Dokuz Eylül Üniversitesi Mühendislik Fakültesi Fen ve Mühendislik Dergisi
Dokuz Eylul University Faculty of Engineering Journal of Science and Engineering

Basılı/Printed ISSN: 1302-9304. Elektronik/Online ISSN: 2547-958X

Feasibility of Hydrocarbon Gas Injection in Valdemar Field of Danish Central Graben in the North Sea

Kuzey Denizi'ndeki Danimarka Merkez Graben Valdemar Alanına Hidrokarbon Gaz Enjeksiyonunu Fizibilite Çalışması

Vural Sander Suiçmez[1*]

[1] Quantum Reservoir Impact, LLC., Houston, Texas, USA
Sorumlu Yazar / Corresponding Author *: vss@imperial.ac.uk

Geliş Tarihi / Received: 29.03.2018
Kabul Tarihi / Accepted: 05.09.2018
DOI:10.21205/deufmd.2019216106
Araştırma Makalesi/Research Article

Atıf şekli/ How to cite: SUİÇMEZ, V.S. (2019). Feasibility of Hydrocarbon Gas Injection in Valdemar Field of Danish Central Graben in the North Sea. DEUFMD, 21(61), 55-66.

Abstract

Valdemar Field was discovered as early as 1977 in the central part of the Danish Central Graben in the North Sea. Significant hydrocarbon volume is reported in the Lower Cretaceous formation which has been developed via pure pressure depletion for the last few decades. Due to the tight nature of the Lower Cretaceous and declining reservoir pressure, the average economic ultimate recovery (EUR) from Valdemar field is significantly lower than what is achievable in the neighboring fields such as Dan, Halfdan or Gorm where water flooding is utilized for pressure support. On top of this, lack of sufficient petrophysical data stand as an important barrier to better understand the certain shortcomings as well as to make reliable predictions for the future performance of the field.

In the course of this study, we investigate different development options for the Valdemar Field. We utilize both analytical and numerical methods to study water and/or gas injection opportunities to boost the production and hence EUR in Valdemar. We first compare the efficiency of water and gas injection by employing analytical techniques. Results suggest that better injectivities, availability and short response times may make hydrocarbon gas injection a promising candidate for a further development option. That kind of a development scheme would, however, require a significant capital expenditure such as building a new well head platform and installation of a high pressure gas injection compressor.

We present a detailed phase behavior study on a recently obtained Lower Cretaceous oil sample. Both static and dynamic PVT tests, such as the swelling test and multi-contact experiments, were conducted and a reliable compositional model was built. We then construct a 3-D box model to study gas injection via long horizontal wells in a line drive mode. Model honors petropyhsical information obtained from the available well log data. It is further tuned to history match the production and pressure data, which is also in line with the previously developed full-field model.

Results suggest that additional oil can be recovered via hydrocarbon gas injection in Valdemar field. We conduct a set of sensitivity studies to optimize the gas injection process. We show that the key

parameter is, by far, the gas injection rate. Higher injection rates result in higher pressure drops and hence development of a large miscible zone, which significantly increase the oil production. This would, in return, require larger compression power and more gas recycling capacity.
Keywords: *gas injection, oil field development, modelling, production enhancement*

Öz

Valdemar Sahasının keşfi Kuzey Denizindeki Danimarka Merkez Grabeninin orta kesiminde 1977 senesinde gerçekleştirilmiştir. Son bir kaç on yıl boyunca sadece basınç tükenimine dayalı olarak geliştirilen sahanın Alt Kretase formasyonunda önemli hidrokarbon hacimlerinin mevcudiyeti rapor edilmiştir. Basınç desteğinin sağlanması için su itim mekanizmasının kullanıldığı Valdemar sahasına komşu olan Dan, Halfdan veya Gorn gibi sahalardan elde edilenin aksine az geçirimli özelikte olan Alt Kretase ve azalan rezervuar basınçları sebeplerinden dolayı Valdemar sahasının ortalama ekonomik nihai kurtarım (ENK) değeri oldukça düşüktür. Bunlara ilave olarak, yeterli petrofiziksel verinin elde olmaması; sahanın gelecek performansı hakkında güvenilir ölçüde tahminler yapılabilmesinin yanısıra belirli eksikliklerin daha iyi anlaşılabilmesinde önemli bir engeldir.

Üretimin ve dolayısıyla ENK'nin arttırılma fırsatları için su ve/veya gaz enjeksiyon çalışmalarının hem analitik hem de numerik metotları kullanılmaktadır. İlk olarak analitik teknikler kullanılarak su ve gaz enjeksiyonunun verimliliği karşılaştırılmıştır. Elde edilen sonuçlar; sahanın dahada geliştirilmesi seçeneği için gaz enjeksiyonunun daha iyi enjekte edilmesi, bulunabilirlik ve kısa sonuç alma süresi nedenleriyle daha umut verici olduğunu göstermiştir. Bu tür bir geliştirme planı, her ne var ki; yeni bir kuyubaşı platformunun yerleştirilmesi ve yüksek basınçlı gaz enjeksiyon kompresörlerinin montajları gibi büyük bir yatırım harcaması gerektirecektir.

