.8	0.46	0.40	2.53E+08	5.15E+08		-5.43E+07	0.00E+00	-2.17E+07	7.46E+08	1.87E+09	1.01E+10
12	2024	0.13	1.22	0.77	0.45	0.37	1.89E+08	4.63E+08		-4.42E+07	0.00E+00	-1.62E+07	6.36E+08	1.73E+09	1.07E+10
13	2025	0.08	1.05	0.8	0.25	0.34	1.07E+08	2.37E+08		-2.72E+07	0.00E+00	-9.19E+06	3.35E+08	9.90E+08	1.11E+10
14	2026	0.03	0.85	0.76	0.09	0.31	3.70E+07	7.84E+07		-1.02E+07	0.00E+00	-3.17E+06	1.12E+08	3.61E+08	1.12E+10
15	2027	0.05	0.58	0.83	0	0.29	5.67E+07	0.00E+00		-1.70E+07	0.00E+00	-4.86E+06	5.19E+07	1.81E+08	1.12E+10
16	2028	0.01	0.59	0.82	0	0.26	1.04E+07	0.00E+00		-3.40E+06	0.00E+00	-8.95E+05	9.54E+06	3.62E+07	1.12E+10
17	2029	0.05	0.59	0.72	0	0.24	4.80E+07	0.00E+00	-3.60E+08	-1.70E+07	-8.72E+07	-4.12E+06	-4.33E+07	-1.79E+08	1.12E+10
TOTAL:		4.01	14.64	11.22	4.222		9.36E+09	5.77E+09	-3.96E+09	-1.36E+09	-3.14E+09	-8.03E+08	1.12E+10	2.24E+10	

HIGH CASE (CAPEX, OPEX)

Oil price	105	USD/Bbl	3962.580785	NOK/Sm^3
Gas price	2.8	NOK/Sm^3		
Interest rate	0.09			
Exchange rate	6	NOK/USD		
Discount rate	0.08			
Opex	21	USD/Bbl	792.5161571	NOK/Sm^3

	Time	Oil production(Oil Sale)	Gas production, excl. fuel	Gas Injection	Gas Sale	Discount factor	Income from Oil (Discounted)	Income from Gas (Discounted)	CAPEX	OPEX	CAPEX (discounted amount)	OPEX (discounted amount)	NPV	Net Cash Flow	Cumulative PV Cash Flow
	year	Msm3	Gsm3	Gsm3	Gsm3		NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK
1	2013	0	0	0	0	0.92	0.00E+00	0.00E+00	-2.80E+09	0.00E+00	-2.58E+09	0.00E+00	-2.58E+09	-2.80E+09	-2.58E+09
2	2014	0	0	0	0	0.85	0.00E+00	0.00E+00	-2.80E+09	0.00E+00	-2.37E+09	0.00E+00	-2.37E+09	-2.80E+09	-4.95E+09
3	2015	0.26	0.0915	0.209	0	0.78	8.02E+08	0.00E+00	-2.80E+09	-2.06E+08	-2.18E+09	-1.60E+08	-1.54E+09	-1.98E+09	-6.48E+09
4	2016	0.86	0.6925	0.767	0	0.72	2.44E+09	0.00E+00		-6.82E+08	0.00E+00	-4.88E+08	1.95E+09	2.73E+09	-4.53E+09
5	2017	0.73	1.196	0.804	0.392	0.66	1.91E+09	7.23E+08		-5.79E+08	0.00E+00	-3.81E+08	2.25E+09	3.41E+09	-2.28E+09
6	2018	0.5	1.33	0.76	0.57	0.61	1.20E+09	9.68E+08		-3.96E+08	0.00E+00	-2.40E+08	1.93E+09	3.18E+09	-3.54E+08
7	2019	0.42	1.31	0.81	0.5	0.56	9.28E+08	7.81E+08		-3.33E+08	0.00E+00	-1.86E+08	1.52E+09	2.73E+09	1.17E+09
8	2020	0.26	1.3	0.76	0.54	0.51	5.29E+08	7.76E+08		-2.06E+08	0.00E+00	-1.06E+08	1.20E+09	2.34E+09	2.37E+09
9	2021	0.29	1.23	0.81	0.42	0.47	5.43E+08	5.55E+08		-2.30E+08	0.00E+00	-1.09E+08	9.89E+08	2.10E+09	3.36E+09
10	2022	0.18	1.35	0.8	0.55	0.43	3.10E+08	6.69E+08		-1.43E+08	0.00E+00	-6.20E+07	9.17E+08	2.11E+09	4.27E+09
11	2023	0.16	1.26	0.8	0.46	0.40	2.53E+08	5.15E+08		-1.27E+08	0.00E+00	-5.07E+07	7.17E+08	1.80E+09	4.99E+09
12	2024	0.13	1.22	0.77	0.45	0.37	1.89E+08	4.63E+08		-1.03E+08	0.00E+00	-3.79E+07	6.15E+08	1.67E+09	5.61E+09
13	2025	0.08	1.05	0.8	0.25	0.34	1.07E+08	2.37E+08		-6.34E+07	0.00E+00	-2.14E+07	3.23E+08	9.54E+08	5.93E+09
14	2026	0.03	0.85	0.76	0.09	0.31	3.70E+07	7.84E+07		-2.38E+07	0.00E+00	-7.40E+06	1.08E+08	3.47E+08	6.04E+09
15	2027	0.05	0.58	0.83	0	0.29	5.67E+07	0.00E+00		-3.96E+07	0.00E+00	-1.13E+07	4.54E+07	1.59E+08	6.08E+09
16	2028	0.01	0.59	0.82	0	0.26	1.04E+07	0.00E+00		-7.93E+06	0.00E+00	-2.09E+06	8.35E+06	3.17E+07	6.09E+09
17	2029	0.05	0.59	0.72	0	0.24	4.80E+07	0.00E+00	-8.40E+08	-3.96E+07	-2.04E+08	-9.60E+06	-1.65E+08	-6.81E+08	5.93E+09
TOTAL:		4.01	14.64	11.22	4.222		9.36E+09	5.77E+09	-9.24E+09	-3.18E+09	-7.33E+09	-1.87E+09	5.93E+09	1.53E+10	

APPENDIX C - Economical calculations for subsea completion at low oil price.

BASE CASE (CAPEX, OPEX)

Oil price	45	USD/Bbl	1698.248908	NOK/Sm^3
Gas price	1.2	NOK/Sm^3		
Interest rate	0.09			
Exchange rate	6	NOK/USD		
Discount rate	0.08			
Opex	15	USD/Bbl	566.0829693	NOK/Sm^3

	Time	Oil production(Oil Sale)	Gas production, excl. fuel	Gas Injection	Gas Sale	Discount factor	Income from Oil (Discounted)	Income from Gas (Discounted)	CAPEX	OPEX	CAPEX (discounted amount)	OPEX (discounted amount)	NPV	Net Cash Flow	Cumulative PV Cash Flow
	year	Msm3	Gsm3	Gsm3	Gsm3		NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK
1	2013	0	0	0	0	0.92	0.00E+00	0.00E+00	-2.00E+09	0.00E+00	-1.84E+09	0.00E+00	-1.84E+09	-2.00E+09	-1.84E+09
2	2014	0	0	0	0	0.85	0.00E+00	0.00E+00	-2.00E+09	0.00E+00	-1.69E+09	0.00E+00	-1.69E+09	-2.00E+09	-3.53E+09
3	2015	0.26	0.0915	0.209	0	0.78	3.44E+08	0.00E+00	-2.00E+09	-1.47E+08	-1.56E+09	-1.15E+08	-1.33E+09	-1.71E+09	-4.86E+09
4	2016	0.86	0.6925	0.767	0	0.72	1.05E+09	0.00E+00		-4.87E+08	0.00E+00	-3.49E+08	6.98E+08	9.74E+08	-4.16E+09
5	2017	0.73	1.196	0.804	0.392	0.66	8.17E+08	3.10E+08		-4.13E+08	0.00E+00	-2.72E+08	8.55E+08	1.30E+09	-3.31E+09
6	2018	0.5	1.33	0.76	0.57	0.61	5.15E+08	4.15E+08		-2.83E+08	0.00E+00	-1.72E+08	7.58E+08	1.25E+09	-2.55E+09
7	2019	0.42	1.31	0.81	0.5	0.56	3.98E+08	3.35E+08		-2.38E+08	0.00E+00	-1.33E+08	6.00E+08	1.08E+09	-1.95E+09
8	2020	0.26	1.3	0.76	0.54	0.51	2.27E+08	3.33E+08		-1.47E+08	0.00E+00	-7.55E+07	4.84E+08	9.42E+08	-1.47E+09
9	2021	0.29	1.23	0.81	0.42	0.47	2.33E+08	2.38E+08		-1.64E+08	0.00E+00	-7.75E+07	3.93E+08	8.32E+08	-1.07E+09
10	2022	0.18	1.35	0.8	0.55	0.43	1.33E+08	2.87E+08		-1.02E+08	0.00E+00	-4.43E+07	3.75E+08	8.64E+08	-6.99E+08
11	2023	0.16	1.26	0.8	0.46	0.40	1.09E+08	2.21E+08		-9.06E+07	0.00E+00	-3.62E+07	2.93E+08	7.33E+08	-4.06E+08
12	2024	0.13	1.22	0.77	0.45	0.37	8.12E+07	1.99E+08		-7.36E+07	0.00E+00	-2.71E+07	2.53E+08	6.87E+08	-1.53E+08
13	2025	0.08	1.05	0.8	0.25	0.34	4.60E+07	1.01E+08		-4.53E+07	0.00E+00	-1.53E+07	1.32E+08	3.91E+08	-2.11E+07
14	2026	0.03	0.85	0.76	0.09	0.31	1.59E+07	3.36E+07		-1.70E+07	0.00E+00	-5.28E+06	4.42E+07	1.42E+08	2.31E+07
15	2027	0.05	0.58	0.83	0	0.29	2.43E+07	0.00E+00		-2.83E+07	0.00E+00	-8.10E+06	1.62E+07	5.66E+07	3.93E+07
16	2028	0.01	0.59	0.82	0	0.26	4.47E+06	0.00E+00		-5.66E+06	0.00E+00	-1.49E+06	2.98E+06	1.13E+07	4.23E+07
17	2029	0.05	0.59	0.72	0	0.24	2.06E+07	0.00E+00	-6.00E+08	-2.83E+07	-1.45E+08	-6.86E+06	-1.32E+08	-5.43E+08	-8.94E+07
TOTAL:		4.01	14.64	11.22	4.222		4.01E+09	2.47E+09	-6.60E+09	-2.27E+09	-5.24E+09	-1.34E+09	-8.94E+07	3.01E+09	

LOW CASE (CAPEX, OPEX)

Oil price	45	USD/Bbl	1698.248908	NOK/Sm^3
Gas price	1.2	NOK/Sm^3		
Interest rate	0.09			
Exchange rate	6	NOK/USD		
Discount rate	0.08			
Opex	9	USD/Bbl	339.6497816	NOK/Sm^3

	Time	Oil production(Oil Sale)	Gas production, excl. fuel	Gas Injection	Gas Sale	Discount factor	Income from Oil (Discounted)	Income from Gas (Discounted)	CAPEX	OPEX	CAPEX (discounted amount)	OPEX (discounted amount)	NPV	Net Cash Flow	Cumulative PV Cash Flow
	year	Msm3	Gsm3	Gsm3	Gsm3		NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK
1	2013	0	0	0	0	0.92	0.00E+00	0.00E+00	-1.20E+09	0.00E+00	-1.10E+09	0.00E+00	-1.10E+09	-1.20E+09	-1.10E+09
2	2014	0	0	0	0	0.85	0.00E+00	0.00E+00	-1.20E+09	0.00E+00	-1.02E+09	0.00E+00	-1.02E+09	-1.20E+09	-2.12E+09
3	2015	0.26	0.0915	0.209	0	0.78	3.44E+08	0.00E+00	-1.20E+09	-8.83E+07	-9.34E+08	-6.88E+07	-6.59E+08	-8.47E+08	-2.78E+09
4	2016	0.86	0.6925	0.767	0	0.72	1.05E+09	0.00E+00		-2.92E+08	0.00E+00	-2.09E+08	8.37E+08	1.17E+09	-1.94E+09
5	2017	0.73	1.196	0.804	0.392	0.66	8.17E+08	3.10E+08		-2.48E+08	0.00E+00	-1.63E+08	9.64E+08	1.46E+09	-9.78E+08
6	2018	0.5	1.33	0.76	0.57	0.61	5.15E+08	4.15E+08		-1.70E+08	0.00E+00	-1.03E+08	8.27E+08	1.36E+09	-1.52E+08
7	2019	0.42	1.31	0.81	0.5	0.56	3.98E+08	3.35E+08		-1.43E+08	0.00E+00	-7.96E+07	6.53E+08	1.17E+09	5.01E+08
8	2020	0.26	1.3	0.76	0.54	0.51	2.27E+08	3.33E+08		-8.83E+07	0.00E+00	-4.53E+07	5.14E+08	1.00E+09	1.02E+09
9	2021	0.29	1.23	0.81	0.42	0.47	2.33E+08	2.38E+08		-9.85E+07	0.00E+00	-4.65E+07	4.24E+08	8.98E+08	1.44E+09
10	2022	0.18	1.35	0.8	0.55	0.43	1.33E+08	2.87E+08		-6.11E+07	0.00E+00	-2.66E+07	3.93E+08	9.05E+08	1.83E+09
11	2023	0.16	1.26	0.8	0.46	0.40	1.09E+08	2.21E+08		-5.43E+07	0.00E+00	-2.17E+07	3.07E+08	7.69E+08	2.14E+09
12	2024	0.13	1.22	0.77	0.45	0.37	8.12E+07	1.99E+08		-4.42E+07	0.00E+00	-1.62E+07	2.63E+08	7.17E+08	2.40E+09
13	2025	0.08	1.05	0.8	0.25	0.34	4.60E+07	1.01E+08		-2.72E+07	0.00E+00	-9.19E+06	1.38E+08	4.09E+08	2.54E+09
14	2026	0.03	0.85	0.76	0.09	0.31	1.59E+07	3.36E+07		-1.02E+07	0.00E+00	-3.17E+06	4.63E+07	1.49E+08	2.59E+09
15	2027	0.05	0.58	0.83	0	0.29	2.43E+07	0.00E+00		-1.70E+07	0.00E+00	-4.86E+06	1.94E+07	6.79E+07	2.61E+09
16	2028	0.01	0.59	0.82	0	0.26	4.47E+06	0.00E+00		-3.40E+06	0.00E+00	-8.95E+05	3.58E+06	1.36E+07	2.61E+09
17	2029	0.05	0.59	0.72	0	0.24	2.06E+07	0.00E+00	-3.60E+08	-1.70E+07	-8.72E+07	-4.12E+06	-7.08E+07	-2.92E+08	2.54E+09
TOTAL:		4.01	14.64	11.22	4.222		4.01E+09	2.47E+09	-3.96E+09	-1.36E+09	-3.14E+09	-8.03E+08	2.54E+09	6.55E+09	

HIGH CASE (CAPEX, OPEX)

Oil price	45	USD/Bbl	1698.248908	NOK/Sm^3
Gas price	1.2	NOK/Sm^3		
Interest rate	0.09			
Exchange rate	6	NOK/USD		
Discount rate	0.08			
Opex	21	USD/Bbl	792.5161571	NOK/Sm^3

