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PLANNING AND IMPLEMENTING THE REDEVELOPMENT OF VOLVE FIELD, NORWEGIAN NORTH SEA USING KNOWLEDGE DISCOVERY IN DATABASES DATA MINING AND NUMERICAL SIMULATION TECHNIQUES

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Abstract

In this study, a brownfield development plan was investigated by mining the data pack from Equinor Volve field repository, modelling and simulating to establish the quantity of hydrocarbon that is still recoverable therefrom. This is aimed at identifying the most appropriate technique for recovering additional oil from the brown field. Firstly, a data-mining algorithm that is based on knowledge discovery in databases (KDD) was developed, the reservoir model was built and utilised in history matching and selection of enhanced oil recovery option. The preceding development achieved 46% recovery thus a window of 8-12% additional recovery was set as a goal. The field development plan has two options; the best technical option which had a double peripheral layout spot pattern with 7 injectors (2 water 5 WAG) and 10 producers (3 of which were horizontal and 7 vertical). The incremental increase goal was hit, with recovery increasing by 10% by year 3 and 12% by year 4. However, it was felt the impact on the environment of such a project was simply too significant thus the recommended case took the form of 6 producers and 1 water injector. This was the improved reactivated well trajectory case.

Keywords: Data mining (DM), Enhanced oil recovery (EOR), Field development plan (FDP), Knowledge discovery in databases (KDD), Water alternating gas (WAG).

1. Introduction

This study was to investigate the benefit of using a KDD data-mining algorithm in the development of brownfields. The energy landscape has changed significantly from the past, clearly there has been a shift in public opinion. Unconventional sources along with drilling in extreme environments are more controversial now. This means more focus must be placed on conventional sources in non-extreme environments. As well as this the energy transition is fundamental to the survival of this industry, drilling in environmentally sensitive areas or conducting practices which are excessively damaging may take away from this. Redeveloping brownfields has the potential to facilitate necessary oil demand whilst minimizing environmental risk. This is because the majority of large new fields are discovered in environmentally sensitive areas i.e., Artic or are unconventional i.e., oil sands, whereas conventional brown fields in non-sensitive areas are relatively abundant.

The implementation of data mining in the brownfield development process truly adds a unique selling point. Data has arisen from the peripheries of the global economy to centre stage and using data to increase field efficiency would transform countless projects. This adds a novel dimension on how field redevelopment studies might be done.

There has been past work on combining data mining in the brownfield development process and to a large degree this implementation has been met with success. Possibly the most interesting system researched was Top-Down Intelligent Reservoir Modelling [1]. This technique combined reservoir modelling with AI and DM. The main selling feature of this method it only requires field production data and some well log data i.e. porosity, thickness and S_{wi}. Other data can be added at the engineer's prerogative. It is this flexibility in data requirement that sets this method truly apart, a main disadvantage is that in order to get reliable results a minimum of 5 years of production history is required along with a large number of wells.

The authors have proposed to compare the impact of the data mining by comparing a data-mined case to the production prediction of the original development. This is a novel way of redeveloping a field and will use data extracted to improve the recovery of the brownfield. The scientific contribution of the study is significant, a KDD algorithm was fashioned in the pursuit of an effective data-mining system whilst using an industry standard reservoir modelling software to create the model. The study was organised as follows: a literature review was conducted on brownfields, data mining and reservoir modelling. A data-mining algorithm was created and used. An investigation into the previous development plan was undertaken and this information along the information acquired through data mining was used to create a new development scheme, enhancement and development strategy.

2.Methods and Approach

The method of this study entails seven steps as shown in Fig. 1. Figure 1 shows the methodology as i) background study, ii) data mining, iii) reservoir modelling, iv) development plan, v) development scheme, vi) enhancement, vii) finally development strategy. This is not strictly chronological, but each new step depends on the previous and each previous step is supplemented by the subsequent.