Bu çalışmada; Alt Kretase formasyonundan elde edilmiş olan petrol numunesine yönelik olarak detaylı bir faz davranış çalışması verilmektedir. Şişme testi ve çoklu temas deneyleri gibi hem statik hem de dinamik PVT analizleri gerçekleştirilmiş ve güvenilir bir kompozisyon modeli elde edilmiştir. Uzun yatay kuyular boyunca çizgi hattı modu şeklinde gaz enjeksiyonunun çalışılması için 3-Boyutlu bir model oluşturulmuştur. Model mevcut olan kuyu log verilerinden elde edilen petrofizik bilgilerini dikkate almaktadır. Model ayrıca daha önce geliştirilmiş olan tam alan modeliyle aynı doğrultuda olan üretim ve basınç verilerinin tarihsel eşleşmesine uyarlanmıştır.

Sonuçlar Valdemar sahasından gaz enjeksiyonu yoluyla ilave petrolün üretilebileceğine işaret etmektedir. Gaz enjeksiyonu sürecinin optimize edilmesine yönelik olarak bir dizi duyarlılık çalışması yürütülmektedir. Çalışma anahtar parametrenin en önde geleninin gaz enjeksiyon oranı olduğunu göstermiştir. Daha yüksek enjeksiyon oranları petrol üretim artışını büyük ölçüde artıracak daha fazla basınç azalımları ve böylelikle geniş karışabilir alanların oluşmasına yol açacaktır. Bu sonuç olarak daha büyük kompresyon gücüne ve daha yüksek gaz geri dönüşüm kapasitesine olan ihtiyacı doğuracaktır.
Anahtar Kelimeler: *gaz enjeksiyonu, petrol sahası geliştirilmesi, modelleme, üretim geliştirme*

1. Introduction

The Valdemar field is located in the central part of the Central Graben in the Danish North Sea at the junction between the Tail End Graben, the Salt Dome Province and the Arne Elin Graben Figure 1. It consists of a northern reservoir called North Jens and a southern reservoir called Bo, which are both anticlinal chalk structures associated with tectonic uplift.

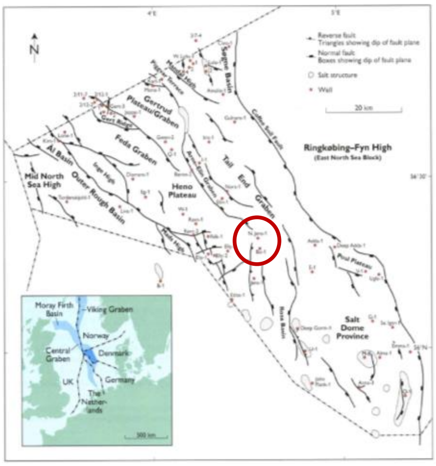

Figure 1. Regional overview of the Danish Central Graben. Red circle indicates the location of the Valdemar field.

The Valdemar Field comprises several separate accumulations. Oil and gas have initially been discovered in Danian/Upper Cretaceous chalk formation. However, large volumes of hydrocarbons have later been identified in the Lower Cretaceous chalk formation. The extremely low permeability layers in the Lower Cretaceous possess challenging production properties in the most parts of the Valdemar Field.

The measured gas permeabilities on non-fractured Lower Cretaceous samples range from 0.01 to less than 4mD with a predominance around 0.4mD. However, fracture permeability may increase the effective permeability of the formation by a factor of around five, Frykman, [1]. Although we observe low permeabilities throughout the Lower Cretaceous formation, reservoir properties are generally good with respect to porosity and hydrocarbon saturations, Jakobsen et al., [2].

The first Lower Cretaceous producer in Valdemar field was drilled in 1989, which was quickly followed by another four wells. From 2005 onwards, an extensive development campaign was initiated from an additional unmanned platform in the northern area. The wells were drilled horizontally in a parallel pattern following the north-south trending crest of the anticline see Figure 2. The wells were stimulated with induced sand fractures to enable vertical communication through the low permeability shale and marl beds.

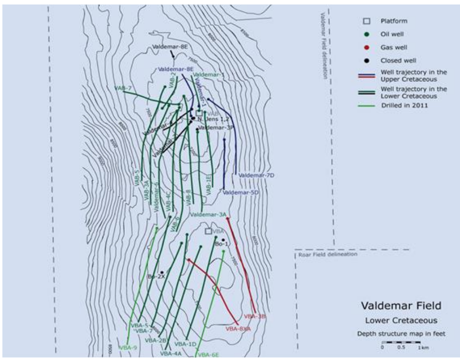

Figure 2. Valdemar field depth structure map. Note the north-south trending horizontal well trajectories. A total number of 16 wells were completed in Lower Cretaceous formation.

The field is currently being developed by a total number of 21 wells (16 of which were completed in the Lower Cretaceous) on natural depletion mode. The North Jens area of the Valdemar Field has been developed as a satellite to the nearby Tyra field with two bridge-connected, unmanned wellhead platforms, Valdemar AA and AB. The Bo area of the Valdemar Field has been developed with an unmanned wellhead platform, Valdemar BA, where the production goes through a 16” multiphase pipeline being transported to the nearby Tyra East via the Roar platform. Figure 3 shows a schematic of the Valdemar field’s facility network.

In the course of this study, we evaluate different development options for Valdemar field. Results confirm that additional oil can be recovered via hydrocarbon gas injection. In the rest of this paper, we will first discuss the analytical tools which are utilized to compare the efficiency of the water flooding with the gas injection. We then present the gas injection workflow and discuss the details of the scenarios built to study the feasibility of hydrocarbon gas injection in Valdemar field.

