TPG4851 EIT-GULLFAKS VILLAGE 2013

How to extract 10% more oil from the Gullfaks Field?

Group V

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Abstract

The Gullfaks Village 2013 has a focus on IOR on the Gullfaks South subsea development that came into production in 1999. Today the field is in the tail-end of its oil production phase, but with significant amount of gas condensate to be produced during the next 20 years.
With the natural flow, the minimum field economical rate of $2*10^6$ Sm3/d will be reached in 2029 with a total recovery factor of 58%.

Statoil plans to boost this recovery by introducing subsea gas compression. We have found that two subsea compressor systems are sufficient for the production requirement. They can prolong the plateau production by 2.5 years and increased the recovery factor to 75%. A low pressure modification improves the recovery further up to 80%.

Sensitivity analysis has also been performed. Some parameters such as 10% decrease of the oil and gas price, 10% more downtime and shutting down two wells from the L template have significant effects on the cumulative net present value (CNPV).

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Preface

This is the technical report for Group 5 in TPG4851 - Experts in Team, Gullfaks Village, Spring 2013. EiT is a compulsory course for all students in Master's studies at NTNU. Experts in Team was established by NTNU in 2001 because the industry expressed a wish that students should learn to work in multidisciplinary teams. Gullfaks Village was among the first villages – created in collaboration with Statoil. EiT offers several villages for students with different topics, and the students can choose between them. Every year students with different backgrounds work together in groups. At the end of the course the groups have to deliver technical and process reports that their grades will be based on. Some of the objectives of EiT are to encourage students to apply their academic learning to real world problems and to develop teamwork skills.

The main objective of this technical report is to investigate and give recommendations for the installation of subsea compressors that could increase gas recovery by 10% from the L and M templates in the Gullfaks Sør segment that is part of Gullfaks Satellite fields. The report consists of 2 parts: Part A that had to be done by all groups and Part B in which every group chose their own task. In part A, reference cases for the wells in the L and M templates was made for natural flow and with the subsea compressor. In part B, we selected some IOR-challenges. We worked on optimizing production management and sensitivity analysis for the subsea compressor. We also considered a low pressure modification.

All the group members have tried to fulfill their responsibilities in the best way in order to reach the group's goal.

The group would like to thank the following (but not limited to) people for their guidance. The village supervisors: Professor Jon Kleppe and Jan Ivar Jensen, professor Michael Golan and his Ph.D. students, EIT learning assistants Simon Brasøy Fjeldvær, Henninge Torp Bie and the Statoil project supervisors: Petter Eltvik , Hallstein Ånes, Roger Oen Jensen.

Introduction Gullfaks

The field - Gullfaks South

Field history

Gullfaks South was discovered in 1978, and production started in 1986. It is located in the northern part of the North Sea, approximately 175 km northwest of Bergen. Gullfaks South is situated in the blocks 34/10 and 33/12, just a bit south of the main field 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 South is done by eleven subsea templates, that are connected to the platforms Gullfaks A and C through the Gullfaks South 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 in 2008, the total oil volume in Gullfaks South is 39.3 MSm^3 and 2.9 MSm^3 condensate. The total gas volume is 1.25 GSm^3 and the water volume is 175.1 MSm^3. The information also state that the Gullfaks South field had produced 3.3 MSm^3 of oil/condensate and 2.0 GSm3 gas. Since September 2008, the oil in the field has been shut in due to low pressure.

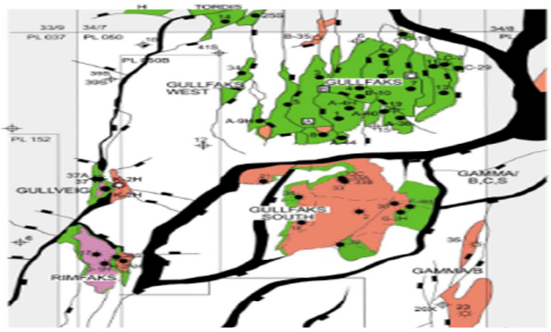


Figure 1: The Gullfaks main field

Geology and reservoir

The Gullfaks field is among the oldest oil fields on the Norwegian continental shelf. The field consist two structural compartments, the western and eastern, and contain most complex fault patterns that intersect and divide the field into small fault blocks (Ole Peterson, 1992)

The Gullfaks reservoir mainly occurs at 2400-3400 m below sea level and consists of rotated fault blocks of sandstone. These include the Brent group (middle Jurassic), and the Cook, Statfjord and Lunde formations (lower Jurassic to upper Triassic). Brent, Cook and Lunde have good reservoir qualities compared with Statfjord, which has poor permeability.

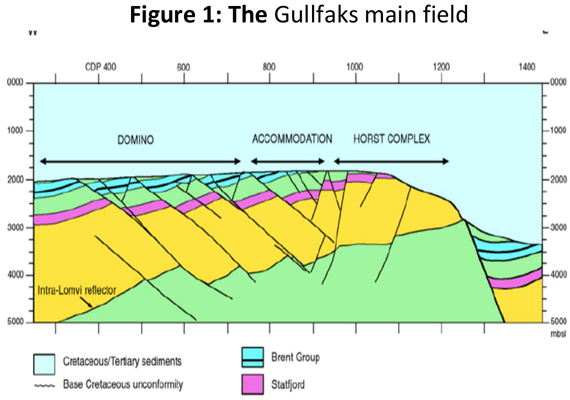


Figure 2: Gullfaks. Horizons, fault structure.

Recovery strategy

Recovery from the Brent reservoir in Gullfaks South is driven by pressure depletion after gas injection ceased in 2009. The Brent reservoir in Rimfaks is produced by full pressure maintenance by gas injection, whereas the Statfjord Formation has partial pressure support from gas injection. The Gullveig and Gulltopp deposits are recovered by pressure depletion and natural aquifer drive.

PART A: Natural flow and subsea compressor

1 Introduction Part A

The two reservoir units in Gullfaks South field are producing as two independent subsea fields (Template L and M) but with joint production pipelines to the Gullfaks C platform.
The two fields have been producing oil and gas since 1999 but entered a new production mode in 2009. According to the new production scheme, the two fields will produce liquid rich gas where the liquid comes from gas condensate (Template M) and from mobile liquid oil in the bottom of the reservoir of the other field (Template L).

The objective of the part A is to predict the productions for the two templates L & M with and without subsea compressor and see the improvements that we get. A preliminary study will be conducted to assess the length of the production plateau and the impact of introducing subsea compression.

For this study, considerable simplification assumptions have been made. It is assumed that the gas is a dry gas, that its depletion and recovery characteristics can be modeled by reservoir tank model, and that the flow in the wells and the pipeline can be represented by isothermal flow equations

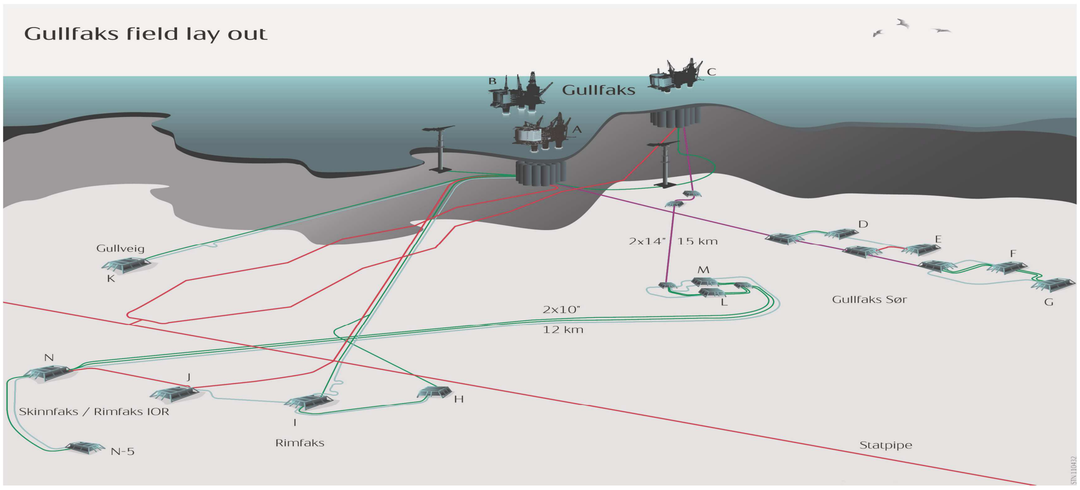


Figure 3: Overview of the Gullfaks field

Illustration: Statoil

2 Natural flow production

2.1 Description of the calculation

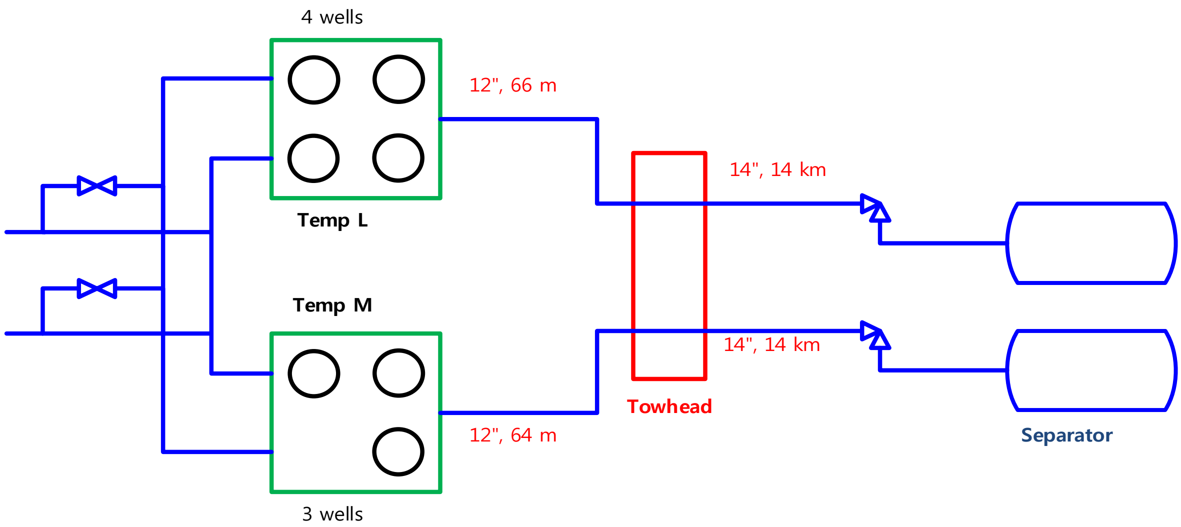


Figure 4: The production piping layout for the natural flow

We start the production at the 31st of December 2008 with a total plateau rate of 10 MSm^3/d, as this is the time we have information about such things as the GIIP.

An excel spreadsheet was developed in order to calculate the plateau length of the field for the natural flow without using the subsea compressors and also study the evolution of the rate in templates L and M until it reached the field minimum economical rate of 2 MSm^3/d.

The rate is controlled by using one of the two possible chokes. We can either do it from the chokes in the Christmas trees at the templates or the ones located at the Gullfaks C platform. The latter choke position is the one that has been used in most of this report. In both cases the production streams from the two templates are separate all the way to the platform. There is no manifold in the towhead (shown in **Figure 4**).

We have made the calculations of the plateau length production for both cases to see if there is any effect of the choke position in the production rate.

The input data for the two gas field L and M are listed in the appendix of this report.

2.2 Results

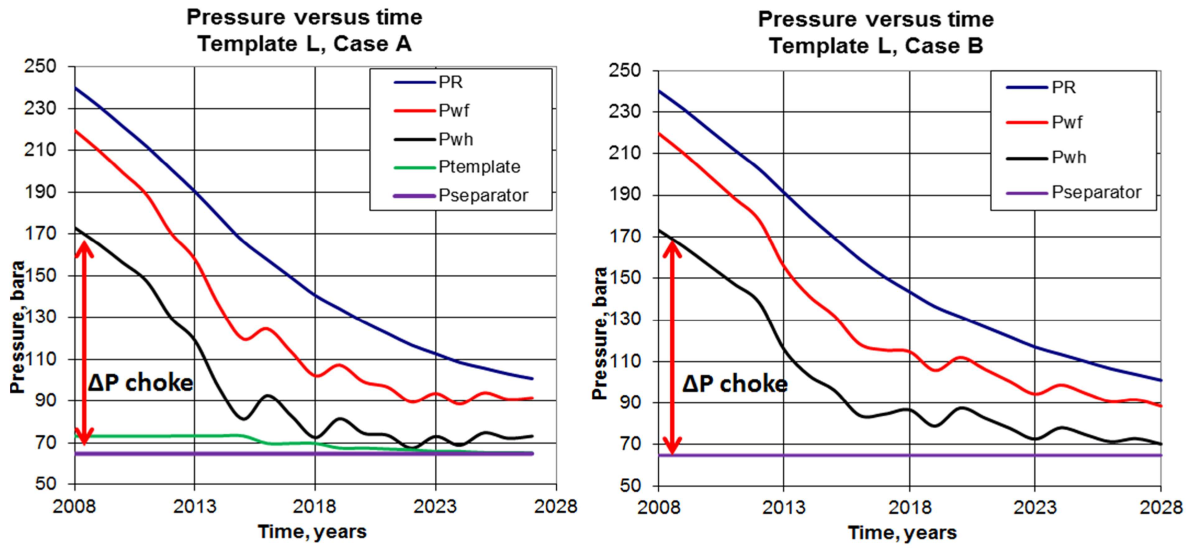


Figure 5: The pressure drop for the two different positions of the choke

The results regarding the natural plateau length and the decrease of the rate are very close for the two choke positions – and they result in virtually the same recovery – 58%. The difference between the two cases (Choke at the Christmas tree versus at the platform) is mostly limited to the fact that the pressure drop in the choke is located in two different positions, as we can see above. The minimum field economical rate of 2 MSm^3/d will be reached at the end of 2028. **Figure** 6 illustrates the evolution of the total production rate and the rate of template L and M.

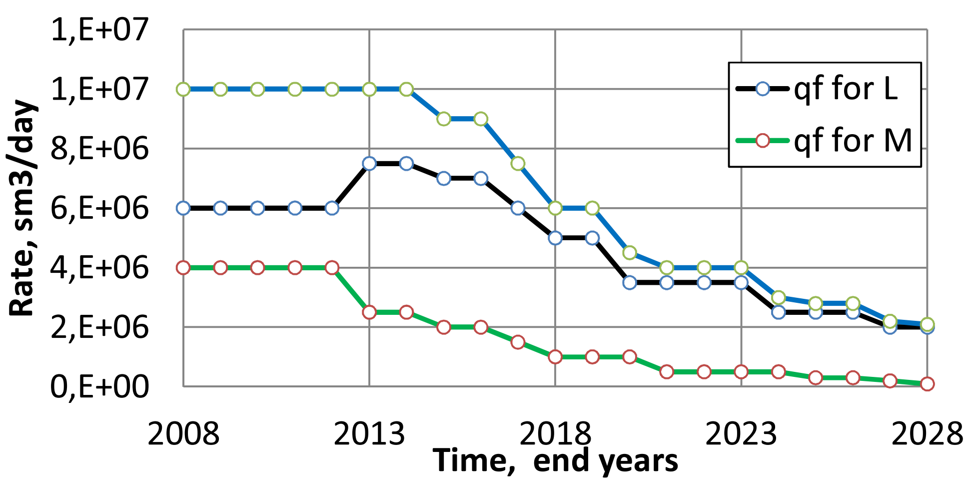


Figure 6: Gas production rate versus time for the natural flow

The rates of template L and M are set initially to 6 MSm^3/d and 4 MSm^3/d, respectively. With these values we could keep the natural plateau rate of 10 MSm^3/d up to 2012.

However it's possible to prolong the natural plateau for 2 more years by varying the rate of template L and M with the choke. After 2015 the total field rate starts to decrease until it reached the minimum field economical rate of 2 MSm^3/d in the end of 2028. Note that in the plots the time is the end of the year.

3 Subsea compressor

Because companies want to find and develop oil and gas in more remote, deep and harsh locations or in more challenging reservoirs , they have to find a new ways of doing it or to improve technologies to overcome harsh conditions . Therefore, in Gullfaks South, Statoil will install two subsea wet gas compressors. In addition, by using wet gas compressor we are making our work easier, because as opposed to a dry gas compressor one does not have to separate the oil and gas and then mix it again. The compressor is the main part of Gullfaks 2013 project. The purpose of the wet gas compressor is to compress oil and gas and pressurize the flow. The installation and compressor itself is very expensive. Every little improvement on the compressor we can make is important and we can get more income from it. Much of the information in this section is from the Framo/Statoil paper on the compressor, listed in the references.

3.1 Construction

Our subsea wet gas compressor is called WGC4000, is made by Framo Engineering, and it is a centrifugal compressor. Centrifugal compressor packages utilized for upstream gas processing often must operate under wet gas conditions in which the fluid handled by the compression package contains a mixture of liquid and gaseous phases. This compressor is very heavy, large and requires a large amount of floor space as compared to a dry gas compressor. It has 10+11 stages that make the compressor very powerful. Below are some figures which show cross sections of a similar compressor and the fluid flow inside of it.

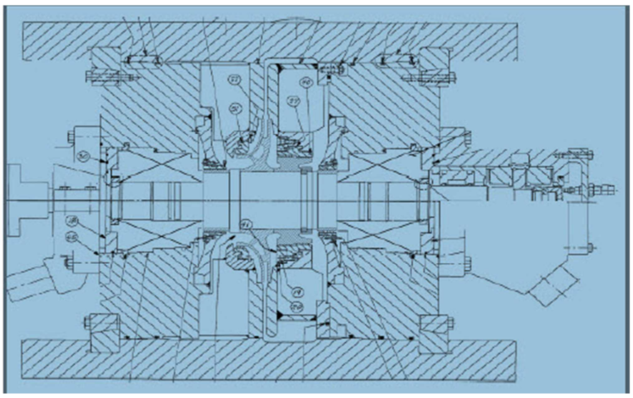


Figure 7: Fluid flow in a cross section of the compressor

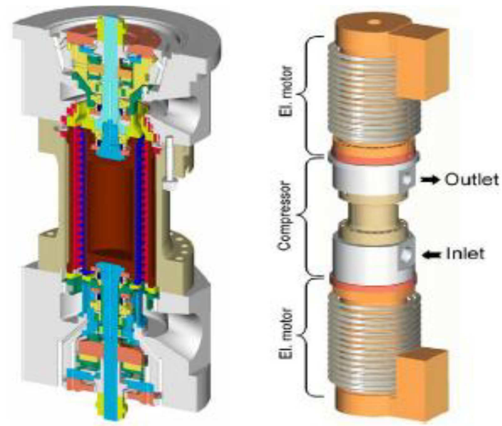


Figure 8: Cross section of the compressor

In Gullfaks South for the template L and M we need 2 compressors; plus, at least 2 coolers for improving efficiency and avoiding hydrate generation. The compressors are put in a layout such that they can be operated in four different modes:

1. Bypass mode. Framo engineers say that they have it, but it will not be used during production.
2. Single compressor mode. This can be used if the production rate is low.
3. Parallel production mode .The mode usually will be used on high flow rate, at the beginning of production.
4. Series production mode. This mode will be used on high pressure head and towards the end of production.

Under specific conditions these we can change the mode in order to improve the efficiency of the compressors, or to ensure that they can operate. Some limitations and properties of the compressor are listed below:

Table 1: Limitations of the WGC4000

Parameters	Limitation
Max Discharge pressure	120 bara
Max Suction pressure	80 bara
Min Suction temperature	35^{o} C
Max Discharge temperature	110^{o} C
Max flow rate (Q)	4,140 m^3/h
DP	32 bara
Polytropic efficiency	0,84 (max)
RPM	1200-4500

3.1.1 Gullfaks subsea wet gas compression system

The Gullfaks subsea compressor system is planned to be located in the vicinity of the L and M templates on Gullfaks Satellite Phase-2, and will facilitate compression of gas from the L, M, N (N5) templates. The wet gas compression system includes all process, WGC4000's coolers, flow mixer, instrumentation and control equipment required for safe and efficient operation of the subsea wet gas compression system.

Figure 9: Subsea Coolers

3.1.2 Subsea gas cooler's function in the system

- Gas compression during normal production without exceeding the temperature limitations on the system outlet.

- Startup of the compressors without overheating before routing the production through the compressors.
- Operating at low production rate requiring a large degree of re-circulating without exceeding the temperature limitations on the system outlet
- Starting up one compressor without overheating while the other compressor is running.
- Stopping one compressor without overheating while the other compressor is running.