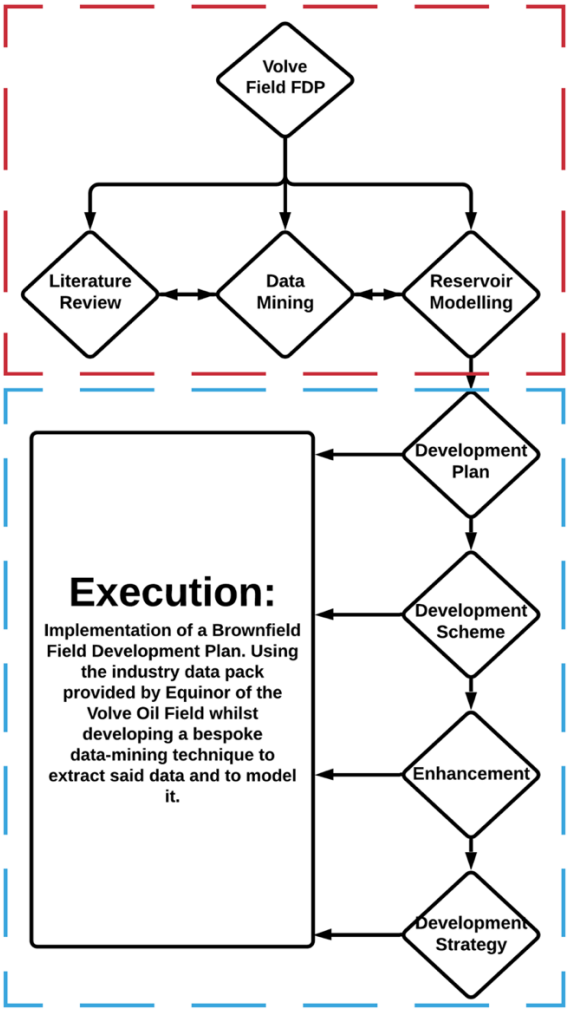


Fig. 1. Volve field development methodology involving 7 sections with a general downward sequence.

2.1. Background study

A brownfield is different from a green field in that it has already been developed. In an effort to extend economic life more and more operators are returning to such fields, often involving the use of improved oil recovery techniques. Brownfields have numerous advantages including but not limited to existing infrastructure and a treasure trove of available historical data.

The core subject is to calculate the potential brownfields offer. It is seldom that an operator would return to a field where the situation remains the same; it's more common that it is felt that there have been new reservoirs in the field or extensions in the boundaries of known reservoirs. Using modern technology is a key attribute in determining the increased potential of brownfields. The Energy Information Administration (EIA) researched in order to determine the potential of brownfields;

they presented that, of 200 well known fields worldwide in completely different environments from 1977 to 1993, 44% had increased reservoir by 2 to 3 times, 22% by 3 to 4 times and 9% by at least 4 times [2]. This is supported by Antariksa et al. [3] who in their study, presented the undeveloped oil present in multilayer reservoirs. The reasons for revisiting the fields include the following:

- Remaining not swept oil.
- Even at 90% water cut, a lot of oil can be produced especially in oil wet reservoirs.
- More modern technology such as advances in EOR and reservoir modelling which have progressed considerably in the past 20 years.
- Oil price dictates the feasibility of brownfields if prices are high enough [3].

Al-Khaledi and Qadri [4] presented a study on a Brownfield project in the Middle East (Kuwait) from the Kuwait National Oil Company. It too agreed with Antariksa et al. [3]; putting the case that these projects do have great economic potential. For this case in the Burgan Fields there was success but only at the expense of a considerable amount of economic and industrial input. Due to the complexity, it absorbed the most proficient teams, it can be argued this difficulty could be an advantage, becoming a specialisation within the industry. Lessons from brownfield projects in mature regions like the North Sea could be exported and employed around the world [4].

Kumar et al. [5] presented clear challenges in the execution of offshore brownfield projects. Chief constraints are available space on existing platform and minimum production shutdown requirements. Although daunting these challenges may appear there are ways to mitigate these technical hurdles. Implementing electrical changeover philosophy minimising production shutdown and optimising space with innovating machine learning can be solutions to these challenges.