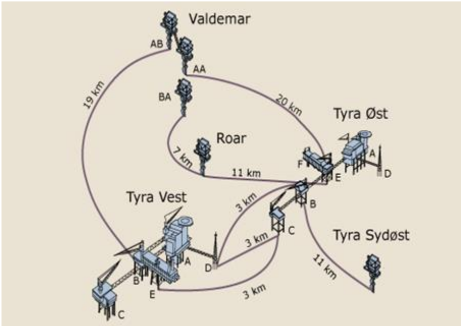

Figure 3. A schematic of the Valdemar field's facility network. Note that all the wells were drilled from the three unmanned wellhead platforms, AA, AB and BA.

2. Analytical Model

A quick screening study is employed to investigate water versus gas displacement efficiency in a specific part of the Valdemar Lower Cretaceous reservoir. The oil displacement efficiency of a water or gas flooding can be calculated using water-oil or gas-oil relative permeability curves and oil-water or gas-water viscosities. The established procedure is to construct a plot of the fractional flow of water versus water saturation and a plot of the fractional flow of gas versus gas saturation. Performances of water saturation before and after breakthrough are then estimated based on the frontal displacement theory of Buckley and Leverett [3].

We utilize imbibition relative permeability curve for water injection although drainage relative permeabilties are used for the gas flooding. Corresponding fractional flow curves can be seen in Figure 4. Hydrocarbon in place and the absolute permeability values, i.e. 0.5 mD, are assumed to be equal for the two displacement scenarios. The recovery factor calculated at the breakthrough time is around 58% for waterflooding and 28% for gas injection.

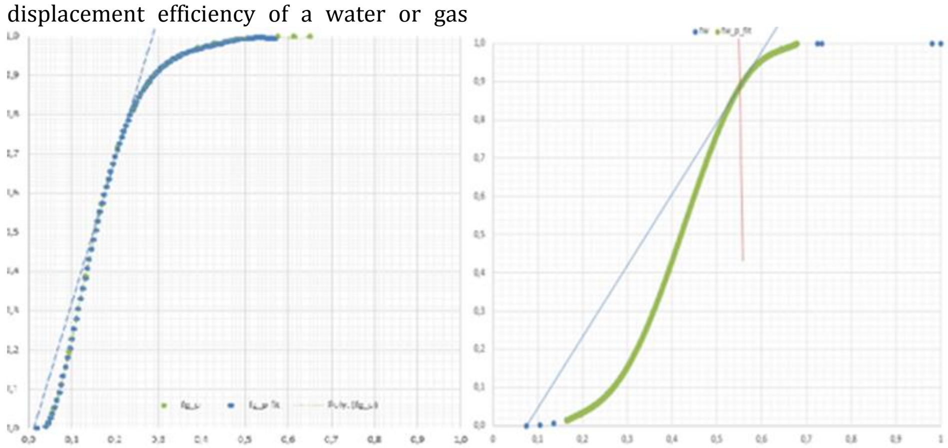

Figure 4. Gas-oil (left) and water-oil (right) fractional flow curves. Results suggest that better injectivities and relatively short response times make gas injection a good candidate for a further development option.

Although the ultimate recovery is substantially lower via gas injection, significantly shorter response time makes it a promising candidate for a further development option. It is estimated that breakthough reaches after two years via gas injection whereas it is around 32 years with waterflooding. As gas can be re-injected, it may significantly increase oil recovery given a longer time span. Furthermore, processes such as the viscosity and IFT reduction and component exchange during gas injection may substantially boost the recovery factors estimated by the one-dimensional Buckley-Leverett [3] analysis.

3. Gas Injection

Gas injection is one of the most widely used enhanced oil recovery (EOR) techniques in the world, Kokal and Al-Kaabi, [4]. Gas flooding is considered as an efficient oil recovery technique as it improves the microscopic displacement efficiency and reduces the residual oil saturation significantly below the levels that can typically be achieved via water injection. If the gas injection process is operated at certain reservoir conditions (pressure and temperature), displacing (injected gas) and displaced (reservoir oil) fluids may become miscible, which would substantially boost the production in such resources.

Gas injection projects are typically undertaken when and where there is a readily available gas supply; Johns and Dindoruk [5]. In the course of this study, we consider re-injecting the produced hydrocarbon gas back into the reservoir in order to improve and maintain the reservoir pressure as well as to take advantage of the typical other benefits associated with gas displacements such as the vaporization of the light/intermediate oil components, viscosity reduction and swelling of oil. In order to account for all those effects and accurately predict the performance of gas floods, it is crucial to conduct compositional simulations that are based on a thermodynamically-consistent model such as a cubic equation of state (EOS).

An EOS model, in principle, is capable of predicting all the pressure-volume-temperature (PVT) data, using only the composition of the original reservoir fluid. However, its predictive capabilities are considered to be less reliable unless a set of parameters such as the critical pressure, critical temperature, and acentric factor for each pseudo-component is properly tuned to match the experimental data. Therefore, as a first step, a representative oil sample was taken and sent to a commercial PVT laboratory to conduct a set of phase behavior experiments which were then used to tune our EOS model.

3. 1. Phase behavior

A set of static (constant composition expansion and differential liberation experiments) and dynamic (swelling test and multi-contact experiments) PVT experiments was conducted in Schlumberger Reservoir Laboratories in Edmonton, Alberta, Canada. Experimental data were then used to generate and tune a 10-component EOS model.

A detailed composition of the synthetic gas and the export gas was provided to the vendor. Synthetic gas was used for recombination with the stock tank oil (STO) to obtain a representative reservoir fluid, whereas the export gas was utilized as the injection gas in the swelling experiments.