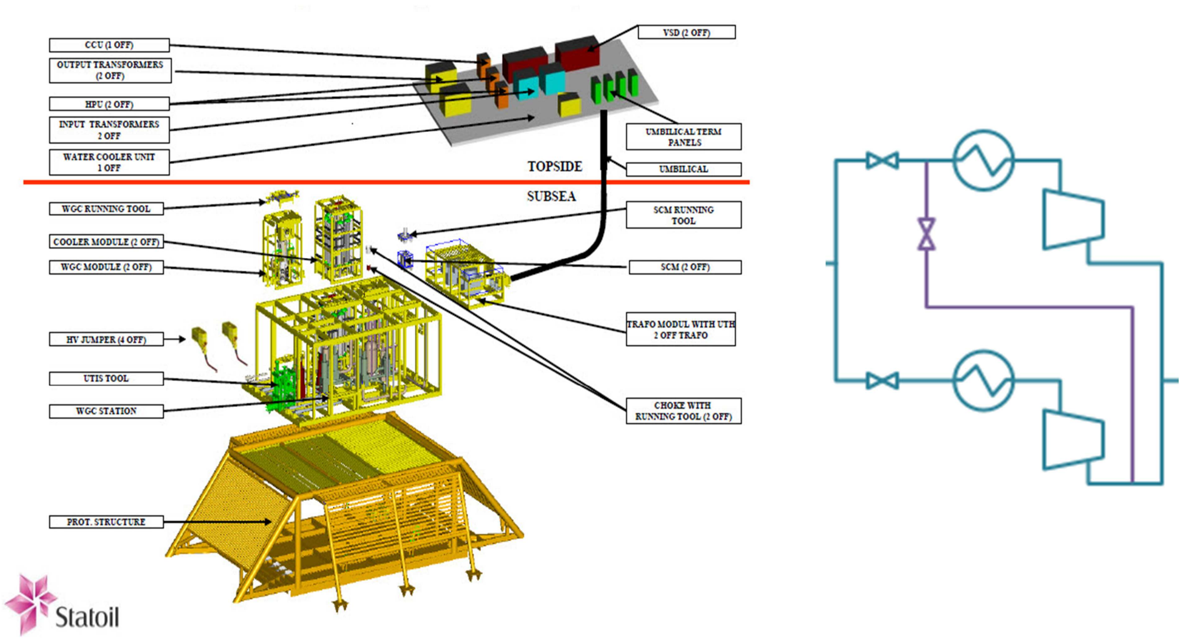


Figure 10: Gullfaks subsea gas compression system

3.1.3 System and its control

After the templates L and M we have two subsea compressors. Before the compressors there are 2 coolers. The compressors could be in either parallel or in series, as mentioned in more detail above. There is a test line, valves and chokes that can change the mode of operation from parallel to series. It is shown in purple on the scheme. With the test line we can also recirculate the flow. All the systems are controlled by different modules.

3.2 Compression stage production

In this part, we conducted a subsea compression study starting from the end of the natural flow plateau. The compression is arranged in two consecutive stages. In both of them, the chokes that are used are fully open (in practice this means that the chokes are not used to control the production). The Excel sheet from part A was extended to be used also here.

In stage A: The field production rate is maintained constant with declining compressor suction pressure and increasing pressure difference over the compressor. We do this calculation until the pressure increment reaches 32 bara.

In stage B: The pressure increment is maintained constant (Boosting pressure across the compressor) at 32 bara and therefore the field production rate starts to decline. We do the calculations until the minimum field economical rate of 2 MSm^3/d is reached.

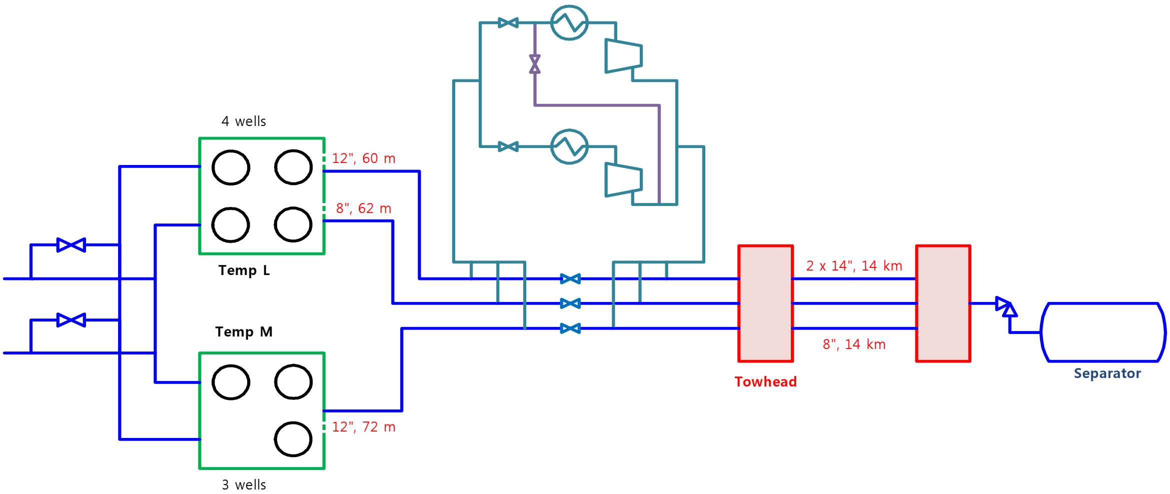


Figure 11: The production piping layout with the subsea compressor

The subsea compression station will be installed just downstream of the L and M templates, which tie back to Gullfaks C, from which the system will be powered and controlled.

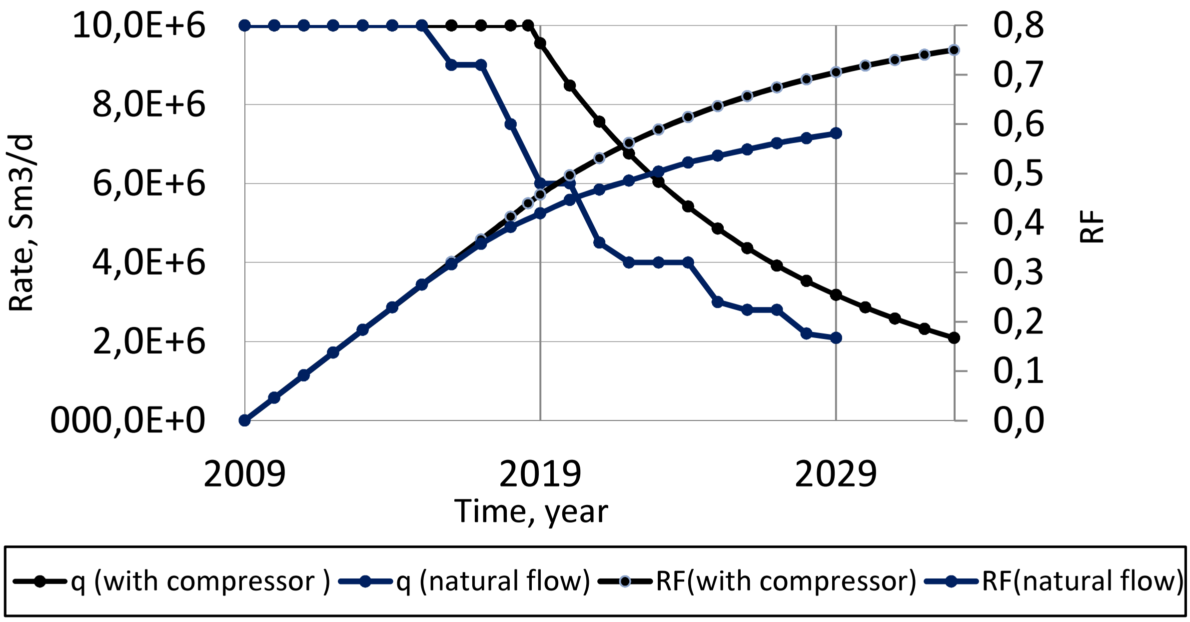


Figure 12**: Natural flow versus subsea compressor case**

The two plots above (**Figure 12**) show the improvement that we got when using the subsea compressor:

- The plateau production is sustained for a longer period (2,5 years).
- The minimum field economical rate of 2 MSm^3/day is reached 4 years later
- The recovery factor is improved from 58% to 75%.

We are conscious about the fact that these are very high values for the recovery. We believe that this is due to our very simplified assumptions. In reality the number will probably not be this high, but will still be significantly improved when compared with just the natural flow

3.3 Compressor map, results and discussions/modifications

The excel program used for getting the compressor map made was made by the Ph.D. students advising us and is based on the fundamental equations for compressors. It was utilized for confirming the performance and operation of the compressors in given production condition. The compressor suction pressure, P_{suc}, discharge pressure, P_{disc}, inlet temperature, T_{in}, and flow rate are the input parameters for composing the compressor map. And since two compressors of the system can be operated in either parallel or series, the user of the program also has to select the operating mode. The program was designed for giving the compressor maps, discharge temperature and power consumption, corresponding to the four input parameters, after assuming the polytrophic efficiency of the compressor. Consequently, selecting the proper polytrophic efficiency is the most important procedure for running this program and this work will be done by comparing each compressor map iteratively.

Figure 13 is one of the performance envelope of the compressor, which is one of compressor maps that we can get from the program. Corresponding to the input parameters the operating point (shown in red) is dotted on the envelope and it indicates power consumption and inlet flow rate calculated from the input production rate, inlet temperature and suction pressure. This red dot also indicates the proper rotation speed in rpm of the wheel in the compressor. This value is necessary for determining the appropriate polytrophic efficiency.

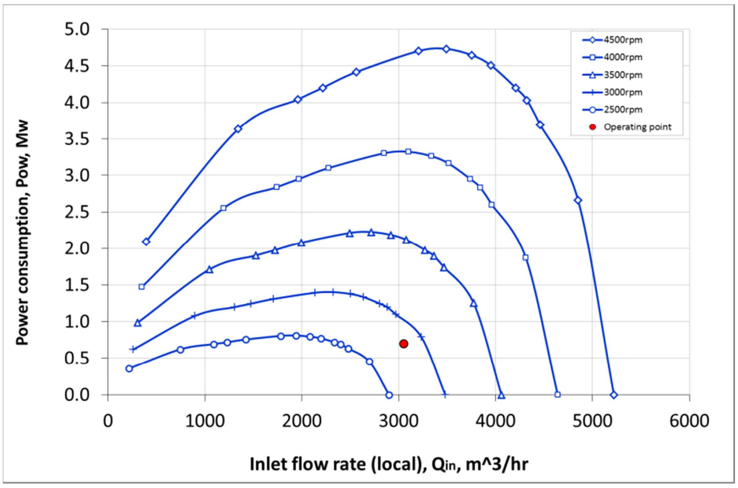


Figure 13: Performance envelope of the compressor

Figure 14 shows another of the compressor maps from this program and the vertical axis is polytropic efficiency. For the given four input parameters, a red dotted line is drawn on the map. The rotation speed is gained from **Figure 13** and the red dotted line indicates the efficiency of the compressor. If this efficiency is different from the assumed efficiency, we should assume this new polytropic efficiency and repeat the same procedure over, checking the new value each time. Therefore, finding the proper polytropic efficiency unavoidably requires iterative work. The iterative procedure can end when the difference between the two efficiencies is below some predetermined criterion of error.

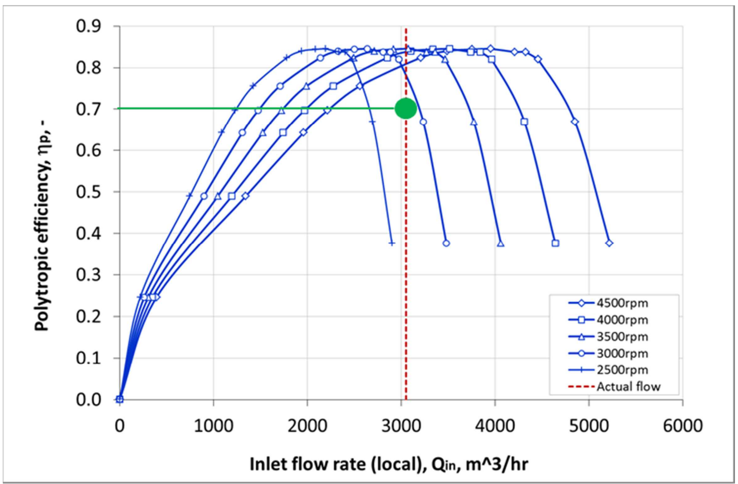


Figure 14: Polytropic efficiency of the compressor

The following three figures show the typical procedure of finding the proper polytropic efficiency. The work started from setting 0.80 of polytropic efficiency and ends with confirming that a value of 0.70 for the efficiency is suitable.

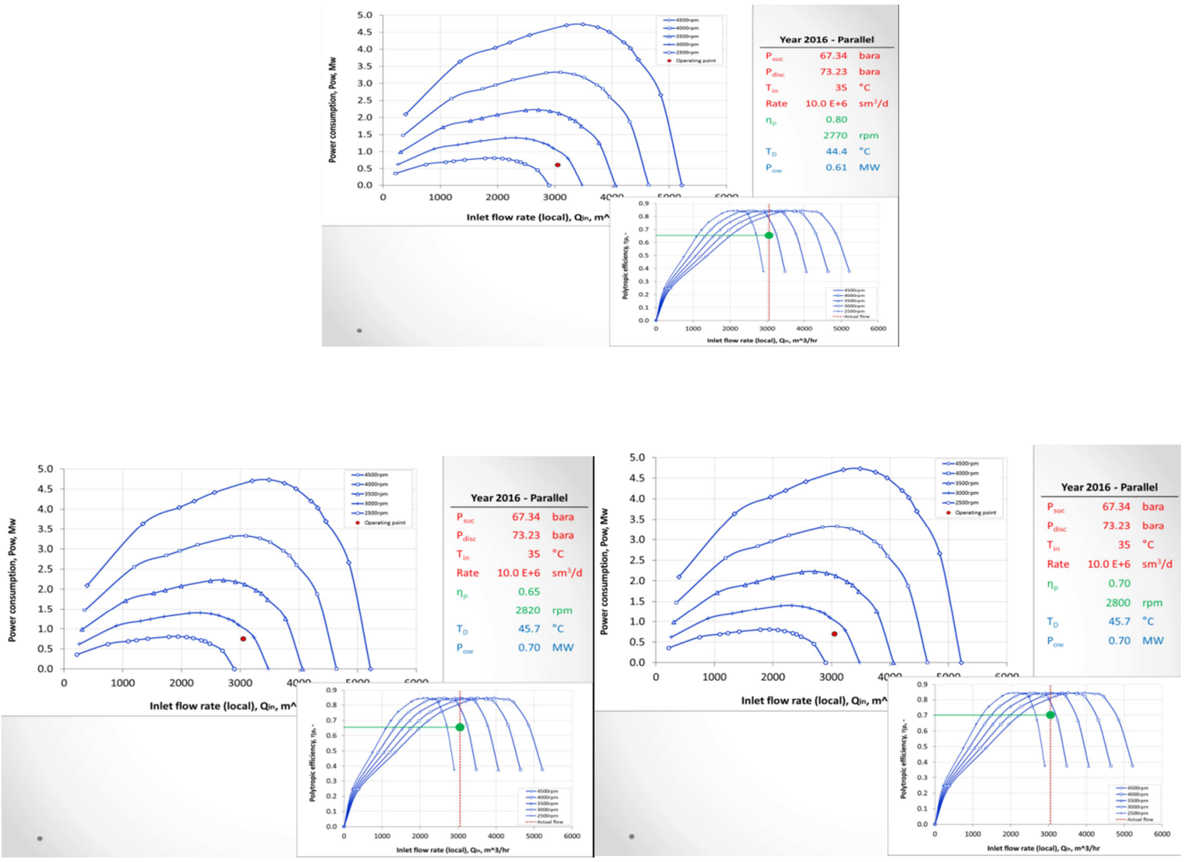


Figure 15: Procedure of finding the polytropic efficiency

Through the aforementioned procedure, we extracted the performance of the wet gas compressor in every production year. In the first years, the compressor system will be operated in parallel mode and after we have come to approximately 2020 it will be converted to series mode. This is between one and two years after the compression plateau ends. Note that this holds even with the later low pressure modification. Since conceptually parallel operation is for high production rate and series is for high pressure ratio, the result is quite reasonable qualitatively. In every year, the operating conditions such as discharging temperature and flow rate are satisfied within the limitations of the compressor. The detailed operating conditions and feasibility study are contained in the *Appendix – Compressor Performance of each year* section at the end of this report.

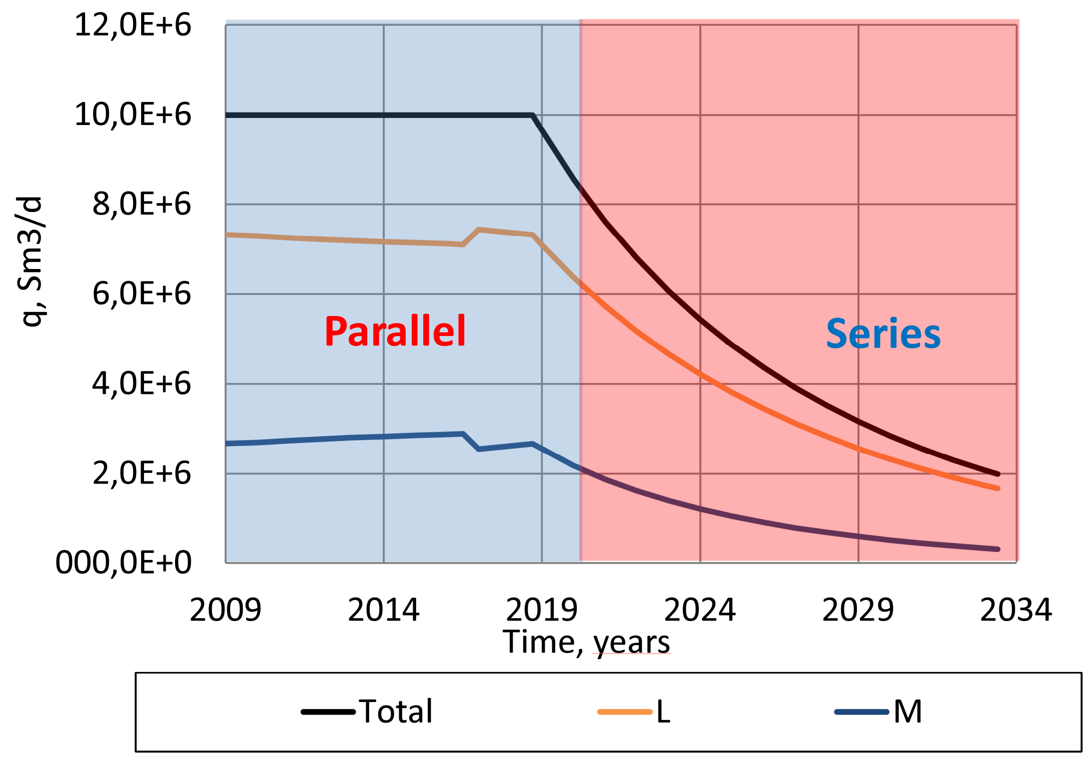


Figure 16: Compressor in parallel versus in series over the time of operation.

4 Economics

If the solution is going to be a success, it is required that the project is economically profitable. This implies that there has to be a positive cumulative net present value (CNPV), which is an estimate for the total cash flow in present value. It is calculated by summing the discounted net cash flow for each period, i.e.

$$CNPV = \sum_{t=0}^{N} \frac{R_t}{(1+i)^t},$$

where R_t is the net cash flow, t is time passed, N is the total number of periods and i is the discount rate. The CNPV is a key point when evaluating the project to see if it is a worthwhile investment.

Due to limited information about the different expenditures and difficulties predicting the oil and gas price, a lot of estimations were done. For the calculations it was assumed that the oil price was 100 USD/bbl and the gas price was 0,40 USD/ Sm^3 and that they both remained constant throughout production. History has shown us that oil and gas prices are far from stable. Over the last 5 years the oil price has varied from about 40 to 140 USD/bbl, showing how simplified these assumptions are. As they depend on many independent factors it is almost impossible to predict, although they have been increasing as a general trend. Due to the amount of uncertainty related to the oil and gas prices, they are regarded as two of the biggest sources of error. The effects of reducing them by 10% are therefore examined in the chapter concerning sensitivity analysis. The discount rate was set to 8%. It was also assumed that the exchange rates for NOK, USD and EURO remained unchanged from today's rates, meaning that 1 USD is equal to 5.7 NOK and 0.77 EURO. As with the oil and gas prices, the currency rates depend on various independent factors and are difficult to predict, although they tend to be more stable.

For the capital expenditures (capex), numbers were gathered from various newspapers articles. Framo Engineering, who constructed the compressor, has an EPC (engineering, procurement and construction) contract worth 900 million NOK. Subsea 7 is the company responsible for installing the compressor, which will happen in 2015 at the cost of 70 million USD. Apply Sørco has a contract worth 375 million NOK for topside M&M, while Nexans is procuring the power supply for the compressor, which will cost 16 million EURO. The operational expenditures (opex) were estimated to be 5% of capex for Framo and Subsea 7 and 1% for Apply Sørco and Nexans for each year after the year of approval (moving versus stationary parts). This means that the opex of for example Framo will be 45 MNOK each year. It was assumed that the capex would be distributed among three stages, where 25% of the cost would be paid at the time of approval, 50% at installation and 25% at startup. Estimated taxes were provided by Statoil until 2029 (shown in **Table 2**), and then estimated by us for the remaining years.