	Time	Oil production(Oil Sale)	Gas production, excl. fuel	Gas Injection	Gas Sale	Discount factor	Income from Oil (Discounted)	Income from Gas (Discounted)	CAPEX	OPEX	CAPEX (discounted amount)	OPEX (discounted amount)	NPV	Net Cash Flow	Cumulative PV Cash Flow
	year	Msm3	Gsm3	Gsm3	Gsm3		NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK
1	2013	0	0	0	0	0.92	0.00E+00	0.00E+00	-2.80E+09	0.00E+00	-2.58E+09	0.00E+00	-2.58E+09	-2.80E+09	-2.58E+09
2	2014	0	0	0	0	0.85	0.00E+00	0.00E+00	-2.80E+09	0.00E+00	-2.37E+09	0.00E+00	-2.37E+09	-2.80E+09	-4.95E+09
3	2015	0.26	0.0915	0.209	0	0.78	3.44E+08	0.00E+00	-2.80E+09	-2.06E+08	-2.18E+09	-1.60E+08	-2.00E+09	-2.56E+09	-6.94E+09
4	2016	0.86	0.6925	0.767	0	0.72	1.05E+09	0.00E+00		-6.82E+08	0.00E+00	-4.88E+08	5.58E+08	7.79E+08	-6.38E+09
5	2017	0.73	1.196	0.804	0.392	0.66	8.17E+08	3.10E+08		-5.79E+08	0.00E+00	-3.81E+08	7.46E+08	1.13E+09	-5.64E+09
6	2018	0.5	1.33	0.76	0.57	0.61	5.15E+08	4.15E+08		-3.96E+08	0.00E+00	-2.40E+08	6.89E+08	1.14E+09	-4.95E+09
7	2019	0.42	1.31	0.81	0.5	0.56	3.98E+08	3.35E+08		-3.33E+08	0.00E+00	-1.86E+08	5.47E+08	9.80E+08	-4.40E+09
8	2020	0.26	1.3	0.76	0.54	0.51	2.27E+08	3.33E+08		-2.06E+08	0.00E+00	-1.06E+08	4.53E+08	8.83E+08	-3.95E+09
9	2021	0.29	1.23	0.81	0.42	0.47	2.33E+08	2.38E+08		-2.30E+08	0.00E+00	-1.09E+08	3.62E+08	7.67E+08	-3.59E+09
10	2022	0.18	1.35	0.8	0.55	0.43	1.33E+08	2.87E+08		-1.43E+08	0.00E+00	-6.20E+07	3.58E+08	8.23E+08	-3.23E+09
11	2023	0.16	1.26	0.8	0.46	0.40	1.09E+08	2.21E+08		-1.27E+08	0.00E+00	-5.07E+07	2.79E+08	6.97E+08	-2.95E+09
12	2024	0.13	1.22	0.77	0.45	0.37	8.12E+07	1.99E+08		-1.03E+08	0.00E+00	-3.79E+07	2.42E+08	6.58E+08	-2.71E+09
13	2025	0.08	1.05	0.8	0.25	0.34	4.60E+07	1.01E+08		-6.34E+07	0.00E+00	-2.14E+07	1.26E+08	3.72E+08	-2.58E+09
14	2026	0.03	0.85	0.76	0.09	0.31	1.59E+07	3.36E+07		-2.38E+07	0.00E+00	-7.40E+06	4.21E+07	1.35E+08	-2.54E+09
15	2027	0.05	0.58	0.83	0	0.29	2.43E+07	0.00E+00		-3.96E+07	0.00E+00	-1.13E+07	1.30E+07	4.53E+07	-2.53E+09
16	2028	0.01	0.59	0.82	0	0.26	4.47E+06	0.00E+00		-7.93E+06	0.00E+00	-2.09E+06	2.39E+06	9.06E+06	-2.53E+09
17	2029	0.05	0.59	0.72	0	0.24	2.06E+07	0.00E+00	-8.40E+08	-3.96E+07	-2.04E+08	-9.60E+06	-1.93E+08	-7.95E+08	-2.72E+09
TOTAL:		4.01	14.64	11.22	4.222		4.01E+09	2.47E+09	-9.24E+09	-3.18E+09	-7.33E+09	-1.87E+09	-2.72E+09	-5.42E+08	

APPENDIX D - Economical calculations for new production unit at base oil price.

BASE CASE (CAPEX, OPEX)

Oil price	75	USD/Bbl	2830.414847	NOK/Sm^3
Gas price	2	NOK/Sm^3		
Interest rate	0.09			
Exchange rate	6	NOK/USD		
Discount rate	0.08			
Opex	15	USD/Bbl	566.0829693	NOK/Sm^3

	Time	Oil production(Oil Sale)	Gas production, excl. fuel	Gas Injection	Gas Sale	Discount factor	Income from Oil (Discounted)	Income from Gas (Discounted)	CAPEX	OPEX	CAPEX (discounted amount)	OPEX (discounted amount)	NPV	Net Cash Flow	Cumulative PV Cash Flow
	year	Msm3	Gsm3	Gsm3	Gsm3		NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK
1	2013	0	0	0	0	0.92	0.00E+00	0.00E+00	-4.67E+09	0.00E+00	-4.30E+09	0.00E+00	-4.30E+09	-4.67E+09	-4.30E+09
2	2014	0	0	0	0	0.85	0.00E+00	0.00E+00	-4.67E+09	0.00E+00	-3.95E+09	0.00E+00	-3.95E+09	-4.67E+09	-8.25E+09
3	2015	0.26	0.0915	0.209	0	0.78	5.73E+08	0.00E+00	-4.67E+09	-1.47E+08	-3.64E+09	-1.15E+08	-3.18E+09	-4.08E+09	-1.14E+10
4	2016	0.86	0.6925	0.767	0	0.72	1.74E+09	0.00E+00		-4.87E+08	0.00E+00	-3.49E+08	1.40E+09	1.95E+09	-1.00E+10
5	2017	0.73	1.196	0.804	0.392	0.66	1.36E+09	5.17E+08		-4.13E+08	0.00E+00	-2.72E+08	1.61E+09	2.44E+09	-8.43E+09
6	2018	0.5	1.33	0.76	0.57	0.61	8.58E+08	6.91E+08		-2.83E+08	0.00E+00	-1.72E+08	1.38E+09	2.27E+09	-7.05E+09
7	2019	0.42	1.31	0.81	0.5	0.56	6.63E+08	5.58E+08		-2.38E+08	0.00E+00	-1.33E+08	1.09E+09	1.95E+09	-5.96E+09
8	2020	0.26	1.3	0.76	0.54	0.51	3.78E+08	5.54E+08		-1.47E+08	0.00E+00	-7.55E+07	8.56E+08	1.67E+09	-5.10E+09
9	2021	0.29	1.23	0.81	0.42	0.47	3.88E+08	3.97E+08		-1.64E+08	0.00E+00	-7.75E+07	7.07E+08	1.50E+09	-4.40E+09
10	2022	0.18	1.35	0.8	0.55	0.43	2.21E+08	4.78E+08		-1.02E+08	0.00E+00	-4.43E+07	6.55E+08	1.51E+09	-3.74E+09
11	2023	0.16	1.26	0.8	0.46	0.40	1.81E+08	3.68E+08		-9.06E+07	0.00E+00	-3.62E+07	5.12E+08	1.28E+09	-3.23E+09
12	2024	0.13	1.22	0.77	0.45	0.37	1.35E+08	3.31E+08		-7.36E+07	0.00E+00	-2.71E+07	4.39E+08	1.19E+09	-2.79E+09
13	2025	0.08	1.05	0.8	0.25	0.34	7.66E+07	1.69E+08		-4.53E+07	0.00E+00	-1.53E+07	2.30E+08	6.81E+08	-2.56E+09
14	2026	0.03	0.85	0.76	0.09	0.31	2.64E+07	5.60E+07		-1.70E+07	0.00E+00	-5.28E+06	7.72E+07	2.48E+08	-2.48E+09
15	2027	0.05	0.58	0.83	0	0.29	4.05E+07	0.00E+00		-2.83E+07	0.00E+00	-8.10E+06	3.24E+07	1.13E+08	-2.45E+09
16	2028	0.01	0.59	0.82	0	0.26	7.46E+06	0.00E+00		-5.66E+06	0.00E+00	-1.49E+06	5.96E+06	2.26E+07	-2.44E+09
17	2029	0.05	0.59	0.72	0	0.24	3.43E+07	0.00E+00	-1.80E+08	-2.83E+07	-4.36E+07	-6.86E+06	-1.62E+07	-6.68E+07	-2.46E+09
TOTAL:		4.01	14.64	11.22	4.222		6.69E+09	4.12E+09	-1.42E+10	-2.27E+09	-1.19E+10	-1.34E+09	-2.46E+09	3.33E+09	

LOW CASE (CAPEX, OPEX)

Oil price	75	USD/Bbl	2830.414847	NOK/Sm^3
Gas price	2	NOK/Sm^3		
Interest rate	0.09			
Exchange rate	6	NOK/USD		
Discount rate	0.08			
Opex	9	USD/Bbl	339.6497816	NOK/Sm^3

	Time	Oil production(Oil Sale)	Gas production, excl. fuel	Gas Injection	Gas Sale	Discount factor	Income from Oil (Discounted)	Income from Gas (Discounted)	CAPEX	OPEX	CAPEX (discounted amount)	OPEX (discounted amount)	NPV	Net Cash Flow	Cumulative PV Cash Flow
	year	Msm3	Gsm3	Gsm3	Gsm3		NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK
1	2013	0	0	0	0	0.92	0.00E+00	0.00E+00	-2.80E+09	0.00E+00	-2.58E+09	0.00E+00	-2.58E+09	-2.80E+09	-2.58E+09
2	2014	0	0	0	0	0.85	0.00E+00	0.00E+00	-2.80E+09	0.00E+00	-2.37E+09	0.00E+00	-2.37E+09	-2.80E+09	-4.95E+09
3	2015	0.26	0.0915	0.209	0	0.78	5.73E+08	0.00E+00	-2.80E+09	-8.83E+07	-2.18E+09	-6.88E+07	-1.68E+09	-2.15E+09	-6.62E+09
4	2016	0.86	0.6925	0.767	0	0.72	1.74E+09	0.00E+00		-2.92E+08	0.00E+00	-2.09E+08	1.53E+09	2.14E+09	-5.09E+09
5	2017	0.73	1.196	0.804	0.392	0.66	1.36E+09	5.17E+08		-2.48E+08	0.00E+00	-1.63E+08	1.72E+09	2.60E+09	-3.37E+09
6	2018	0.5	1.33	0.76	0.57	0.61	8.58E+08	6.91E+08		-1.70E+08	0.00E+00	-1.03E+08	1.45E+09	2.39E+09	-1.93E+09
7	2019	0.42	1.31	0.81	0.5	0.56	6.63E+08	5.58E+08		-1.43E+08	0.00E+00	-7.96E+07	1.14E+09	2.05E+09	-7.85E+08
8	2020	0.26	1.3	0.76	0.54	0.51	3.78E+08	5.54E+08		-8.83E+07	0.00E+00	-4.53E+07	8.87E+08	1.73E+09	1.02E+08
9	2021	0.29	1.23	0.81	0.42	0.47	3.88E+08	3.97E+08		-9.85E+07	0.00E+00	-4.65E+07	7.38E+08	1.56E+09	8.40E+08
10	2022	0.18	1.35	0.8	0.55	0.43	2.21E+08	4.78E+08		-6.11E+07	0.00E+00	-2.66E+07	6.73E+08	1.55E+09	1.51E+09
11	2023	0.16	1.26	0.8	0.46	0.40	1.81E+08	3.68E+08		-5.43E+07	0.00E+00	-2.17E+07	5.27E+08	1.32E+09	2.04E+09
12	2024	0.13	1.22	0.77	0.45	0.37	1.35E+08	3.31E+08		-4.42E+07	0.00E+00	-1.62E+07	4.50E+08	1.22E+09	2.49E+09
13	2025	0.08	1.05	0.8	0.25	0.34	7.66E+07	1.69E+08		-2.72E+07	0.00E+00	-9.19E+06	2.37E+08	6.99E+08	2.73E+09
14	2026	0.03	0.85	0.76	0.09	0.31	2.64E+07	5.60E+07		-1.02E+07	0.00E+00	-3.17E+06	7.93E+07	2.55E+08	2.81E+09
15	2027	0.05	0.58	0.83	0	0.29	4.05E+07	0.00E+00		-1.70E+07	0.00E+00	-4.86E+06	3.57E+07	1.25E+08	2.84E+09
16	2028	0.01	0.59	0.82	0	0.26	7.46E+06	0.00E+00		-3.40E+06	0.00E+00	-8.95E+05	6.56E+06	2.49E+07	2.85E+09
17	2029	0.05	0.59	0.72	0	0.24	3.43E+07	0.00E+00	-1.08E+08	-1.70E+07	-2.62E+07	-4.12E+06	4.01E+06	1.65E+07	2.85E+09
TOTAL:		4.01	14.64	11.22	4.222		6.69E+09	4.12E+09	-8.51E+09	-1.36E+09	-7.15E+09	-8.03E+08	2.85E+09	9.92E+09	

HIGH CASE (CAPEX, OPEX)

Oil price	75	USD/Bbl	2830.414847	NOK/Sm^3
Gas price	2	NOK/Sm^3		
Interest rate	0.09			
Exchange rate	6	NOK/USD		
Discount rate	0.08			
Opex	21	USD/Bbl	792.5161571	NOK/Sm^3

	Time	Oil production(Oil Sale)	Gas production, excl. fuel	Gas Injection	Gas Sale	Discount factor	Income from Oil (Discounted)	Income from Gas (Discounted)	CAPEX	OPEX	CAPEX (discounted amount)	OPEX (discounted amount)	NPV	Net Cash Flow	Cumulative PV Cash Flow
	year	Msm3	Gsm3	Gsm3	Gsm3		NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK
1	2013	0	0	0	0	0.92	0.00E+00	0.00E+00	-6.53E+09	0.00E+00	-6.01E+09	0.00E+00	-6.01E+09	-6.53E+09	-6.01E+09
2	2014	0	0	0	0	0.85	0.00E+00	0.00E+00	-6.53E+09	0.00E+00	-5.53E+09	0.00E+00	-5.53E+09	-6.53E+09	-1.15E+10
3	2015	0.26	0.0915	0.209	0	0.78	5.73E+08	0.00E+00	-6.53E+09	-2.06E+08	-5.08E+09	-1.60E+08	-4.67E+09	-6.00E+09	-1.62E+10
4	2016	0.86	0.6925	0.767	0	0.72	1.74E+09	0.00E+00		-6.82E+08	0.00E+00	-4.88E+08	1.26E+09	1.75E+09	-1.50E+10
5	2017	0.73	1.196	0.804	0.392	0.66	1.36E+09	5.17E+08		-5.79E+08	0.00E+00	-3.81E+08	1.50E+09	2.27E+09	-1.35E+10
6	2018	0.5	1.33	0.76	0.57	0.61	8.58E+08	6.91E+08		-3.96E+08	0.00E+00	-2.40E+08	1.31E+09	2.16E+09	-1.21E+10
7	2019	0.42	1.31	0.81	0.5	0.56	6.63E+08	5.58E+08		-3.33E+08	0.00E+00	-1.86E+08	1.04E+09	1.86E+09	-1.11E+10
8	2020	0.26	1.3	0.76	0.54	0.51	3.78E+08	5.54E+08		-2.06E+08	0.00E+00	-1.06E+08	8.26E+08	1.61E+09	-1.03E+10
9	2021	0.29	1.23	0.81	0.42	0.47	3.88E+08	3.97E+08		-2.30E+08	0.00E+00	-1.09E+08	6.76E+08	1.43E+09	-9.61E+09
10	2022	0.18	1.35	0.8	0.55	0.43	2.21E+08	4.78E+08		-1.43E+08	0.00E+00	-6.20E+07	6.37E+08	1.47E+09	-8.97E+09
11	2023	0.16	1.26	0.8	0.46	0.40	1.81E+08	3.68E+08		-1.27E+08	0.00E+00	-5.07E+07	4.98E+08	1.25E+09	-8.47E+09
12	2024	0.13	1.22	0.77	0.45	0.37	1.35E+08	3.31E+08		-1.03E+08	0.00E+00	-3.79E+07	4.28E+08	1.16E+09	-8.04E+09
13	2025	0.08	1.05	0.8	0.25	0.34	7.66E+07	1.69E+08		-6.34E+07	0.00E+00	-2.14E+07	2.24E+08	6.63E+08	-7.82E+09
14	2026	0.03	0.85	0.76	0.09	0.31	2.64E+07	5.60E+07		-2.38E+07	0.00E+00	-7.40E+06	7.50E+07	2.41E+08	-7.75E+09
15	2027	0.05	0.58	0.83	0	0.29	4.05E+07	0.00E+00		-3.96E+07	0.00E+00	-1.13E+07	2.92E+07	1.02E+08	-7.72E+09
16	2028	0.01	0.59	0.82	0	0.26	7.46E+06	0.00E+00		-7.93E+06	0.00E+00	-2.09E+06	5.37E+06	2.04E+07	-7.71E+09
17	2029	0.05	0.59	0.72	0	0.24	3.43E+07	0.00E+00	-2.52E+08	-3.96E+07	-6.11E+07	-9.60E+06	-3.64E+07	-1.50E+08	-7.75E+09
TOTAL:		4.01	14.64	11.22	4.222		6.69E+09	4.12E+09	-1.98E+10	-3.18E+09	-1.67E+10	-1.87E+09	-7.75E+09	-3.23E+09	

APPENDIX E - Economical calculations for new production unit at high oil price.

