Gullfaks Village 2011

Part A – Group 5

1 Introduction

The main purpose of this part is to demonstrate and get an understanding of the challenges related to production with pressure depletion and aquifer support. The task is to match the measured data with calculated data using the material balance equation, and then calculate the recovery factor in the Beta ridge. To do this the data provided is gathered in Microsoft Excel and the pressure versus time is analyzed.

To do the material balance for the Beta ridge some assumptions have been done. The most significant one is that it is assumed full communication within the whole area and therefore it can be seen as one field. This means that the production and injection for the wells is summarized. In 1986 the initial pressure was given to be approximately 380 bar and the total compressibility was $9{\cdot}10^{-5}$. To avoid a negative pressure we had to assume an immense pore volume, between, 5-10 billion Sm^3, therefore an initial approximation of 7 billion Sm^3 was selected after analyzing the data.

After doing the calculations and the material balance a sensitivity analysis is done by changing the uncertainty factors separately. For example what will be the effects of decreasing the compressibility or by changing the pore volume of the field.

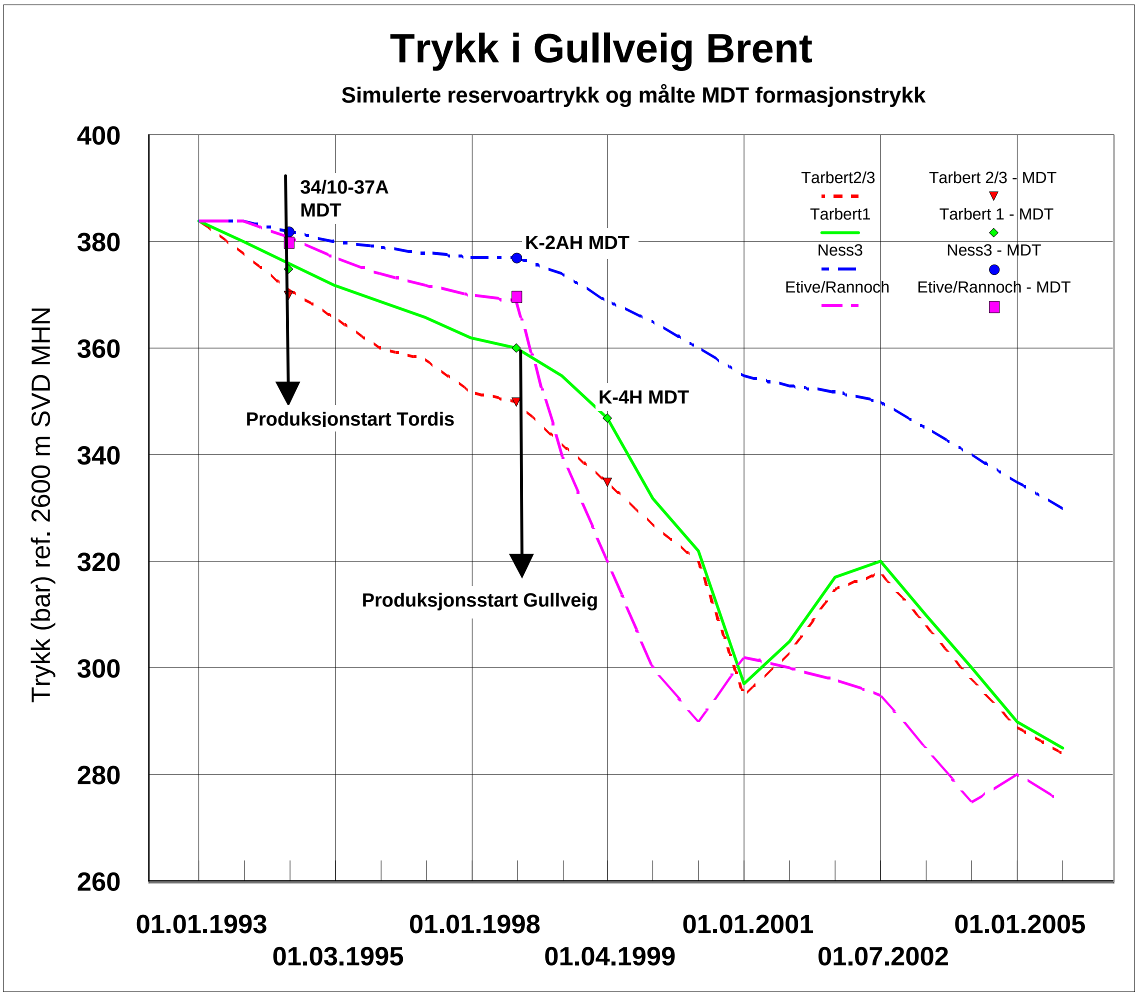

Figure 1: Original given graph

2 Material balance

The material balance in this case is a very simple calculation. The calculated ΔV, the assumed pore volume and compressibility is used to calculate the pressure drop:

$$\Delta V = V \cdot c \cdot \Delta P \Rightarrow \Delta P = \frac{\Delta V}{V \cdot c}$$