Table 2: Economic inputs

Capex								
Firm	Amount	Currency	In USD	Start	End	Year 1	Year 2	Year 3
Apply Sørco	375 000 000	NOK	65 773 500	2013	2015	16 443 375	32 886 750	16 443 375
Framo	900 000 000	NOK	157 856 400	2012	2015	39 464 100	78 928 200	39 464 100
Nexans	16 000 000	EURO	20 852 800	2013	2015	5 213 200	10 426 400	5 213 200
Subsea 7	70 000 000	USD	70 000 000	2013	2015	17 500 000	35 000 000	17 500 000

Opex						
	Amount pr yr	Currency	In USD	Start	End	Total
Apply Sørco	3 750 000	NOK	657 735	2013	2032	12 496 965
Framo	45 000 000	NOK	7 892 820	2013	2032	149 963 580
Nexans	160 000	EURO	208 528	2013	2032	3 962 032
Subsea 7	3 500 000	USD	3 500 000	2013	2032	66 500 000

Opex, taxes in MNOK										
2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
2,9	2,7	2,9	31,0	35,1	37,5	52,1	33,7	31,4	45,9	30,7

Opex, taxes in MNOK (cont.)										
2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
30,2	41,8	26,8	26,7	41,2	26,4	26,6	45,2	30,5	30,5	45,2

Currency calculations	
NOK => USD	0,175396
Euro => USD	1,3033

Constants	
Inflation	0
Discount rate	0,08
ft3 => Sm3	0,028
mmbtu => Sm3	26,37
Barrel => Sm3	6,29

Distribution of OPEX	
Moving parts	5 %
Non-moving parts	1 %

Distribution of CAPEX		
Approval	Install	Startup
25 %	50 %	25 %

Prices			
	NOK/Sm3	USD/bbl	USD/Sm3
Gas Price	2,3		0,403
Oil Price		100	628,93

As shown in **Figure 17** the CNPV in 2032 has barely exceeded 12 billion USD for our base case with compressor. For the natural flow case, the CNPV will result will be 10,25 billion USD. This means that we can increase the profit with 1,75 billion USD by using compressor, which strongly suggests that it is a profitable investment. Since the Gullfaks field was already operating in 2008, there will be a cash inflow for three years before the first expenditure in 2012. The years when capex are being paid (2012-2016) are obviously the periods with the most expenditures.

The graph show that even on these years, the net cash flow is positive.

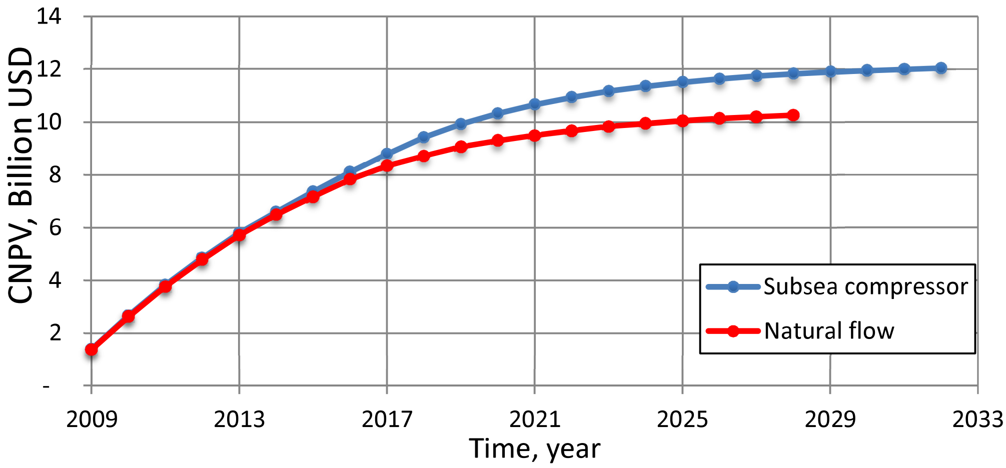


Figure 17: CNPV for subsea compressor case and natural flow

PART B: Optimizing production management and sensitivity analysis

5 Introduction Part B

In part A we found that the subsea compressor has a big effect on how long we can keep the plateau production rate and that it improved the recovery factor significantly. One of the IOR-challenges of part B is to optimize the production management and timing of the subsea compressor.

In this part we will see the effect of the low pressure modification and also what effect the pipeline diameter has on the production and the economics of the field. A sensitivity analysis has also been made to study the effect of changing some parameters like the number of wells, the oil and gas prices, downtime and delays for the subsea compressor installation.

6 Comparison between gas condensate and wet gas

6.1 Description of the model

Gas-condensate reservoirs differ from dry-gas reservoirs. Understanding of phase and fluid flow behavior relationships is essential if we want to make accurate engineering computations for gas-condensate systems. In the previous parts, a simplifying assumption was made by considering the gas as a dry gas instead of condensate gas.

Reservoir material balance for dry gas reservoirs are well known and widely used. We could conduct production calculations by using the simple equations for dry gas.

In order to check whether using the assumption of dry gas is a good approach, a comparison was made between the dry gas material balance calculation and IPT-MATBAL, a calculation program for condensate developed by Milan Edvard Wolf Stanko a PhD student in NTNU.

The dry gas method uses reservoir pressure, gas production rate and producing gas-oil ratio to determine the condensate production.

IPT-MATBAL uses a material balance based on the MBO properties that can be used for gas condensate. It requires reservoir information (pressure, porosity, temperature, water and gas saturations etc.), standard gas production rate and uses a series of equation to determine the condensate production.

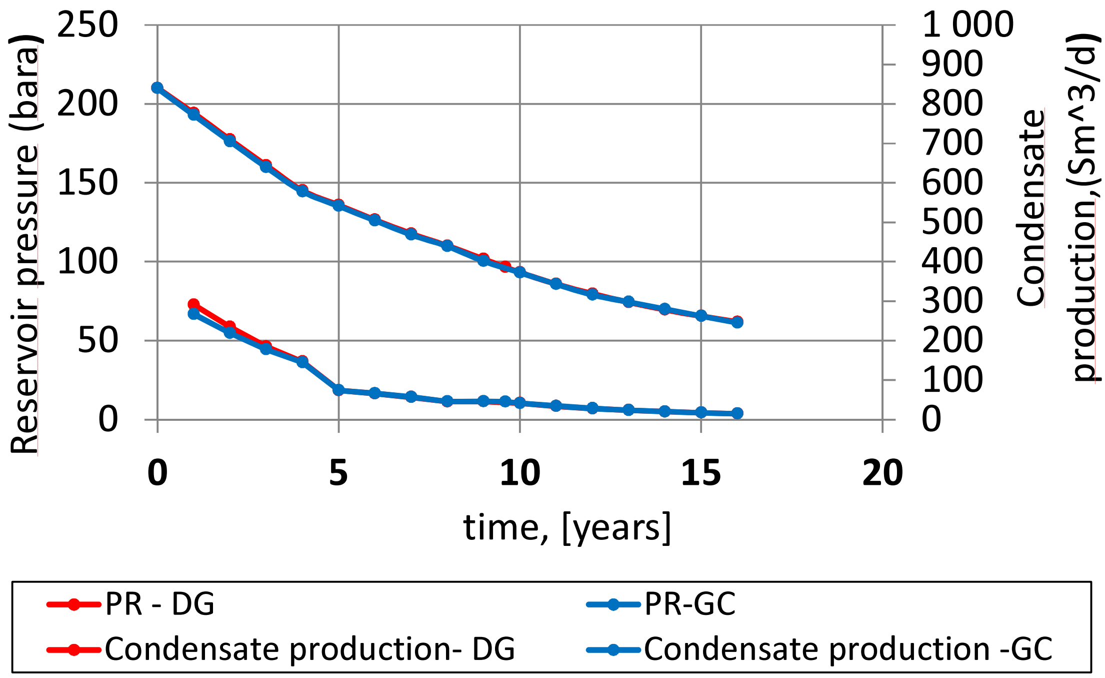


Figure 18: Dry gas versus gas condensate

The result shows that, the condensate we got using material balance for dry gas is close to the one with the condensate reservoir calculation from IPT-MATBAL.

The dry gas approach for condensate calculation can therefore be used.

6.2 Discussion and conclusion

The main advantage of using the dry gas material balance solution is its simplicity and a minimal requirement for input data. Gas production rate, producing gas-oil ratio and PVT information are all usually available to reservoir engineers.

It provides a practical engineering tool for industry studies as it requires data which is generally available in normal production operations. The obtained condensate in place using the mentioned procedure was in agreement with the condensate calculated value for Template L and M using more complex equations for the gas condensate.

7 Optimizing production management

We saw in the previous part that we could raise the recovery factor by 29% by installing the subsea compressors.

In this part we will see whether it's possible to improve the recovery further by making other changes. Two cases have been studied here:

Changing the pipeline diameter

- Low pressure modification

7.1 Pipeline diameter modification

From the layout in **Figure 11** we can see that in addition to the pipelines used, there is a pipeline of 8" to Gullfaks C which is occupied by the high pressure gas from Template N. We assume that this high pressure will occupy the pipeline from the M-Template and that the production from M-template will have to go in the 8" pipeline. It means that we substitute one of the 14" pipes with a pipeline of 8".

In order to see the difference between the two cases a plot of the production rate and the recovery is shown in the graph below.

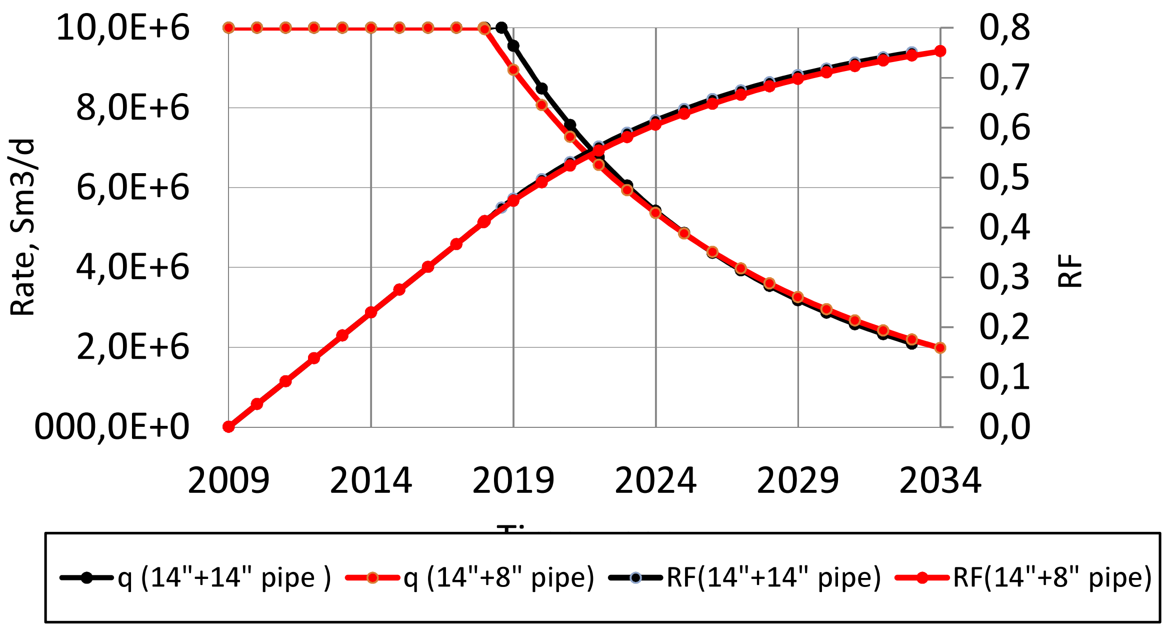


Figure 19: Effect of pipeline diameter modification on the total production rate and recovery factor

From the **Figure 19** we can see that with the 8” pipeline:

- The natural plateau ended one year earlier.
- The minimum field economical rate of 2 MSm^3/day is reached one year later (end 2033).
- There is no significant change in the total recovery factor.

From the result we can conclude that the difference between the two cases is not very important and that the 8” pipeline did not improve the recovery factor. However they will differ when we consider the economic numbers.

In order to not confound this with the low pressure modification we chose to stop at 5 $MMSm^3$/d just before the modification. These are therefore not the final CNPV numbers. It is not optimal, but we had to make a choice.

The table below shows the CNPV of this case and the one with the 8” pipelines.

Table 3: Effect of pipeline diameter modification on the CNPV

Case	CNPV in USD (In 2024)
14” + 14 “ pipelines	11 346 459 697
14” + 8” pipelines	11 156 807 441

The CNPV results shows that the little change in the production of the two cases has a bigger impact in the economics since we got a difference of USD $190 million in 2024. This means that is more profitable to use the 14”. This is not so surprising.

7.2 Low pressure production modification

Initially the inlet pressure at the separators on Gullfaks C is kept at 65 bara. One way to increase the gas recovery from the reservoirs is to do a so called low pressure modification (referred to as LPM later) on the platform. This involves in some way lowering the pressure required in front of the separators from the original 65 bara to 28 bara, thus making it possible to bring the reservoir pressure further down and still having sufficient differential pressure for further profitable production. This can, and it is our impression that the plan is that it will, be done at some point independent of the decision to install the subsea compressors in 2015.

7.2.1 Approaches

There are at least two main ways to perform the low pressure production modification. For our purposes the technical end result is the same, since we do not need simulate what happens in the separators (at least not here, it is possible to to use other tools like HYSYS for a more accurate model). The differences will thus lie in the economics and the technical feasibility and complexity of the modification itself. We will consider very simplified cases, as we do not know enough about the actual processes.

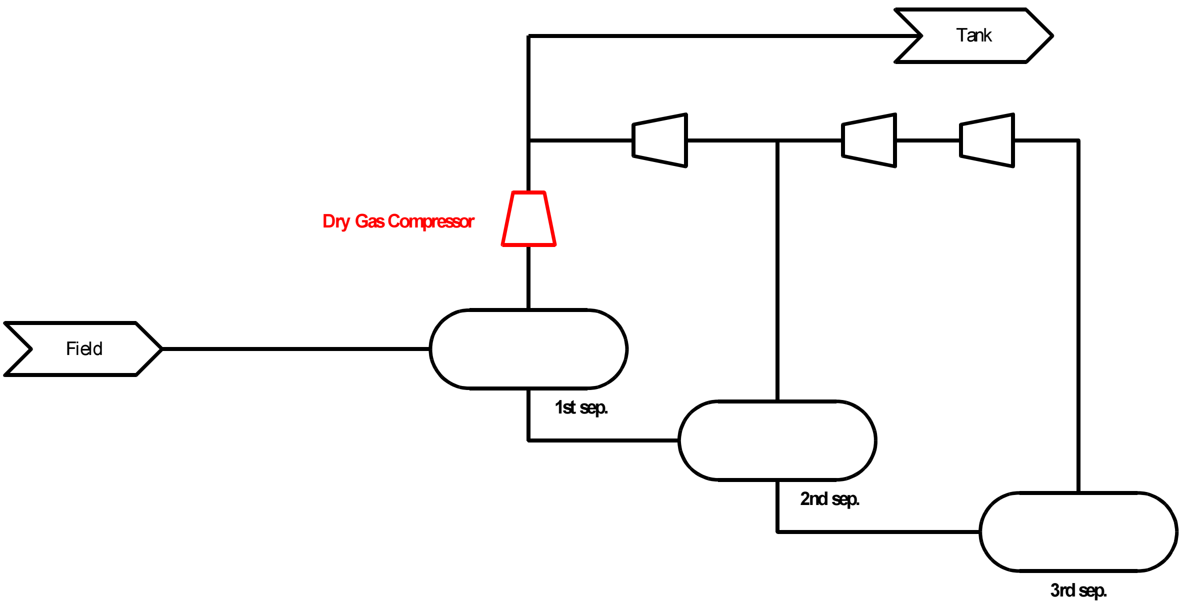


Figure 20: First approach. A dry gas compressor is added after the first separator stage.

7.2.1.1 Lowering first stage separator pressure and installing a dry gas compressor

The first method is to actually modify the first separator stage in order to allow a lower inlet pressure. This will also involve installing a dry gas compressor after the first stage, in order to boost the pressure back up to 65 bara again, shown in Error! Reference source not found. above. It is a fairly complex system, so this may be harder to actually perform in practice than described here. This method has been used in other places before, and for example on the Statoil operated Kristin platform such a modification is planned[1] to be completed next year. Because of the lower pressure in the first stage separator, it is our understanding that this will yield less gas condensate than before the modification. This kind of modification is estimated to cost approximately NOK 1 billion.[2]

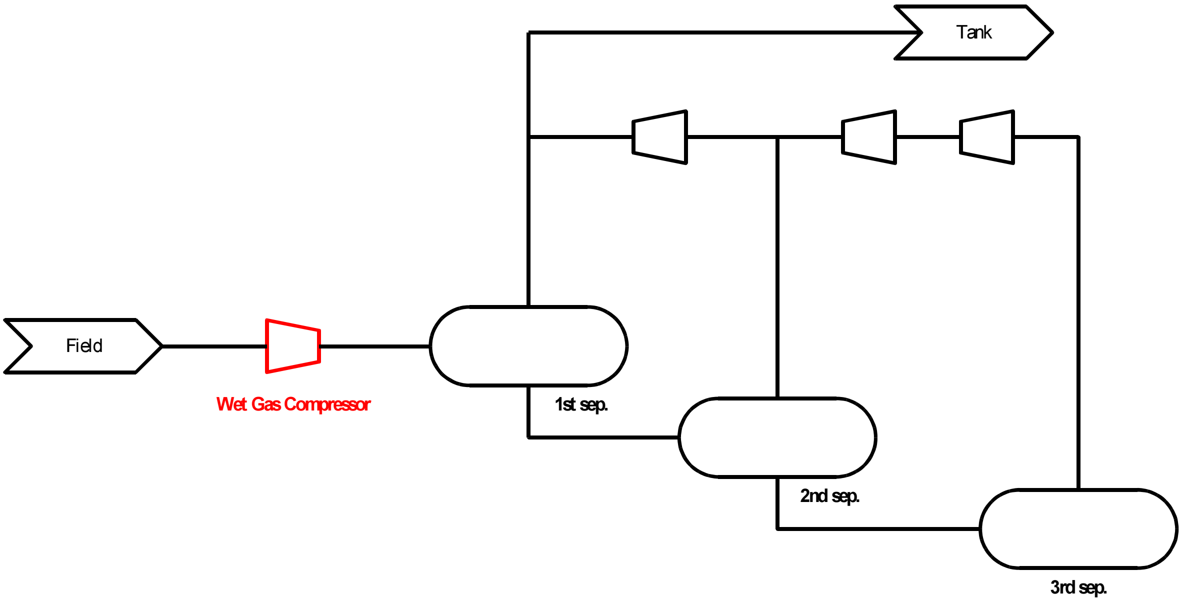


Figure 21: Second approach. A wet gas compressor is installed in front of the first separator stage.

7.2.1.2 Installing a wet gas compressor in front of the first stage separator

The second approach to the modification is to install a wet gas compressor topside on the platform, like in **Figure 211**, capable of bringing the pressure from 28 bara to the required 65 bara in front of the first stage of the separator trains. One of the advantages to this is that no changes should be needed to be made to the separators, which again is a very complex system. Another benefit is that there should be no change to the amount of condensate produced. However, a (pretty big) disadvantage is that we do not know of any examples of platforms where such a modification has been performed. It is also probably much more expensive than the first option.

It is not clear to us which of the methods Statoil has chosen to use, but it is more likely that it is the first approach. Both have their benefits and disadvantages, but choosing an already established and tested method is safer.

[1] http://www.akersolutions.com/en/Global-menu/Media/Press-Releases/All/2010/Aker-Solutions-wins-Kristin-low-pressure-production-LPP-modification-contract/

[2] Statoil's introductory presentation for the Gullfaks village. The Kristin contract also mentions a number of the same order, NOK 0.9 billion.

7.2.2 Timing

The timing of the low pressure modification should be chosen in such a way as to maximize gain, while also taking into account other issues. There are various reasons as to why it is desirable to wait as long as possible with the modification. One reason is that for mechanical and thermodynamical reasons we do not want to have larger pressure drops than needed. There are also limitations to production on the platform. Another is that if the first, more conventional, approach is picked there will be substantially less condensates after the low pressure modification[3]. Since the condensates are very profitable, this is not something we want to happen before it is necessary. Lastly, prolonging the time before the modification reduces the net present value of the expense of actually performing it. It is also found that Statoil wishes to keep the rate of gas flow above 2.5 MSm^3/d as long as possible in each of the two pipelines between the L and M templates and the Gullfaks C platform. This is due to the increased risk of accumulation of hydrates if the flow rate is too low, as the flow then is not sufficient to drag water with it. For this reason, and perhaps others, Statoil has chosen in their own simulations to do the low pressure modification at approximately the point where the decreasing total production rate (which is split over the two pipelines) reaches 5 MSm^3/d. This shall therefore be the starting point, and other possible timings for the low pressure modification will be compared with this as sensitivity analysis.