BASE CASE (CAPEX, OPEX)

Oil price	105	USD/Bbl	3962.580785	NOK/Sm^3
Gas price	2.8	NOK/Sm^3		
Interest rate	0.09			
Exchange rate	6	NOK/USD		
Discount rate	0.08			
Opex	15	USD/Bbl	566.0829693	NOK/Sm^3

	Time	Oil production(Oil Sale)	Gas production, excl. fuel	Gas Injection	Gas Sale	Discount factor	Income from Oil (Discounted)	Income from Gas (Discounted)	CAPEX	OPEX	CAPEX (discounted amount)	OPEX (discounted amount)	NPV	Net Cash Flow	Cumulative PV Cash Flow
	year	Msm3	Gsm3	Gsm3	Gsm3		NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK
1	2013	0	0	0	0	0.92	0.00E+00	0.00E+00	-4.67E+09	0.00E+00	-4.30E+09	0.00E+00	-4.30E+09	-4.67E+09	-4.30E+09
2	2014	0	0	0	0	0.85	0.00E+00	0.00E+00	-4.67E+09	0.00E+00	-3.95E+09	0.00E+00	-3.95E+09	-4.67E+09	-8.25E+09
3	2015	0.26	0.0915	0.209	0	0.78	8.02E+08	0.00E+00	-4.67E+09	-1.47E+08	-3.64E+09	-1.15E+08	-2.95E+09	-3.79E+09	-1.12E+10
4	2016	0.86	0.6925	0.767	0	0.72	2.44E+09	0.00E+00		-4.87E+08	0.00E+00	-3.49E+08	2.09E+09	2.92E+09	-9.11E+09
5	2017	0.73	1.196	0.804	0.392	0.66	1.91E+09	7.23E+08		-4.13E+08	0.00E+00	-2.72E+08	2.36E+09	3.58E+09	-6.75E+09
6	2018	0.5	1.33	0.76	0.57	0.61	1.20E+09	9.68E+08		-2.83E+08	0.00E+00	-1.72E+08	2.00E+09	3.29E+09	-4.75E+09
7	2019	0.42	1.31	0.81	0.5	0.56	9.28E+08	7.81E+08		-2.38E+08	0.00E+00	-1.33E+08	1.58E+09	2.83E+09	-3.17E+09
8	2020	0.26	1.3	0.76	0.54	0.51	5.29E+08	7.76E+08		-1.47E+08	0.00E+00	-7.55E+07	1.23E+09	2.40E+09	-1.94E+09
9	2021	0.29	1.23	0.81	0.42	0.47	5.43E+08	5.55E+08		-1.64E+08	0.00E+00	-7.75E+07	1.02E+09	2.16E+09	-9.24E+08
10	2022	0.18	1.35	0.8	0.55	0.43	3.10E+08	6.69E+08		-1.02E+08	0.00E+00	-4.43E+07	9.35E+08	2.15E+09	1.06E+07
11	2023	0.16	1.26	0.8	0.46	0.40	2.53E+08	5.15E+08		-9.06E+07	0.00E+00	-3.62E+07	7.32E+08	1.83E+09	7.42E+08
12	2024	0.13	1.22	0.77	0.45	0.37	1.89E+08	4.63E+08		-7.36E+07	0.00E+00	-2.71E+07	6.26E+08	1.70E+09	1.37E+09
13	2025	0.08	1.05	0.8	0.25	0.34	1.07E+08	2.37E+08		-4.53E+07	0.00E+00	-1.53E+07	3.29E+08	9.72E+08	1.70E+09
14	2026	0.03	0.85	0.76	0.09	0.31	3.70E+07	7.84E+07		-1.70E+07	0.00E+00	-5.28E+06	1.10E+08	3.54E+08	1.81E+09
15	2027	0.05	0.58	0.83	0	0.29	5.67E+07	0.00E+00		-2.83E+07	0.00E+00	-8.10E+06	4.86E+07	1.70E+08	1.86E+09
16	2028	0.01	0.59	0.82	0	0.26	1.04E+07	0.00E+00		-5.66E+06	0.00E+00	-1.49E+06	8.95E+06	3.40E+07	1.86E+09
17	2029	0.05	0.59	0.72	0	0.24	4.80E+07	0.00E+00	-1.80E+08	-2.83E+07	-4.36E+07	-6.86E+06	-2.47E+06	-1.02E+07	1.86E+09
TOTAL:		4.01	14.64	11.22	4.222		9.36E+09	5.77E+09	-1.42E+10	-2.27E+09	-1.19E+10	-1.34E+09	1.86E+09	1.13E+10	

LOW CASE (CAPEX, OPEX)

Oil price	105	USD/Bbl	3962.580785	NOK/Sm^3
Gas price	2.8	NOK/Sm^3		
Interest rate	0.09			
Exchange rate	6	NOK/USD		
Discount rate	0.08			
Opex	9	USD/Bbl	339.6497816	NOK/Sm^3

	Time	Oil production(Oil Sale)	Gas production, excl. fuel	Gas Injection	Gas Sale	Discount factor	Income from Oil (Discounted)	Income from Gas (Discounted)	CAPEX	OPEX	CAPEX (discounted amount)	OPEX (discounted amount)	NPV	Net Cash Flow	Cumulative PV Cash Flow
	year	Msm3	Gsm3	Gsm3	Gsm3		NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK
1	2013	0	0	0	0	0.92	0.00E+00	0.00E+00	-2.80E+09	0.00E+00	-2.58E+09	0.00E+00	-2.58E+09	-2.80E+09	-2.58E+09
2	2014	0	0	0	0	0.85	0.00E+00	0.00E+00	-2.80E+09	0.00E+00	-2.37E+09	0.00E+00	-2.37E+09	-2.80E+09	-4.95E+09
3	2015	0.26	0.0915	0.209	0	0.78	8.02E+08	0.00E+00	-2.80E+09	-8.83E+07	-2.18E+09	-6.88E+07	-1.45E+09	-1.86E+09	-6.39E+09
4	2016	0.86	0.6925	0.767	0	0.72	2.44E+09	0.00E+00		-2.92E+08	0.00E+00	-2.09E+08	2.23E+09	3.12E+09	-4.16E+09
5	2017	0.73	1.196	0.804	0.392	0.66	1.91E+09	7.23E+08		-2.48E+08	0.00E+00	-1.63E+08	2.47E+09	3.74E+09	-1.69E+09
6	2018	0.5	1.33	0.76	0.57	0.61	1.20E+09	9.68E+08		-1.70E+08	0.00E+00	-1.03E+08	2.07E+09	3.41E+09	3.72E+08
7	2019	0.42	1.31	0.81	0.5	0.56	9.28E+08	7.81E+08		-1.43E+08	0.00E+00	-7.96E+07	1.63E+09	2.92E+09	2.00E+09
8	2020	0.26	1.3	0.76	0.54	0.51	5.29E+08	7.76E+08		-8.83E+07	0.00E+00	-4.53E+07	1.26E+09	2.45E+09	3.26E+09
9	2021	0.29	1.23	0.81	0.42	0.47	5.43E+08	5.55E+08		-9.85E+07	0.00E+00	-4.65E+07	1.05E+09	2.23E+09	4.31E+09
10	2022	0.18	1.35	0.8	0.55	0.43	3.10E+08	6.69E+08		-6.11E+07	0.00E+00	-2.66E+07	9.52E+08	2.19E+09	5.26E+09
11	2023	0.16	1.26	0.8	0.46	0.40	2.53E+08	5.15E+08		-5.43E+07	0.00E+00	-2.17E+07	7.46E+08	1.87E+09	6.01E+09
12	2024	0.13	1.22	0.77	0.45	0.37	1.89E+08	4.63E+08		-4.42E+07	0.00E+00	-1.62E+07	6.36E+08	1.73E+09	6.65E+09
13	2025	0.08	1.05	0.8	0.25	0.34	1.07E+08	2.37E+08		-2.72E+07	0.00E+00	-9.19E+06	3.35E+08	9.90E+08	6.98E+09
14	2026	0.03	0.85	0.76	0.09	0.31	3.70E+07	7.84E+07		-1.02E+07	0.00E+00	-3.17E+06	1.12E+08	3.61E+08	7.09E+09
15	2027	0.05	0.58	0.83	0	0.29	5.67E+07	0.00E+00		-1.70E+07	0.00E+00	-4.86E+06	5.19E+07	1.81E+08	7.15E+09
16	2028	0.01	0.59	0.82	0	0.26	1.04E+07	0.00E+00		-3.40E+06	0.00E+00	-8.95E+05	9.54E+06	3.62E+07	7.16E+09
17	2029	0.05	0.59	0.72	0	0.24	4.80E+07	0.00E+00	-1.08E+08	-1.70E+07	-2.62E+07	-4.12E+06	1.77E+07	7.31E+07	7.17E+09
TOTAL:		4.01	14.64	11.22	4.222		9.36E+09	5.77E+09	-8.51E+09	-1.36E+09	-7.15E+09	-8.03E+08	7.17E+09	1.78E+10	

HIGH CASE (CAPEX, OPEX)

Oil price	105	USD/Bbl	3962.580785	NOK/Sm^3
Gas price	2.8	NOK/Sm^3		
Interest rate	0.09			
Exchange rate	6	NOK/USD		
Discount rate	0.08			
Opex	21	USD/Bbl	792.5161571	NOK/Sm^3

	Time	Oil production(Oil Sale)	Gas production, excl. fuel	Gas Injection	Gas Sale	Discount factor	Income from Oil (Discounted)	Income from Gas (Discounted)	CAPEX	OPEX	CAPEX (discounted amount)	OPEX (discounted amount)	NPV	Net Cash Flow	Cumulative PV Cash Flow
	year	Msm3	Gsm3	Gsm3	Gsm3		NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK
1	2013	0	0	0	0	0.92	0.00E+00	0.00E+00	-6.53E+09	0.00E+00	-6.01E+09	0.00E+00	-6.01E+09	-6.53E+09	-6.01E+09
2	2014	0	0	0	0	0.85	0.00E+00	0.00E+00	-6.53E+09	0.00E+00	-5.53E+09	0.00E+00	-5.53E+09	-6.53E+09	-1.15E+10
3	2015	0.26	0.0915	0.209	0	0.78	8.02E+08	0.00E+00	-6.53E+09	-2.06E+08	-5.08E+09	-1.60E+08	-4.44E+09	-5.71E+09	-1.60E+10
4	2016	0.86	0.6925	0.767	0	0.72	2.44E+09	0.00E+00		-6.82E+08	0.00E+00	-4.88E+08	1.95E+09	2.73E+09	-1.40E+10
5	2017	0.73	1.196	0.804	0.392	0.66	1.91E+09	7.23E+08		-5.79E+08	0.00E+00	-3.81E+08	2.25E+09	3.41E+09	-1.18E+10
6	2018	0.5	1.33	0.76	0.57	0.61	1.20E+09	9.68E+08		-3.96E+08	0.00E+00	-2.40E+08	1.93E+09	3.18E+09	-9.85E+09
7	2019	0.42	1.31	0.81	0.5	0.56	9.28E+08	7.81E+08		-3.33E+08	0.00E+00	-1.86E+08	1.52E+09	2.73E+09	-8.32E+09
8	2020	0.26	1.3	0.76	0.54	0.51	5.29E+08	7.76E+08		-2.06E+08	0.00E+00	-1.06E+08	1.20E+09	2.34E+09	-7.12E+09
9	2021	0.29	1.23	0.81	0.42	0.47	5.43E+08	5.55E+08		-2.30E+08	0.00E+00	-1.09E+08	9.89E+08	2.10E+09	-6.14E+09
10	2022	0.18	1.35	0.8	0.55	0.43	3.10E+08	6.69E+08		-1.43E+08	0.00E+00	-6.20E+07	9.17E+08	2.11E+09	-5.22E+09
11	2023	0.16	1.26	0.8	0.46	0.40	2.53E+08	5.15E+08		-1.27E+08	0.00E+00	-5.07E+07	7.17E+08	1.80E+09	-4.50E+09
12	2024	0.13	1.22	0.77	0.45	0.37	1.89E+08	4.63E+08		-1.03E+08	0.00E+00	-3.79E+07	6.15E+08	1.67E+09	-3.89E+09
13	2025	0.08	1.05	0.8	0.25	0.34	1.07E+08	2.37E+08		-6.34E+07	0.00E+00	-2.14E+07	3.23E+08	9.54E+08	-3.56E+09
14	2026	0.03	0.85	0.76	0.09	0.31	3.70E+07	7.84E+07		-2.38E+07	0.00E+00	-7.40E+06	1.08E+08	3.47E+08	-3.46E+09
15	2027	0.05	0.58	0.83	0	0.29	5.67E+07	0.00E+00		-3.96E+07	0.00E+00	-1.13E+07	4.54E+07	1.59E+08	-3.41E+09
16	2028	0.01	0.59	0.82	0	0.26	1.04E+07	0.00E+00		-7.93E+06	0.00E+00	-2.09E+06	8.35E+06	3.17E+07	-3.40E+09
17	2029	0.05	0.59	0.72	0	0.24	4.80E+07	0.00E+00	-2.52E+08	-3.96E+07	-6.11E+07	-9.60E+06	-2.27E+07	-9.35E+07	-3.42E+09
TOTAL:		4.01	14.64	11.22	4.222		9.36E+09	5.77E+09	-1.98E+10	-3.18E+09	-1.67E+10	-1.87E+09	-3.42E+09	4.69E+09	

APPENDIX F - Economical calculations for new production unit at low oil price.