3 Pressure drop

Plot when the pressure drop is calculated and subtracted from the initial pressure:

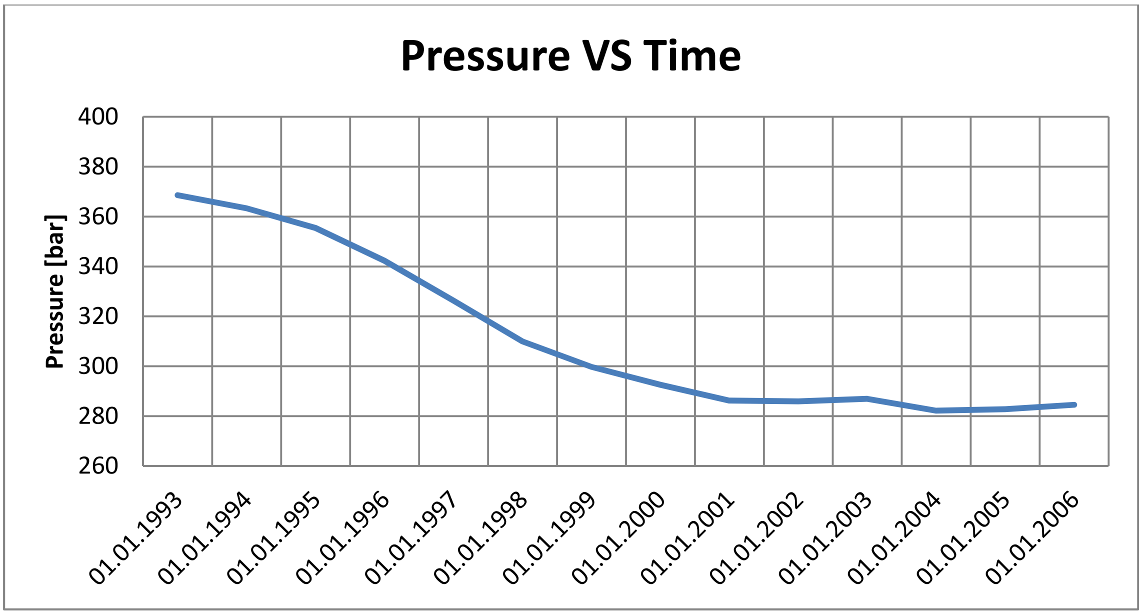

Figure 2: Pressure VS Time

The graph illustrates that there is a small pressure drop in the beginning. This is possibly due to a careful production the first few years. This is further implied when the pressure drop became more considerable in 1994 when the Tordis production well was introduced, and the introduction of Vigdis and Gullveig in 1996 and 1997. After all the production wells were introduced the pressure drop started to stabilize, and around year 2000 an increase in the pressure appeared. This was mainly because that all the injection wells started their injection just before year 2000.

When comparing the new graph to the given, the same tendencies are revealed from 1993-2001. Compared to the given graph the new graph is a bit flatter the first couple of years, but the pressure drop during the first 8 years is equal. The curve lies about 10bar below the simulated. This could imply that there either is a pressure increase before 1993 or that the assumed initial pressure is too low.

From 2001 until July 2003 there is a significant pressure increase due to an increase in injection rate in the simulated graph. The reason for the more dramatic increase in the simulated is possibly due to it is one well that will be more sensitive to an injection in that area compared to the calculated which sees the Beta Ridge as one field. This could imply that there is not full communication in the whole Beta Ridge, as then the tendencies should be the same in the whole area.

4 Look to the past

Plotting the period before 1993 confirms there is no tendency of a period with pressure increase:

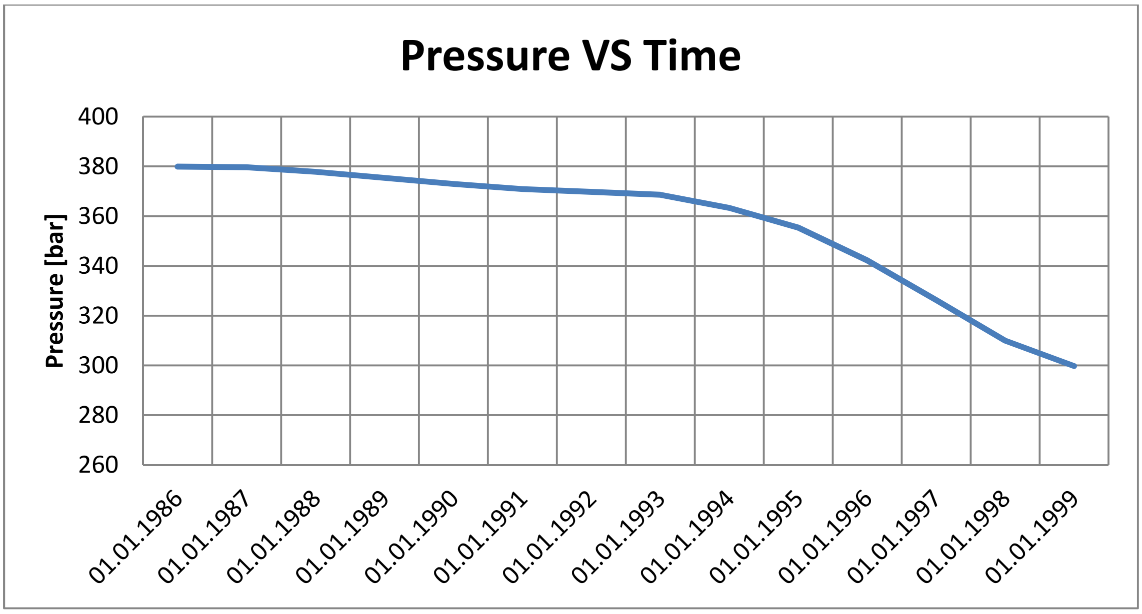

Figure 3: Before 1993

5 Increase of bar

By increase the initial value to 390 bar the values of the simulated fits better the given plot. This could either indicate that the assumed initial pressure is too low or that the properties in this area deviate some from the general area. As mentioned this indicates that there probably is not full communication in the whole Beta Ridge.

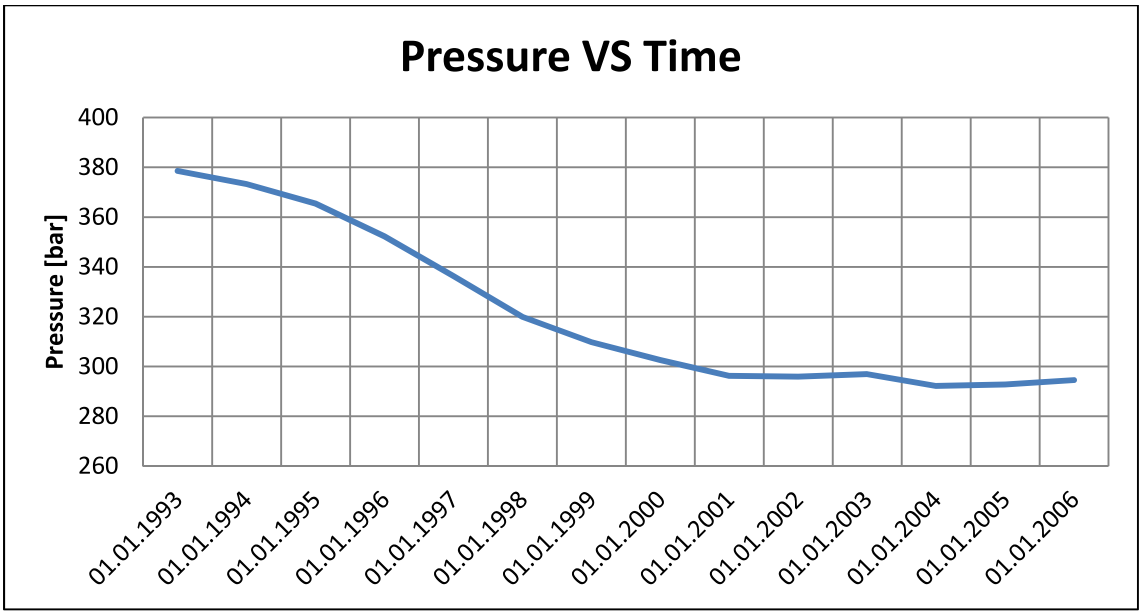

Figure 4: Bar increased to 390

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6 Different pore volumes

The effect of changing the volume:

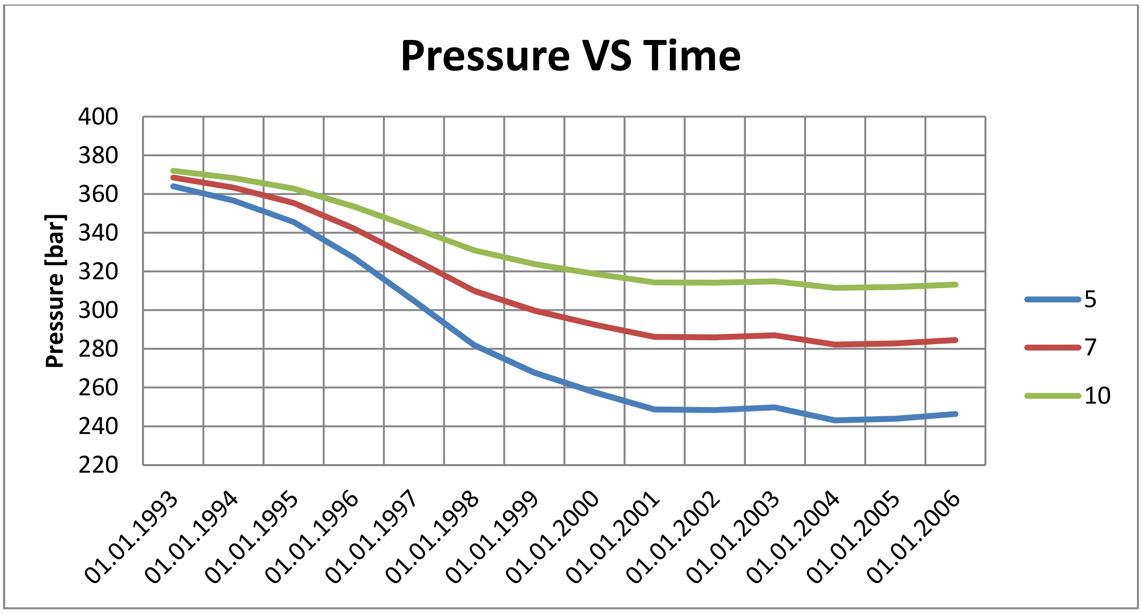

Figure 5: Volume of $5 \cdot 10^9$ Sm^3, $7 \cdot 10^9$ Sm^3 and $10 \cdot 10^9$ Sm^3,

By changing the pore volume the pressure drop is effected which the equation demonstrates as well. It relies linearly on the volume:

$$\Delta V = V \cdot c \cdot \Delta P \Rightarrow \Delta P = \frac{\Delta V}{V \cdot c}$$

7 Changing the compressibility

Checking for the effects from changing the compressibility we see that we get the same effect as for the volume. As we can see the pressure drop is linearly dependent on the compressibility as it is for the volume.

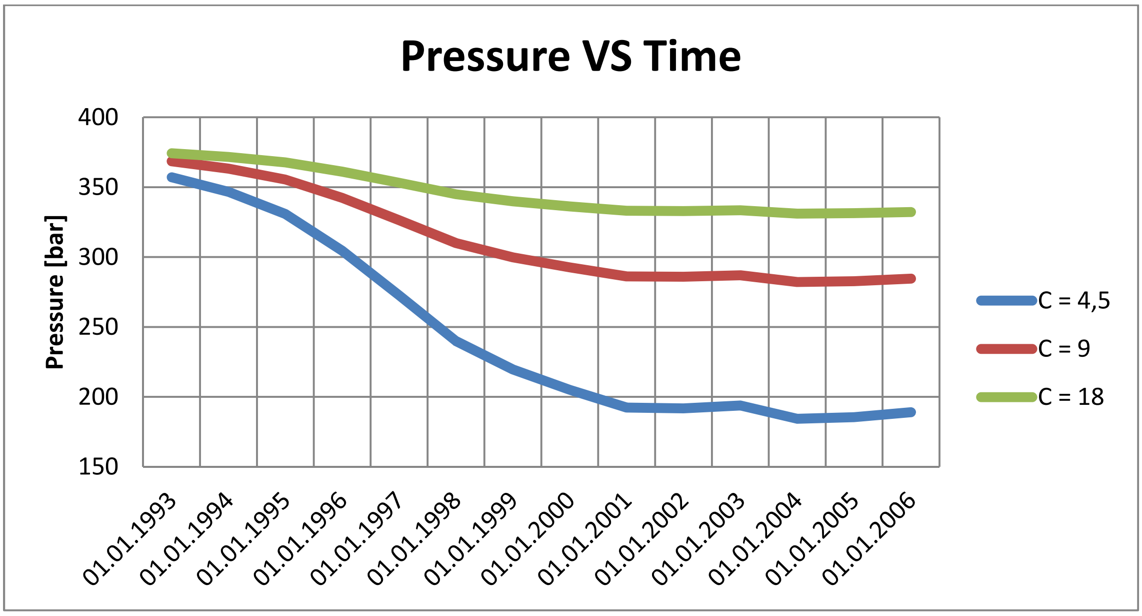

Figure 6: Compressibility of $4{,}5 \cdot 10^{-5}$ bar^{-1}, $9 \cdot 10^{-5}$ bar^{-1} and $18 \cdot 10^{-5}$ bar^{-1}

8 Conclusion point 2 & 3

Similar pressure drop in the calculated and the simulated, but the calculated lies somewhat lower on the curve. This is possible due to a higher initial pressure in the well A-32 than we were given for the Beta Ridge. The deviation after 2001 might be caused by the lack of communication compared to our assumption of full communication. Full communication should give the same tendency over the whole field and not just in the area close to the injection zone.

9 Point 4. Possible interference within the fields and estimation of the recovery factors.

To find out if the fields interfere with each other, we both plotted the cumulative production/injection rates versus time and the average yearly production/injection rate versus time.

By first looking at graphs of the average yearly production and injection rates, we clearly see some communication between the different fields. Especially the fields that are located close to each other seem to interfere, both during production and injection.