7.2.3 Subsea compressor strategy

One issue is apparent as soon as any simulation of production with the low pressure production modification implemented is attempted together with operation of the subsea compressors. The suction pressure in the compressors will immediately go far below the listed minimum suction pressure[4] of 19.9 bara if we still insist to keep the differential pressure over each compressor at the maximum ΔP of 32 bar like before. There are at least two ways of dealing with this problem, presented below. They are not very different, but we will see that there are some differences.

7.2.3.1 ΔP constant

The first possible solution is to lower the requirement of constant ΔP from 32 bar, say to 15 bar, after the low pressure modification has been performed. This will still cause the suction pressure to go below the minimum suction pressure listed, but not below what the aforementioned paper says the compressors have been tested at (13 bara). The value of 15 bar

[3] We do not pick up this with IPT MATBAL, but on the other hand it also turned out that the condensate production is not as significant as previously believed.

[4] According to the paper http://www.onepetro.org/mslib/servlet/onepetropreview?id=OTC-21346-MS by Framo on the subsea compressor, this is 19.9 bara, although the paper also mentions that it has been tested at 13 bara suction pressure.

is not totally unfounded, but is based on information we have acquired from a source we are unable to list here.

7.2.3.2 Suction pressure constant

Another solution involves fixing the suction pressure to the listed minimum suction pressure of the compressors. This way we should be able to stay inside the confines of what the compressor is actually able to perform in reality. There is however a sacrifice; the ΔP over the compressor will steadily decrease over time, which will give a smaller overall recovery.

The second strategy is probably a safer and more realistic approach, as we do not know if the subsea compressor can actually operate at the lower suction pressures over extended periods of time (or what the efficiency will be). Therefore it should be considered the main strategy. We have received conflicting information as to how important the minimum suction pressure is. In either case it is interesting to compare both of them, and see how much of a difference it makes.

7.2.4 Simulation

Simulations have been done for both of the strategies for the subsea compressors, and also for the case of only natural flow with no subsea compressors. In order for the data to be comparable, everything else about the simulations has been made as close as possible. Simulations were done using Excel and our standard assumptions of dry gas and so on, which have already been mentioned in this report. The IPT MATBAL program, provided by NTNU, was used to obtain the gas condensate production rates. We stopped the simulations when the total production rate reaches the minimum economical rate of 2 MSm^3/d. Only the case with 2 14” pipelines was considered for the low pressure modification.

The strategy that was used is listed below. It is not in full detail, but should give an idea of what has been done.

7.2.4.1 With subsea compressors

1. Natural plateau: Total production rate held constant at 10 MSm^3/d. Here one has another degree of freedom because the flow in the two pipelines is independent. For lack of a better choice what has been picked here is to keep the differential pressures over the chokes at Gullfaks C the same for both the pipelines. This ensures that both of them hit 0 bar at the same time.
2. Compression plateau: Total production rate constant at 10 MSm^3/d, ends as soon as the ΔP over the compressor reaches 32 bar.
3. Post plateau: The ΔP over subsea compressors is held at 32 bar.
4. Low pressure modification: Separator pressure lowered to 28 bara. The different strategies used here are explained above.

7.2.4.2 Natural flow

1. Natural plateau: Identical to the above.
2. Post plateau: The chokes on the platform are fully open.
3. Low pressure modification: Separator pressure lowered to 28 bara.

7.2.5 Simulation results

7.2.5.1 With subsea compressors

For clarity all the plots in this section will use solid lines for the reference case of no low pressure production modification, dashed lines for the case of constant suction pressure and dotted lines for the case of constant ΔP.

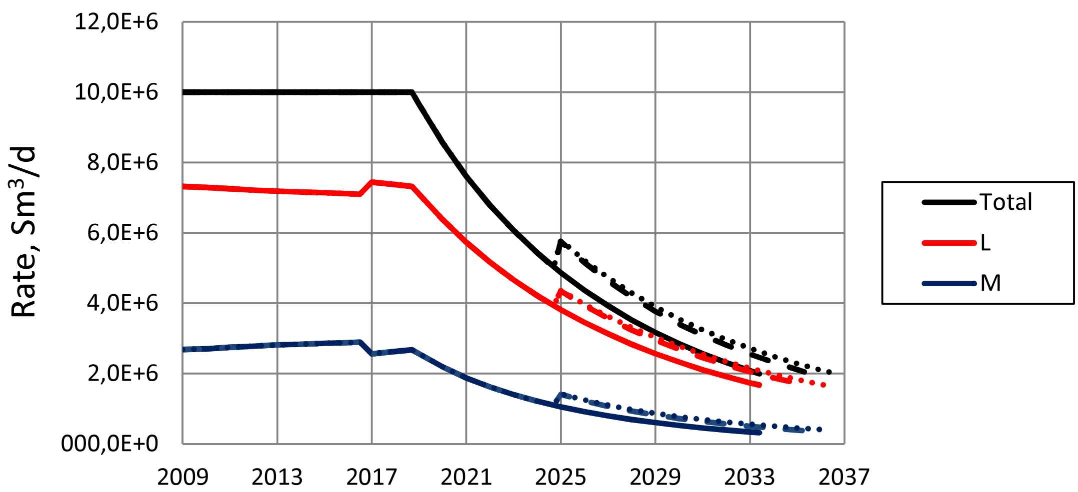


Figure 22: Extraction rates (Q)

From the simulation we find that the natural plateau ends in the middle of 2016, the compression plateau ends in autumn 2018 and the low pressure modification is performed fall of 2024 (This is the same for both approaches, since they only differ after the LPM).

The first thing we plot is the production rates for each template, together with the total production rate. This is shown in

Figure 22 above.

We see that there is a small difference between two strategies, and that the one where the pressure difference is held constant wins out. About one more year of production is gained. This is to be expected, as the pressure difference will be smaller in the other case. Both of them are significantly better than no low pressure modification, gaining multiple years of production at higher rates.

This is also reflected in the recovery factor (as it is just an integrated version of the last plot), shown in **Figure 23**. We see that the recovery factor is extremely large – increased to 80% - and that production in some cases continues until the second half of the 2030s. We will come back to this point in the later section “Deviation from Statoil’s simulation”.

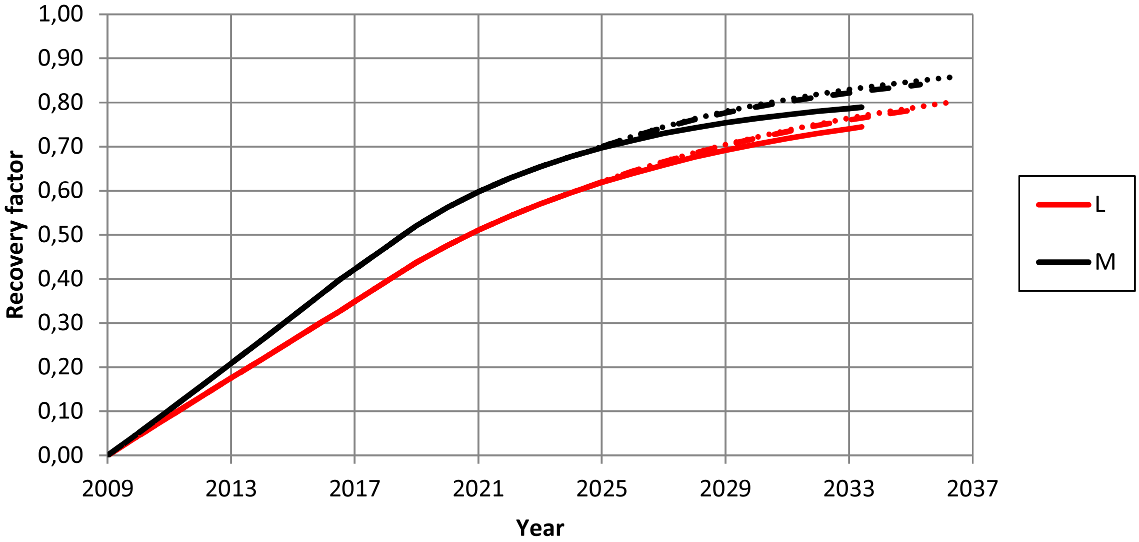


Figure 23: Recovery factor

It is also very important to know that we are within the operational limits of the subsea compressors, such that the simulations actually are meaningful. We have checked every year for the main case of constant suction pressure with the provided compressor map, and there should be no issues with operation. The compressors will operate in parallel until 2020 and in series thereafter. More details are in the part about the compressors. Note that we have not considered the operation of the topside compressors that are a part of the low pressure modification, as that would be significantly harder to do, and also further from our main task.

As mentioned earlier, the suction pressure goes below the listed minimum suction pressure if we keep the ΔP at 15 bar, in fact down to 14 bar. **Figure 24** shows the suction pressure and discharge pressure for the compressors over time. We note that the discharge pressures are nearly identical for the two strategies.

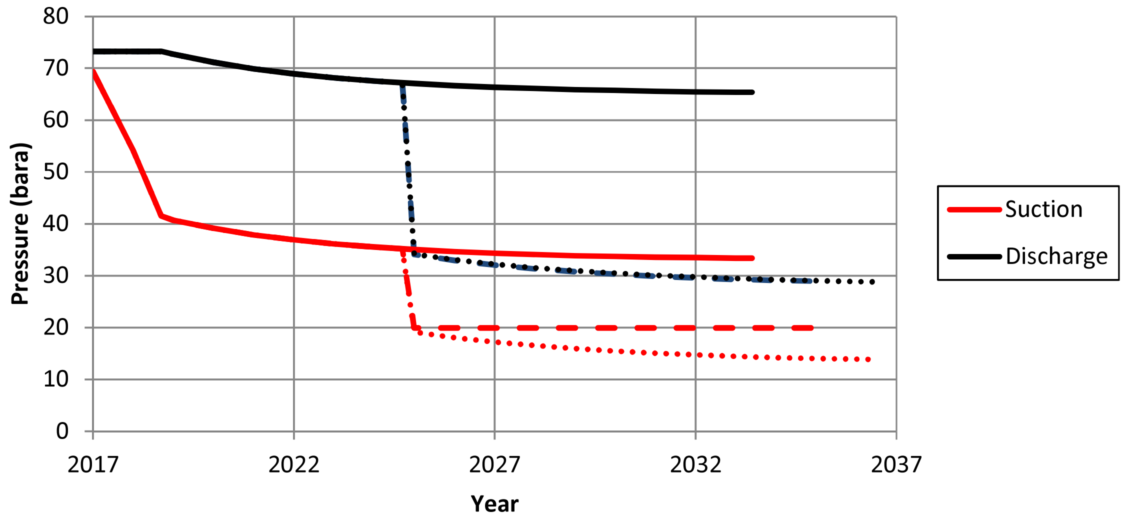


Figure 24: Compressor pressures

Another way to visualize this is to plot the pressure ratio Rp of the discharge pressure over the suction pressure, which preferably should be as low as possible.. This is shown in Figure 25, where we observe that it even decreases compared with only using the subsea compressor in the main case. This is in line with what we found with the compressor map.

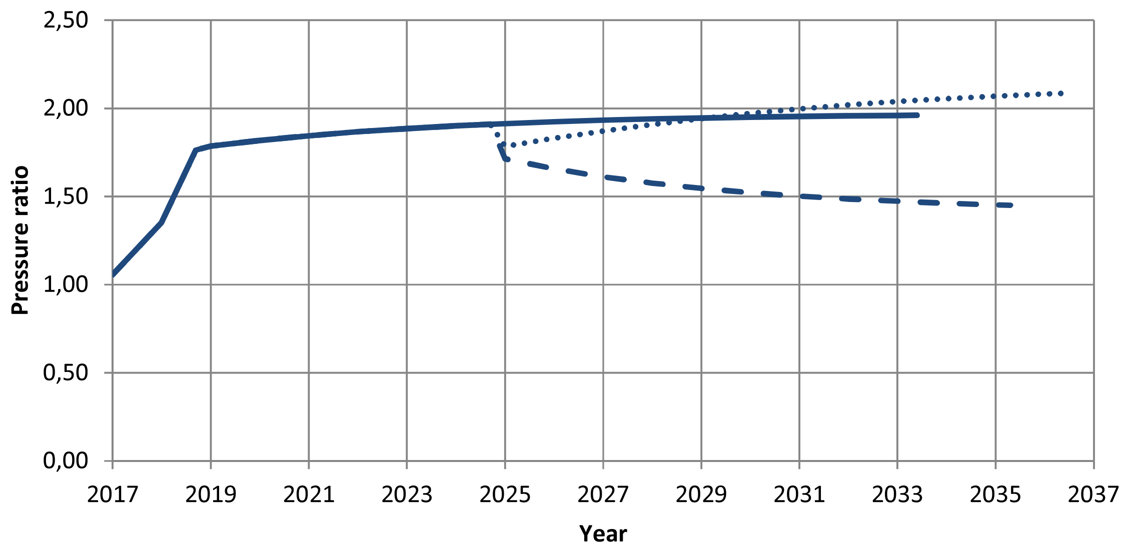


Figure 25: Compressor pressure ratio (Rp)

The condensate production rate is shown in **Figure 26**, where we observe that there is no significant increase in the production after the LPM is implemented. We also note that the production rate drops of so fast that most of the condensate is produced before the modification. As mentioned, this is produced using IPT-MATBAL, and it may be that using HYSYS or similar will provide other numbers, since it will take into account any changes to the separators. However this would probably only mean a further decrease, and the rate is already so low that it won't have a big effect.

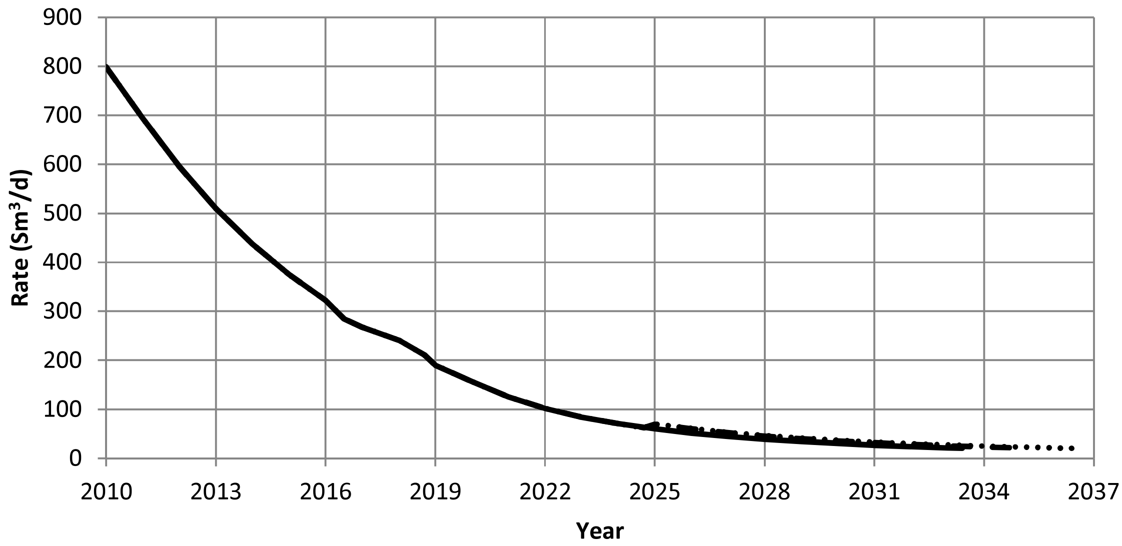


Figure 26: Gas condensate production

7.2.5.2 Natural flow

The plots will in this section use solid lines for the reference case of no low pressure modification and dashed lines in the case of low pressure modification.

For completeness we have also considered the low pressure modification with only natural flow. In this case the modification is performed towards the end of 2021.

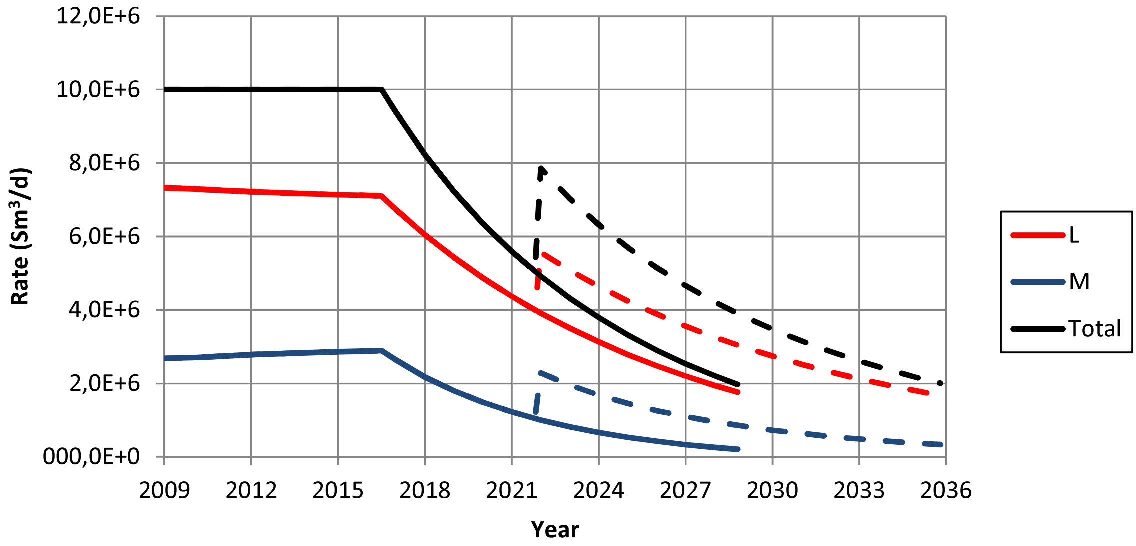


Figure 27: Extraction rates (Q)

From **Figure 27** we see that the gain in production rate from the low pressure modification with natural flow is much greater than with the subsea compressors; seven whole years more of production. This is not too unexpected, partially because in the compressor case we had to reduce the ΔP, and thus lessening to impact of the modification.

In fact, from **Figure 28** we see that the recovery rivals, and actually slightly exceeds, that of not performing a low pressure modification, but using subsea compressors. One must however consider that this happens very late, which will affect the economics negatively, as we will see.

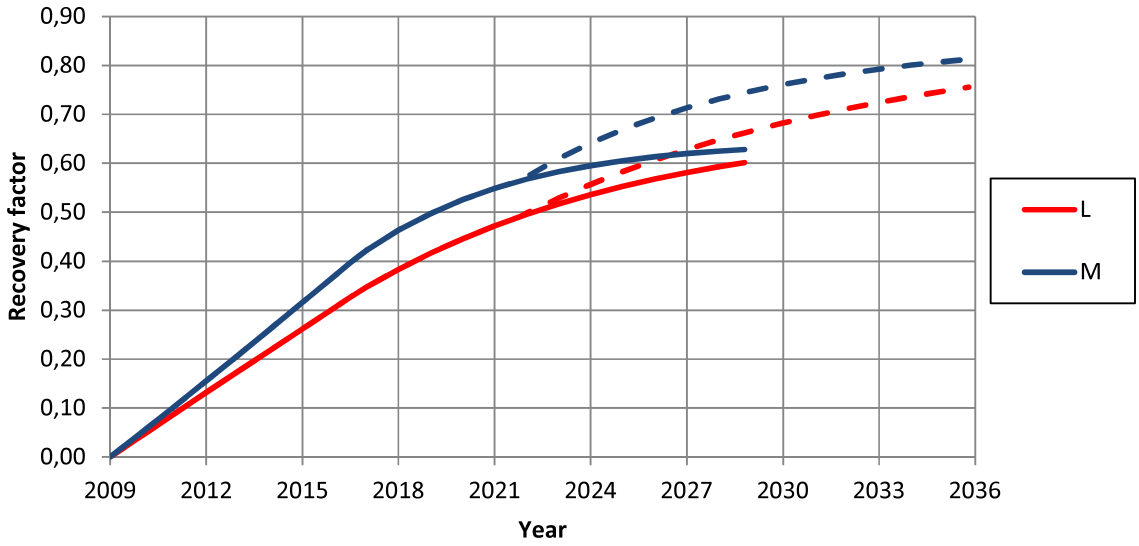


Figure 28: Recovery factor

Lastly we plot the condensate production also for this case. We see that the difference is much bigger here than it was with the subsea compressors, but the production rate is still quite low.