BASE CASE (CAPEX, OPEX)

Oil price	45	USD/Bbl	1698.248908	NOK/Sm^3
Gas price	1.2	NOK/Sm^3		
Interest rate	0.09			
Exchange rate	6	NOK/USD		
Discount rate	0.08			
Opex	15	USD/Bbl	566.0829693	NOK/Sm^3

	Time	Oil production(Oil Sale)	Gas production, excl. fuel	Gas Injection	Gas Sale	Discount factor	Income from Oil (Discounted)	Income from Gas (Discounted)	CAPEX	OPEX	CAPEX (discounted amount)	OPEX (discounted amount)	NPV	Net Cash Flow	Cumulative PV Cash Flow
	year	Msm3	Gsm3	Gsm3	Gsm3		NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK
1	2013	0	0	0	0	0.92	0.00E+00	0.00E+00	-4.67E+09	0.00E+00	-4.30E+09	0.00E+00	-4.30E+09	-4.67E+09	-4.30E+09
2	2014	0	0	0	0	0.85	0.00E+00	0.00E+00	-4.67E+09	0.00E+00	-3.95E+09	0.00E+00	-3.95E+09	-4.67E+09	-8.25E+09
3	2015	0.26	0.0915	0.209	0	0.78	3.44E+08	0.00E+00	-4.67E+09	-1.47E+08	-3.64E+09	-1.15E+08	-3.41E+09	-4.38E+09	-1.17E+10
4	2016	0.86	0.6925	0.767	0	0.72	1.05E+09	0.00E+00		-4.87E+08	0.00E+00	-3.49E+08	6.98E+08	9.74E+08	-1.10E+10
5	2017	0.73	1.196	0.804	0.392	0.66	8.17E+08	3.10E+08		-4.13E+08	0.00E+00	-2.72E+08	8.55E+08	1.30E+09	-1.01E+10
6	2018	0.5	1.33	0.76	0.57	0.61	5.15E+08	4.15E+08		-2.83E+08	0.00E+00	-1.72E+08	7.58E+08	1.25E+09	-9.35E+09
7	2019	0.42	1.31	0.81	0.5	0.56	3.98E+08	3.35E+08		-2.38E+08	0.00E+00	-1.33E+08	6.00E+08	1.08E+09	-8.75E+09
8	2020	0.26	1.3	0.76	0.54	0.51	2.27E+08	3.33E+08		-1.47E+08	0.00E+00	-7.55E+07	4.84E+08	9.42E+08	-8.26E+09
9	2021	0.29	1.23	0.81	0.42	0.47	2.33E+08	2.38E+08		-1.64E+08	0.00E+00	-7.75E+07	3.93E+08	8.32E+08	-7.87E+09
10	2022	0.18	1.35	0.8	0.55	0.43	1.33E+08	2.87E+08		-1.02E+08	0.00E+00	-4.43E+07	3.75E+08	8.64E+08	-7.49E+09
11	2023	0.16	1.26	0.8	0.46	0.40	1.09E+08	2.21E+08		-9.06E+07	0.00E+00	-3.62E+07	2.93E+08	7.33E+08	-7.20E+09
12	2024	0.13	1.22	0.77	0.45	0.37	8.12E+07	1.99E+08		-7.36E+07	0.00E+00	-2.71E+07	2.53E+08	6.87E+08	-6.95E+09
13	2025	0.08	1.05	0.8	0.25	0.34	4.60E+07	1.01E+08		-4.53E+07	0.00E+00	-1.53E+07	1.32E+08	3.91E+08	-6.82E+09
14	2026	0.03	0.85	0.76	0.09	0.31	1.59E+07	3.36E+07		-1.70E+07	0.00E+00	-5.28E+06	4.42E+07	1.42E+08	-6.77E+09
15	2027	0.05	0.58	0.83	0	0.29	2.43E+07	0.00E+00		-2.83E+07	0.00E+00	-8.10E+06	1.62E+07	5.66E+07	-6.76E+09
16	2028	0.01	0.59	0.82	0	0.26	4.47E+06	0.00E+00		-5.66E+06	0.00E+00	-1.49E+06	2.98E+06	1.13E+07	-6.75E+09
17	2029	0.05	0.59	0.72	0	0.24	2.06E+07	0.00E+00	-1.80E+08	-2.83E+07	-4.36E+07	-6.86E+06	-2.99E+07	-1.23E+08	-6.78E+09
TOTAL:		4.01	14.64	11.22	4.222		4.01E+09	2.47E+09	-1.42E+10	-2.27E+09	-1.19E+10	-1.34E+09	-6.78E+09	-4.58E+09	

LOW CASE (CAPEX, OPEX)

Oil price	45	USD/Bbl	1698.248908	NOK/Sm^3
Gas price	1.2	NOK/Sm^3		
Interest rate	0.09			
Exchange rate	6	NOK/USD		
Discount rate	0.08			
Opex	9	USD/Bbl	339.6497816	NOK/Sm^3

	Time	Oil production(Oil Sale)	Gas production, excl. fuel	Gas Injection	Gas Sale	Discount factor	Income from Oil (Discounted)	Income from Gas (Discounted)	CAPEX	OPEX	CAPEX (discounted amount)	OPEX (discounted amount)	NPV	Net Cash Flow	Cumulative PV Cash Flow
	year	Msm3	Gsm3	Gsm3	Gsm3		NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK
1	2013	0	0	0	0	0.92	0.00E+00	0.00E+00	-2.80E+09	0.00E+00	-2.58E+09	0.00E+00	-2.58E+09	-2.80E+09	-2.58E+09
2	2014	0	0	0	0	0.85	0.00E+00	0.00E+00	-2.80E+09	0.00E+00	-2.37E+09	0.00E+00	-2.37E+09	-2.80E+09	-4.95E+09
3	2015	0.26	0.0915	0.209	0	0.78	3.44E+08	0.00E+00	-2.80E+09	-8.83E+07	-2.18E+09	-6.88E+07	-1.91E+09	-2.45E+09	-6.85E+09
4	2016	0.86	0.6925	0.767	0	0.72	1.05E+09	0.00E+00		-2.92E+08	0.00E+00	-2.09E+08	8.37E+08	1.17E+09	-6.01E+09
5	2017	0.73	1.196	0.804	0.392	0.66	8.17E+08	3.10E+08		-2.48E+08	0.00E+00	-1.63E+08	9.64E+08	1.46E+09	-5.05E+09
6	2018	0.5	1.33	0.76	0.57	0.61	5.15E+08	4.15E+08		-1.70E+08	0.00E+00	-1.03E+08	8.27E+08	1.36E+09	-4.22E+09
7	2019	0.42	1.31	0.81	0.5	0.56	3.98E+08	3.35E+08		-1.43E+08	0.00E+00	-7.96E+07	6.53E+08	1.17E+09	-3.57E+09
8	2020	0.26	1.3	0.76	0.54	0.51	2.27E+08	3.33E+08		-8.83E+07	0.00E+00	-4.53E+07	5.14E+08	1.00E+09	-3.06E+09
9	2021	0.29	1.23	0.81	0.42	0.47	2.33E+08	2.38E+08		-9.85E+07	0.00E+00	-4.65E+07	4.24E+08	8.98E+08	-2.63E+09
10	2022	0.18	1.35	0.8	0.55	0.43	1.33E+08	2.87E+08		-6.11E+07	0.00E+00	-2.66E+07	3.93E+08	9.05E+08	-2.24E+09
11	2023	0.16	1.26	0.8	0.46	0.40	1.09E+08	2.21E+08		-5.43E+07	0.00E+00	-2.17E+07	3.07E+08	7.69E+08	-1.93E+09
12	2024	0.13	1.22	0.77	0.45	0.37	8.12E+07	1.99E+08		-4.42E+07	0.00E+00	-1.62E+07	2.63E+08	7.17E+08	-1.67E+09
13	2025	0.08	1.05	0.8	0.25	0.34	4.60E+07	1.01E+08		-2.72E+07	0.00E+00	-9.19E+06	1.38E+08	4.09E+08	-1.53E+09
14	2026	0.03	0.85	0.76	0.09	0.31	1.59E+07	3.36E+07		-1.02E+07	0.00E+00	-3.17E+06	4.63E+07	1.49E+08	-1.48E+09
15	2027	0.05	0.58	0.83	0	0.29	2.43E+07	0.00E+00		-1.70E+07	0.00E+00	-4.86E+06	1.94E+07	6.79E+07	-1.47E+09
16	2028	0.01	0.59	0.82	0	0.26	4.47E+06	0.00E+00		-3.40E+06	0.00E+00	-8.95E+05	3.58E+06	1.36E+07	-1.46E+09
17	2029	0.05	0.59	0.72	0	0.24	2.06E+07	0.00E+00	-1.08E+08	-1.70E+07	-2.62E+07	-4.12E+06	-9.71E+06	-4.01E+07	-1.47E+09
TOTAL:		4.01	14.64	11.22	4.222		4.01E+09	2.47E+09	-8.51E+09	-1.36E+09	-7.15E+09	-8.03E+08	-1.47E+09	2.01E+09	

HIGH CASE (CAPEX, OPEX)

Oil price	45	USD/Bbl	1698.248908	NOK/Sm^3
Gas price	1.2	NOK/Sm^3		
Interest rate	0.09			
Exchange rate	6	NOK/USD		
Discount rate	0.08			
Opex	21	USD/Bbl	792.5161571	NOK/Sm^3

	Time	Oil production(Oil Sale)	Gas production, excl. fuel	Gas Injection	Gas Sale	Discount factor	Income from Oil (Discounted)	Income from Gas (Discounted)	CAPEX	OPEX	CAPEX (discounted amount)	OPEX (discounted amount)	NPV	Net Cash Flow	Cumulative PV Cash Flow
	year	Msm3	Gsm3	Gsm3	Gsm3		NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK	NOK
1	2013	0	0	0	0	0.92	0.00E+00	0.00E+00	-6.53E+09	0.00E+00	-6.01E+09	0.00E+00	-6.01E+09	-6.53E+09	-6.01E+09
2	2014	0	0	0	0	0.85	0.00E+00	0.00E+00	-6.53E+09	0.00E+00	-5.53E+09	0.00E+00	-5.53E+09	-6.53E+09	-1.15E+10
3	2015	0.26	0.0915	0.209	0	0.78	3.44E+08	0.00E+00	-6.53E+09	-2.06E+08	-5.08E+09	-1.60E+08	-4.90E+09	-6.29E+09	-1.64E+10
4	2016	0.86	0.6925	0.767	0	0.72	1.05E+09	0.00E+00		-6.82E+08	0.00E+00	-4.88E+08	5.58E+08	7.79E+08	-1.59E+10
5	2017	0.73	1.196	0.804	0.392	0.66	8.17E+08	3.10E+08		-5.79E+08	0.00E+00	-3.81E+08	7.46E+08	1.13E+09	-1.51E+10
6	2018	0.5	1.33	0.76	0.57	0.61	5.15E+08	4.15E+08		-3.96E+08	0.00E+00	-2.40E+08	6.89E+08	1.14E+09	-1.44E+10
7	2019	0.42	1.31	0.81	0.5	0.56	3.98E+08	3.35E+08		-3.33E+08	0.00E+00	-1.86E+08	5.47E+08	9.80E+08	-1.39E+10
8	2020	0.26	1.3	0.76	0.54	0.51	2.27E+08	3.33E+08		-2.06E+08	0.00E+00	-1.06E+08	4.53E+08	8.83E+08	-1.34E+10
9	2021	0.29	1.23	0.81	0.42	0.47	2.33E+08	2.38E+08		-2.30E+08	0.00E+00	-1.09E+08	3.62E+08	7.67E+08	-1.31E+10
10	2022	0.18	1.35	0.8	0.55	0.43	1.33E+08	2.87E+08		-1.43E+08	0.00E+00	-6.20E+07	3.58E+08	8.23E+08	-1.27E+10
11	2023	0.16	1.26	0.8	0.46	0.40	1.09E+08	2.21E+08		-1.27E+08	0.00E+00	-5.07E+07	2.79E+08	6.97E+08	-1.24E+10
12	2024	0.13	1.22	0.77	0.45	0.37	8.12E+07	1.99E+08		-1.03E+08	0.00E+00	-3.79E+07	2.42E+08	6.58E+08	-1.22E+10
13	2025	0.08	1.05	0.8	0.25	0.34	4.60E+07	1.01E+08		-6.34E+07	0.00E+00	-2.14E+07	1.26E+08	3.72E+08	-1.21E+10
14	2026	0.03	0.85	0.76	0.09	0.31	1.59E+07	3.36E+07		-2.38E+07	0.00E+00	-7.40E+06	4.21E+07	1.35E+08	-1.20E+10
15	2027	0.05	0.58	0.83	0	0.29	2.43E+07	0.00E+00		-3.96E+07	0.00E+00	-1.13E+07	1.30E+07	4.53E+07	-1.20E+10
16	2028	0.01	0.59	0.82	0	0.26	4.47E+06	0.00E+00		-7.93E+06	0.00E+00	-2.09E+06	2.39E+06	9.06E+06	-1.20E+10
17	2029	0.05	0.59	0.72	0	0.24	2.06E+07	0.00E+00	-2.52E+08	-3.96E+07	-6.11E+07	-9.60E+06	-5.01E+07	-2.07E+08	-1.21E+10
TOTAL:		4.01	14.64	11.22	4.222		4.01E+09	2.47E+09	-1.98E+10	-3.18E+09	-1.67E+10	-1.87E+09	-1.21E+10	-1.11E+10	

Part B - Group 2
Gullfaks Village 2010

”Drilling through the depleted Brent formation using UBD, MPD or conventional drilling”

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Trondheim, 28.04.2010

Contents.

1 Underbalanced Drilling.

1.1 What is Underbalanced Drilling?

Underbalanced Drilling (UBD) means that the pressure of the drilling fluid in the borehole is intentionally maintained below the formation pore fluid pressure, in the open hole section of the well.

As a result, formation fluids flow into the well when a permeable formation is penetrated during underbalanced drilling. For this reason underbalanced drilling is sometimes referred to as “flow drilling”.

Special equipment and procedures are required to control formation fluid inflow during underbalanced drilling.

UBD technique has become an art in the modern oil industry, often applied to avoid or mitigate formation damage, reduce lost circulation risk, enhanced recovery and increase ROP. However, in recent years, several new challenge have appeared, making the stability issue in shale’s more difficult to handle, and thus also more important to solve. For operational benefit, there has been an increasing demand by the industry for better understanding of shale behavior in underbalanced drilling. Shale is specifically mentioned in this setting, due to the fact that borehole instability is more pronounced in such formations than any other formation. From field experience, it was found that shale make up more than 75 % of drilled formations, and more than 70 % of borehole problems are caused by shale instability. In addition, many fields are in a depleting trend, infill drilling would be a big challenge; the same is true for drilling in tectonically active areas, in deep sea, and in deep and geologically complex surroundings. In practice, infill drilling operation requires UBD to penetrate heterogeneous formation pressured zone. For several reasons, UBD can be a good tool in near futures. However; a reliability borehole stability material models is needed, one that can solve the following possible uncertainties:

- Geo-pressured shale which is unstable and tends to slough into the wellbore when the high pore pressure is alleviated by the lower wellbore pressure;
- Hole collapse or wellbore caving due to insufficient “support” by the wellbore pressure.

All this uncertainties is a result of mechanical borehole instability, it can result in hole enlargements or hole collapse which causes fill on trips, poor directional control, poor cementing, repeated reaming, or, in extreme conditions, stuck drill pipe.

It is assumed that during UBD in shale, due to lack of mud support immediate shear failure may occur depending on type of shale formation and its rock strength. However, if the borehole would overcome the initial failure risk, instability risk may be reduced by equilibrating pore pressure. But due to the extremely low permeability of shale, the pore fluid cannot flow freely, which causes redistribution of stresses and possibility wellbore instability. So, knowledge of collapse pressure model in addition to pore pressure behavior in shale is considered the most crucial factors for wellbore design in UBD.

1.2 Why Underbalanced Drilling?

UBD offers several significant over conventional drilling techniques. They are discribed further.

1.2.1 Increased ROP .

UBD operations with lightened drilling fluids, can lead to increased ROP which are greater than these for wells drilled OBD with conventional liquid drilling fluids.

1.2.2 Increased Bit Life.

Bit life is increased when lightened drilling fluids are used instead of conventional drilling mud. UBD removes the confinement imposed on the rock by the overbalance pressure. It can decrease the apparent strength of the rock and reduce the work that must be done to drill away a given volume of rock. This increased drilling efficiency can increase the amount of hole that can be drilled before the bit reaches a critical wear state.

1.2.3 Minimized Lost Circulation.

Lost circulation occurs when drilling fluid enters into an open formation down hole, rather than returning to the surface. It is possible for drilling fluid to be lost by flow into a very permeable zone. For naturally fractured reservoir lost of circulation is frequently occurred. Lost circulation can be very costly during conventional drilling. The lost fluid has to be replaced, and the losses have to be mitigated, usually by adding **LCM** to the mud (to plug off the path by which the fluid is entering the formation). **UBD effectively prevents lost circulation problems** since there is no physical force driving drilling fluid into the formation if the well is drilled underbalanced.

1.2.4 Reduced Formation Damage.

Formation damage can occur when liquids, solids or both enter into the formation, during conventional drilling. There is a less chance for drilling fluids to enter into the formation in case of UBD, since the drilling fluids pressure in the wellbore is less than the pore pressure.

1.2.5 Earlier Production.

When a well is drilled underbalanced, hydrocarbon production can start as soon as a productive zone is penetrated. With suitable surface equipment, it is possible to collect oil and gas while drilling.

1.2.6 Reduced Stimulation Requirements.

Following conventional drilling operations, wells are often stimulated to increase their productivity. Stimulation can include acidizing or surfactant treatments, to remove formation damage, or hydraulic fracturing can be used to guarantee adequate production in low permeability reservoirs or to bypass damage in higher permeability formations. Reduced formation damage means lower stimulation costs.

1.2.7 Improved Formation Evaluation.

When a well is drilled underbalanced, formation fluids flow into the wellbore from any permeable formation in the open hole section. Penetrating any hydrocarbon bearing formation with adequate drive and permeability will result in an increased hydrocarbon cut in the drilling fluid returning to the surface. With adequate logging and drilling records, UBD can indicate potentially productive zones, as the well is drilled. Conversely, during conventional drilling, overbalance pressure prevents formation inflows; hydrocarbon-bearing zones have to be identified from cuttings, core analysis, logging or DSTs.