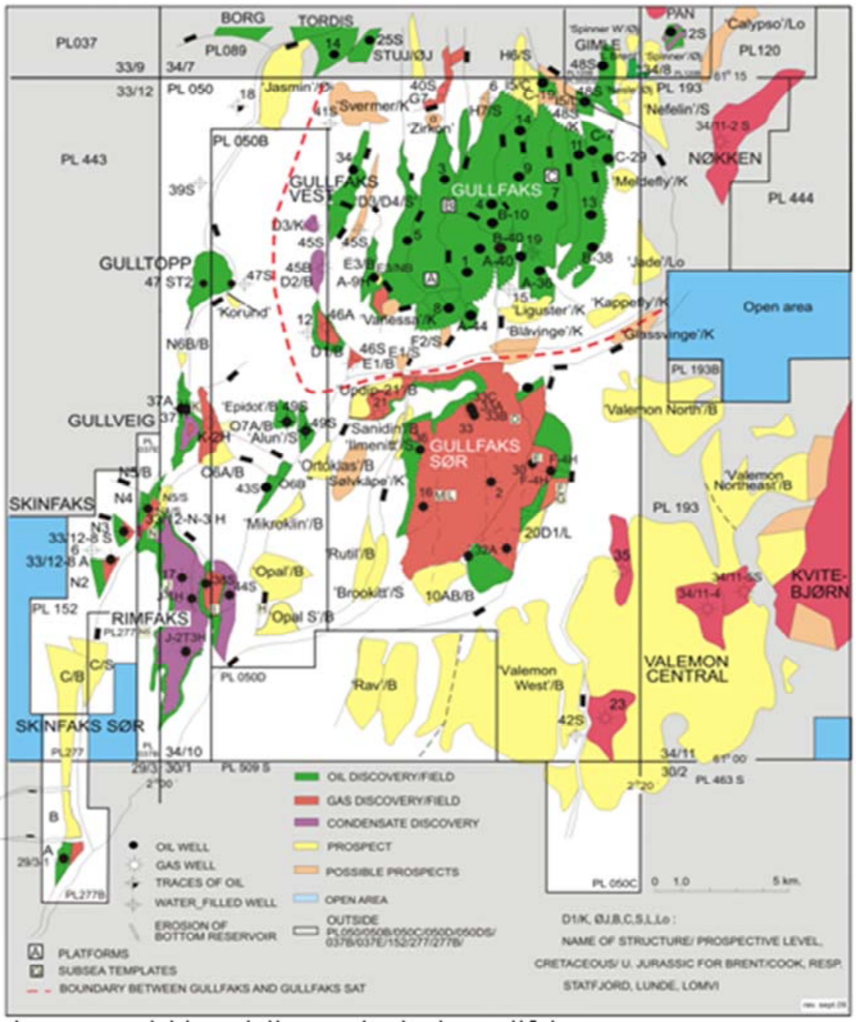

Figure 7: Gullfaks overview. Beta Ridge is located to the west.

Tordis vs Vigdis:

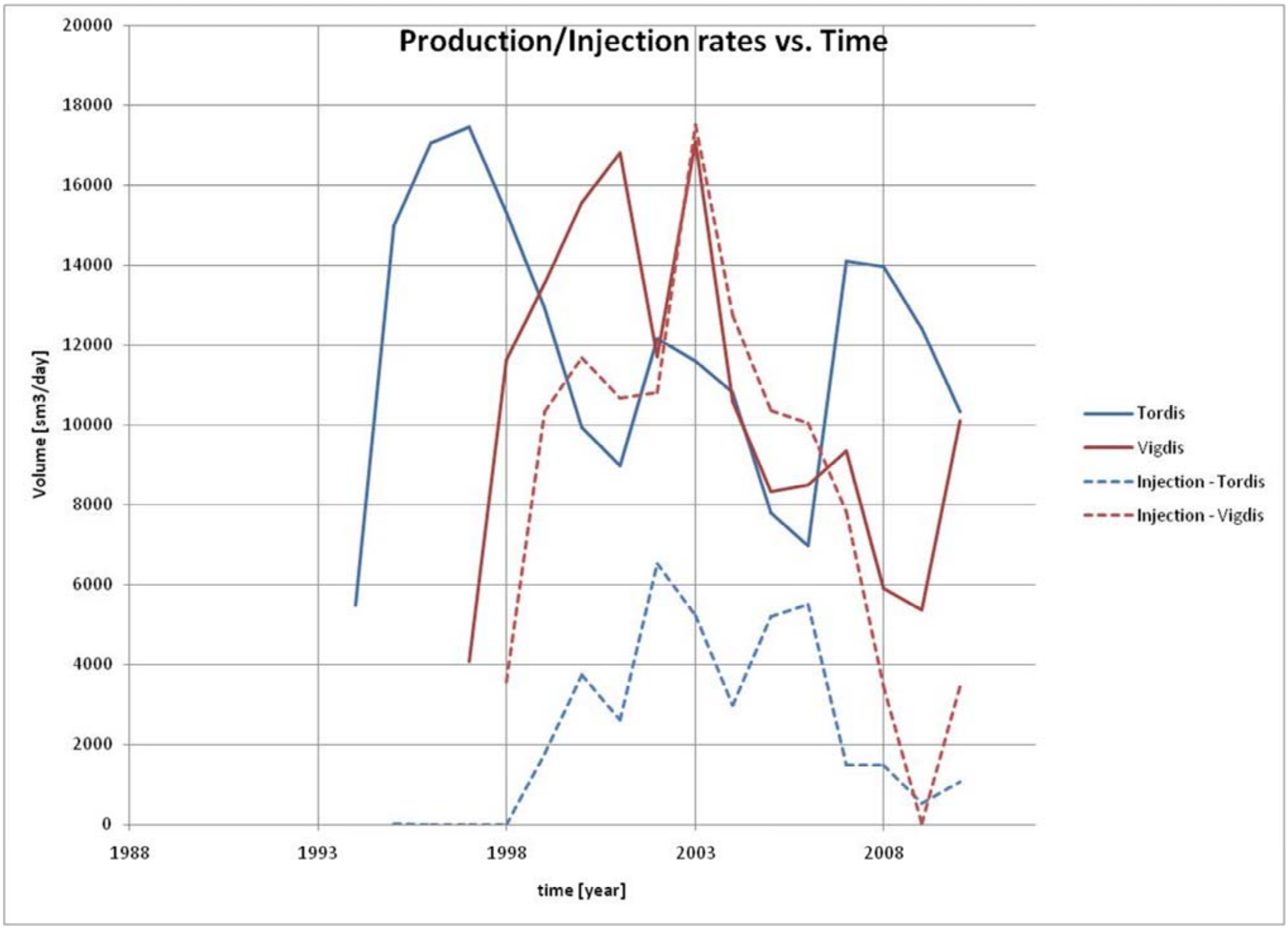

Figure 8: Tordis/Vigdis production and injection rates.

In the northern part of the ridge, Tordis and Vigdis are located. From the graphs we can see that the production rate of the Tordis field decreases once the Vigdis field starts producing in 1997. This happens before any injection has been initiated, and could be an indication that the fields are interfering with each other. Also around year 2006 there is a possible sign of interference between the two fields. The production from the Vigdis field gets a sudden increase while the injection in Vigdis still is decreasing. On the other hand, there is an increase in the injection rate in the Tordis field around the same time period. It might therefore be reasonable to assume that this increase might have lead to the sudden increase in the production in the Vigdis field.

Gullveig vs Gullfaks Vest:

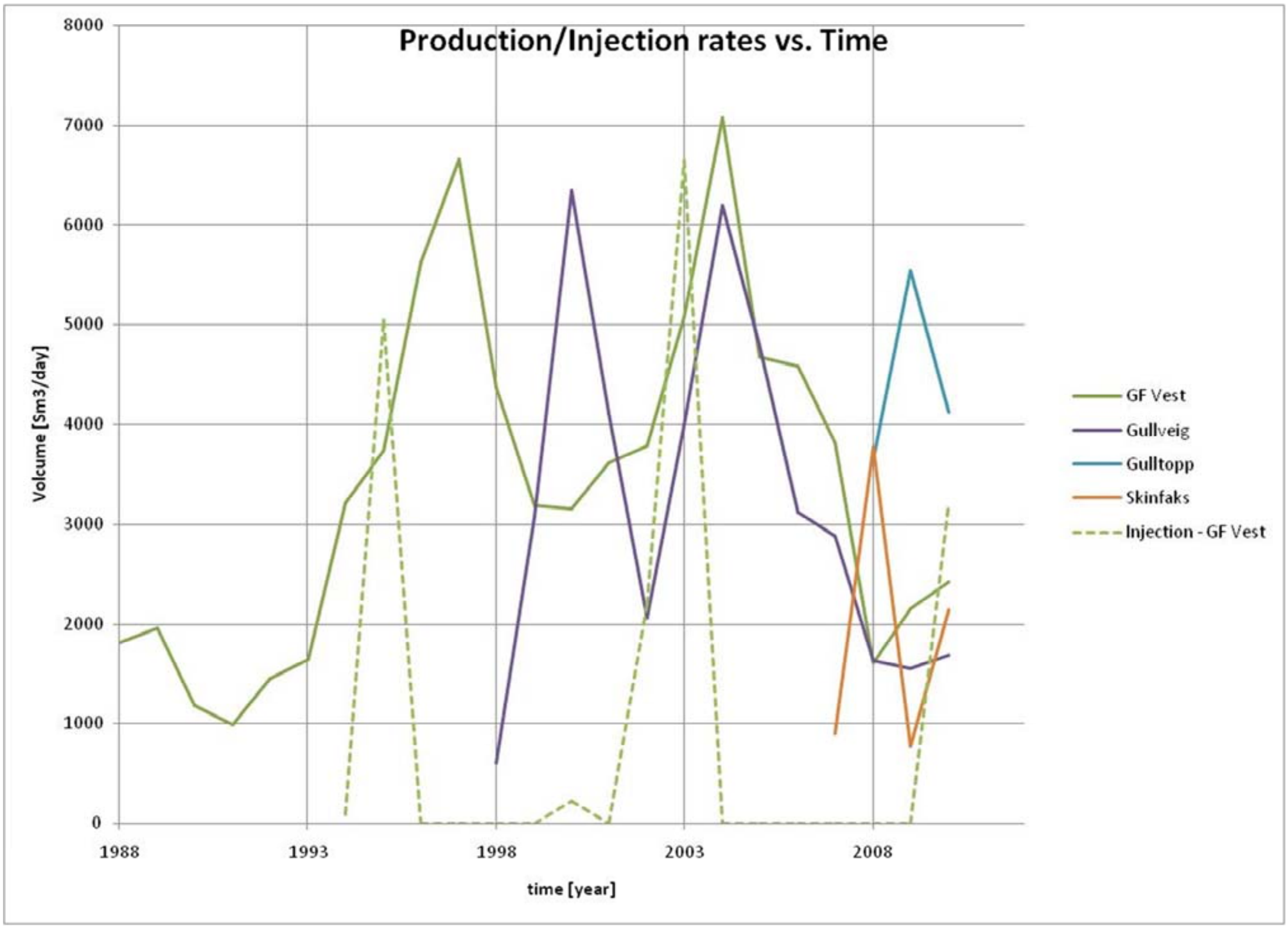

Figure 9: Gullveig/Gullfaks Vest production and injection rates.

We can also see indication of interference between the Gullfaks Vest and Gullveig fields. Around year 2001 injection is initiated in the Gullfaks Vest field, and from the plotted data we can see that the production rates of both the Gullveig and Gullfaks Vest fields are increasing with approximately the same amount.

When we make an estimate for the recovery factor we must state some assumptions because of the lack of information. First of all we have to assume the volume of oil in the reservoir, initial oil in place (IOIP). From the reservoir management plan we find that $80*10^6$ Sm^3 is a reasonable assumption for the volume of oil at production start. Our numbers includes oil, water and gas which mean that we have to assume how much of the production actually is oil. In the beginning for each production well we can assume that all that is produced is oil, but sooner or later we get water break-through due to the water drive which maintains the pressure in the wells. The water cut will also increase. It might only be 10-20 % in the first phase, but in the late life of the well the water-cut could be 80-90 % which would affect our results when calculating the recovery factor.

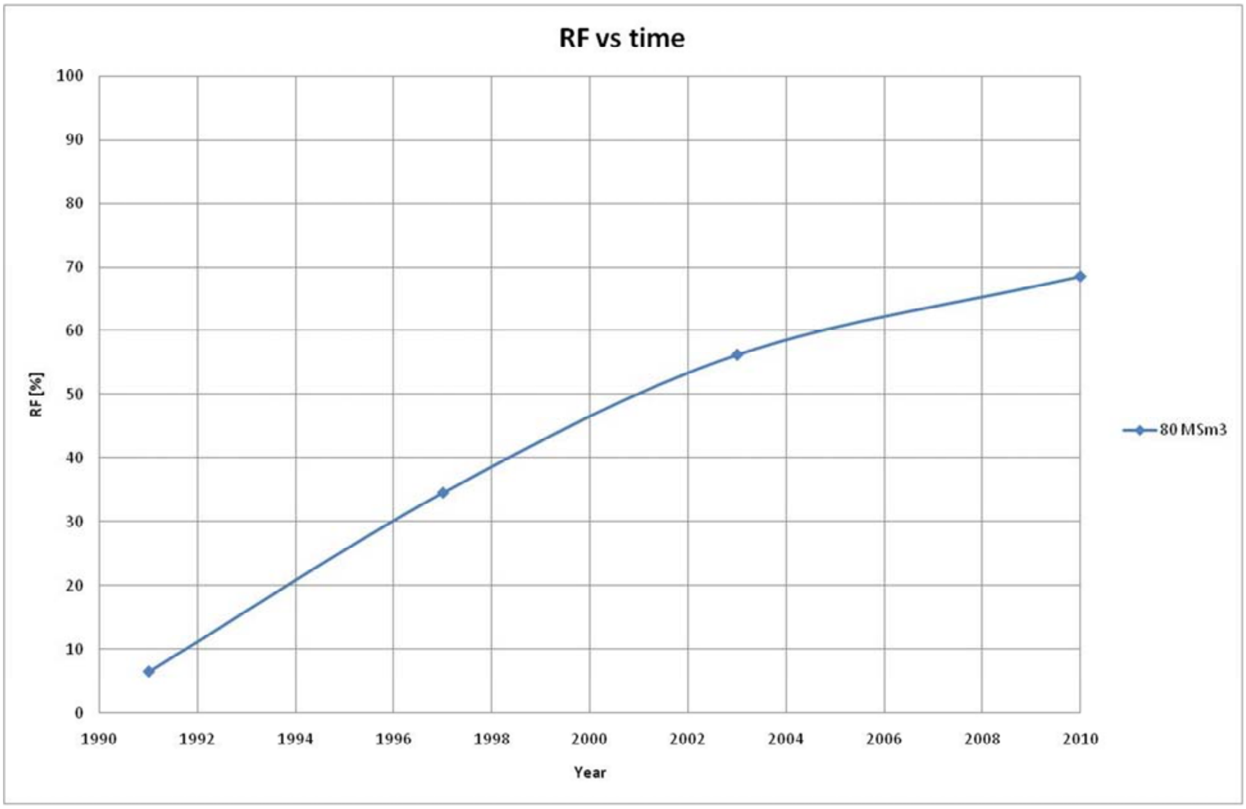

Figure 10: Estimated recovery factor 2010.