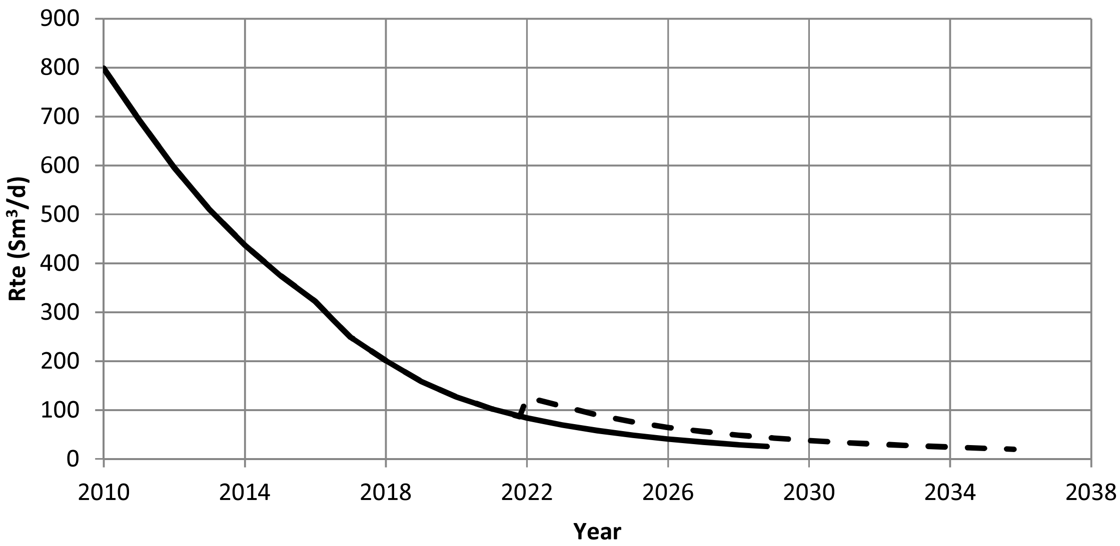


Figure 29: Gas condensate production

7.2.6 Economics

The most important metric for considering the value of the modification is of course the total cumulative net present value of the project. In **Table 4** we have summarized the CNPV at the end of production for all the cases we have considered.

Table 4: Total cumulative net present value

	Without LPM	**With LPM**
Natural flow	$10.987 billion	$11.963 billion
Compressor, constant suction	$12.037 billion	$12.199 billion
Compressor, constant ΔP	$12.037 billion	$12.265 billion

Even at a cost of NOK 1 billion, we obtain a value of USD $162 million for the modification in the main case. Note also that LPM with natural flow is comparable with the compressor case with no LPM, being somewhat lower even with slightly higher recovery.

7.2.7 Sensitivity

Does the timing have any impact on the value of the modification, and if that is the case: How large an impact? These are questions we want to answer. We have considered two other timings. One where we do the modification when the production reaches 4 MSm^3/d (later), and one where we do the modification when the production reaches 6 MSm^3/d (earlier).

7.2.7.1 With subsea compressors

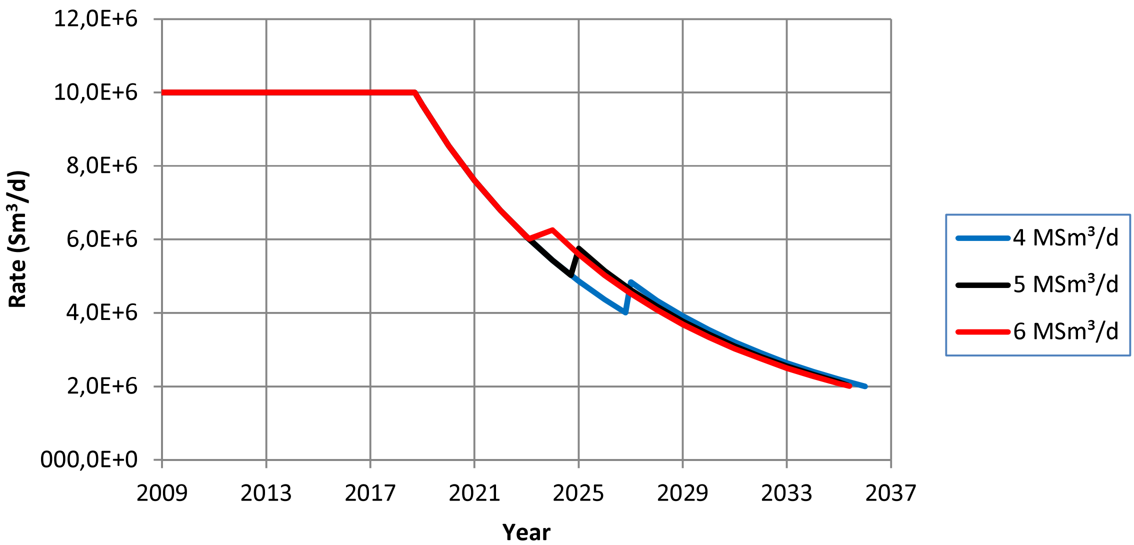


Figure 30: Gas production rates (Q) for different timings

From **Figure 30**, showing the total production rate over time, we see that this shifts the LPM back one and a half year in the 4 MSm^3/d case, and forward by two years in the 6 MSm^3/d case. Other than that it is not easy to see from the plot what effect it will have on the value.

7.2.7.2 Natural flow

Figure 31 shows the same plot for the natural flow case. It looks very similar, and the shifts are also almost the same.

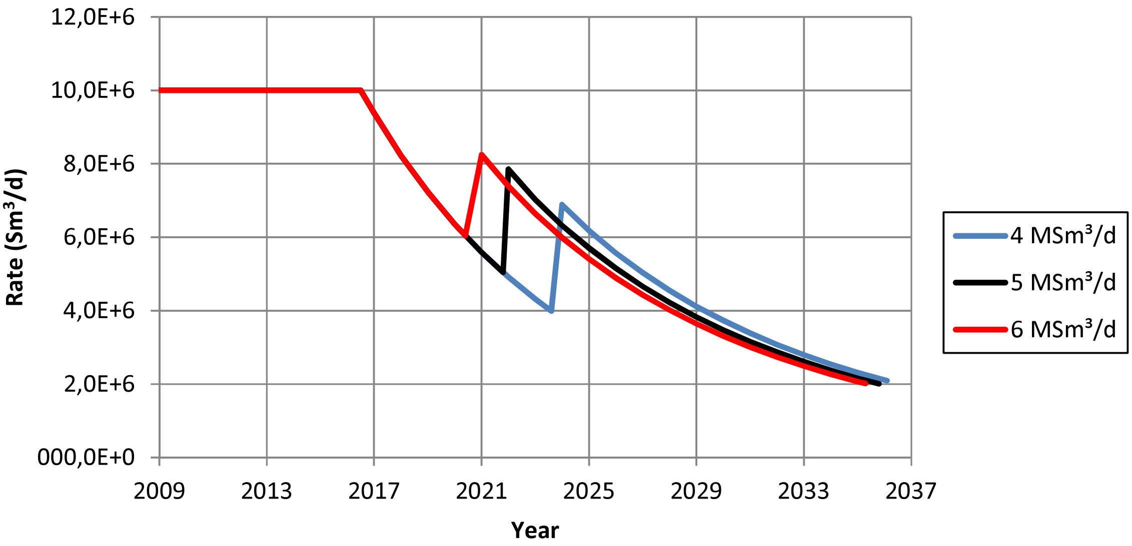


Figure 31: Gas production rates (Q) for different timings.

7.2.8 Economics

In **Table 5** we have tabulated the value of all the considered cases.

Table 5: Total cumulative net present value

	4 MSm^3/d	5 MSm^3/d	6 MSm^3/d
With subsea comp.	$12.193 billion	$12.199 billion	$12.215 billion
Natural flow	$11.853 billion	$11.963 billion	$12.010 billion

We see that the difference due to the timing in the cases using the subsea compressors is (relatively) small compared with the value of the modification. At least if we consider the fact that there are other issues regarding the timing that may be more important than just this number.

7.2.9 Conclusion

From the preceding sections we conclude that the lower pressure modification is a worthwhile investment for Statoil, and that performing it when the total production rate reaches 5 MSm^3/d is a good solution. The best overall strategy for operation of the subsea compressor is keeping the suction pressure constant at the minimum of 19.9 bara.

7.2.10 Deviation from Statoil's simulation

Compared with the simulation results shown in graphs in one of Statoil's presentation, everything is moved back multiple years. This is also present in results not connected to the low pressure modification, but is perhaps at its largest here. The deviation seems to grow larger the more time goes by. It is not known exactly what the cause is, but it is most likely connected with the cumulative effect of all the simplified assumptions that have been made regarding dry gas etc. It is our belief that the results are at least internally consistent, so that they can safely be compared with each other, but that they should not be taken as prediction.

It is mentioned in some articles that it is expected that the final recovery factor with both the subsea compressors and the low pressure modification is ~74%,[5] while the one we obtained is as high as 80%.

[5] http://www.statoil.com/en/NewsAndMedia/News/2012/Pages/21May_Gullfaks_Compression.aspx

8 Hydrate Formation Analysis

An endeavor has been made for analysis of hydrate formation under normal operation and in a shut-down period based on the production conditions we deduced from the Excel worksheet. The task to match pipe inlet and outlet pressure from the Excel work with the pipeline model in Hysys was attempted and in this work, critical inconsistencies between the Excel work and the Hysys work were found. The cause is thought to be excessive simplifying assumptions in the Excel work, but it's not something we have determined for sure. In conclusion, hydrate formation analysis is impossible with the given Excel work and using Hysys. The present section is about the details of this phenomenon and its reasons.

8.1 Proposed analysis procedure

8.1.1 Given information

Field layout

Two layouts were utilized for the present analysis:

- Layout with compressor (**Figure 11**): The pipeline inner diameter, its length and basic configuration were taken from this layout.

- Field bathymetry: The following bathymetry information was used for the pipeline desig n, especially vertical pipeline design.

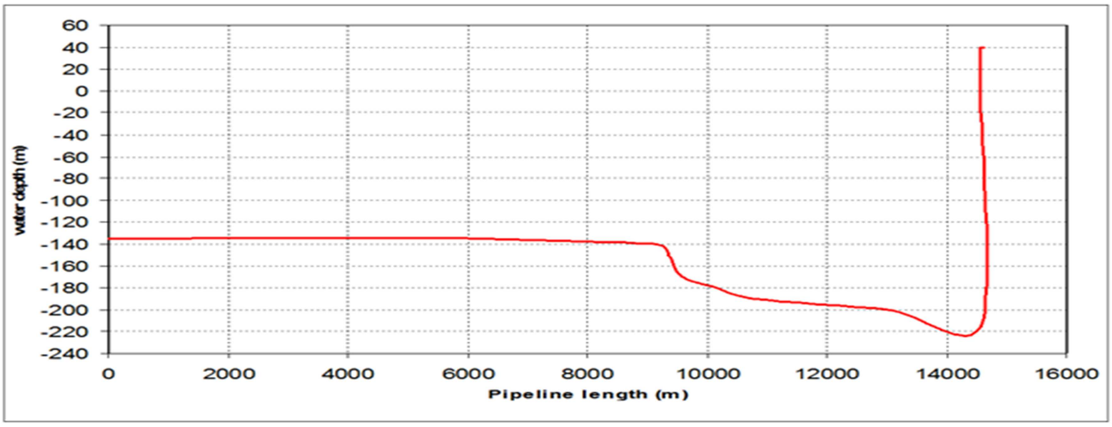


Figure 32: Field bathymetry

Table 6: Segments of pipeline

Location	Water depth	Coordinates UTM (ED50)	
GFC	**216 m**	**N 6 787 110,00**	**E 460 990,00**
GFC SSIV	220 m	N 6 787 145,70	E 460 828,20
Brønnramme L	135 m	N 6 773 997,50	E 456 471,00
Brønnramme M	135 m	N 6 774 030,07	E 456 473,82
Brønnramme N	136,9 m	N 6 772 167,49	E 445 499,91
Satellitt N5	134.5 m	N 6 768 262,50	E 445 025,60
Tie-In Manifold	135.5 m	N 6 773 997,02	E 456 509,37
Tauehode C1 (R01)	217 m	N 6 787 074,00	E 461 096,00
Tauehode C2 (R03)	134 m	N 6 780 533,00	E 458 779,00
Tauehode C3 (R04)	134 m	N 6 780 579,00	E 458 823,00
Tauehode C4	136 m	N 6 774 041,00	E 456 438,00

In Hysys, segments of the pipeline were set based on the above table.

Pressure and production rate data

Pressure and production rate for each year were calculated by the Excel program. The calculation was conducted based on several assumptions shown below (which may be a bit hard to read):

Table 7: Excel calculation for the lox pressure modification

With compressor, with LPM, suction at 19.9 bara (choke at GFC), LPM at 6 MSm^3/d

Natural plateau — Total rate held constant at 10*10^6 sm^3/d. Choke not fully open. Solver used to keep the difference over the choke the same for both templates

		East tank, template L, 4 Wells										West tank, template M, 3 Wells												
Year	Calender year	qf	Gp	Gp/G	PR	Z	qw	Pwf	Pwh	PoutL	DpChokeL	qf	Gp	Gp/G	PR	Z	qw	Pwf	Pwh	PoutM	DpChokeM	DpChokeErr	Psep	qt
		sm3/d	Sm3		bara		Sm3/d	bara	bara	bara	bar	sm3/d	Sm3		bara		Sm3/d	bara	bara	bara		bara^2	bara	sm3/d
0	2009	7.3E+6	000.0E+0	0.00	240	0.95676	1.8E+6	214	166	158	93	2.7E+6	000.0E+0	0.00	210	0.9264	8.9E+05	191	159	158.35	93	1.7E-20	65	10.0E+6
1	2010	7.3E+6	2.4E+9	0.04	229	0.95171	1.8E+6	202	163	155	90	2.7E+6	892.6E+6	0.05	199	0.9229	9.0E+05	179	149	147.95	83	5.6E+01	65	10.0E+6
2	2011	7.3E+6	4.8E+9	0.09	218	0.94679	1.8E+6	189	152	144	79	2.7E+6	1.8E+9	0.10	188	0.9200	9.2E+05	165	138	136.31	71	6.4E+01	65	10.0E+6
3	2012	7.2E+6	7.1E+9	0.13	206	0.94267	1.8E+6	175	142	133	68	2.8E+6	2.7E+9	0.16	176	0.9180	9.3E+05	152	126	124.46	59	7.4E+01	65	10.0E+6
4	2013	7.2E+6	9.5E+9	0.18	195	0.93936	1.8E+6	162	122	112	47	2.8E+6	3.6E+9	0.21	165	0.9170	9.4E+05	138	114	112.41	47	3.8E-19	65	10.0E+6
5	2014	7.2E+6	11.8E+9	0.22	184	0.93685	1.8E+6	149	111	100	35	2.8E+6	4.6E+9	0.26	153	0.9170	9.5E+05	124	102	100.01	35	1.6E-18	65	10.0E+6
6	2015	7.1E+6	14.2E+9	0.26	173	0.93509	1.8E+6	136	99	87	22	2.9E+6	5.5E+9	0.32	142	0.9178	9.5E+05	109	89	87.03	22	7.3E-18	65	10.0E+6
7	2016	7.1E+6	16.5E+9	0.30	163	0.93404	1.8E+6	123	87	73	8	2.9E+6	6.5E+9	0.37	131	0.9196	9.6E+05	94	76	73.06	8	4.3E-18	65	10.0E+6
7.5	2016.5	7.1E+6	17.7E+9	0.33	158	0.93377	1.8E+6	116	81	65	0	2.9E+6	7.0E+9	0.40	126	0.9208	9.7E+05	86	68	65.50	0	4.6E-17	65	10.0E+6

Compression plateau — Total rate held constant at 10*10^6 sm^3/d. Choke fully open. Solver used to solve for template rates (Make PthL and PthM the same).

		East tank, template L, 4 Wells									West tank, template M, 3 Wells													2*14"		
Year	Calender year	qf	Gp	Gp/G	PR	Z	qw	Pwf	Pwh	PthL	qf	Gp	Gp/G	PR	Z	qw	Pwf	Pwh	PthM	PthAvg	PthErr	DpC	Rp	Ptowhead	Psep	qt
		sm3/d	Sm3		bara		Sm3/d	bara	bara	bara	sm3/d	Sm3		bara		Sm3/d	bara	bara	bara	bara	bar^2	bar		bara	bara	sm3/d
8	2017	7.4E+6	18.9E+9	0.35	153	0.93367	1.9E+6	105	70	69	2.6E+6	7.4E+9	0.42	121	0.9221	8.5E+05	86	69	69	69.34	4.5E-26	3.89	1.06	73.23	65	10.0E+6
9	2018	7.4E+6	21.3E+9	0.39	142	0.93400	1.8E+6	90	54	54	2.6E+6	8.2E+9	0.47	111	0.9253	8.8E+05	69	54	54	54.17	1.9E-23	19.06	1.35	73.23	65	10.0E+6
9.7	2018.7	7.3E+6	23.0E+9	0.42	135	0.93463	1.8E+6	79	42	42	2.7E+6	8.9E+9	0.51	104	0.9279	8.9E+05	56	42	42	41.54	4.8E-25	31.69	1.76	73.23	65	10.0E+6

After plateau — Total rate variable. Choke fully open. Solver used to solve for template rates(PthL=PthM and keep pressure difference over compressor at 32 bara).

		East tank, template L, 4 Wells									West tank, template M, 3 Wells														2*14"		
Year	Calender year	qf	Gp	Gp/G	PR	Z	qw	Pwf	Pwh	PthL	qf	Gp	Gp/G	PR	Z	qw	Pwf	Pwh	PthM	PthAvg	PthErr	DpC	DpCErr	Rp	Ptowhead	Psep	qt
		sm3/d	Sm3		bara		Sm3/d	bara	bara	bara	sm3/d	Sm3		bara		Sm3/d	bara	bara	bara	bara	bar^2	bar	bar^2		bara	bara	sm3/d
10	2019	7.1E+6	23.7E+9	0.44	132	0.93498	1.8E+6	77	41	41	2.6E+6	9.1E+9	0.52	101	0.9291	8.5E+05	54	41	41	40.71	1.4E-10	32.00	6.3E-20	1.79	72.71	65	9.7E+6
11	2020	6.4E+6	25.8E+9	0.48	123	0.93639	1.6E+6	71	39	39	2.2E+6	9.8E+9	0.56	92	0.9329	7.3E+05	51	39	39	39.12	5.9E-13	32.00	6.0E-14	1.82	71.12	65	8.6E+6
12	2021	5.7E+6	27.7E+9	0.51	115	0.93806	1.4E+6	66	38	38	1.9E+6	10.5E+9	0.60	85	0.9364	6.3E+05	49	38	38	37.89	8.7E-10	32.00	3.6E-20	1.84	69.89	65	7.6E+6
13	2022	5.2E+6	29.4E+9	0.54	108	0.93989	1.3E+6	62	37	37	1.6E+6	11.0E+9	0.63	79	0.9397	5.4E+05	47	37	37	36.92	8.4E-10	32.00	1.3E-20	1.87	68.92	65	6.8E+6
14	2023	4.7E+6	30.9E+9	0.57	101	0.94181	1.2E+6	59	36	36	1.4E+6	11.5E+9	0.65	74	0.9428	4.7E+05	45	36	36	36.15	5.6E-10	32.00	1.2E-20	1.89	68.15	65	6.1E+6
14.1	2023.1	4.6E+6	31.1E+9	0.57	101	0.94195	1.2E+6	58	36	36	1.4E+6	11.5E+9	0.66	73	0.9430	4.6E+05	45	36	36	36.10	5.7E-11	32.00	3.6E-10	1.89	68.10	65	6.0E+6

Low Pressure Modication — Separator pressure reduced, keep suction pressure (PthAvg) at 19,9 bara