Being an already developed field there are huge caches of data which require analysing and data mining. Data mining (DM) involves extracting useful information in the most efficient manner and showing tendencies. It amalgamates three masteries: statistics, artificial intelligence and machine learning. It uses these three to commoditise big data; it is through this technique that data has become the most valuable resource in the world, overtaking oil in 2017 [6].

Traditionally, the oil industry has been sceptical about the use of big data; preferring the traditional physics-based approaches. However, Balaji et al. [7] presented the recent advances and applications of data-driven methods in the oil industry. Still, a strong grasp of the traditional methods is needed in data driven models, but the process starts off with utilising data to identify issues and their solutions. It was found that organisation and refinement of the data were the most important components of an efficient data driven process.

It is put forward by Benjamini and Leshno [8]; that the cause of the mass utilisation of DM and KDD in particular in the recent years is the accelerated production of cheaper computers, software improvements, inexpensive data storing along with the automated collection of data and the amount of data that continues to be gathered in real time. This opinion is shared in this study, it's obvious that DM use will keep expanding as it almost always creates a competitive advantage. The four key benefits of data mining are [9]:

- Automatic decision making: real time data analysing permits organisations to see anomalies in data which are then examined.
- Prediction and forecasting: knowing the detailed history permits predicting the future accurately.
- Reduction in costs: maximising efficient use of resources drives down the operating expenditure.
- Tailored service: using consumer data, profiles can be formed to understand the customer and better tailor to their needs [10].

With such a system, there are variations on the methods used to data mine. Although different, they centre around three steps: pre-processing, data mining and results validation. Pre-processing is where a target is determined before a specific algorithm is used. This minimises the data to as low an amount as is possible which saves time, but also to have enough data set so as to view indications. Any data which cannot be used is removed and what remains is mined. Data mining then incorporates 6 steps [11]:

i. Detection of Anomalies.
ii. Association learning: realising correlations between different variables.
iii. Clustering: combining data based on similarity.
iv. Classifying: implementing a known structure to the data.
v. Regression: determining a function which fits the data models best.
vi. Summarisation: a presentation of the data [10].

The final step which involves results validation attributes hypothesis to the variable. There can be an infinite number of correlations between variables which are not related to each other (coincidences). Then there will be variables which make an effect and need to be presented. It is essential this covers the entire data set and not an artificially created sample [10, 12].

From the data mining inputs can be made into the reservoir model. This type of modelling is vital in modern development projects. It uses data to model what we think a reservoir looks like. It then goes further and using the structure forecasts how fluid may flow through it over many years. It uses a cooperation of mathematics, science and computer science and its benefit to this study is huge.

The exciting prospect of this is with increasing development in artificial intelligence (AI) the DM will become more and more refined, efficient, and automated. Windarto et al. (2017) discussed the implementation of an AI algorithm developed by the British Petroleum (BP) in Indonesia. An artificial neutral network was implemented using backpropagation. Although some alterations were recommended it was concluded that this system was valuable to BP in further developments [13].

The Volve field is a brownfield, initially developed by Equinor and then abandoned. The field was discovered in 1993, in the central North Sea at a relatively shallow depth of 80m water, 5km north of Sleipner East.

2.2. Data mining

This stage started from the onset and continued until the termination of the study. The data set had 11 folders containing the information and are detailed as follows: [14]

a) Geological Interpretations.
b) GeoScience.
c) Production Data (monthly and daily on a field and well basis).
d) Reports (discovery report in English and PUD report in Norwegian).
e) Reservoir model (Eclipse)
f) Reservoir model (RMS
g) Seismic (from 2 surveys in 2002 and 2010).
h) Well logs.
i) Well logs per well (same data as above, organised on a well basis).
j) Well technical data.
k) Realtime drilling data.