1.2.8 Minimized Differential sticking.

In a well drilled conventionally, a filter cake forms on the bore hole wall from solids deposited when liquid flows from the drilling mud into permeable zones, due to an overbalance pressure. If the drill string becomes embedded in the filter cake, the pressure differential between the wellbore and the fluid in the filter cake can act over such a large area that the axial force required moving the string can exceed its tensile capacity. The drill string is then differentially stuck. There will be no filter cake and no pressure acting to "clamp" the drill string if the well is drilled underbalanced.

1.3 UBD and Borehole Instability.

Borehole instability during UBD operation is a complex phenomenon where many factors are associated to cause mechanical borehole instability. However, mud weight design and well trajectory are accounted as prime factors in borehole design models. According to definition of UBD, mud weight (MW) is set below pore pressure (Pp). It does not necessarily always lead to borehole instability, regardless of formation strength. Therefore, formation strength articulates as Collapse Pressure (CP) in UBD. Evaluation of CP is thus vital in UBD. It will be interesting to investigate how MW, P_P and CP are interlinked in mechanical instability during UBD. A schematic sketch is presented in figure 1 to show different scenarios regulated by MW, P_P and CP and consequences as well. Two scenarios were distinguished.

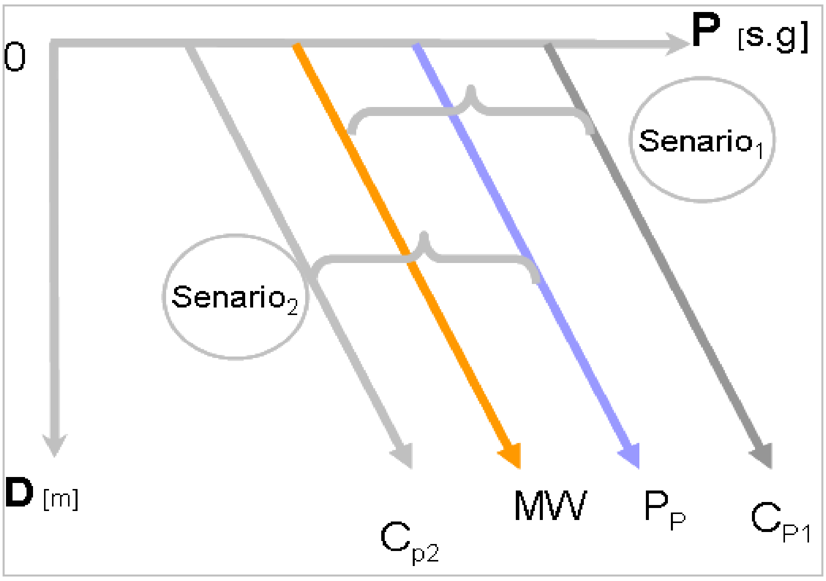


Figure 1 – UBD operation with different MW, P_P and CP. [7]

Scenario-1:

UBD conditions are satisfied by setting the values of MW, P_P, and CP. For this condition. Consequences of UBD will be;

- High ROP,
- High borehole stability risk due to MW $<P_P<$ CP.
- Shear failure or radial tensile failure is the most critical probable.

Scenario-2:

From borehole stability concern this case is favorable for UBD condition due to fact that stability influential parameters satisfy the stability condition (P_P>MW>C_P). The main consequences are;

- High ROP
- Relatively stable borehole

Among the three parameters involved in this model only MW is a controllable parameter. The other two influential parameters CP and P_P are uncontrollable. Very often predictions of these parameters are associated with uncertainties. Due to such limitation, very often field observations of borehole instability did not match with physical interpretation. Reliability of collapse pressure model is therefore essential for interpreting UBD. Because both Senerio-1 and Senerio-2 satisfy UBD condition, although aspects of borehole instability are different, both are not equally stable. Senerio-2 seems to be the most stable one.

2 Managed Pressure Drilling (MPD).

2.1 Defining MPD.

An adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and manage the hydraulic pressure profile accordingly. (IADC's MPD subcommittee).

MPD is separated in two categories by IADC's subcommittee, i.e reactive and proactive.

• *Reactive* – Well is designed for conventional drilling, but equipment is rigged up to quickly react to unexpected pressure changes. (Common to U.S. land programs, using surface backpressure to adjust EMW, enhance well control, etc.)

• *Proactive* – Equipment is rigged up to actively alter the annular pressure profile, potentially extending or eliminating casing points. [1]

The main issues of the MPD system:

- MPD process employs a collection of tools and techniques to mitigate the risks and costs associated with drilling wells that have narrow downhole environmental limits, by proactively managing the annular hydraulic pressure profile.
- System may include control of backpressure, fluid density, fluid rheology, annular fluid level, circulating friction, hole geometry or combinations thereof.
- MPD may allow faster corrective action to deal with observed pressure variation. The ability to control annular pressure dynamically facilitates drilling of what might otherwise be economically unattainable prospects.
- MPD techniques may be used to avoid formation influx. Any flow incidental to the operation will be safely contained using an appropriate process.

The counter piece of definition is "precise control". The technology allows drillers to control bottom hole pressure from the surface within range of 30-50 psi. One MPD method does not address all problems and MPD is application specific. As it is shown on the figure 2, the drilling engineer will have his choice of many options to best address the drilling problems encountered.[2]

Common Drivers for MPD are as follows:

- *Solve drilling related problems such as lost circulation*

• Depleted reservoirs,

• Abnormally pressured formations
• Unstable formations
  - *Increased safety*
• Early influx detection / Improved well control
  - *Cost efficient*
• Quick change of downhole pressure without any changes to mud system
• Increased ROP
• Potential decreased formation damage

Norway UBD/MPD Projects:
Recent: Gullfaks UBO/MPD (SH)*;* Grane MPD (SH)*;* Kristin MPD (SH development); Kvitebjørn MPD (SH)
Past: Tommeliten (Cop); Ula(BPA); Valhall (BPA)
Potential/Study: Njord, Norne, Ekofisk, Oseberg, Gyda, Huldra, and more.

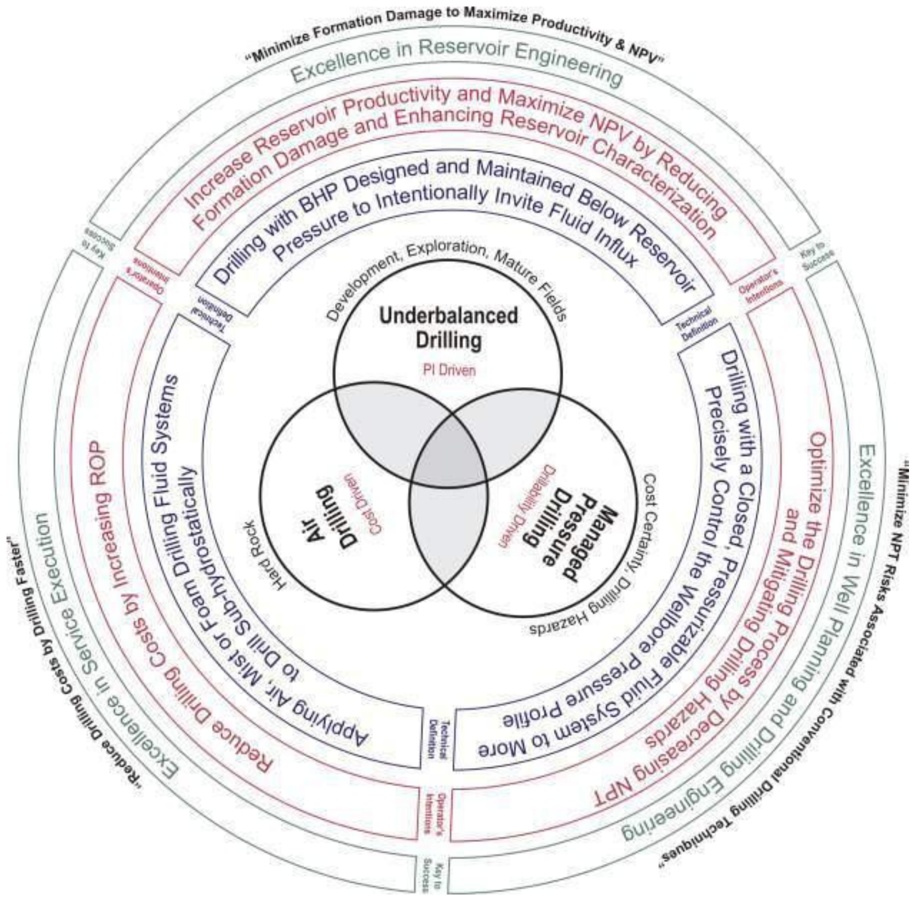


Figure 2 - "Controlled Pressure Drilling" Family of Technologies. [1]

Challenges Implementing MPD in Norway:
- Lack of knowledge to the technology
- Comfort factor (Experience level)
- Establish confidence that "removal" of conventional drilling primary well control barrier element (Mud weight) would not result in reduced safety
- Prove that RCD and Choke technology is dependable for extended drilling operations
- ATEX and NORSOK Equipment requirements – High cost to design/build vs Global
- Continuous work scope to be present [3]

2.2 Hydraulics.

Hydraulics design is operationalized by closed circulating system and MPD equipment. Successful MPD require a proactive plan to illustrate the entire pressure profile and how to control pressure in high or low permeability, fractured zones, sub-salt strata, etc.

The hydraulic design consist of mud type, mud densities, mud pump circulation rates, back pressure to be imposed on surface, drilling rate, cutting size and velocity, wellbore geometry and what depths these factors need to be manipulated or changed.

The wellbore in MPD is closed and able to tolerate pressure, and the driller can better control bottomhole pressure with imposed back pressure from an incompressible fluid, in addition to the hydrostatic pressure of the mud column and annular friction pressure.[2]

3 Reaching the Gullfaks Sør Statfjord Formation.

As it was stated in the challenge 2, the group had to decide on which method to stop for the new wells to reach Gullfaks Sør Statfjord Fm. where they had to be drilled through the Brent Group with the pressure depletion equal to more than 100 bar.

Before that it is necessary to say some words about possible ways to drill the depleted formation:

- Conventional method.

To safely drill a deep well for hydrocarbon exploration or production, it is necessary to prevent formation fluids from flowing into the well. This is typically done by adjusting the density of the drilling mud so that the wellbore pressure throughout the open hole is above the pressure of formation fluids (the pore pressure). On the other hand, the mud density cannot be so great as to cause hydraulic fracturing of the formation (it cannot exceed the fracture pressure). The pore-pressure and fracture-pressure gradients thus provide minimum and maximum values that define a mud-weight window, and this window is used to decide the depth of casing points.

During drilling process, every drilling engineer should keep in mind that increase in borehole pressure will take place due to the annular friction pressure created when well fluids are moved (circulated) along the wellbore, and that situation should be treated in a wise way when choosing a mud weight. In the mud-weight equivalent, this pressure increase is called *Equivalent Circulation Density (ECD)***.**

While taking into consideration all of the curves, i.e. pore pressure curve, collapse pressure curve and fracture curve, there is a challenge in drilling, due to having very narrow window which is equal to 0.06 sg from 1.36 sg to 1.42 sg in mud weight equivalent as seen on the figure 3. When there is question about which mud to choose, the mud engineer will say that it would not be possible to have a necessary mud weight due to density increase while circulation takes place in the borehole. As soon as we will have the circulation in the borehole, the ECD would be higher than the fracture pressure, thus creating fractures in the formation. It should be avoided due to unexpected fluid losses in the open-hole section, causing rapid loss of hydrostatic pressure and possibly allowing flow of formation fluids into the wellbore that could cause a kick or, if not treated properly, an uncontrolled situation, i.e. blow out.

From the figure 3 it is seen that the only limitation is the collapse pressure curve to have a conventional drilling. If the depleted formation would be stronger, the drilling window would be 0.18 sg from 1.24 sg to 1.42 sg in mud weight equivalent, that is enough to have a drilling without MPD or UBD implemented. The possible mud weight could be 1.30 sg in order to have a safety margin of 0.06 sg from pore pressure side and 0.12 sg from the fracture pressure side, as considering static conditions. The ECD at this region would be equal to 11.56 ppg or 1.39 sg. So if we wouldn't be limited by the collapse pressure curve, this region could be drilled conventionally, but the one should remember that a huge overbalanced state would take place that can lead to differential sticking, loss of circulation and increased possibility of blowouts.

- Underbalanced drilling (UBD).

Since we have a depleted formation, thus there will be no production from it, the UBD itself would not be a proper method to use, because the common driver for UBD is the reservoir enhancement by early production and reduced formation damage. In addition the depletion makes the pore pressure very low, so that it would not be practical to have a very low mud weight, in order to allow fluids to flow.

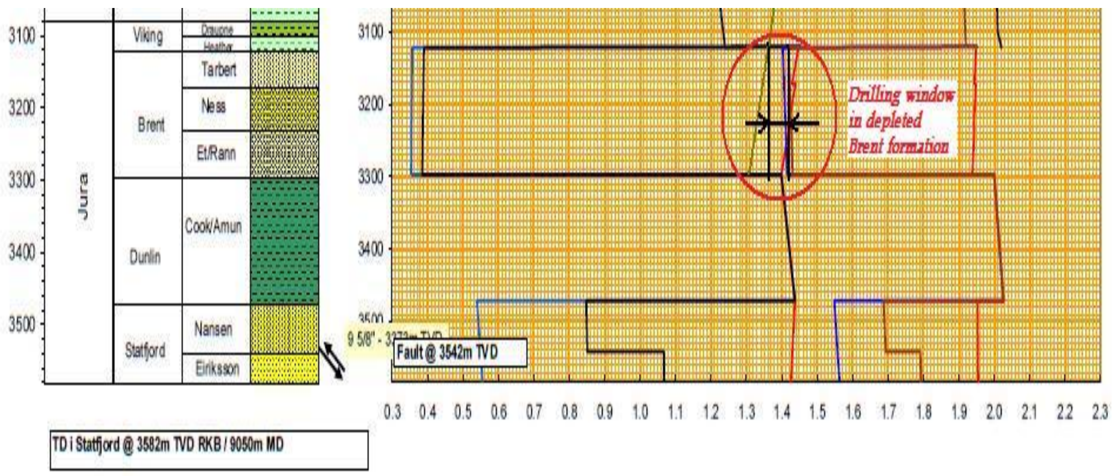


Figure 3 – Drilling window in depleted Brent formation.

- Managed pressure drilling (MPD).

By using all the knowledge of all team members and from the definition which was stated above, we have decided that MPD is the most suitable method to drill this depleted formation. The Brent formation is sandstone, which is argillaceous, medium grained and has fair porosity (22.2 %) and permeability (370 mD – 1874 mD), thus creating some specific issues in drilling process. The implementation of that method is discussed further in the report in a more detailed way.

4 Managed pressure drilling (MPD) implementation.

4.1 Drilling process.

Drilling of the Brent formation create a number of challenges. Risks which could occur are as follows:

- Faulting – Crossing faults could result in lost circulation.
- Clay (in)stability – it is well known that a clay formation such as the Kimmeridge clay formation requires a certain mud density and mud rheology to maintain borehole stability.

- Lost Circulation – it is a well known phenomena that if the pore pressure is reduced that will correspond to a reduction in fracture pressure. This is a major problem while drilling (severely) depleted reservoirs.
- Differential sticking – the mud density required to stabilize the Kimmeridge Clay formation will cause a considerable overbalance within the Brent formation. Especially if this is depleted.

From the 4 main risks discussed above can be seen that these risks cannot be assessed in isolation.

The key issues for these hole sections are:

- Barite sag
- Induced Lost Circulation
- Pore Pressure Prediction
- ECD Management
- Formation Strength and kick tolerance
- Borehole Ballooning and Flow Back

Barite Sag

This occurs when Barite settles towards the low side of the hole, resulting in a significant variation in mud density. If sag occurs, there is the potential to create lost circulation, well control incidents, ECD fluctuation, torque & drug difficulties, logging difficulties and poor cement jobs. It is a slow process, not usually becoming apparent until the mud has been static for a considerable period of time (after trips, logging or running casing). As the sag occurs, it results in a zone of lighter mud (possibly up to 1 ppg less than normal) above a zone of heavier mud (possibly up to 1 ppg above normal). As the hole is circulated, the lighter mud is seen in the returns before bottoms up, followed by the mud at a density above the nominal. As the light mud is displaced from the hole it is replaced with mud at the correct density. The extra density of the heavy mud now just below surface can be sufficient in wells where the pore pressure and fracture pressure are close together, to increase the bottomhole pressure up to the fracture pressure resulting in a loss of returns.