		East tank, template L, 4 Wells									West tank, template M, 3 Wells													2*14"		
Year	Calender year	qf	Gp	Gp/G	PR	Z	qw	Pwf	Pwh	PthL	qf	Gp	Gp/G	PR	Z	qw	Pwf	Pwh	PthM	PthAvg	PthErr	DpC	Rp	Ptowhead	Psep	qt
		sm3/d	Sm3		bara		Sm3/d	bara	bara	bara	sm3/d	Sm3		bara		Sm3/d	bara	bara	bara	bara	bar^2	bar		bara	bara	sm3/d
15	2024	4.7E+6	32.4E+9	0.60	95	0.94399	1.2E+6	46	20	19.9	1.5E+6	12.0E+9	0.68	68	0.9463	5.1E+05	28	20	19.9	19.90	7.3E-16	15.16	1.76	35.06	28	6.3E+6
16	2025	4.3E+6	33.8E+9	0.62	89	0.94617	1.1E+6	43	20	19.9	1.3E+6	12.4E+9	0.71	63	0.9496	4.4E+05	27	20	19.9	19.90	4.2E-17	13.87	1.70	33.77	28	5.6E+6
17	2026	3.9E+6	35.1E+9	0.65	84	0.94832	966.1E+3	40	20	19.9	1.2E+6	12.8E+9	0.73	58	0.9526	3.9E+05	26	20	19.9	19.90	7.0E-17	12.84	1.64	32.74	28	5.0E+6
18	2027	3.5E+6	36.3E+9	0.67	79	0.95041	876.9E+3	38	20	19.9	1.0E+6	13.1E+9	0.75	54	0.9553	3.4E+05	26	20	19.9	19.90	2.5E-16	11.99	1.60	31.89	28	4.5E+6
19	2028	3.2E+6	37.3E+9	0.69	74	0.95243	797.3E+3	36	20	19.9	892.3E+3	13.4E+9	0.77	51	0.9578	3.0E+05	25	20	19.9	19.90	1.8E-17	11.30	1.57	31.20	28	4.1E+6
20	2029	2.9E+6	38.3E+9	0.71	70	0.95436	725.9E+3	34	20	19.9	784.9E+3	13.7E+9	0.78	48	0.9600	2.6E+05	25	20	19.9	19.90	1.6E-16	10.74	1.54	30.64	28	3.7E+6
21	2030	2.6E+6	39.1E+9	0.72	67	0.95620	661.9E+3	33	20	19.9	692.0E+3	13.9E+9	0.79	45	0.9620	2.3E+05	25	20	19.9	19.90	1.7E-17	10.28	1.52	30.18	28	3.3E+6
22	2031	2.4E+6	39.9E+9	0.74	63	0.95794	604.3E+3	32	20	19.9	611.5E+3	14.1E+9	0.81	42	0.9639	2.0E+05	24	20	19.9	19.90	3.2E-16	9.91	1.50	29.81	28	3.0E+6
23	2032	2.2E+6	40.6E+9	0.75	60	0.95959	552.4E+3	31	20	19.9	541.3E+3	14.3E+9	0.82	40	0.9655	1.8E+05	24	20	19.9	19.90	4.3E-17	9.60	1.48	29.50	28	2.8E+6
24	2033	2.0E+6	41.3E+9	0.76	57	0.96114	505.6E+3	30	20	19.9	479.9E+3	14.4E+9	0.82	38	0.9670	1.6E+05	24	20	19.9	19.90	5.5E-18	9.34	1.47	29.24	28	2.5E+6
25	2034	1.9E+6	41.9E+9	0.77	55	0.96260	463.2E+3	29	20	19.9	425.9E+3	14.6E+9	0.83	37	0.9683	1.4E+05	24	20	19.9	19.90	1.9E-16	9.14	1.46	29.04	28	2.3E+6
26	2035	1.7E+6	42.5E+9	0.78	52	0.96398	424.9E+3	28	20	19.9	378.4E+3	14.7E+9	0.84	35	0.9695	1.3E+05	24	20	19.9	19.90	8.3E-19	8.96	1.45	28.86	28	2.1E+6
26.4	2035.4	1.6E+6	42.7E+9	0.79	51	0.96449	410.8E+3	28	20	19.9	361.2E+3	14.7E+9	0.84	35	0.9700	1.2E+05	24	20	19.9	19.90	5.0E-18	8.90	1.45	28.80	28	2.0E+6

In the above Excel calculation, the whole production period is divided into 4 stages and each of them were named – Natural plateau, Compression plateau, After plateau, and Low Pressure Modification. The yellow-shaded regions correspond to the main input data for Hysys

- Production rate: total and each template
- Pressure: wellhead, template (compressor inlet, compressor outlet), towhead, separator

8.1.1.1 Pipeline information

Besides basic information of pipeline from part A, several specifications are necessary for the present analysis, such as roughness, heat transfer coefficient, and outer diameter. The following values for each parameter were used.

- Pipe wall conductivity : 1.1 W/mK (from SPE literature)
- Overall heat transfer coefficient : 1.5 W/m^{2}C (from SPE literature)
- Ambient temperature : 6 °C

The pipe roughness value is the unique parameter that can be manipulated by the analyzer for the purpose of matching pressure values in Hysys with those from the Excel work.

8.1.2 Field Modeling

With the above given information, field modeling was conducted in Hysys. The following worksheet shown in the figure below is the modeling result. The four horizontal pipelines represent the four aforementioned production stages above.

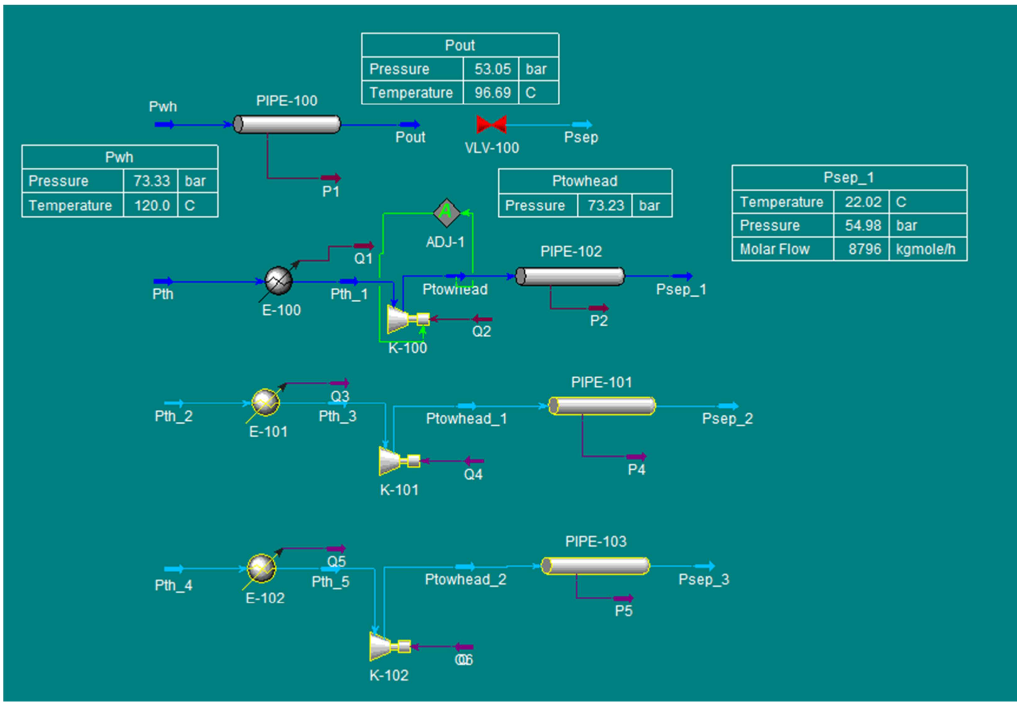


Figure 33: Field modeling in Hysys

Comments for each part are listed below:

- Pipeline: Beggs and Brill's (1973) model was selected because the model shows good agr eement in every inclined pipeline. And the given information of pipeline was inserted.
- Compressor: Centrifugal type compressor was used and its efficiency was manipulated and determined by adjusting in Hysys in order to match the discharge temperature with it from compressor performance analysis.
- Valve: Isenthalpic valve
- Cooler
- Pipeline heater (Additional)

From the SPE literature, we know that the pipelines in Gullfaks South field are enclosed by a bundle system and in the bundle a hot water circulation system is equipped for heating near the pipeline. From the literature, cooled water is heated top-side by a HRSG system and its capacity is 50 MW. So, to consider this hot water system, heat was supposed to be added during the Hysys modeling. However, because of the failure in a previous work stage, it wasn't installed in the model.

8.2 Assumption

In order to simplify the analysis procedure, the analysis was conducted based on two main assumptions.

- 8 inch pipeline is not used for normal operation.
- Temperature drop along the pipeline from the well to the well head is negligible.

8.3 Problem during analysis

In conclusion, the problem that occurred was the impossibility of matching pipe inlet and outlet pressure between Hysys and the Excel work.

During production at high pressure, there was no problem. For example, for the first year of production, 2009, inlet and outlet pressure in Hysys can be manipulated to have the same value as that in the Excel work by controlling the pipe roughness value. As a result, based on given coefficients associated with heat transfer, Hysys gives some value for the temperature drop. This value will be used in hydrate formation analysis.

Year	Calender year	qf	Gp	Gp/G	PR	Z	qw	Pwf	Pwh	PoutL
		sm3/d	Sm3		bara		Sm3/d	bara	bara	bara
0	2009	7.3E+6	000.0E+0	0.00	240	0.95676	1.8E+6	214	166	158
1	2010	7.3E+6	2.4E+9	0.04	229	0.95171	1.8E+6	202	163	155
2	2011	7.3E+6	4.8E+9	0.09	218	0.94679	1.8E+6	189	152	144

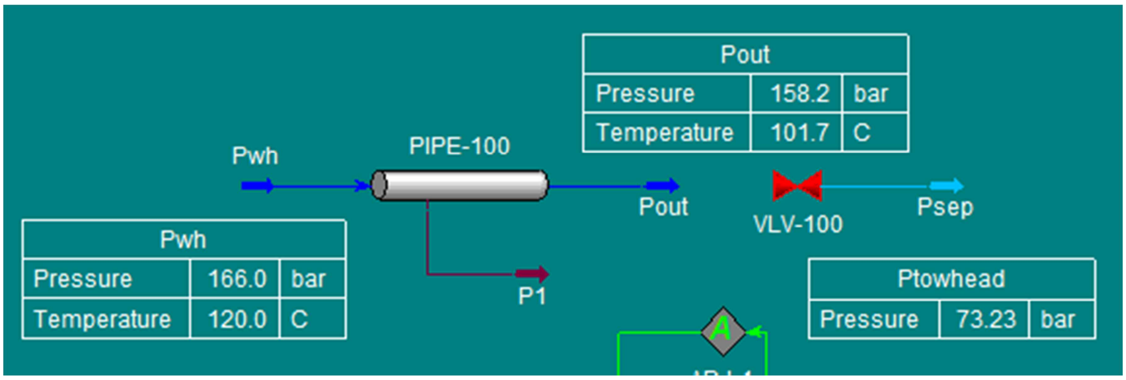


Figure 34: Compatibility in pipeline between Hysys and Excel work in the case of 2009

However, as the years go by and the inlet pressure is decreased, the problems start to occur. As the inlet pressure decreases, differences between inlet and outlet pressure decrease as well. The problem in this stage is that Hysys cannot meet this small a pressure drop. i.e., no matter how small roughness is, even if it has 0 value, Hysys gives a lower outlet pressure than Excel work under the same inlet pressure and given (fixed) pipeline information. To illustrate it, in 2017, towhead pressure (pipe inlet) is 73.23 bar and separator pressure (pipe outlet) is 65.0 bar, and if the roughness has a zero value, the outlet pressure in outlet is 55 bar.

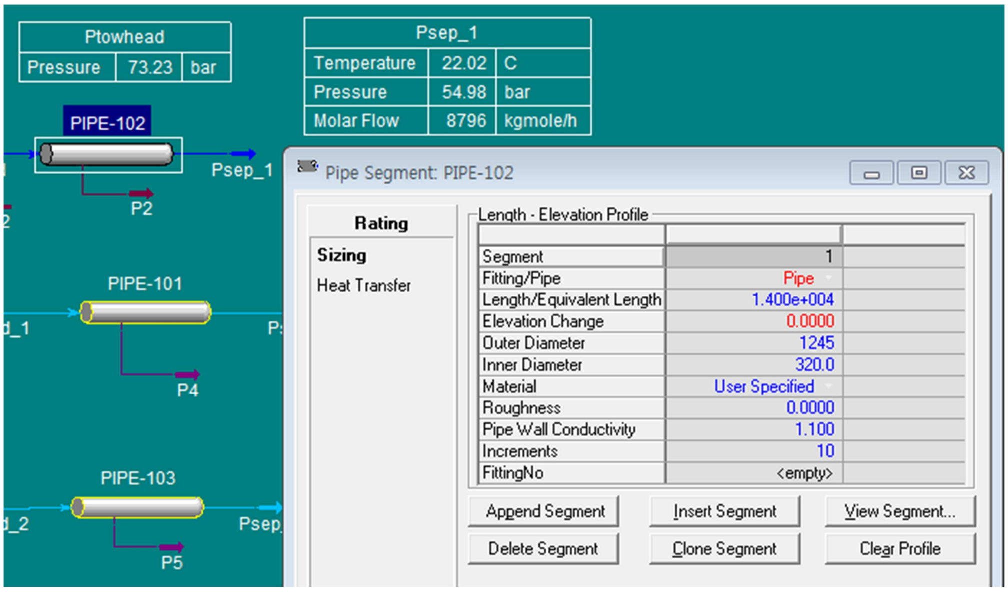


Figure 35: Incompatibility in pipeline between Hysys and Excel work in the case of 2017

Numerous attempts to resolve this problem was done, for example changing to a two-phase model, neglect the vertical riser line which causes gravitational pressure drop and even put a negative value in for the roughness, even if this does not making sense. However, every endeavor resulted in the lower outlet pressure. Since the pipeline model in Hysys is incompatible with that in Excel, we concluded that further work in this area is meaningless.

8.4 Discussion

In connection with the cause of the hydrate analysis failure, our group had a discussion with one of the teaching assistants, Mayembe. Even though the cause was not definitely pinned down, obviously, it is thought that incompatibilities of the simplifying assumptions in our equations for calculating the pressure drop in the pipeline are at fault.

9 Sensitivity analysis

Sensitivity analysis was done in four cases, and compared with the base case, ending at 5 MSm^3/d (to not confound with the low pressure modification). The four cases were: 10% increase in downtime, reduced number of wells, one year delay in the compressor installation and lastly a 10% decrease in the oil and gas price.

9.1 10% increase in downtime

When compared with the base case, 10% increase downtime prolonged natural plateau and compressor plateau by one year and the minimum field economic rate is reached three years later. However, no effect on the recovery rate has been observed (**Table 8**), it just takes more time. This might be due to the effect of pressure drop in the reservoir (decrease in the production rate per year).

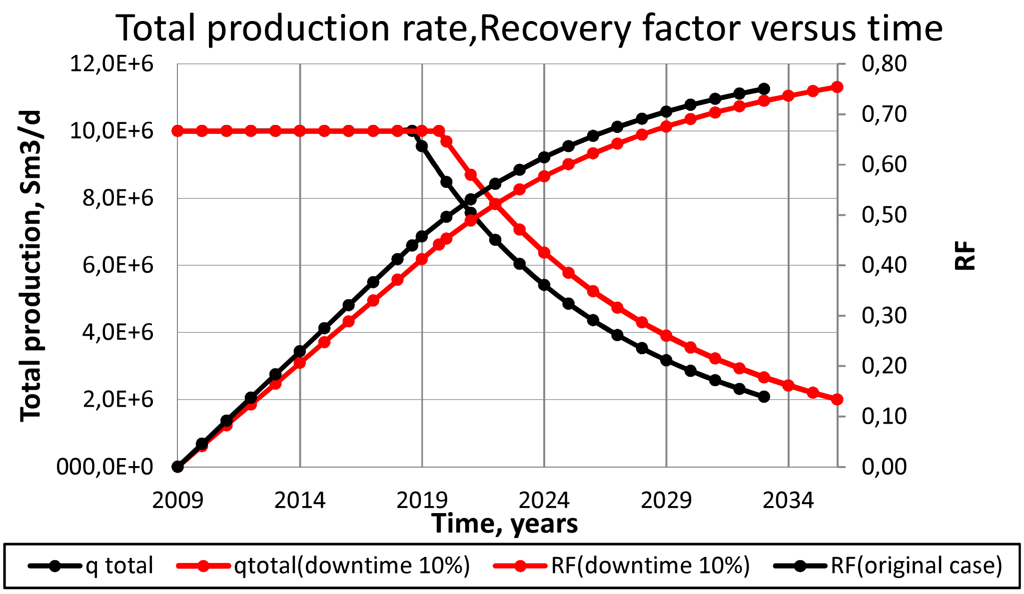


Figure 36: Effect of 10% downtime on production rate and recovery factor

9.2 Reduced number of wells

Shutdown of wells affect the production rate per day .This has affected much the constant plateau rate (10 MSm3/d). The compressor plateau can be only maintained for production rate of 8.5 MSm3/d and 7.5 MSm3/d for the cases of shut down of wells in both L and M templates and L, respectively. The wellhead pressure decreases when we reduce the number of wells. There will be less energy than needed to maintain the flow rate constant at 10 MSm3/d, and therefore the compressor plateau rate is less than 10 MSm3/d.

The end of the constant plateau was reached six month earlier than the base case. The recovery factor decreased to 0.67 when we shut down the wells from L-template.

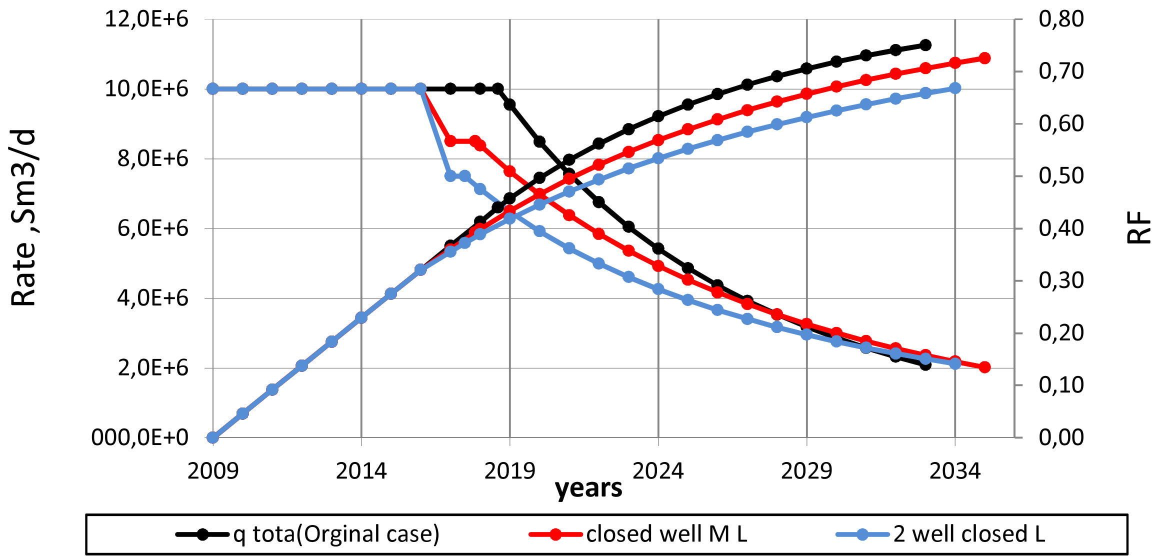


Figure 37: Effect of shutdown of wells on production rate and recovery factor

9.3 Delay of compressor installation

In this part we assume that the subsea compressor starts 1 year after the end of the natural plateau.

During the period 2016-2017, the choke is fully open and therefore there is no more energy to keep the rate constant at 10 MSm3/d. For that reason the rate decreases down to 9.1 MSm3/d.

In 2017 the compressor is started and we could maintain the rate of 9.1 MSm3/d for three more years.

The figure below shows the result when the compressor is installed one year later.

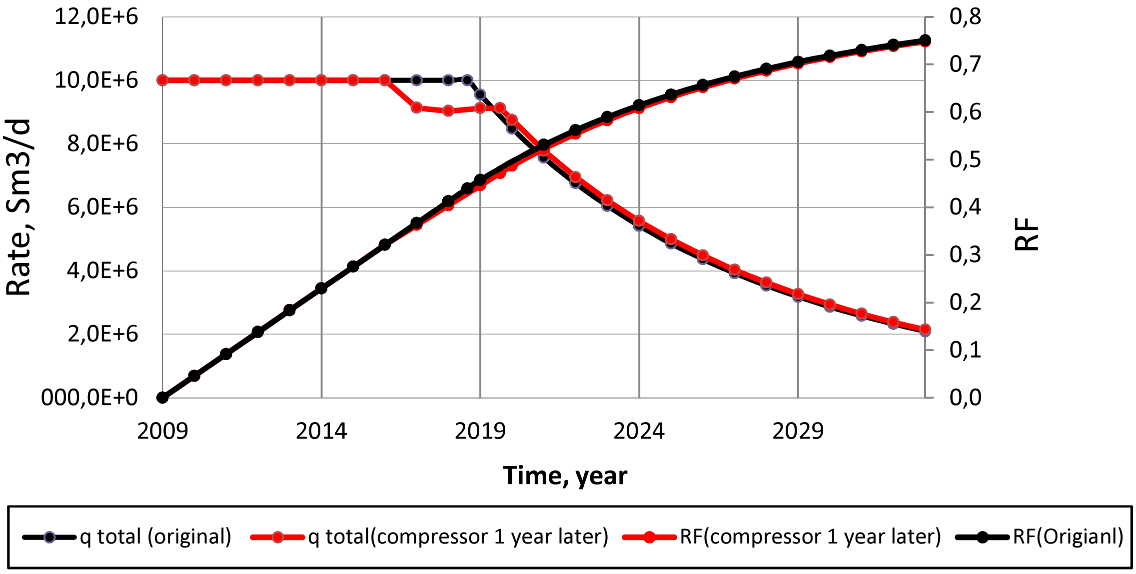


Figure 38: Effect of one year delay of compressor installation on production rate and Recovery Factor

The effect of each sensitivity analysis case on production and the cumulative net present value (in 2021) is shown in the table below:

	Base case	10% Downtime	Shutdown well		Compressor (one year later)
Start of production	2009	2009	2009	2009	2009
End of natural plateau	2016	2017	2016	2016	2016
Compressor plateau rate(MSm3/d)	10	10	8,5	7,5	9,10E+00
End of compressor plateau	2018,6	2019,7	2018	2018	2019,6
Minimum fields economic rate (2MSm3/d)	2033	2036	2035	2034	2033
Recovery factor	0,75	0,75	0,73	0,67	0,75
Cumulative net present value (CNPV) at 2021	10,66	9,72	9,95	9,57	10,46

Table 8: Summary the main results of the sensitivity analysis

Each parameter affects the CNPV, as shown in the **Table 8**. The effect on CNPV for each sensitivity analysis case: 10% increase in downtime, one year delayed compressor installation and shut down of wells is listed. The CNPV is from the time where each case reaches a total production rate of 5 MSm^3/d .