The method was centred on the KDD format including pre-processing, data mining and deployment. Pre-processing this data set was vital in setting out a clear view of what data needed to be gathered (business understanding). This was done in 5 sections: previous reports, reservoir model, production profile, seismic and well logs. The data mining algorithm dubbed Volve Oil Field Data mining (VOF-DM) algorithm was designed based on Decision Tree Data Mining (categorical) where a series of statements were put forward and only the data which was on the affirmative side of these statements went forward. There were 5 nodes in the decision tree: broad selection, focused selection, format selection, current version and finally evaluation and interpretations. The 5 stages filtered out various data types which were deemed surplus to requirements. The final stage is deployment with the next stage to initiate the reservoir modelling section. The decision tree flowchart algorithm is depicted in Fig. 2.

Figure 2 shows that the pre-processing is in 5 topics. Broad selection takes folders from the original data pack which fit these five sections, focused selection goes into these folders and filter key files, format selection filters correct software or language, current version filters dated, interpretation/evaluation filters through the remaining to remove surplus data, deployment occurs when the data is ready to be put into the reservoir model.

2.2.1. Model validation

The model validation took two forms: in-sample validation and out-of-sample validation. To start with, the in-sample validation, for this we assess the depth of the nodes. This is standard in assessing whether the branches of the decision tree extend too much or not far enough. From running both greater and lesser number of nodes it was assessed that fewer, provided an ineffective system which did not provide a significant difference than not using the DM at all. Adding more created a more complex system which did not significantly affect the results.

For the out-of-sample validation, a new data set was sourced courtesy of the Oil and Gas Authority Open Data. Using the same principles and steps, this data was

input into our model. This method of cross-validation is highly reputable and considered an essential part of accurate model validation. The results of this were clear, with minimal modification a functional prediction was created. This clearly shows the predictive performance of the DM algorithm.

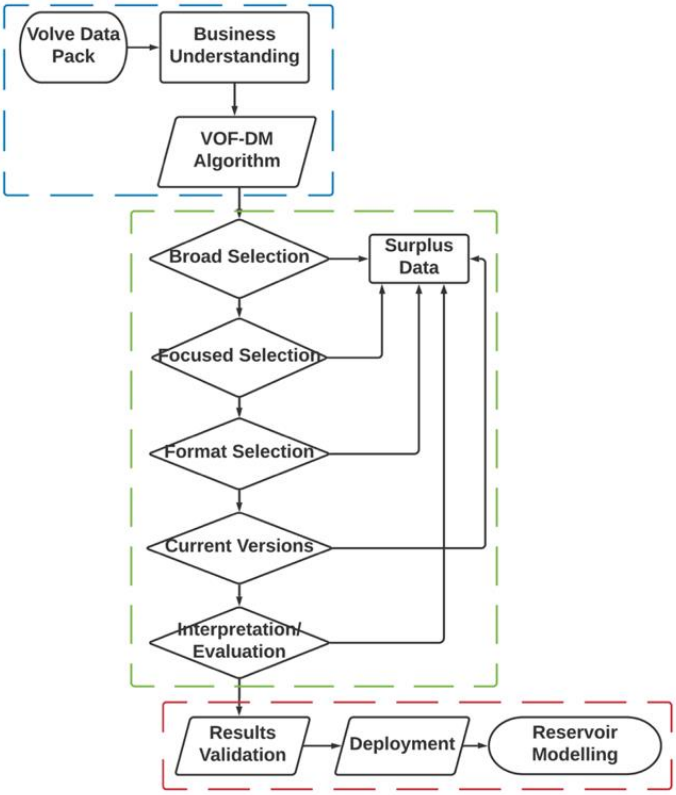


Fig. 2. VOF-DM algorithm decision tree.

2.2.2. Results

Combining the DM with pre-processing and evaluation there were 7 stages. The method was successful: out of 40,000 files initially in the data pack, only 80 were remaining. This reduced down to 0.2% in terms of files required. The final volume was 2GB of storage compared to the original pack size of 5TB.

2.2.3. Efficacy of data mining

In order to determine the efficacy of the data-mining a simple yet effective method was conducted. Out of the remaining files which were not extracted, 100 were sampled at random. For each of these files two questions were asked:

i. Do the contents of this file add value to the thesis?

ii. Do the contents of this file affect the final results of the thesis?