Induced Lost Circulation

Considering the close proximity of the formation pore pressure and fracture pressure it is important to be aware of the potential to induce lost circulation so measures can be taken to avoid it.

Induced lost circulation can be caused by:

- Surge pressures while running in hole.
- High initial pump pressures and the ECD required in breaking circulation. It is recommended to rotate the string prior to starting the mud pumps in order to break the gels. The pumps can then be started and slowly brought up to speed. Note however, that if the mud density is approaching the fracture pressure, consideration should be given to stopping rotation after breaking the gels, then establishing circulation slowly, then starting rotation again.
- Barite sag
- Higher annular mud density after a trip (weighted slug, cooler mud etc.)
- Increasing rotational speeds can induce losses – the drillstring rpm should be increased in stages.

Pore pressure Prediction and Kick Detection

Considering the degree of uncertainty over the pore pressure profile in this well, accurate pore pressure monitoring and prediction are vital in drilling the well successfully. Monitoring and plotting a combination of a number of trends and indicators, together with geological information provides the best means of interpreting any pore pressure changes. This can be achieved by combining real time drilling parameters (Dxc exponent plot, normalized drilling rate, torque etc) and all surface measurements (gas levels, temperature, mud density, mud temperature, mud salinity, cuttings shape etc).[4]

All of those obstacles can be avoided by proper technique implemented during drilling of depleted formation. Measures, which would be taken as it was decided by the team, are to case before entering into the Brent formation. The casing would be placed at the 3100 m TVD and implementing MPD to avoid the problems connected with loss circulation and clay instability, however the group suggests taking care about differential sticking during using MPD, because the bottomhole pressure will cause a considerable overbalance within the Brent formation (as you can see from figure 3, the depletion is from initial 1.43 sg to 0.39 sg or from initial 449 bars to 122 bars, i.e. the pressure depletion equals to 327 bars). For that reason oil-based mud could be a good solution for decreasing a friction. However the team agreed upon usage of a designer mud based on cesium/potassium (Cs/K) formate mud.

By looking at the pore pressure prognosis, we have set necessary casings during drilling conventionally before the Brent formation. Our plan differs with the suggested plan in the data presentation which was sent to us from Statoil. We have different casing points, which are set according to our casing program. Our team agreed upon passing the Shetland formation, with fairly high pore pressure, by a conventional method since the drilling window is quite wide. The next decision was about setting a 9 5/8” casing. After drilling the depleted formation we have decided to continue drilling, without casing it, further through Dunlin formation which has a thick with a silty, micaceous claystone lithology. The collapse pressure of the shale is sufficient to have an underbalance process. Since the permeability is very low, there will be no problems with fluids coming into borehole. The group has decided to place the 9 5/8” casing at the beginning of the Statfjord formation (waskaolinitic, coarse sand that has fair to good porosity but with several tight calcareous-cemented sand streaks) at 3490 m TVD by drilling into it. Since it is a reservoir, the continuation of drilling in it would create an overbalance that could damage the formation, hence affect the future production. After setting a casing, the well should be drilled to TD by using a conventional method and setting a 7” liner for well completion.

The group took into account another possibility in setting the 9 5/8” casing after Brent formation by drilling 5-10 m into shale formation. The drilling window is quite wide so it is possible to perform drilling in shale then entering to the Statfjord formation, but it has some difficulties in choosing of the mud type since we have to maintain two kinds of formations: shale and sandstone. Another issue is the huge overpressure which would be created in the reservoir, thus creating other problems such as differential sticking, loss of circulation, etc. So it is not the best solution. There is also a way to separate shale and sandstone formations by setting a 7” liner after drilling Dunlin formation, but, by doing this, the well would be completed with 5” liner that is also not the best way.

4.2 Choosing of Mud Weight for drilling Shetland and Brent formation.

In order to have a proper mud weight, the one should consider the equivalent circulating density when choosing it. Based on that, the group had done some estimation on the possible

ECD, which could take place during drilling. The most critical is the place with narrow window, so calculations were performed for those regions, i.e. when passing through Brent depleted formation, where MPD will be used, and drilling Shetland formation.

Formulas below are used for calculation of annular pressure loss and equivalent circulating density.[5]

1. Determine n: $n = 3.32 \log \frac{\theta_{600}}{\theta_{300}}$

2. Determine K: $K = \frac{\theta_{300}}{511^n}$

3. Determine annular velocity (v) in ft/min: v = (24.5 x Q) ÷ ($Dh^2 – Dp^2$)

4. Determine critical velocity (Vc) in ft/min:

$$Vc = \left(\frac{3.878 \times 10^4 \times K}{MW}\right)^{\frac{1}{2-n}} \times \left(\frac{2.4}{Dh - Dp} \times \frac{2n+1}{3n}\right)^{\frac{n}{2-n}}$$

5. Pressure loss for laminar flow (Ps), psi:

$$Ps = \left(\frac{2.4v}{Dh - Dp} \times \frac{2n+1}{3n}\right)^n \times \left(\frac{KL}{300(Dh - Dp)}\right)$$

6. Pressure loss for turbulent flow (Ps), psi:

$$Ps = \frac{7.7 \times 10^{-5} \times MW^{0.8} \times Q^{1.8} \times PV^{0.2} \times L}{(Dh - Dp)^3 \times (Dh + Dp)^{1.8}}$$

7. Determine equivalent circulating density (ECD),:

ECD in ppg = Ps ÷ 0.052 ÷ TVD in ft in ppg

ECD in kg/l = ECD in ppg * 0.12

Abbreviation meaning

Θ300: viscometer dial reading at 300 rpm
Θ600: viscometer dial reading at 600 rpm
Q: Flow rate in gpm
Dh: Diameter of hole
Dp: Diameter of drill pipe, drill collar or BHA in ft
v: annular velocity in ft/min
L: length of drill pipe, drill collar or BHA in ft
MW: Mud Weight
PV: Plastic viscosity

4.2.1 Equivalent circulating density (ECD) in kg/l in Shetland formation.

Mud weight = 1.70 kg/l = 14.19 ppg
Θ300 = 71

Θ600 = 94
Plastic viscosity = 23 cps
Circulation rate = 1188.77 gpm
Hole diameter = 20 in.
Drill collar OD = 7.0 in.
Drill pipe OD = 6.625 in
Drill collar length = 328.08 ft
Drill pipe length = 13497.4 ft
True vertical depth = 5118.11 ft

1. Determine n:
$n = 3.32 \log \frac{94}{71} = 0.405$

2. Determine K:
$K = \frac{71}{511^{0.405}} = 5.694$

3. Determine annular velocity (v) in ft/min around drill pipe:

v = (24.5 x 1188.77) ÷ (20^2 – 6.625^2) = 81.8 ft/min

4. Determine critical velocity (Vc) in ft/min around drill pipe:

$$Vc = \left(\frac{3.878 \times 10^4 \times 5.694}{14.19}\right)^{\frac{1}{2-0.405}} \times \left(\frac{2.4}{20-6.625} \times \frac{2 \times 0.405 + 1}{3 \times 0.405}\right)^{\frac{0.405}{2-0.405}} = 303.6\ ft/min$$

The annular velocity around drill pipe is less than the critical velocity around drill pipe so this is laminar flow. The equation #5 (for laminar flow) must be applied in this case.

Pressure loss for laminar flow (Ps), psi:

$$Ps = \left(\frac{2.4 \times 81.8}{20-6.625} \times \frac{2 \times 0.405 + 1}{3 \times 0.405}\right)^{0.405} \times \left(\frac{5.694 \times 13497.4}{300 \times (20-6.625)}\right) = 66.7\ psi$$

5. Determine annular velocity (v) in ft/min around drill collar:

v = (24.5 x 1188.77) ÷ (20^2 – 7^2) = 83.0 ft/min

6. Determine critical velocity (Vc) in ft/min around drill collar:

$$Vc = \left(\frac{3.878 \times 10^4 \times 5.694}{14.19}\right)^{\frac{1}{2-0.405}} \times \left(\frac{2.4}{20-7} \times \frac{2 \times 0.405 + 1}{3 \times 0.405}\right)^{\frac{0.405}{2-0.405}} = 305.8\ ft/min$$

The annular velocity around drill collar is less than the critical velocity around drill collar so this is laminar flow. The equation #5 (for laminar flow) must be applied in this case.

Pressure loss for laminar flow (Ps), psi:

$$Ps = \left(\frac{2.4 \times 83.0}{20 - 7} \times \frac{2 \times 0.405 + 1}{3 \times 0.405}\right)^{0.405} \times \left(\frac{5.694 \times 328.08}{300 \times (20 - 7)}\right) = 1.7\ psi$$

Total annular pressure loss = **annular pressure loss around drill pipe + annular pressure loss around drill collar**

Ps = 66.7+1.7 = 68.4 psi

7. Determine equivalent circulating density (ECD):

ECD = 68.4 ÷ 0.052 ÷ 5118.11 = 0.26 ppg = 0.031 kg/l

So chosen mud weight has the density of 1.7 kg/l, when drilling Shetland formation

4.2.2 Equivalent circulating density (ECD) in kg/l in Brent formation.

Mud weight = 1.252 kg/l = 10.45 ppg
ϴ300 = 49
ϴ600 = 63
Plastic viscosity = 20 cps
Circulation rate = 1003.85 gpm
Hole diameter = 12.25 in.
Drill collar OD = 7.0 in.

Drill pipe OD = 5.875 in
Drill collar length = 328.08 ft
Drill pipe length = 23668 ft
True vertical depth = 10171 ft

1. Determine n:

$$n = 3.32 \log \frac{63}{49} = 0.362$$

2. Determine K:

$$K = \frac{49}{511^{0.362}} = 5.114$$

3. Determine annular velocity (v) in ft/min around drill pipe:

v = (24.5 x 1003.85) ÷ (12.25² – 5.875²) = 212.9 ft/min

4. Determine critical velocity (Vc) in ft/min around drill pipe:

$$Vc = \left(\frac{3.878 \times 10^4 \times 5.114}{10.45}\right)^{\frac{1}{2-0.362}} \times \left(\frac{2.4}{12.25 - 5.875} \times \frac{2 \times 0.362 + 1}{3 \times 0.362}\right)^{\frac{0.362}{2-0.362}} = 365.5\ ft/min$$

The annular velocity around drill pipe is less than the critical velocity around drill pipe so this is laminar flow. The equation #5 (for laminar flow) must be applied in this case.

Pressure loss for laminar flow (Ps), psi:

$$Ps = \left(\frac{2.4 \times 212.9}{12.25 - 5.875} \times \frac{2 \times 0.362 + 1}{3 \times 0.362}\right)^{0.362} \times \left(\frac{5.114 \times 23668}{300 \times (12.25 - 5.875)}\right) \quad = 366.3\ psi$$

5. Determine annular velocity (v) in ft/min around drill collar:

v = (24.5 x 1003.85) ÷ (12.25^2 – 7^2) = 243.4 ft/min

6. Determine critical velocity (Vc) in ft/min around drill collar:

$$Vc = \left(\frac{3.878 \times 10^4 \times 5.114}{10.45}\right)^{\frac{1}{2-0.362}} \times \left(\frac{2.4}{12.25 - 7} \times \frac{2 \times 0.362 + 1}{3 \times 0.362}\right)^{\frac{0.362}{2-0.362}} = 381.6\ ft/min$$

The annular velocity around drill collar is less than the critical velocity around drill collar so this is laminar flow. The equation #5 (for laminar flow) must be applied in this case.

Pressure loss for laminar flow (Ps), psi:

$$Ps = \left(\frac{2.4 \times 243.4}{12.25 - 7} \times \frac{2 \times 0.362 + 1}{3 \times 0.362}\right)^{0.362} \times \left(\frac{5.114 \times 328.08}{300 \times (12.25 - 7)}\right) \quad = 6.6\ psi$$

Total annular pressure loss = **annular pressure loss around drill pipe + annular pressure loss around drill collar**

Ps = 366.3+6.6 = 372.9 psi

7. Determine equivalent circulating density (ECD):

ECD = 372.9 ÷ 0.052 ÷ 10171 = 0.71 ppg = 0.085 kg/l

The calculated mud weight is 1.252 kg/l, which will be used for depleted Brent Formation. As it will be discussed further, there will be a choke on a surface which would create an additional backpressure of 10 bars or in mud weight equivalent 0.033 kg/l. The total bottomhole pressure would be the sum of static mud weight, ECD and back pressure, i.e. 1.37 kg/l.

All of the chosen mud weights are fitted into the pore pressure prognosis graph as shown on a figure 4.

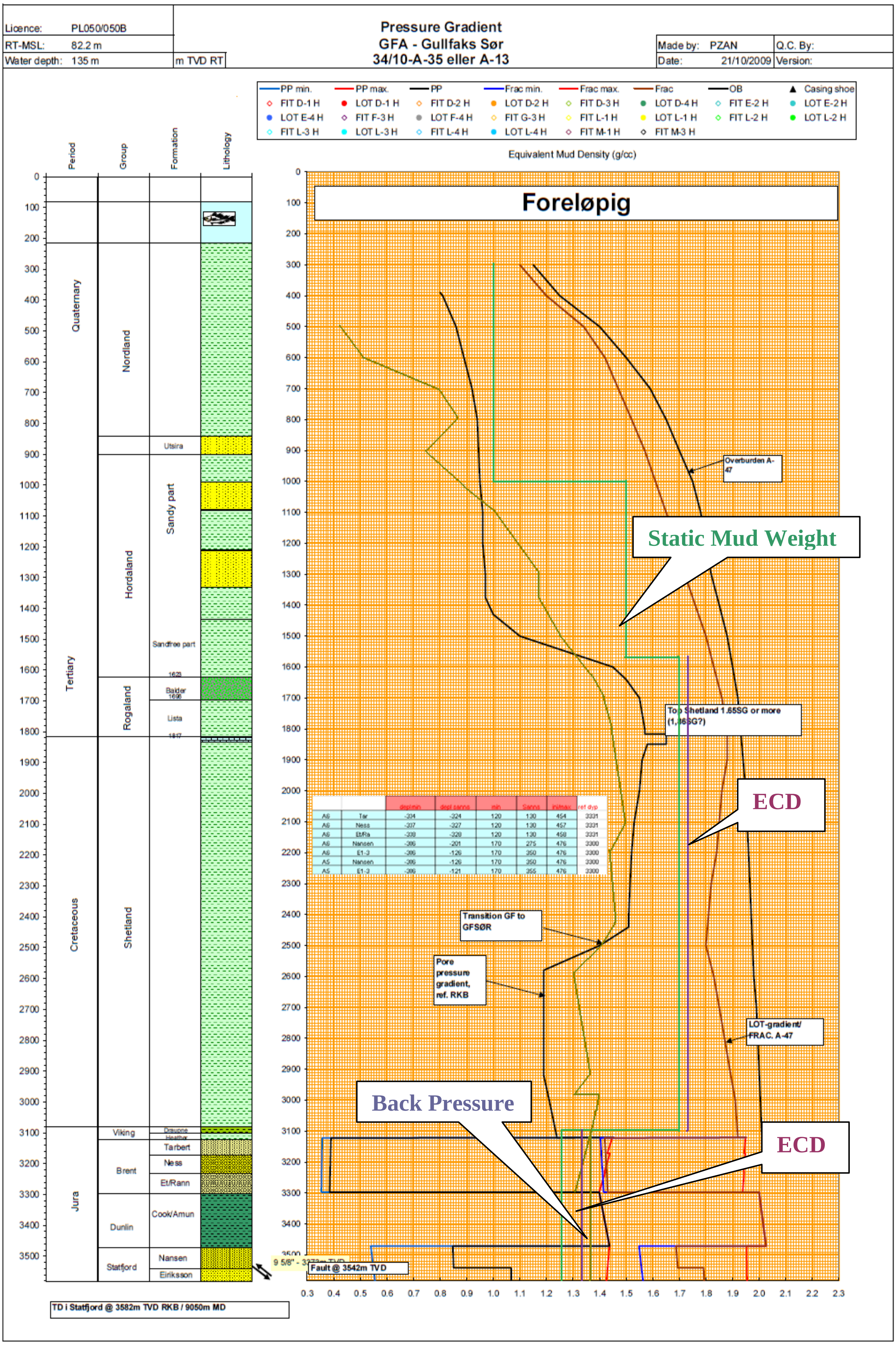


Figure 4 – Pore pressure prognosis graph with mud weights fitted into it.