Swelling test is a single-contact phase-behavior experiment to measure the solubility of injected gas in reservoir oil. It is commonly conducted in a visual PVT cell where a predetermined volume of injection gas is added to the reservoir fluid at the reservoir temperature. The increase in the volume as well as the total sample volume is determined. The newly created mixture is then subjected to a constant composition expansion (CCE) experiment and the saturation pressure and liquid shrinkage are measured. This is repeated for a number of steps by increasing the mole fraction of gas added into the cell.

Results of the experimentally measured and numerically predicted swelling data and the corresponding saturation pressure versus mole fraction of the injection gas (P-x diagram) can be seen in Figures 5 and 6 respectively. Note that 10-component EOS model satisfactorily predicts the measured data obtained during the swelling experiments Figure 5.

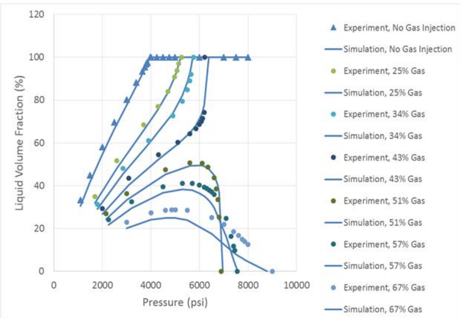

Figure 5. Experimentally measured liquid volume fraction versus Pressure. Note that the behavior is satisfactorily mimicked with a 10-component EOS model.

Although the minimum miscibility pressure (MMP) for reaching a first contact miscible (FCM) displacement is often unpractical, miscibility can be achieved via the repeated contacts of the displacing (gas) and displaced (oil) fluids. This is called the multiple contact miscibility (MCM) and the required MMP is often significantly lower than the one required for reaching the FCM.

With the well-characterized 10-component EOS model, we conduct a set of slim-tube simulations at reservoir temperature to estimate the MMP for MCM. As can be seen in Figure 7, we calculate the MMP to be around 5,500 psi.

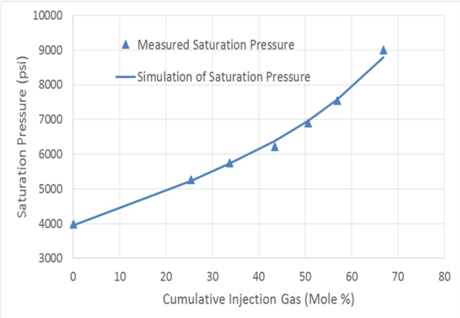

Figure 6. Saturation pressure versus mole fraction of the export gas injected. Note that the maximum amount of mole fraction of gas achieved in the experiment is 67%. Critical point lies between 43% and 51% of mole fraction of gas injection. This confirms that the first contact miscibility (FCM) pressure with the export gas at reservoir temperature is above 9,000 psi which is, as expected, significantly higher than the initial reservoir pressure.

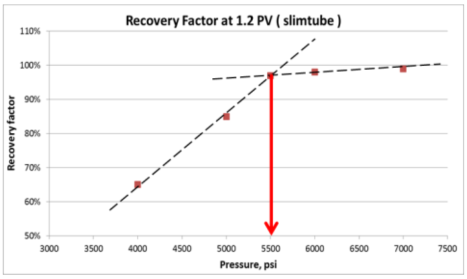

Figure 7. Recovery factor at 1.2 pore volumes (PV) of gas injection versus Pressure. Note the intersection of the two slopes, which suggests an MMP of around 5,500 psi.

3. 2. Development concept

An underlying assumption for implementation of a continuous lean gas injection for secondary recovery is that water injection would not be as effective as gas flooding in Valdemar field due its lower compressibility and higher viscosity as compared to gas.

Figure 8 shows the proposed gas injection development plan. It involves drilling injectors between the existing producers. A total of five injectors are planned in North Jens while five injectors are planned in Bo area. A new unmanned STAR wellhead platform will be used to drill those wells. Injectors may also be stimulated with induced sand fractures similar to existing producers.

A new lean gas injection compressor on Tyra production platform will be built which to be linked to Valdemar with a hydrocarbon gas injection flow line. All fluid processing will take place through the original production lines. Valdemar gas lift installation project is an ongoing project and is expected to be implemented within the next few years. Hence it is safe to assume that gas lift facilities will already be installed by the time the project may be initiated.

4. Simulation Model

A three-dimensional box model with 1 horizontal producer and 2 horizontal half injectors was built to represent Valdemar Lower Cretaceous reservoir in North Jens and Bo areas see Figure 9. A well spacing of around 400 and 550 ft between the producer and injector was utilized for North Jens and Bo areas respectively. This is inline with the average distance between a producer and an injector, if an injector is to be drilled between two existing producers in North Jens and Bo. The horizontal section of the wells is around 600 ft in the box model, which is significantly shorter than the actual horizontal length of the wells that is around 10,000ft. Therefore, we scale all our injection and production rates to a 10,000 ft well's horizontal section by assuming that the rates are directly proportional with the length of the horizontal trajectory.

Layer thicknesses and average porosities associated with each layer were calibrated against the available log data. Permeability values and dynamic properties such as the capillary pressure and relative permeabilities were taken from the previously conducted full field simulation study. The model was calibrated to match the performance of one of the North Jens wells. Figure 10 shows the estimated oil and total liquid rate and its comparison against the well test data and full field model predictions respectively. Figure 11 compares the actual and simulated bottomhole pressures (BHP). The lowest bottom hole producing pressure of around 1,700 psi was observed in the depletion mode. The observed trend was deemed satisfactory to proceed with the further development work.