Out of the 100 files 4 answered yes to the first question and 0 answered yes to the second. This leads to the conclusion that based on the quality check conducted,

out of the remaining files 4% would have added value to the thesis and 0% would have changed the outcome.

2.3. Reservoir modelling

The model has dimensions of 108×100×63, with a cell count of 680,400 and 183,545 active cells. The grid size is 50×50 m with 1-3m of thickness. This model is shown along with oil producing wells (Fig. 3).

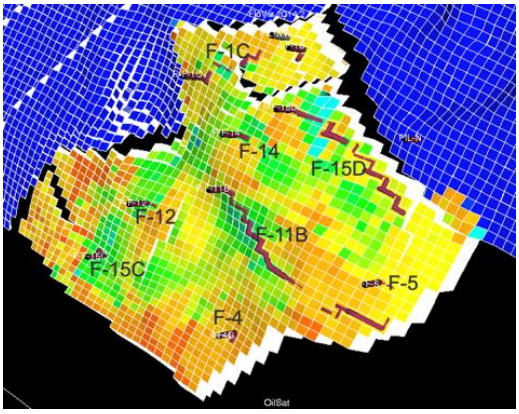


Fig. 3. Well location in reservoir model as provided in the Volve data pack [11].

The 8 oil producing wells are labelled: F-1C, F-15D, F-5, F-14, F-11B, F-12, F-15C and F-4 The values from the reservoir model indicated a STOIIP of $22x10^6$ m^3 [14]. In order to run models and produce results a number of steps were required. A history match was conducted on the model and through information provided in the data mining this history match was improved.

The first simulation took approximately 6 hours; as it was a very detailed run. To decrease this time, the number of CPU processors used were increased to 6 from 4 and the CPR solver was activated. This reduced the simulation time to 2 hours. The computer utilised was the HP EliteDesk 800 G3, it has Intel Core i5-7500 3.4 GHz (Quad Core), 8GB DDR4-2400, 256 SSD, Intel HD Graphics 630.

2.4. Development plan investigation

The development plan was an investigation into certain parameters of the previous development. This stage was vital; running the simulation takes a significant length of time, thus well placement must be considered thoroughly. Using field properties and data to best assess the method of redevelopment is pertinent.

2.4.1. Identifying existing producing wells and injector wells

The field had 24 wells, of these only 11 were Volve field development wells, that was because although all wells were useful in mapping the reservoir and appraising its value, only 11 were considered economically viable. Wells PIL-N and PIL-NW were drilled into the Utsira formation for water production. The purpose of the now 11 wells and 2 water wells are detailed in Table 1 [14].

Table 1. Table of Volve development wells [14].

Well	Category	Date Operation Commencing	Comments
I-F-4	Injector	20/04/2008	First injector
I-F-5	Injector	18/08/2008	Second injector
I-F-1B	Injector	01/10/2013	Final injector
I-F-4G	Injector	N/A	Deviated well
P-F-12	Producer	10/02/2008	First producer
P-F-14	Producer	09/07/2008	Second producer
P-F-15C	Producer	06/03/2009	Third producer
P-F-11B	Producer	23/07/2013	Fourth producer
P-F-15D	Producer	16/01/2014	Fifth producer
P-F-1C	Producer	22/04/2014	Sixth producer
P-F-5	Producer	18/04/2016	Converted injector
PIL-N	W. Producer	07/09/2008	First water producer
PIL-NW	W. Producer	08/07/2008	Second water producer

2.4.2. Recovery factor from primary production

With the first injector well operational from 20/04/2008, about 2 months from first oil the recovery from primary production was low. 1.731×10^5 Sm^3 of oil was produced in this time with STOIIP at 2.2×10^7 Sm^3; giving a primary recovery factor of 0.8% [14].

2.4.3. Recovery factor from the secondary production due to water injection

Using the simulation, the recovery factor at the end of the secondary production was found to be 46%. Note to reader in some older Equinor documents on the Volve field the recovery factor was stated as 54%, this value was outdated as it did not take into account the revaluation of the field size due to data acquired from well A-F-11A. This well showed that the reservoir had an increased boundary with more favourable conditions and so increased the STOIIP of the reservoir.