4.3 Necessary measures to take in order to be able to drill wells to Gullfaks Sør Statfjord.

Our team suggested taking ideas and techniques from development of Kvitebjorn, as Statoil had similar and successful experience with depleted formations on it.

For having a clear picture of implemented measures, it was decided to list them step by step:

Planning and management [6]

1. Professional management is vital to a successful MPD operation. The complexity of MPD operations and the coordination of services, equipment and personnel require a high level of supervision and management. The importance of project control, organizational structure, reporting lines and operational support roles should not be underestimated. The offshore organizational structure used during MPD operations is shown in figure 5 to illustrate this point.
2. Even the most sophisticated equipment has limitations that need to be considered in planning and execution. The equipment package requires an optimal setup to perform to its full potential. This setup must be based on the planned operations.
   The MPD crew must be aware of the system's strengths and weaknesses, and these must be reflected in operational plans, contingency procedures and operational execution. Hydraulic modeling simulations are important during MPD preparations and represent the foundation of all plans, procedures, contingencies and equipment setup. It is of utmost importance that everyone has the skills and motivation to do their work properly. MPD must not commence until all personnel are competent for the upcoming tasks. This includes working as a team, as well as performing their individual responsibilities.

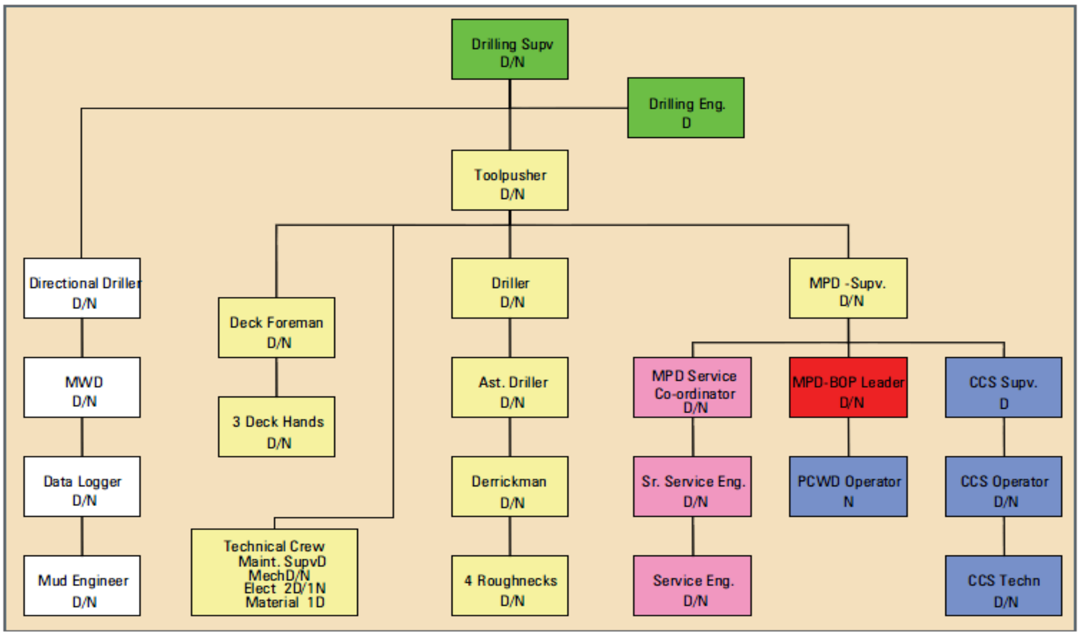


Figure 5 – Organizational structure during MPD process. [6]

3. An extensive series of hazard identifications (HAZIDs), hazard and operability studies (HAZOPs), peer reviews and workshops should be conducted, covering every aspect of the proposed operation. These consultations should refine the methods, configurations and procedures that are going to be employed.

Equipment and Technologies[6]

The equipment layout schematic is shown on the figure 6.

1. *Usage of rotating control head.*
   MPD centers on the use of a rotating control head (RCH) to provide a dynamic annulus seal that diverts the return mud flow through a surface choke. It is this choke that controls the back-pressure in the annulus and permits the manipulation of the downhole pressure profile. The mud weight is selected to be lower than the well's initial pore pressure. The annulus friction plus annulus back-pressure brings the downhole pressure profile back to balance, or slightly above balance. In this way the well is kept in balance, at all times preventing influx and hole collapse.
2. Downhole temperature changes affect mud weight and viscosity, pipe movements, rotation, torque, cuttings load, etc., all of which produce continuous and significant variations in downhole pressure. Only by compensating for these can constant bottom hole pressure (BHP) be achieved. Compensation should be performed by manipulating the choke and adjusting the annulus back-pressure.
3. Automatic choke control is an essential requirement. Accurate input to the choke controller from the flow model is one aspect; the accurate and timely control of choke movements is another. Both are required for the system to react fast enough and work well.
4. Mass flowmeters should be applied during MPD. They are highly accurate and, with the appropriate software, can provide exceptional kick detection and fingerprinting system.
5. *Usage of continuous circulation system (CCS).*
   Continuous circulation system (CCS) permits full circulation during drill pipe connections. It is only by maintaining full circulation at all times that the impact of downhole temperature changes can be controlled. By maintaining the downhole temperature profile with minimum variations, we can achieve something close to hydraulic stability in the well. This is a great benefit to choke control and improves the sensitivity for detecting trends in other parameters. By continuous circulation we can also eliminate the barite sag problem if the one would exist.

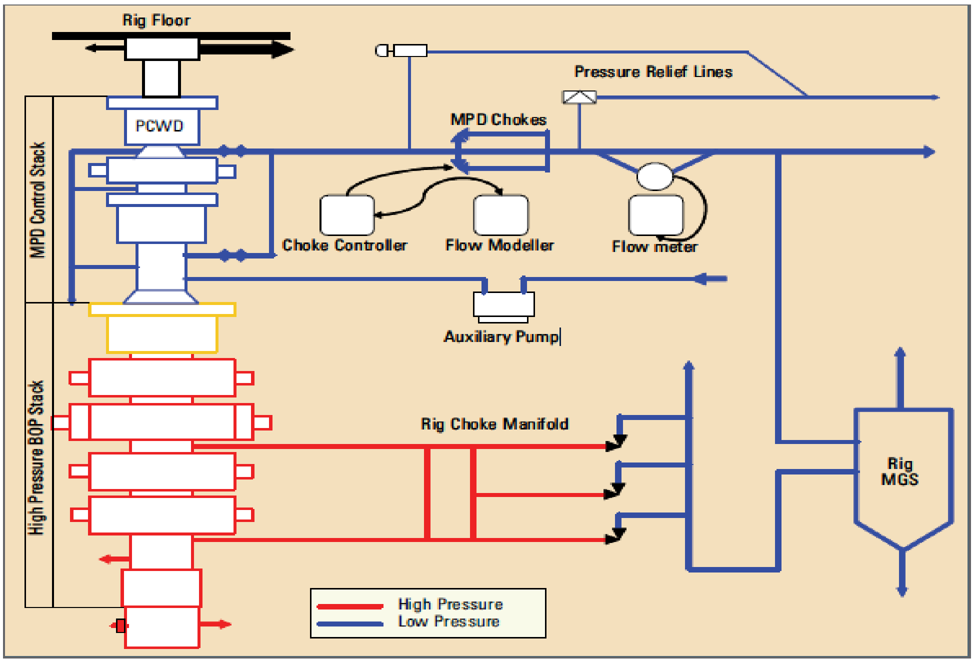


Figure 6 – The equipment layout during MPD process. [6]

6. Designer mud based on cesium/potassium (Cs/K) formate mud should be used. By drilling with this mud, the existing fracture gradient would be supported and possibly enhanced and also ECD would decrease. A crosslinked isolation mud pill in Cs/K formate base fluid should also be implemented to support weighted mud placed above lighter mud for trip in/out procedures. Minimising the mud interface and preventing the heavy mud “sliding” downhole is a critical requirement when the well is brought into pressure balance to perform trips.
7. During drilling process, besides a high pressure BOP, a pressure control while drilling (PCWD) rotating control head should be implemented.
8. The dual redundant automatic chokes should be used to avoid choke erosion.
9. Pressure relief valves should be included in the return flowline to protect equipment and the well.
10. The auxiliary pump is necessary for MPD drilling process to continuously circulate clean mud from the active system across the wellhead for keeping the annulus full and providing a continuous mud flow to allow the choke to maintain the desired back-pressure. This will ensure full pressure control over the annulus regardless of the main mud pumps.
11. Using of RPM sensors instead of pump stroke counters to know the performance of pumps.
12. Training of the personnel for a case of rig power failure.
13. Manual control of the flow rate during taking LWD surveys and pressure points.
14. Considering gas events during drilling. [6]

Even if many points were mentioned and process was described, our team advices to improve and adjust all the suggestions during a real drilling process for having a successful project.

5 Casing Program

Casing Program is defined as a systematic way of preventing the collapse of the borehole during drilling operations and hydraulically isolating the wellbore fluids from the subsurface formations and formation fluids.

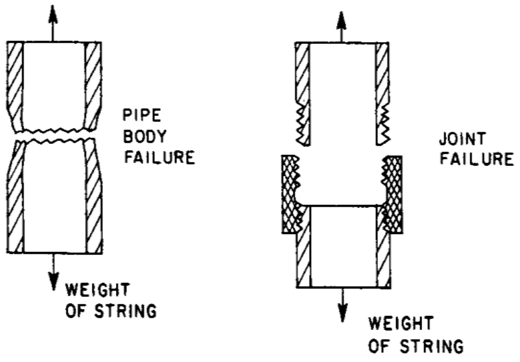
As a result of this it minimizes damage of both the subsurface environment by the drilling process and the well by a hostile subsurface environment, and provides a high strength flow conduit for the drilling fluid to the surface and, and with the blowout preventers (BOP), permits the safe control of formation pressure. [9]

When we design casing, it must be designed to withstand the maximum burst pressure, collapse pressure, and axial tensile forces (i.e. casing performance properties) that we anticipate that the casing will ever be exposed to. We then increase this by design factors. Casing is way over designed, because it will be exposed to hostile treatment from rotation of the drill string inside it, pressures imposed on it from the inside and outside, and tension forces from changing internal pressures, external pressures, and changing temperatures during treatment and production. It will also be called upon to keep formation fluids in place long after in the well is plugged and abandoned. [9]

5.1 Generalized API casing performance properties and calculations

As already stated above the most important performance properties of casing include its rated values for axial tensile, burst and collapse pressures.

Axial Tensile: This results from the weight of the casing string suspended below the joint of interest. Body yield strength is the tensional force required to cause the pipe body to exceed its elastic limit. Joint strength is the minimum tensional force required to cause joint failure. See figure 7.



(a) TENSION FAILURE IN PIPE BODY OR JOINT

Figure 7 – Tension failure in pipe body or joint. [9]

The Pipe body strength in tension can be computed by use of simplified body diagram. The force F_{ten} tending to pull apart the pipe is resisted by the strength of the pipe walls, which exert a counterforce , F_2 and F_2 is given by

$F_2 = \sigma_{yield} * A_s$,

where σ_{yield} is the minimum yield strength in psi and A_s is the cross sectional area of the steel.

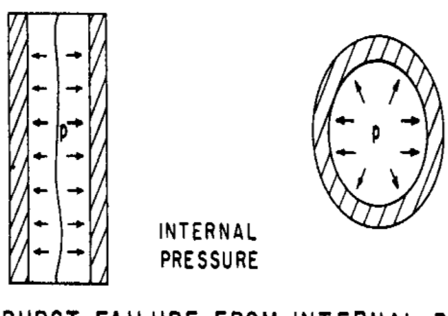
Thus the pipe body strength is given by :

$F_{ten} = \pi/4 * \sigma_{yield} (d_n^2 - d^2)$,

where d_n=Nominal diameter of casing pipe,
d= internal diameter of casing pipe.

This is the minimal force that would be expected to cause permanent deformation of the pipe .The expected minimum force required to pull the pipe in two would be significantly higher than this value.

Burst pressure: This is the minimal internal pressure that will cause the casing to fail or rupture in the absence of external pressure and axial loading. See figure 8



(b) BURST FAILURE FROM INTERNAL PRESSURE

Figure 8 – Burst failure from internal pressure. [9]

The burst pressure is derived from the Barlows equation:

ρ_{br}=0,875*(2 *σ_{yield}*t)/ d_n,

where 87.5%= minimum allowable wall thickness,
$(\sigma_{yield})_e$= minimum yield strength in psi,
d_n/t=upper limit of the plastic collapse range.

Collapse pressure: This is the minimal external pressure that will cause the casing walls to collapse in the absence of internal pressure and axial loading. See figure 9.

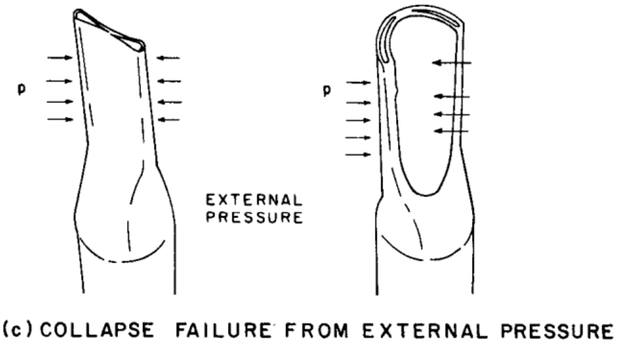


Figure 9 – Collapse failure from external pressure. [9]

This is derived from a complex classical elasticity theory that can establish the radial stress and tangential hoop stress in the pipe wall.

ρ_{cr}=$(\sigma_{yield})_e$*(F_4/(d_n/t))-F_5,

where F_4 &F_5= empirical coefficients used for collapse pressure determination.
d_n/t=upper limit of the plastic collapse range.
$(\sigma_{yield})_e$= minimum yield strength in psi.

5.2 Types of casing strings and their arrangements in a wellbore

Typical arrangement is shown on the figure 10.

5.2.1 Stove pipe (Marine Conductor or foundation pile for offshore rigs)

- Run to prevent wash out of unconsolidated surface formation
- Run to provide a circulation system for drilling fluids and to ensure the stability of the ground under the rig
- Does not carry wellhead equipment
- Can be driven into ground with a pile driver (26 in to 42 in per pile)

5.2.2 Conductor pipe 16”- 48”

- Run from surface to some shallow depth to protect near surface unconsolidated formation.

- Provide a circulation for the drilling mud to protect foundation of the platform.
- May be connecting of BOP or cut at surface or diverter connection.

5.2.3 Surface casing 18 5/8”-20”

- Run to prevent caving of weak formation encountered at shallow depths.
- Set in competent rock like limestone: to ensure that the formation will not fracture at the casing shoe by high mud weight used later in the next hole.
- Protects against shallow blow-out, thus BOPs are connected to the top.

5.2.4 Intermediate casing 7 5/8”-13 3/8”

- Usually set in the transition zone below or above pressured formation (salt and/or caving shale).
- Needs good cementing to prevent communication behind the casing between zones; multistage cementing may be used for long strings.