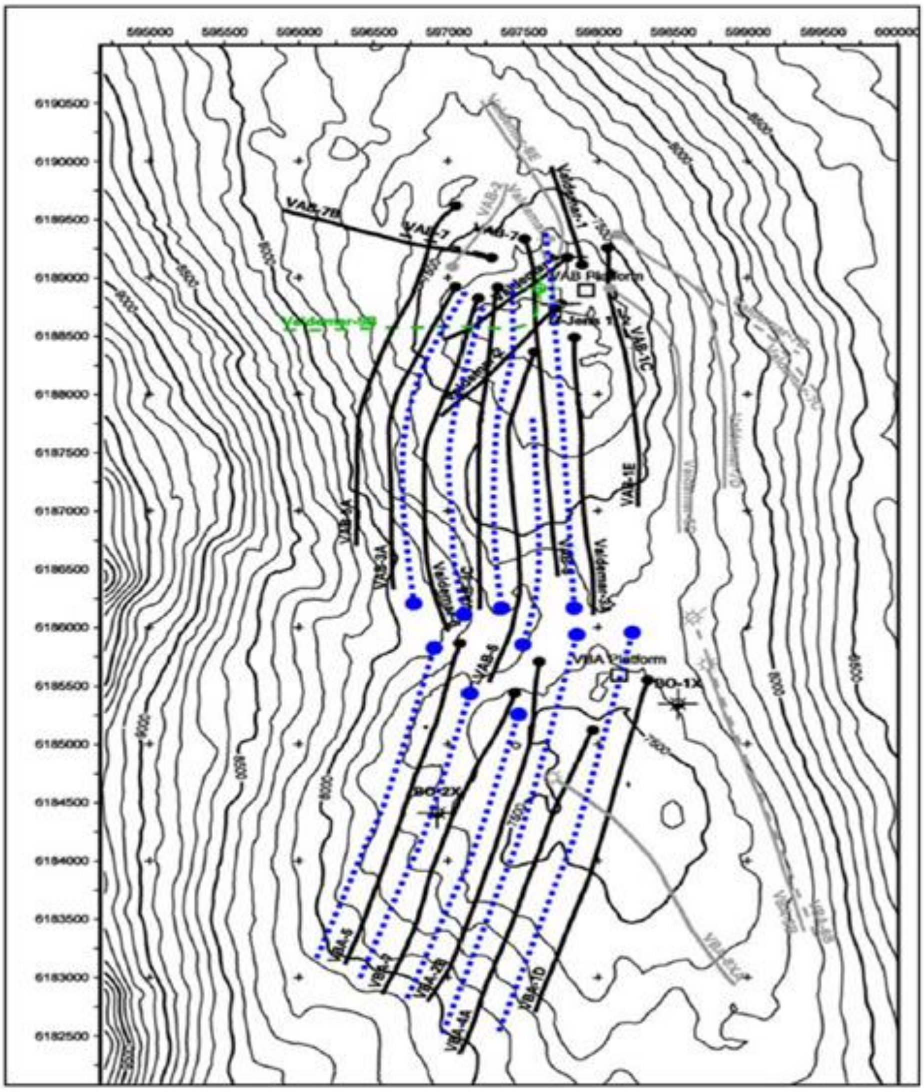

Figure 8. Recommended gas injection development plan in Valdemar field. Note that horizontal trajectories of the gas injection wells are shown by the blue dotted lines. We propose to drill five injectors between the producers in North Jens and Bo areas respectively.

.

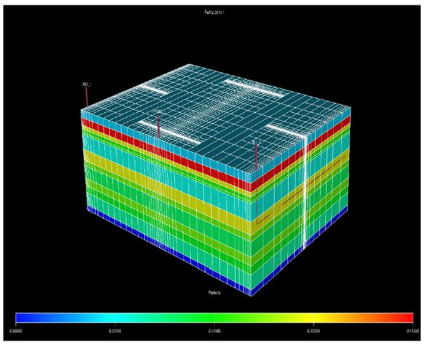

Figure 9. A three-dimensional box model is constructed. Layer thicknesses and associated porosities were calibrated against the available log data. Note that local grid refinement (LGR) is utilized to model stimulated areas both in the producer and the injectors.

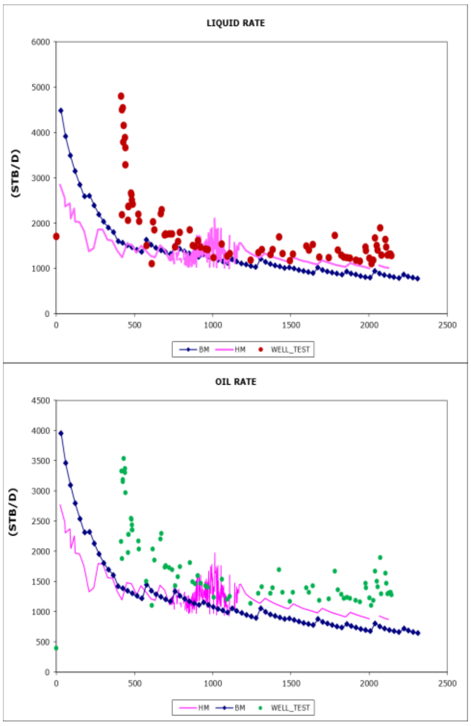

Figure 10. Estimated total liquid (up) and oil (down) production rate with the box model (indicated with blue line) and their comparison against the well test data and previously performed full field model predictions.