Table 9: Effect on CNPV for each sensitivity analysis

	Base case	**10% Downtime**	**Shutdown well**		**Copressor (one year later)**
			M,L	**L**	
Year when the production rate reached 5MSm3/d	2025	2025	2022	2021	2024
CNPV at 5Ms3/d	11,499,968,391	10,615,164,540	10,193,060,099	9,571,252,898	11,153,474,522

9.4 Sensitivity in prices

Because of the number of uncertainties in the oil and gas prices, a sensitivity analysis was done also for this.

The oil and gas prices were lowered to 90 USD/stb and 0.30 USD/Sm^3 respectively and the exchange rates were changed so that 1 USD corresponds to 5.0 NOK and 0.50 EURO.

This effect of 10% decrease in the oil and gas prices was then compared with the base case at minimum field rate of 2MSm3/d. as shown in table below:

Table 10: Effect of 10% decrease of oil and Gas price on CNPV

Case	CNPV in USD (In 2032)
Base case	12,037,480,316,10
10% decrease Oil &Gas price	10,799,845,065,49

10 Conclusion

The main objective of the project is to find a suitable technology to extract more gas from the Gullfaks South field.

By installing a subsea compressor in 2016, it's possible to prolong the plateau production rate of 10 MSm^3/day for 2.5 years and to increase the recovery to 0.75. We are again conscious of the fact that this is a high number due to our simple model and assumptions. In the real case the recovery would not be that high, but it could be significantly improved compared to the natural flow.

The minimum field economical rate of 2 MSm3/day is reached 4 years later which means that we can produce for a longer period.

Installing two compressor systems is sufficient for the production requirement and they can be operated in parallel up to 2020 and in series after that.

One of the assumptions that we made in our calculations is the dry gas approach. By calculating the condensate from both the dry gas and the gas condensate approach (by using IPT-MATBAL) we got similar results which indicates that the dry gas assumption is accurate enough for the condensate calculation (IPT-MATBAL).

There is a little change in the production by changing the pipe diameter from 14" to 8" but the economical result shows a difference of $190 million in 2024 which means that is more profitable to use the 14" pipe.

The other major improvement in gas recovery is with the low pressure modification since it could increase the recovery further to 0.80.

Finally we found that among all the sensitivity analysis that we made, the 10% decrease of oil and gas price is the one that affects the CNPV the most.

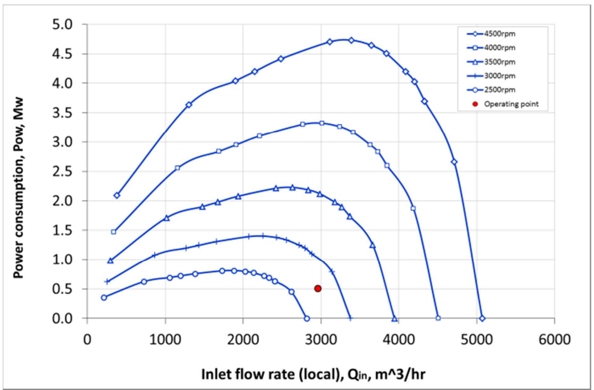
11 Appendix

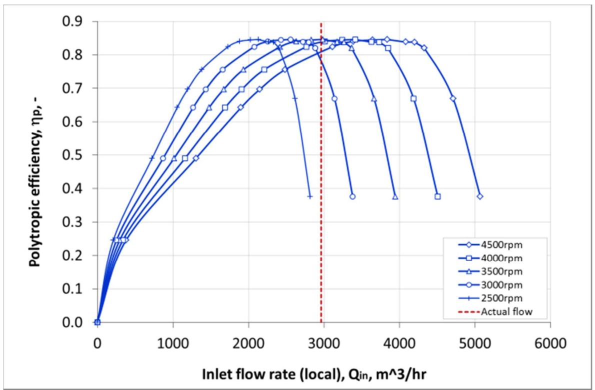
1. Data of the two gas field L and M

Gullfkas South L-M satellite system Pre-comresssion Phase (Start Jan 2009)	East Tank L-Template Fault Block 13 Brent Formation	West Tank M-Template Fault Block 14 Brent Formation			
G=GIIP-Gas cap (31 December 2008)		17,5E+9	Sm3		
Condnsate from Gas Cap (31 December 2008)		4,4E+6	Sm3		
oil legs: STOIIP (31 December 2008)		7,5E+6	Sm3		
Gas in Solution (from oil leg)		1,9E+9	Sm3		
Rs Solution Gas oil Ratio (oil leg) (31 December 2008)		248	Sm3/Sm3		
rs Condensate gas ratio (gas cap) (31 December 2008)		251	Sm3/MSm3		
STOIIP + Condensate (31 December 2008)	34,5E+6		Sm3		
GIIP + diss.gas (31 December 2008)	54,2E+9		Sm3		
Daily Plateau production rate (per template)-Precompression mode	6,0E+6	4,0E+6	Sm3/d		
Wells per template (Pre compression)	4	3			
Production days per year	295	297	day		10% down
T_R	128	112	°C		
Pi, initial Res pressure (01 Jan 2009)	240	210	bara		
Pi, initial Res pressure (1999)	459	446			
C, inflow Back pressure coefficient	1000	700	Sm3/bar^2n		
n, backpressure, exponent	0,8	0,8			
Tubing MD	3515	2800			
Tubing TVD	3100	2500			
Ct, Tubing coefficient 7" (ID=6.094")	38152,4	41163	Sm3/bar		
Elevation coeff Tubing, S	0,43	0,34			
C_{FL} 12".Template L-to-Towhead 66 m (ID=) Pre-compression spool	1403054		Sm3/bar		
C_{FL} 8" Template-to-Towhead 62 m (Id=)	466786		Sm3/bar		
C_{FL} 12".Template M-to-Towhead 64 m (ID=) compression spool		1397663	Sm3/bar		
$C_{PL\ Pipeline}$ 14" Towhead-to-GFC 14000m (ID=0.32m)	148220	148220	Sm3/bar		
$C_{PL\ Pipeline}$ 8" Towhead-to-GFC 14000m (N-Line) (ID=0.197m)	32967	32967	Sm3/bar		
Separator pressure GFC (Inlet Sep)	60	60	bara		
Tope GFC riser pressure (High pressue mode)	65	65			
Tope GFC riser pressure (Low pressue mode)	25	25			
Gas molecular weight (Methane)	19	19	kg/kmole		

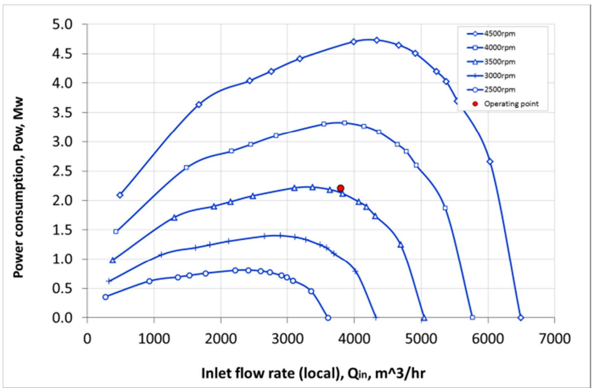
2. Compressor Performance of each year

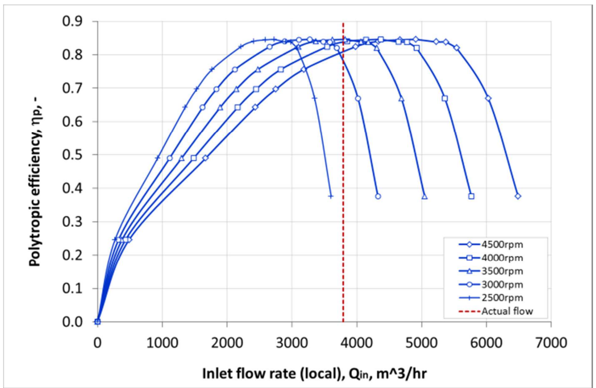
2017			
Period	Compression plateau	Mode	Parallel
Suction pressure [bar]	Discharge pressure [bar]	Suction temperature [C]	Discharge temperature [C]
69.34	73.23	35	42.9
Inlet flow rate(std) [m^3/hr]	Actual inlet flow rate [m^3/hr]	Power consumption [MW]	Efficiency
10.0E+6	2961.9	0.51	0.62



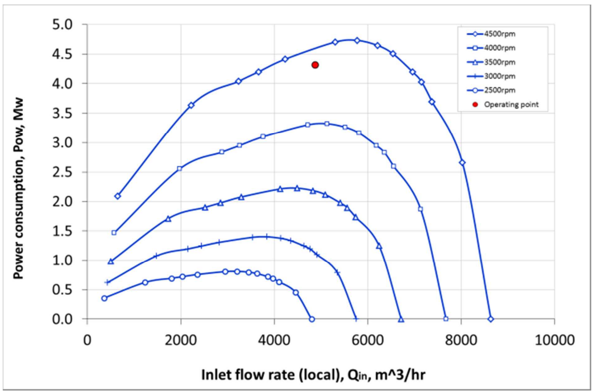


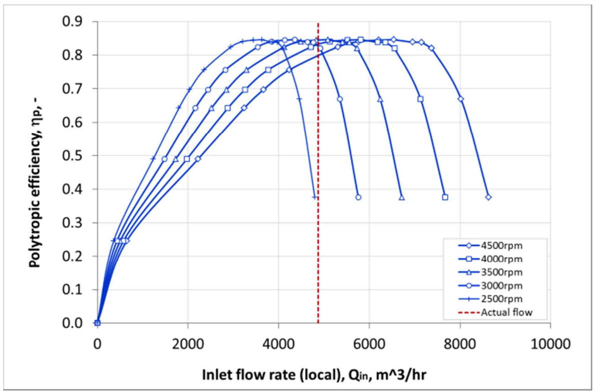
2018 (Parallel)			
Period	Compression plateau	Mode	Parallel
Suction pressure [bar]	Discharge pressure [bar]	Suction temperature [C]	Discharge temperature [C]
54.17	73.23	35	69.1
Inlet flow rate(std) [m^3/hr]	Actual inlet flow rate [m^3/hr]	Power consumption [MW]	Efficiency
10.0E+6	3791.5	2.21	0.82



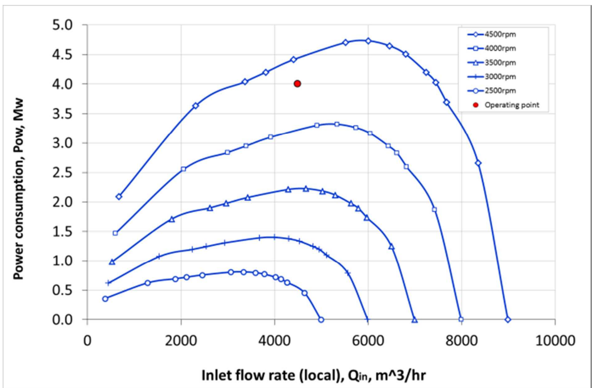


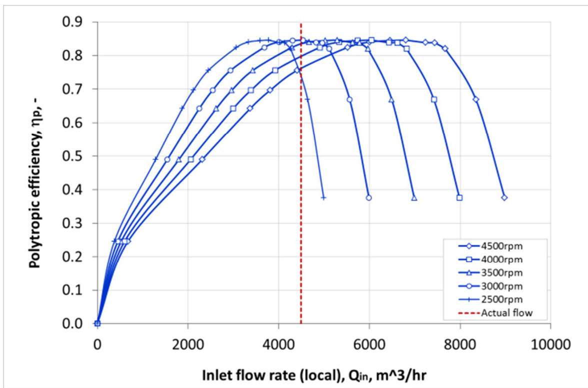
2019 (Parallel)			
Period	After plateau	Mode	Parallel
Suction pressure [bar]	Discharge pressure [bar]	Suction temperature [C]	Discharge temperature [C]
40.71	72.71	35	104.0
Inlet flow rate(std) [m^3/hr]	Actual inlet flow rate [m^3/hr]	Power consumption [MW]	Efficiency
9.7E+6	4872.6	4.32	0.82



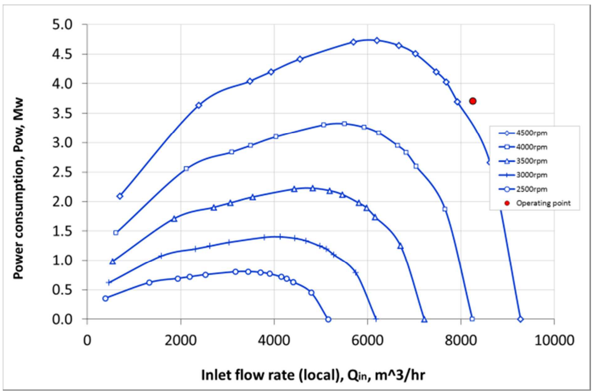


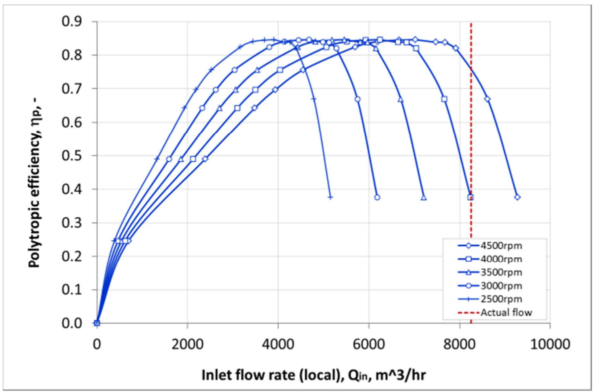
2020 (Parallel)			
Period	After plateau	Mode	Parallel
Suction pressure [bar]	Discharge pressure [bar]	Suction temperature [C]	Discharge temperature [C]
39.12	71.12	35	107.3
Inlet flow rate(std) [m^3/hr]	Actual inlet flow rate [m^3/hr]	Power consumption [MW]	Efficiency
8.6E+6	4491.8	4.01	0.81



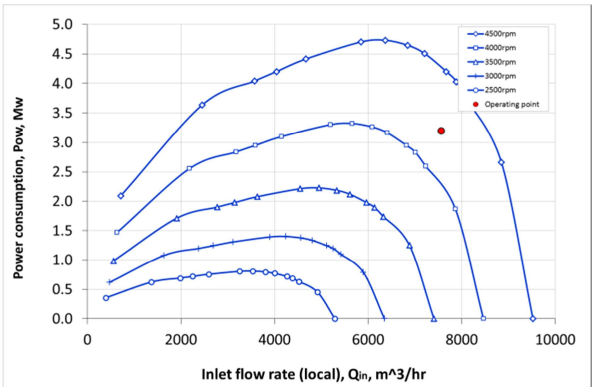


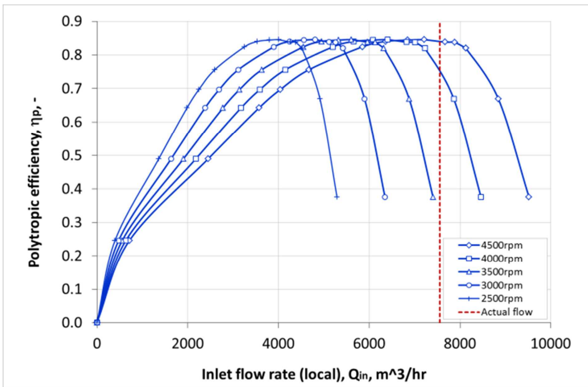
2021 (Series)			
Period	After plateau	Mode	Series
Suction pressure [bar]	Discharge pressure [bar]	Suction temperature [C]	Discharge temperature [C]
37.89	69.89	35	72.6
Inlet flow rate(std) [m^3/hr]	Actual inlet flow rate [m^3/hr]	Power consumption [MW]	Efficiency
7.6E+6	8254.9	3.71	0.76



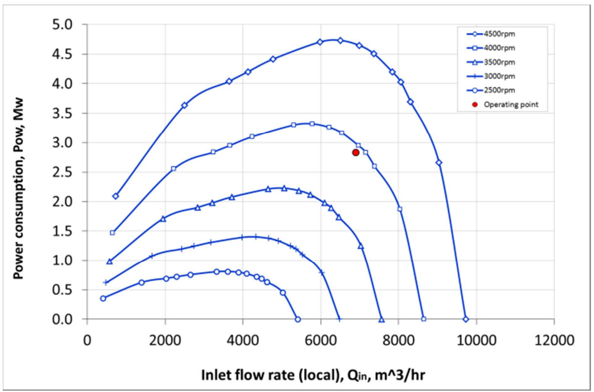


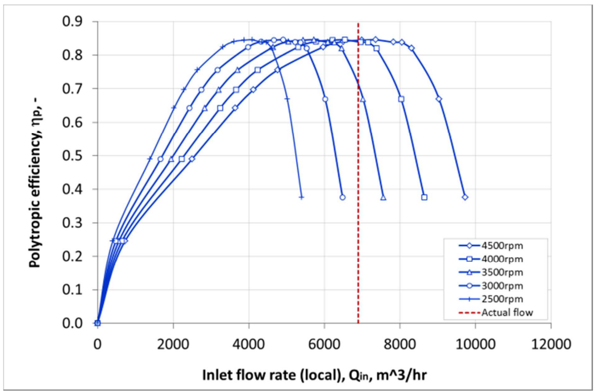
2022 (Series)			
Period	After plateau	Mode	Series
Suction pressure [bar]	Discharge pressure [bar]	Suction temperature [C]	Discharge temperature [C]
36.92	68.92	35	71.3
Inlet flow rate(std) [m^3/hr]	Actual inlet flow rate [m^3/hr]	Power consumption [MW]	Efficiency
6.8E+6	7556.5	3.2	0.8



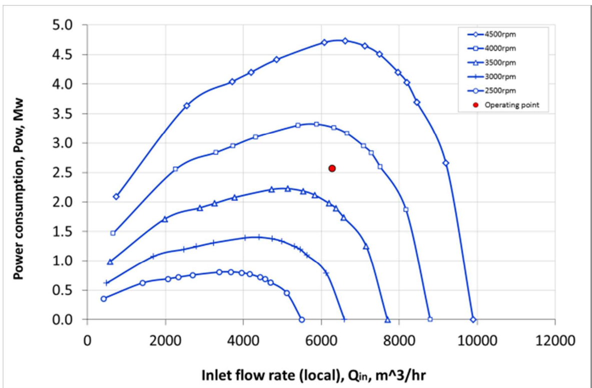


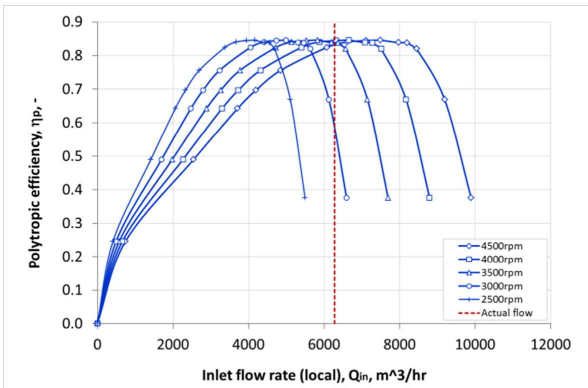
2023 (Series)			
Period	After plateau	Mode	Series
Suction pressure [bar]	Discharge pressure [bar]	Suction temperature [C]	Discharge temperature [C]
36.15	68.15	35	71.0
Inlet flow rate(std) [m^3/hr]	Actual inlet flow rate [m^3/hr]	Power consumption [MW]	Efficiency
6.1E+6	6896.3	2.83	0.82