2.4.4. Material balance giving the relative component energy of the system

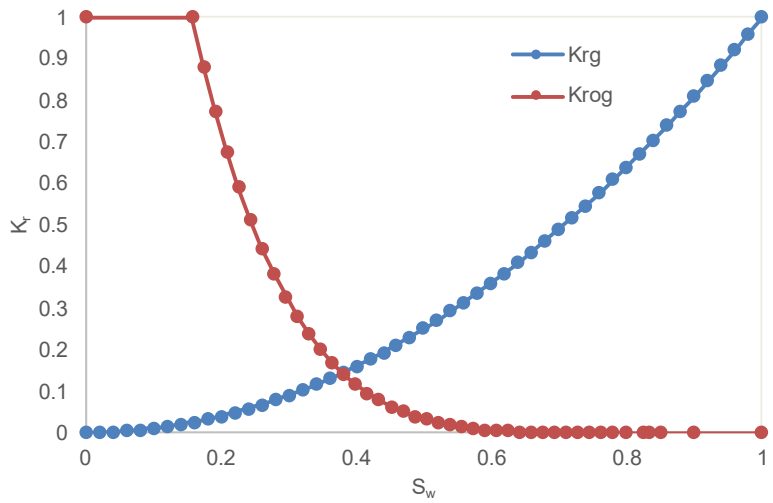
The MBAL values are detailed (Table 2).

Table 2. MBAL values [14].

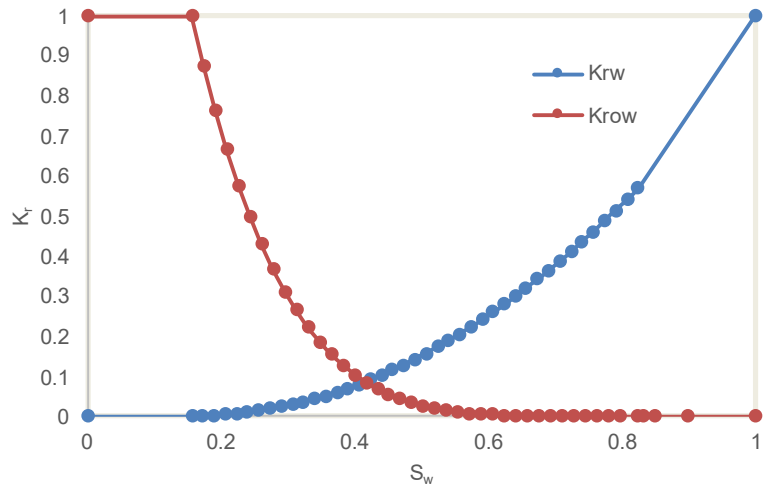
Input	Value	Source
GOR (R)	$114 Sm^3/Sm^3$	Discovery report
Oil gravity (γ_o)	30° API	Discovery report
Gas gravity (γ_g)	0.883	Discovery report
Water salinity	151,200ppm	Print file
CO_2 concentration	9.5%	Discovery report
N_2 concentration	0.46%	Discovery report
H_2S concentration	3.5ppm	Discovery report
Reservoir temperature (T)	230°F	Print file
Bubble point pressure (P_b)	273 Bar	Discovery report
Initial reservoir pressure (P_i)	329.6 Bar	Production results
Porosity (ϕ)	0.225	Discovery report
Connate water saturation	0.203	Log reports
OIIP (N)	21,967,455 Sm^3	Print file
PVT data	Entire table	Ccs results data file
RelPerm tables	3 tables	Relperm data files
Production history	Excel file	Print file
Reservoir thickness (h)	18m	Discovery report

The PVT data gives the oil formation volume factor (B_o) and oil viscosity as a function of pressure for cases. These are increasing GOR values from 27.4 Sm^3/Sm^3 to 156.9 Sm^3/Sm^3 [14].