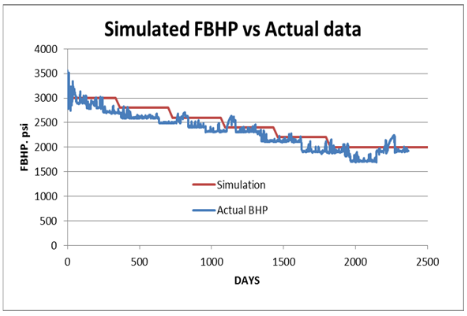

Figure 11. Simulated and actual flowing bottomhole pressures.

4.1. Development scenarios

As we obtain an acceptable history match with the box model, we then continue to study two different gas injection development scenarios which can be seen in Table 1. It is worthwhile to mention that the main constraint in each scenario is the gas handling capacity in Valdemar field. This should not exceed a threshold gas rate of around 160 MMscf/d.

In scenario 1, we study a gas injection rate of 2 MMscf/d, which corresponds to 33 MMscf/d for a 10,000ft horizontal trajectory. BHP is estimated between 3,500 and 4,000 psi. Although this is significantly lower than the calculated MMP, less compression power requirements and ability to drill more wells (due to gas handling capacity constraints) may make this scenario attractive. Whereas in scenario 2, we study a constant gas injection rate of 3.5 MMscf/d, which corresponds to 58 MMscf/d for a 10,000ft horizontal trajectory. BHP is estimated between 5,000 and 6,000 psi which also suggests that miscibility would be developed and can significantly boost the production. However this would also mean higher compression power requirements and ability to drill less wells (due to gas handling capacity constraints).

Table 1: Due to the Valdemar field's facility constraints, two different gas injection rates and corresponding injection pressures are studied.

Case	Rate (600ft), MMscf/d	Rate (10,000ft), MMscf/d	BHP, psi
1	2	33	3500-4000
2	3.5	58	5000-6000

4.2. Hydraulic Fracturing

All production wells were stimulated to improve the productivity in Lower Cretaceous reservoir. Injectors may also be stimulated with induced sand fractures similar to the existing producers. However, this would significantly increase the cost associated with the each injection well. Therefore, we conduct a simulation to find out whether the stimulation would really be required or not. Figure 12 compares the oil production rate and cumulative oil recovery with respect to the time.

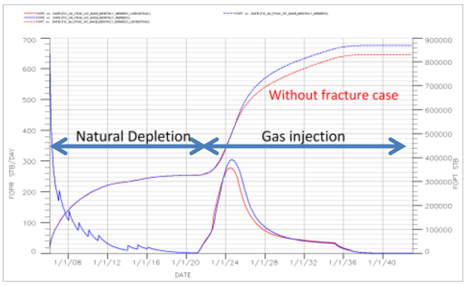

Figure 12. Oil production rate and cumulative oil production versus Time. Note that red color represents without fracturing whereas blue represents with fractures.

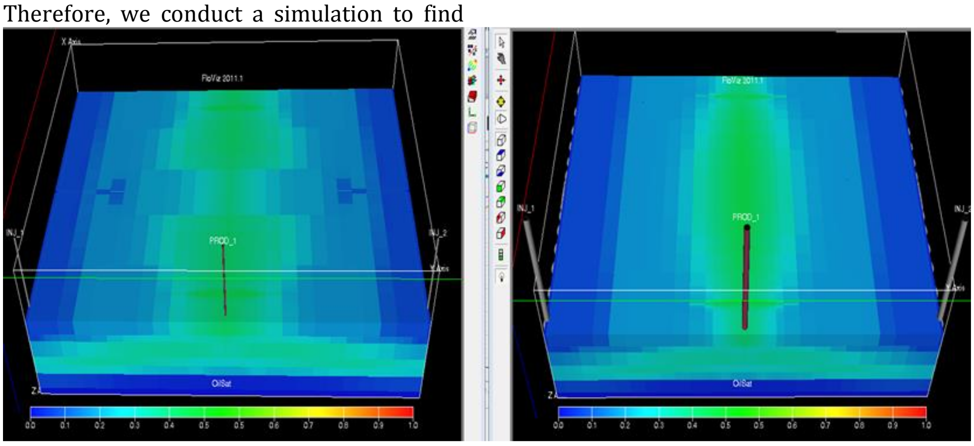

Figure 13. Better volumetric sweep is achieved once hydraulic fractures are introduced in the middle of the horizontal section of the injection wells (left) as compared without fractures (right).

We observe a slight increase in oil production when hydraulic fractures are introduced in the injectors. This can be explained by the better volumetric sweep efficiency that is achieved in the middle section of the horizontal trajectory Figure 13. Note that the producer has two hydraulic fractures in each end (one in the beginning and the other one at the far end) of the horizontal section see Figure 9. Therefore, if the hydraulic fracture is not introduced, once the injected gas reaches the fractured zone, oil production drops significantly which leaves a large volume of oil left unswept in the middle section of the horizontal trajectory see Figure 13. However, as Figure 12 shows, we do not observe a significant increase in cumulative oil production by implementing hydraulic fractures in injectors. Hence we conclude that fracturing may not be needed in injectors and we conduct our further analysis accordingly.

4.3. Gas injection optimization

In order to make gas injection projects economic, availability of suitable injectant is crucial, Johns and Dindoruk [5]. Gas injection projects often require large volumes of injection gas, which must be available at a reasonable cost. Unlike in a cyclic injection mode, such as the water alternating gas

(WAG) flooding, one may expect to obtain high gas recoveries in a continuous secondary gas injection scheme as the gas, being the most non-wetting phase, do not get trapped by the water, which often is the most wetting phase Suicmez et al., [6]. However, gas retention time in the reservoir may result in a significant additional cost due to the depreciation associated with the delay of the sale gas.