5.2.5 Production casing 4 1/2”-9 5/8”

- Isolates production zones
- Provides reservoir fluid control
- Permits selective production in multi zones production

5.2.6 Liner casing

- A string of casing that does not reach the surface
- Hangs on the intermediate casing, by use of suitable packer and slips called liner hanger. [10]

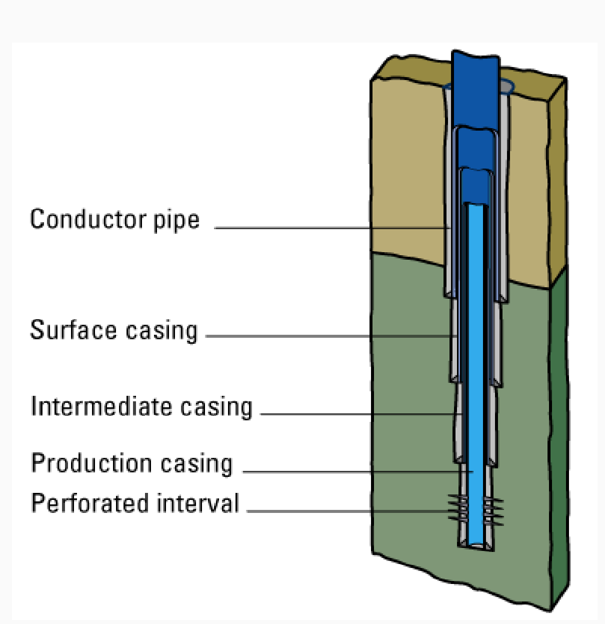


Figure 10 – Types of casing strings and their arrangements in a wellbore. [11]

5.3 Casing Design methodology

- Specification of surface and bottomhole well locations.
- Determination on size of production casing to be used. (by number and size of tubing strings and the type of subsurface artificial lift equipment that may eventually be placed in the well).
- Design of program which encompasses selection of bit sizes, casing sizes, grades, and setting depths.

5.3.1 Selection of casing depths

Determined primarily by:

- pore-pressure and fracture gradients of formation to be penetrated.
- Protection of fresh water aquifers.
- Presence of vulgar lost circulation zones.
- Depleted low pressure zones that tend to cause stuck pipes (As in the case of the brent formation of the gullfaks sør field).
- Salt beds that tend to flow plastically and close the borehole.

5.3.2 Selection of casing sizes

Determined primarily by:

- Necessary inner diameter of production string.
- Number of intermediate casing strings required to reach the depth objective.

5.3.3 Special Design Considerations of casing strings

Shock Loading:

Axial stresses result from sudden velocity changes in a manner that is analogous to water hammer in a pipe caused by sudden valve closure.

Changing Internal pressure:

During cementing operations the casing is exposed to a high internal pressure because of the hydrostatic pressure of the cement slurry and the pump pressure imposed to displace the slurry. This creates hoop stresses in the casing wall which tend to burst the casing and also creates axial stresses which tend to pull the casing apart.

Changing external pressure*:*

Situations are sometimes encountered when the external pressure can be higher than that caused by the mud. This occurs when casing is set through sections of formations (such as salt) that can flow plastically and when casing is set through permafrost, which can thaw and freeze, depending on if the well is open or shut in.

Thermal Effects*:*

This is considered when the temperature variations are not small in the life of the well and hence the resulting axial stresses must be considered.

5.4 Design of the casing string in our wellbore.

The casing program in our well bore was designed based on the pore pressure and fracture gradients provided to us by Statoil. Casings were positioned as indicated in figure 11, with particular interest on the problem zones in the Shetland and Brent formation. To pass the problem zone in the Shetland formation, the well bore was cased at 1570 m TVD with a16 inch casing and the mud weight increased to 1.7 sg which then allowed us to drill through the Shetland formation all the way to 3100m TVD, where we cased again with the 13 3/8 inches casing so we could implement the Managed Pressure Drilling solution in the Brent formation.

Due to the limitation of the Gullfaks Sør wellhead, which doesn't have a 16 in. casing hanger, it was decided to case the borehole with the 16 in. liner that would be supported by 20 in. surface casing.

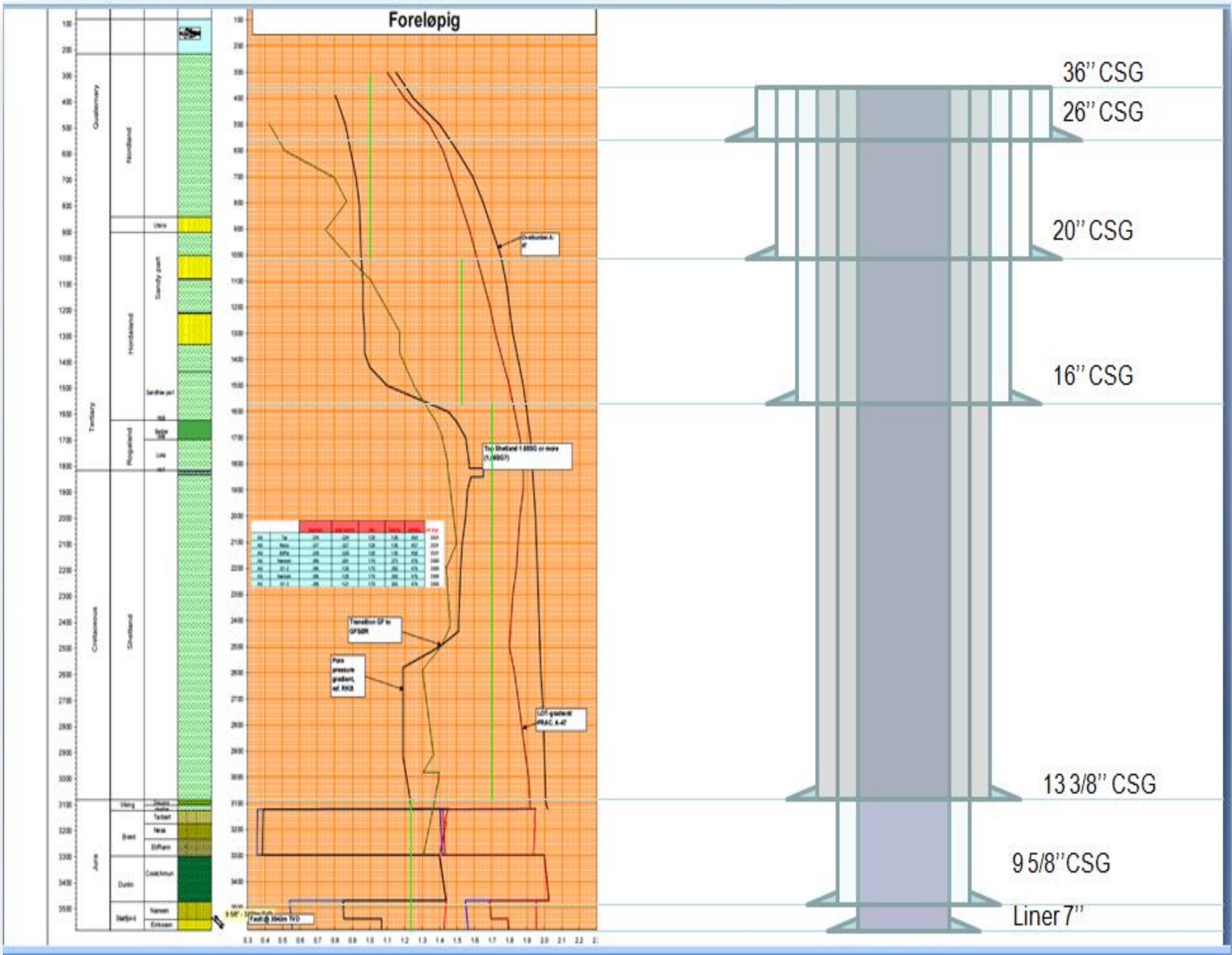


Figure 11 – The casing program.

5.5 New casing points in the well with vertical section at 163,52^0.

The figure 12, which is below, represents the new casing points in the section of a well at the azimuth of 163.52 degrees. This figure is important because it tries as much as possible to show the directionality and points of curvature in our well. This is important because for a successful casing design, the effect of bending has to be accurately defined and calculated so as to determine if a casing can withstand the total axial stresses that the casing will be subjected to, at the bend point.

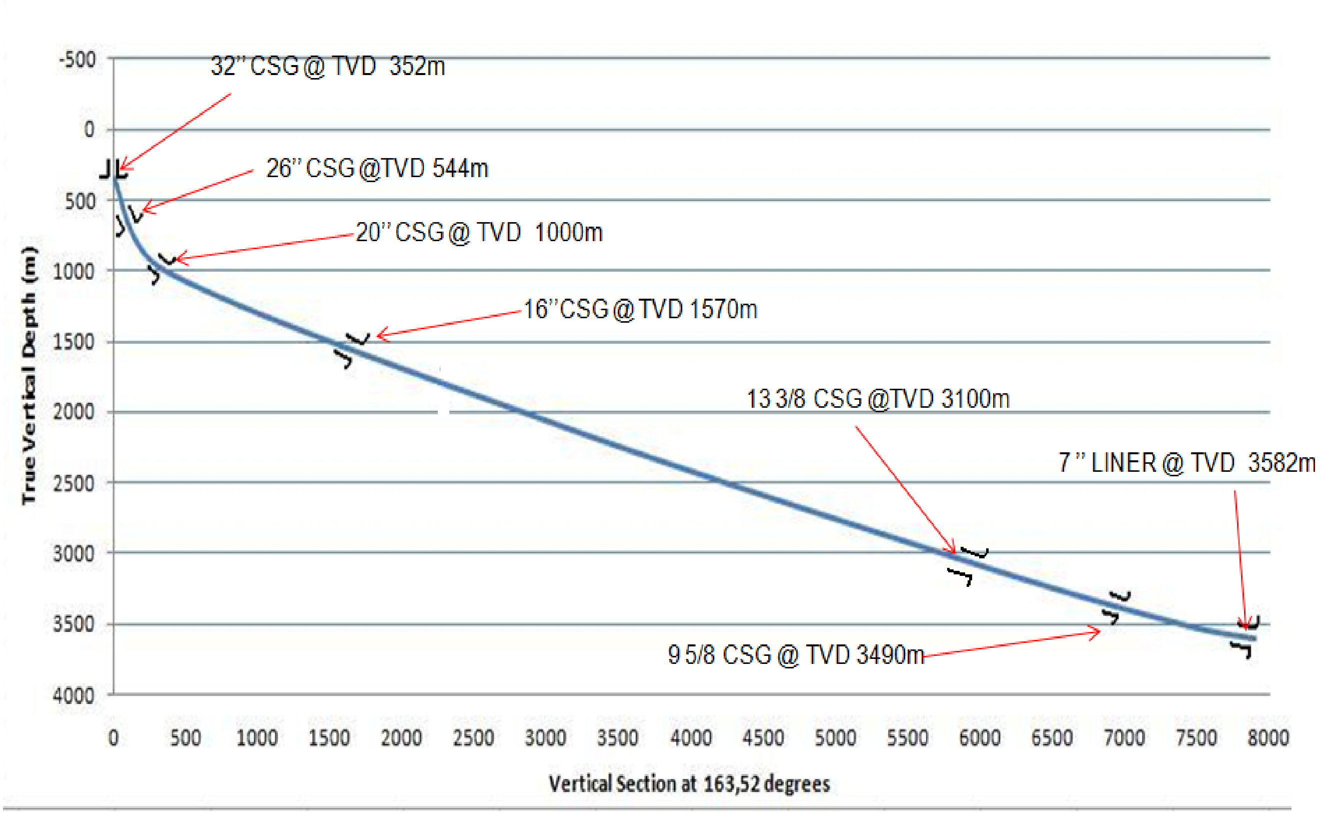


Figure 12 – Well design.

5.6 Effect of the bending on the 20 in. casing.

At the 20'' inch casing point, the effect of bending MUST be considered.

Because when a casing is forced to bend, the axial tension on the convex side of the bend increases greatly. It becomes necessary to calculate the maximum axial stresses acting on the casing joints. The curve representing a wellbore is shown on the figure 13.

It is determined by knowledge of the dogleg severity angle (change in angle, in degrees per 100ft of borehole length).

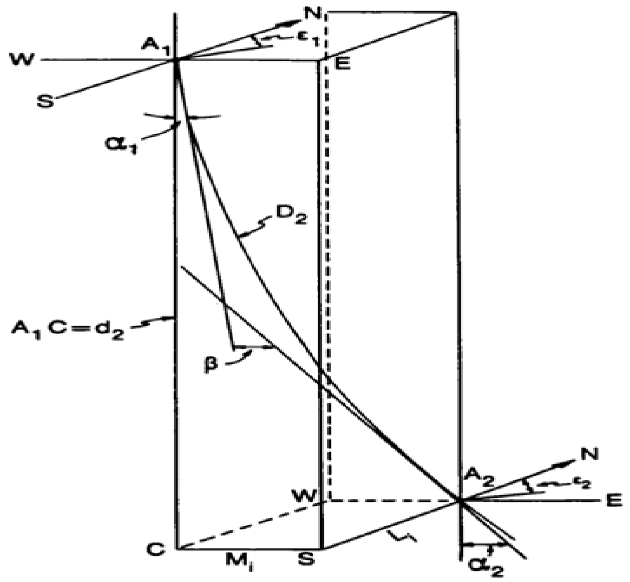


Fig. 8.22—A curve representing a wellbore between Survey Stations A_1 and A_2.

Figure 13 – A curve representing a wellbore between Survey Stations A_1 and A_2. [9]

To determine effect of bending we assume:
dogleg severity angle is 5 deg/100ft = β;
Then,
Weight of Casing = 94 lbf/ft
F_{ab}= Axial Tensile load = 601600 lbf
Nominal pipe body yield strength = 1077000 lbf
Nominal Joint strength = 581000 lbf
Internal diameter = 19.124 inches
Cross Sectional Area = $\pi/4\ (20^2 - 19.124^2)$ = 26.919 sq inches

5.6.1 CASE 1 (uniform contact between casing and borehole wall)

Axial stress without bending = 601600 / 26.919 = 22348.53psi
Additional stress level on convex side = $(\sigma_z)_{max} = 218 * (\beta) * d_n$ = 21800psi
Total stress in situation of uniform contact between casing and the borehole wall
= 22348.53 + 21800 = 44148psi < minimum yield strength of casing 55000psi

5.6.2 CASE 2 (contact between casing and borehole wall only at couplings)

I = Moment of Inertia of beam = $\pi/64 * (20^4 - 19.124^4)$ = 1288.39 inches^4
K = parameter for stress determination = $\sqrt{F_{ab}} / E*I$ = 0.00394
$(\sigma_z)_{max} = 218 * \beta * d_n * (6 * K * L) / \tanh(6 * K * L)$ = 27943.7 psi
Calculated maximum axial stress = 22348.53 + 27943.7= 50292.23 psi
50292.23psi < minimum yield strength of casing 55000psi. [9]

API casing performance properties attached in Appendix 1

6 Conclusion.

By taking into consideration all of the questions of the challenge, we concluded on the best way to solve those issues. MPD implementing is a new understanding of the drilling process, so it still has many uncertainties. We, as a group, have used all the knowledge to make the solution closer to the reality as much as it was possible. To do so, we have made some assumptions to perform calculations which were necessary to prove our method. On the other hand we were using the experience of oil companies to see a real picture of the method. This report could be considered as an advice which could give some fresh ideas into real situations.

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Appendix A

Casing

Water Density , ρw 1000 kg/m3
Acceleration Due to Gravity, g 9.81 m/s2

Type	OD	Weight		ID	Drift	Pressure acting	Height, H	Collapse Pressure	Collapse Pressure	Grade	Burst Strength	Collapse Resistance	Pipe Body yield	Yield Strength
		Nominal		Nominal	ID	on a casing in terms		of formation	of formation				strength	(Minimum)
Casing size	inches	lbm/ft	kg/m	inches	inches	of EMW	m	MPa	psi		psi	psi	1000 lbf	psi
20" Csg	20.000	94.0	139.89	19.124	18.936	0.96	1000	9418	1366	J-55	2108	520	1480	55000
16" Csg	16.000	65.0	96.73	15.250	15.062	1.280	1570	19714	2859	H-40	1641	630	736	40000
13 3/8" Csg	13.375	48.0	71.43	12.715	12.559	1.650	1850	29945	4343	H-40	1727	740	541	40000
9 5/8" Csg	9.625	36.0	53.57	8.921	8.765	1.43	3490	48959	7101	H-40	2560	1720	365	40000
7" liner	7.000	20.0	29.76	6.456	6.331	1.08	3582	37951	5504	H-40	2720	1970	196	40000

Equivalent circulation Density	Back Pressure
0.031	0.033
0.085	