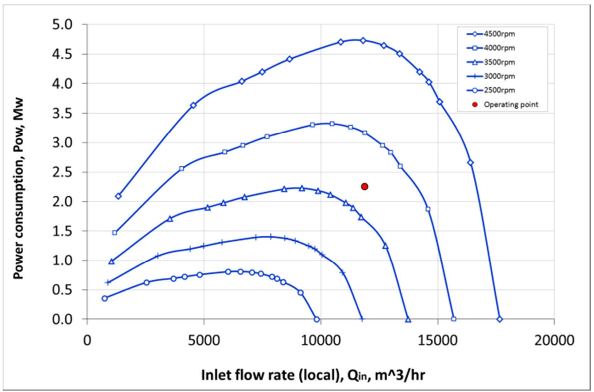
2024 (Series)			
Period	Low pressure modification	Mode	Series
Suction pressure [bar]	Discharge pressure [bar]	Suction temperature [C]	Discharge temperature [C]
19.90	35.06	35	71.5
Inlet flow rate(std) [m^3/hr]	Actual inlet flow rate [m^3/hr]	Power consumption [MW]	Efficiency
6.3E+6	6278.8	2.57	0.82

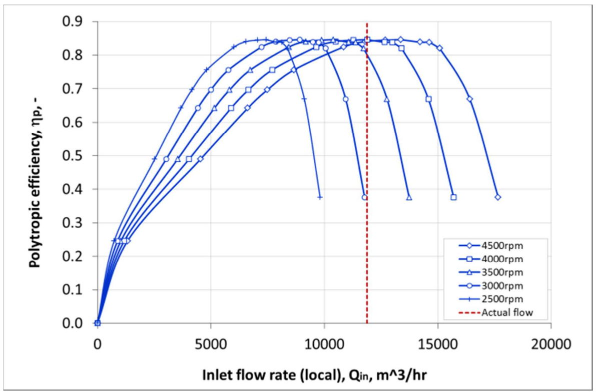




2025 (Series)

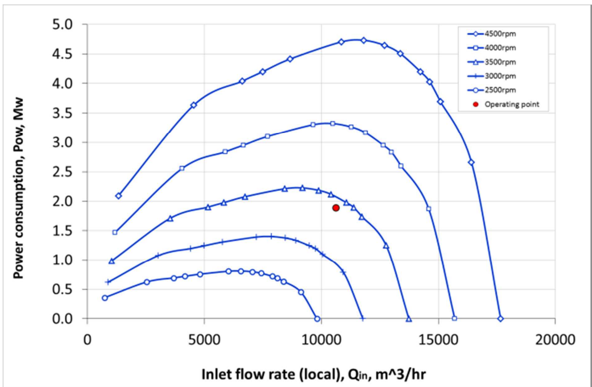
Period	Low pressure modification	Mode	Series
Suction pressure [bar]	Discharge pressure [bar]	Suction temperature [C]	Discharge temperature [C]
19.90	33.77	35	65.3
Inlet flow rate(std) [m^3/hr]	Actual inlet flow rate [m^3/hr]	Power consumption [MW]	Efficiency
5.6E+6	11880.9	2.26	0.82

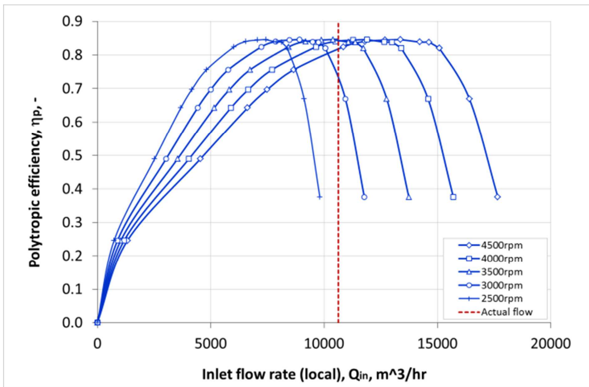




2026 (Series)

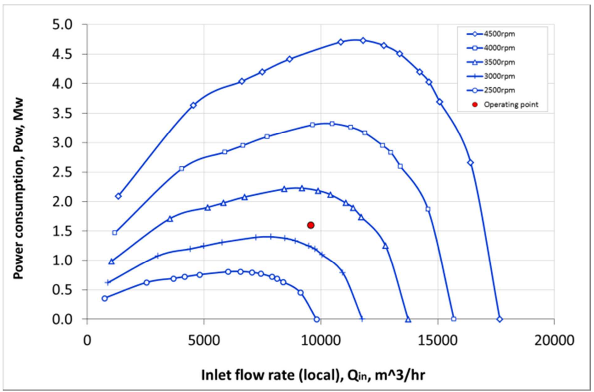
Period	Low pressure modification	Mode	Series
Suction pressure [bar]	Discharge pressure [bar]	Suction temperature [C]	Discharge temperature [C]
19.90	32.74	35	63.3
Inlet flow rate(std) [m^3/hr]	Actual inlet flow rate [m^3/hr]	Power consumption [MW]	Efficiency
5.0E+6	10628.3	1.89	0.82

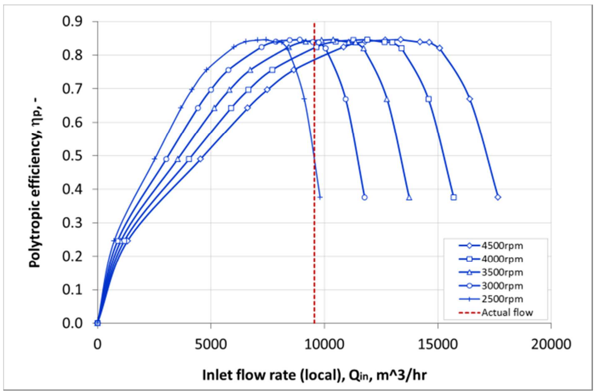




2027 (Series)

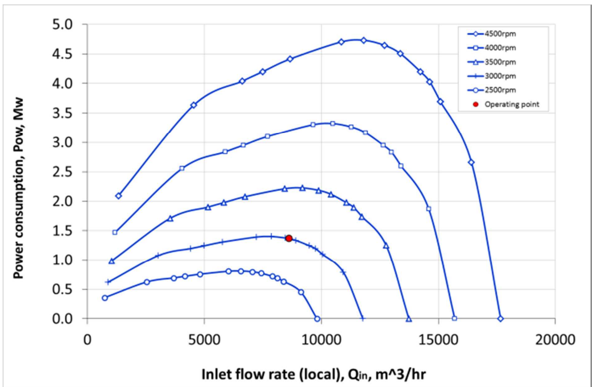
Period	Low pressure modification	Mode	Series
Suction pressure [bar]	Discharge pressure [bar]	Suction temperature [C]	Discharge temperature [C]
19.90	31.89	35	61.7
Inlet flow rate(std) [m^3/hr]	Actual inlet flow rate [m^3/hr]	Power consumption [MW]	Efficiency
4.5E+6	9560.6	1.60	0.82

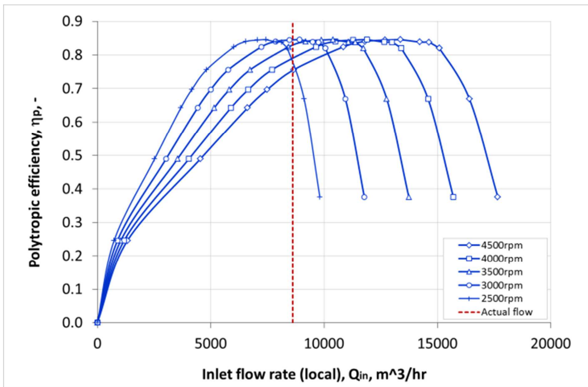




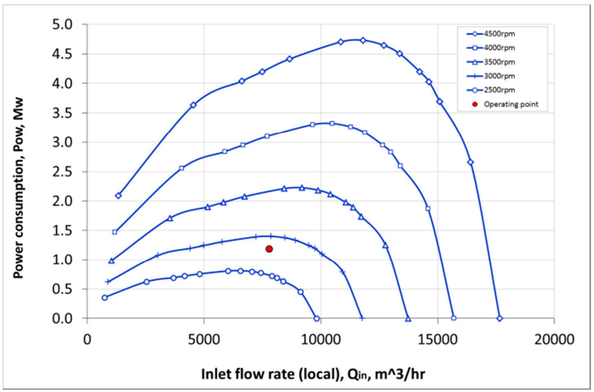
2028 (Series)

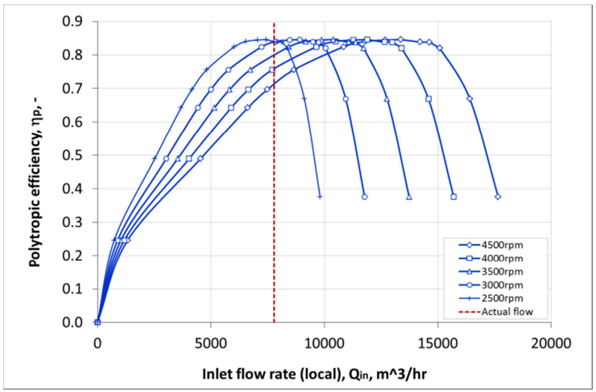
Period	Low pressure modification	Mode	Series
Suction pressure [bar]	Discharge pressure [bar]	Suction temperature [C]	Discharge temperature [C]
19.90	31.20	35	60.4
Inlet flow rate(std) [m^3/hr]	Actual inlet flow rate [m^3/hr]	Power consumption [MW]	Efficiency
4.1E+6	8618.1	1.37	0.82



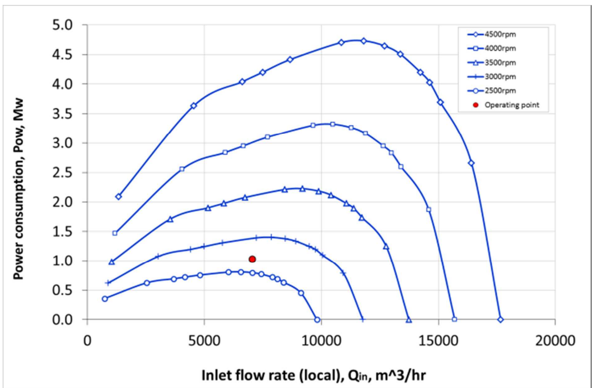


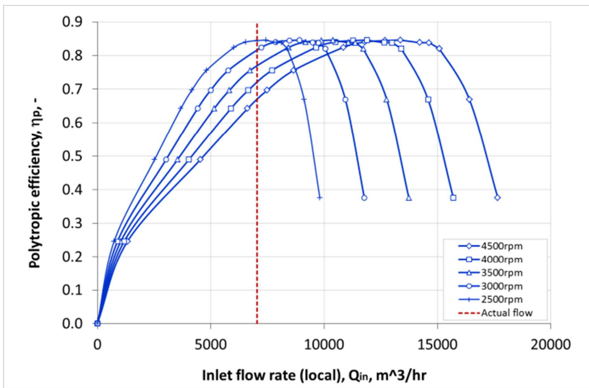
2029 (Series)			
Period	Low pressure modification	Mode	Series
Suction pressure [bar]	Discharge pressure [bar]	Suction temperature [C]	Discharge temperature [C]
19.90	30.64	35	59.3
Inlet flow rate(std) [m^3/hr]	Actual inlet flow rate [m^3/hr]	Power consumption [MW]	Efficiency
3.7E+6	7784.3	1.19	0.82



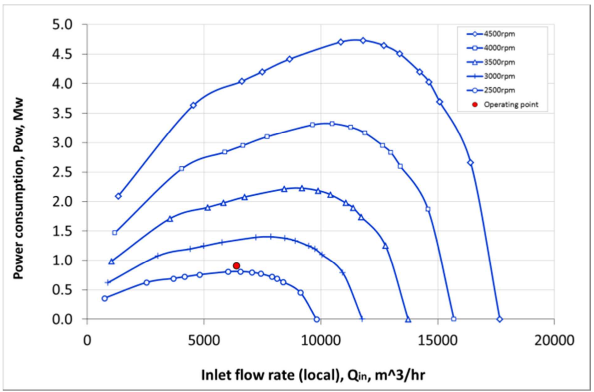


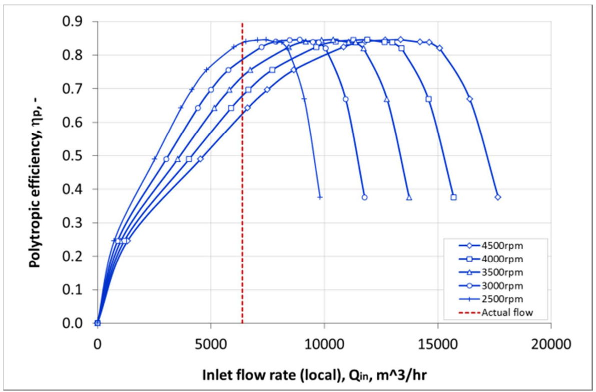
2030 (Series)			
Period	Low pressure modification	Mode	Series
Suction pressure [bar]	Discharge pressure [bar]	Suction temperature [C]	Discharge temperature [C]
19.90	30.18	35	58.4
Inlet flow rate(std) [m^3/hr]	Actual inlet flow rate [m^3/hr]	Power consumption [MW]	Efficiency
3.3E+6	7044.3	1.03	0.82



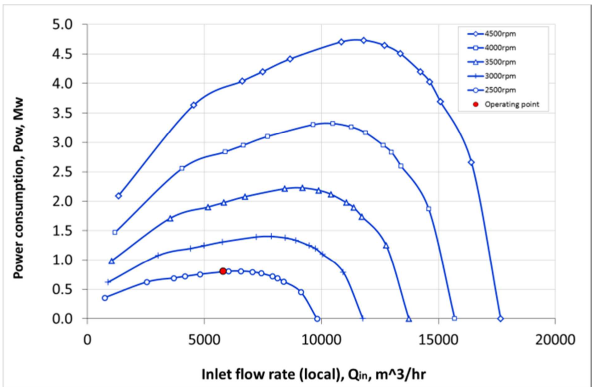


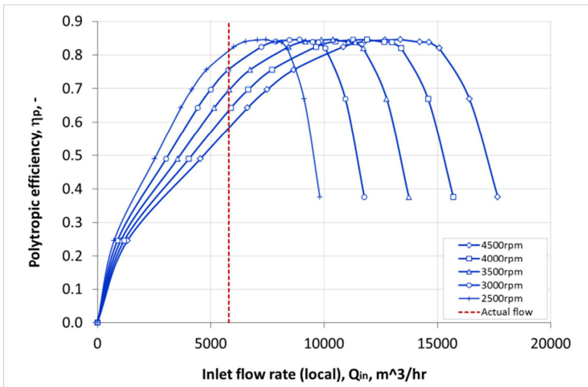
2031 (Series)			
Period	Low pressure modification	Mode	Series
Suction pressure [bar]	Discharge pressure [bar]	Suction temperature [C]	Discharge temperature [C]
19.90	29.81	35	57.6
Inlet flow rate(std) [m^3/hr]	Actual inlet flow rate [m^3/hr]	Power consumption [MW]	Efficiency
3.0E+6	6385.5	0.91	0.82



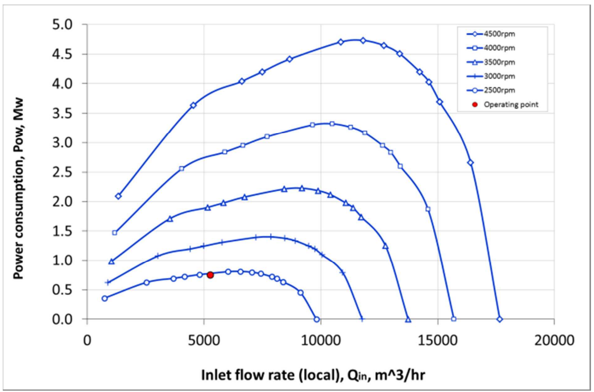


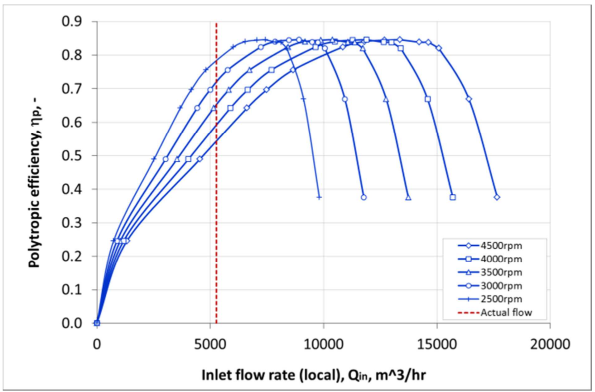
2032 (Series)			
Period	Low pressure modification	Mode	Series
Suction pressure [bar]	Discharge pressure [bar]	Suction temperature [C]	Discharge temperature [C]
19.90	29.50	35	57.3
Inlet flow rate(std) [m^3/hr]	Actual inlet flow rate [m^3/hr]	Power consumption [MW]	Efficiency
2.8E+6	5797.5	0.81	0.81



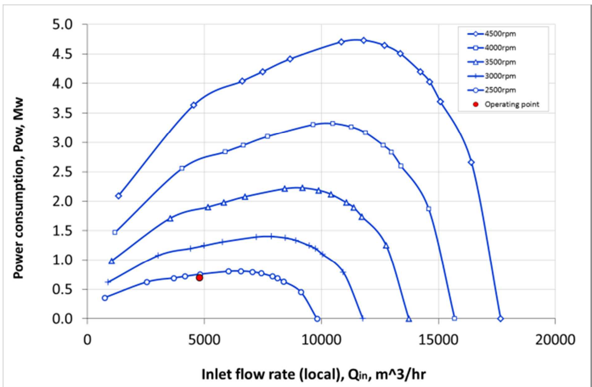


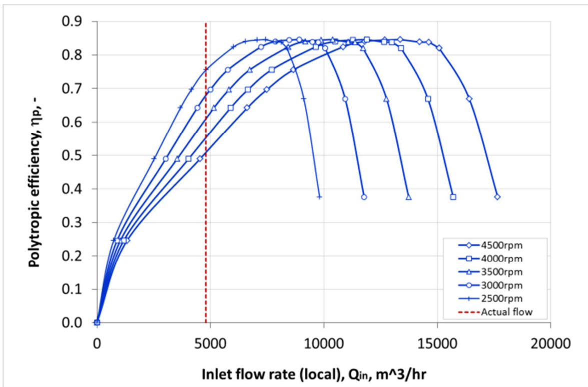
2033 (Series)			
Period	Low pressure modification	Mode	Series
Suction pressure [bar]	Discharge pressure [bar]	Suction temperature [C]	Discharge temperature [C]
19.90	29.24	35	57.6
Inlet flow rate(std) [m^3/hr]	Actual inlet flow rate [m^3/hr]	Power consumption [MW]	Efficiency
2.5E+6	5271.2	0.75	0.78



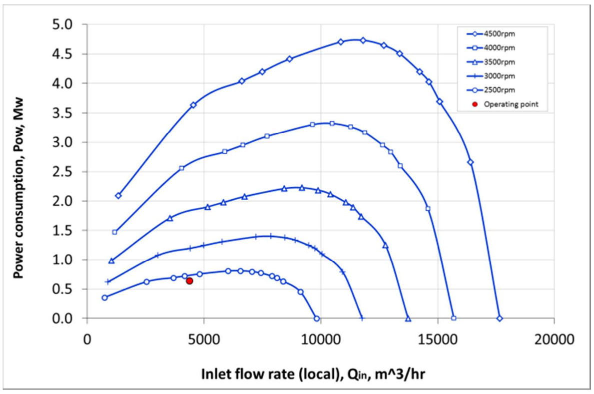


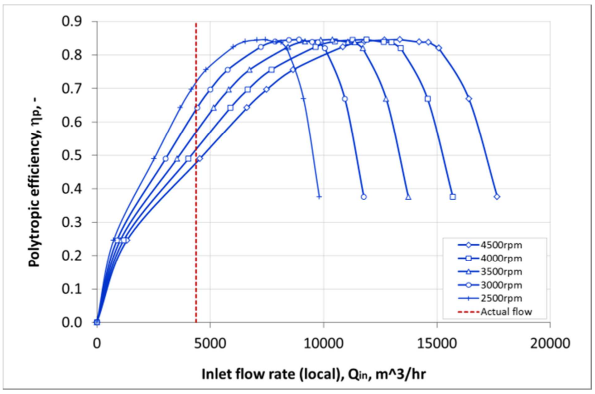
2034 (Series)			
Period	Low pressure modification	Mode	Series
Suction pressure [bar]	Discharge pressure [bar]	Suction temperature [C]	Discharge temperature [C]
19.90	29.04	35	58.1
Inlet flow rate(std) [m^3/hr]	Actual inlet flow rate [m^3/hr]	Power consumption [MW]	Efficiency
2.3E+6	4799.0	0.70	0.75





2035 (Series)			
Period	Low pressure modification	Mode	Series
Suction pressure [bar]	Discharge pressure [bar]	Suction temperature [C]	Discharge temperature [C]
19.90	28.86	35	58.3
Inlet flow rate(std) [m^3/hr]	Actual inlet flow rate [m^3/hr]	Power consumption [MW]	Efficiency
2.1E+6	4374.3	0.64	0.73





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