Therefore, in order to obtain a better gas utilization factor it is crucial to optimize the gas injection process. We study different durations of continuous gas injection. We plot the cumulative oil production with respect to the total hydrocarbon pore volume (HCPV) of gas injection in Figure 14. As can be seen, after around five years of continuous gas injection we observe a clear drop in the slope of the cumulative oil recovery curve, which also suggests a reduction in production rate and hence a lower gas utilization factor. Therefore, in our further analysis, we decide to keep the continuous gas injection for a period of five years in order to optimize the amount of gas injection.

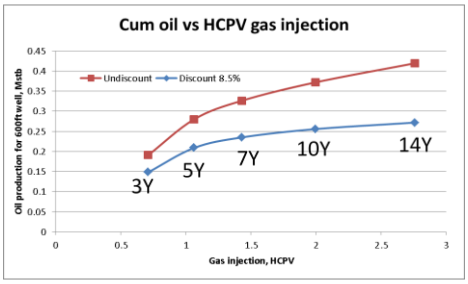

Figure 14. Cumulative oil recovery versus HCPV of gas injection. Note the clear drop in the slope at around five years, which suggests that five years of continuous gas injection may be considered as the most optimum. Reduction in slope at five years is even more visible when a discount rate of 8.5% is applied in order to account for the depreciation of the total oil recovered.

5. Results

We run two scenarios as discussed in Table 1. In order not to exceed the gas handling capacity and to be able to perform five years of continuous hydrocarbon gas injection, we also make an optimization on the drilling sequence.

In scenario 1, we drill a total number of 10 wells with the schedule suggested in Table 2. Therefore, we do not exceed the gas handling capacity of 160 MMstb/d while being able to perform a continuous gas injection scheme for five years per each well Figure 15. Figure 16 shows the corresponding oil production rate versus time.

Table 2: Proposed drilling schedule in scenario 1. Note that a total number of 10 wells is recommended, which is inline with the suggested development concept.

Year	1	6	8	Total
No. Of Injectors	6	3	1	10

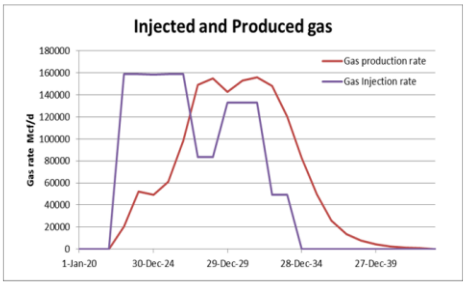

Figure 15. Gas injection and production rate versus Time.

In scenario 2, we limit the total number of injectors to five wells in order to honor the facility constraints. Table 3 suggests the drilling schedule. As can be seen in Figure 17, we limit total gas injection/production within the limit of around 160 MMscf/d and Figure 18 shows the resulting oil production versus time.

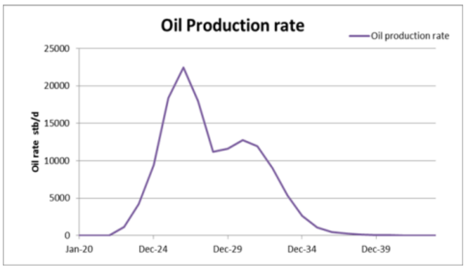

Figure 16. Oil production rate versus Time.

Table 3: Proposed drilling schedule in scenario 2. Note that a total number of five injection wells is proposed, which is only half of our initial proposal.

Year	1	6	Total
No. Of Injectors	3	2	5

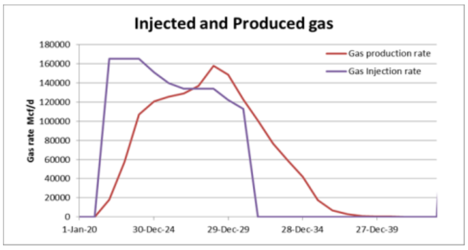

Figure 17. Gas injection and production rate versus Time.

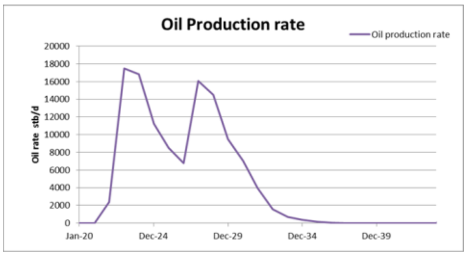

Figure 18. Oil production rate versus Time.

6. Discussion

Results show that an additional amount of oil can be recovered via secondary gas injection in Valdemar Lower Cretaceous reservoir. We studied two scenarios: in scenario 1, we inject gas at a relatively lower pressure (~3500 psi) which enables drilling 10 wells as proposed by the initial development plan; five wells in each of the northern (North Jens) and southern (Bo) areas. Results show that we observe an additional oil recovery of around 51 MMstb (undiscounted).

In scenario 2, we inject the gas at a relatively higher pressure (~5500 psi) which is around the estimated MMP for the MCM displacement see Figure 7. As expected, we observe lower residual oil saturations, especially closer to the injectors where a miscible displacement region is developed which significantly boosts the production. Due to the considerably higher injection rates, we limit our development plan with only five wells that may mean a development of either North Jens or Bo area. We observe an additional oil recovery of around 43 MMstb (undiscounted). It is worthwhile to mention that this scenario has a significant upside potential since a staged development may be considered; once the development is completed in North Jens, Bo development may be initiated afterwards. This, in theory, may double the suggested additional oil recovery.