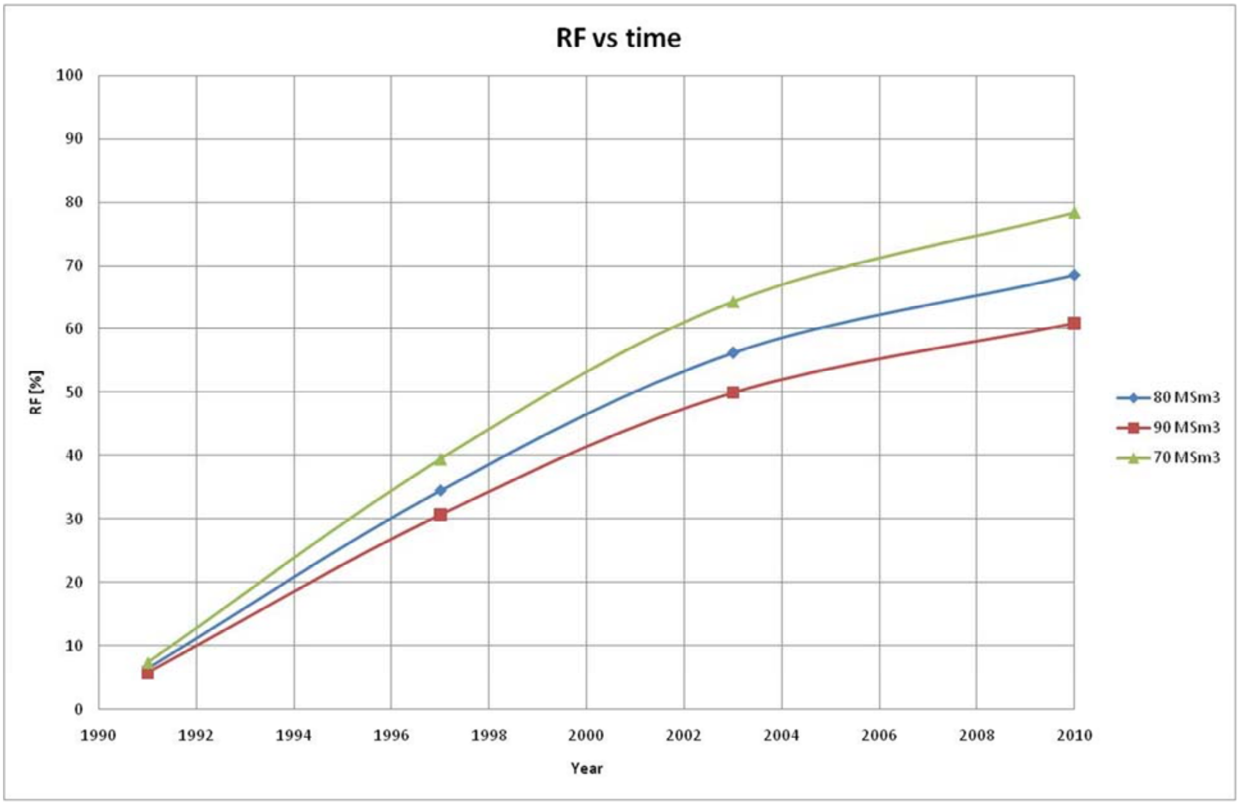

Figure 11: Effect of IOIP on the recovery factor.

We can also analyze the approximated recovery factor based on different assumed IOIP. Increasing or decreasing the assumed initial volume of oil affects the recovery factor quite significantly as recovery factor is defined as cumulative production over IOIP.

Expected recovery factor will be somewhat higher than it is today but it will not increase significantly compared to earlier years. This is because of increasing water-cut and decreasing volume of oil produced in the future. Graphically this means that the inclination of the curve will get close to zero.

10 Conclusion Point 4

As we saw there probably is communication between the different reservoirs, at least between those that lies close to each other. This was seen as injection in one field may also affect the production in a nearby field which does not have any injection. When it comes to the recovery factor we have to make some assumptions. This is due to the lack of data of IOIP and that our production data is given as a total of water, oil and gas. By assuming an initial volume of oil and a growing water-cut in the production, we get a reasonable estimation for the recovery of the fields. We assume that the recovery factor is identical in the different reservoirs but this is not the case in reality. Because of the complexity of the reservoir, the properties are different in the different regions of the field. This means that the geology varies through the Beta Ridge and our calculation is a major simplification.