In order to compare those two scenarios, we look at the production profile, cumulative oil recovery as well as the total amount of gas utilized. To validate the rather significant impact of the optimization work on gas injection, we also compare those two scenarios with an additional scenario, in which high pressure gas injection (as in Scenario 2) is conducted without optimizing the duration of gas injection or the drilling sequence. Gas is injected via 10 wells for a continuous time frame of 14 years. Results are seen in Figures 19 and 20.

As clearly observed, an optimization on duration of gas injection as well as on the drilling sequence may make the process significantly more efficient. Although both scenarios (1 and 2) lead to a significantly lower cumulative oil recovery as compared to a non-optimized gas injection case, we observe higher production rates and hence quicker oil recovery Figure 19. This in turn leads to a quite comparable discounted total oil production Figure 20.

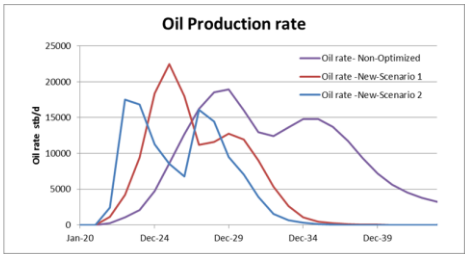

Figure 19. Oil production rate versus time for two different scenarios. Those scenarios are also compared with a case where gas injection is not optimized (see the purple curve).

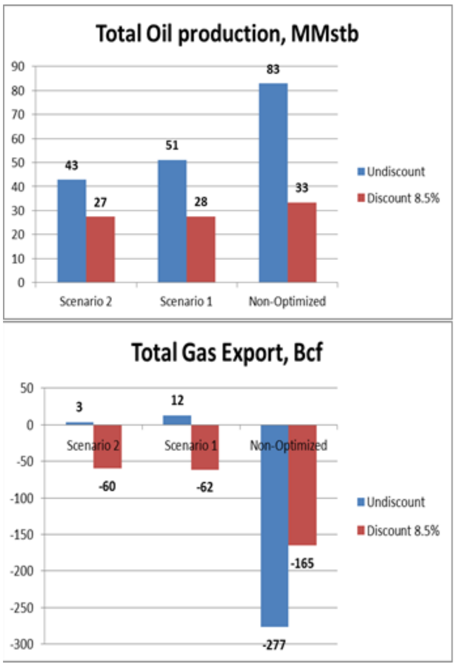

Figure 20. Cumulative oil produced (up) and amount of gas export (down) for each scenario.

We also observe that the total amount of gas exports are not significantly affected once the duration of the gas injection is optimized see Figure 20. Although the total amount of gas export increases in the scenarios 1 and 2, when a discount rate of 8.5% is implemented we observe a total gas loss of around 60 Bcf which is significantly less than what is estimated for the non-optimized gas injection case that is around 165 Bcf.

7. Conclusions

In the course of this study, we investigate different development options for the Valdemar Field. A quick screening study suggests that hydrocarbon gas injection may stand as an alternative to further develop Valdemar Lower Cretaceous reservoir.

A three-dimensional box model was built to study secondary gas injection. Two different scenarios were built. In the first one, low pressure gas injection is employed, which requires less compression power with a total number of 10 injectors. We observe an additional discounted oil recovery of around 28 MMStb. In the second scenario, gas injection is performed at the MMP which significantly reduces the residual oil saturation and hence boost the oil production. With half the number of wells, we estimate an additional cumulative oil recovery of 27 MMSTB. We observe a comparable discounted oil production in each scenario as well as in the non-optimized gas injection case. We also observe significantly less export gas loss with a proper gas injection optimization.

8. Acknowledgements

Authors would like to thank Maersk Oil management to allow publishing this work. We also would like to thank Dr. John Ratulowski of Schlumberger, Edmonton, Canada for performing the PVT experiments and for all the stimulating discussions. We also thank Dr. Niels Lindeloff of Maersk Oil for reviewing and improving the content of the work.

References

[1] Frykman, P. 2002. Modelling of fracture permeability in the Valdemar Field. EFP 97 Priority report. I.7.d, GEUS, Copenhagen, Denmark.

[2] Jakobsen, F., Ineson, J. R., Kristensen, L., Nytoft, H. P., and Stemmerik, L. 2005. The Valdemar Field, Danish Central Graben: field compartmentalization and regional prospectivity of the Lower Cretaceous chalk play. In: Dore, A. G. & Vining, B. A. (eds) Petroleum Geology: North-West Europe and Global Perspectives - Proceedings of the 6th Petroleum Geology Conference, 177–186.

[3] Buckley, S.E. and Leverett, M.C. 1942. Mechanism of fluid displacements in sands. Transactions of the AIME (146), 107–116.

[4] Kokal, S. and Al-Kaabi, A. 2010. Enhanced oil recovery: challenges & opportunities. World Petroleum Council Official Publication, 64 – 69.

[5] Johns, R.T., and Dindoruk, B. 2013. Gas Flooding. pp 1-22. Sheng J.J., ed. 2013. Enhanced Oil Recovery Field Case Studies, Elsevier, USA, 667p.

[6] Suicmez, V.S., Piri, M., and Blunt, M.J. 2007. Pore-scale Simulation of Water Alternate Gas Injection. Transport in Porous Media, Volume 66, p. 259 – 286, DOI 10.1007/s11242-006-0017-9