The RelPerm values were given in large, detailed tables for each region in the model and are shown graphically in Figs. 4(a) and (b) [14].



(a) Graph of K_{rg} and K_{rog} against S_w.



(a) Graph of K_{rw} and K_{row} against S_w.

Fig. 4. Graphs of Volve RelPerm [14].

This data was input, a model for the aquifer was chosen, and regression was conducted. This depicted a system where the overwhelming majority of the energy originates in the water injection (80+%) with a significant minority arising from fluid expansion (5-15%), a minimal input from PV compressibility (5%) and virtually no contribution from water influx. The fact that the field is faulted so intensely has a significant affect, this is confirmed by the variety of fluids in place.

2.4.5. Aquifer strength and strength of the gas cap

As discussed, the natural aquifer strength is minimal, the majority of energy is through the water injectors. With initial reservoir pressure at a greater value than the bubble point pressure the gas cap size is also zero.

2.4.6. Characterisation of the fault pattern

There are 29 faults in the reservoir model which have been input [14].

2.4.7. Completion strategy plan

From the former development 11, separate regions were identified within the Volve field. The associated their fluid contacts are depicted in Table 3.

Table 3. Table of structures WOC, GOC [14].

Structure	WOC (mTVD)	GOC (mTVD)
1- Northwest	3,200.0	500
2- North	3,200.0	500
3- Purged Water	3,025.0	500
4- East	3,200.0	500
5-Prospect N (Eastern Part)	3,000.0	500
6-Prospect Northwest	3,200.0	500
7-Prospect N Upside	2,700.0	500
8- Southwest	3,200.0	500
9-Aquifer West	2,700.0	500
10-Prospect Northwest	3,200.0	500
11-Purged Water	2,910.0	500
12-Outside	2,700.0	500

The GOC depth at 500mTVD means that it is above the top of the structure, this indicates that there is no gas-cap. From the 11 regions it is possible to assess the differing fluid properties, OIIP and recovery factor. These are presented (Table 4).

Table 4. 11 Volve regions and total field by OIIP, production, remaining, transmission and recovery factor [14].

Region	OIIP (Sm^3)	Prod. (Sm^3)	Rem. (Sm^3)	Net Input (Sm^3)
1	4,350,000	4,254,000	1,956,000	1,859,000
2	4,347,000	4,184,000	2,119,000	1,956,000
3	2,621,000	0	1,094,000	-1,526,000
4	8,113,000	1,291,000	4,937,000	-1,885,000
5	0	0	19,000	+19,000
6	1,404,000	216,000	1,200,000	+13,000
7	0	0	3,000	+3,000
8	175,000	0	134,000	-41,000
9	0	0	0	0
10	329,000	0	187,000	-142,000
11	628,000	36,000	338,000	-254,000
Field Average	21,967,000	9,981,000	11,987,000	----

The permeability and porosity of these regions with the average of all the regions (field) at the bottom is detailed (Table 5).

The averages for the regions were gained from two (2) sources, firstly from information acquired in the data mining process and secondly from the results of the reservoir modelling.

Table 5. Average petrophysical properties by region as provided in the Volve data pack [14].

Region	PERM X (mD)	PERM Z (mD)	Kv/Kh	PORO
1	1,798	503	0.280	0.2352
2	1,921	603	0.314	0.2304
3	1,966	588	0.300	0.2288
4	1,697	522	0.308	0.2215
5	2,881	723	0.251	0.2356
6	648	208	0.321	0.2063
7	382	128	0.335	0.2145
8	1,216	275	0.226	0.2504
9	601	200	0.333	0.2096
10	826	242	0.293	0.2017
11	2,278	497	0.218	0.2459
Field Average	1,799	493	0.274	0.2250

2.5. Development scheme

The goal was to increase the field recovery factor from 46% to 54-58%. This 8-12% incremental increase involved seven (7) components: years of production, number of wells, regions of interest, well positions and spot patterns, completion design and model testing as detailed in the logic flow diagram (Fig. 5).

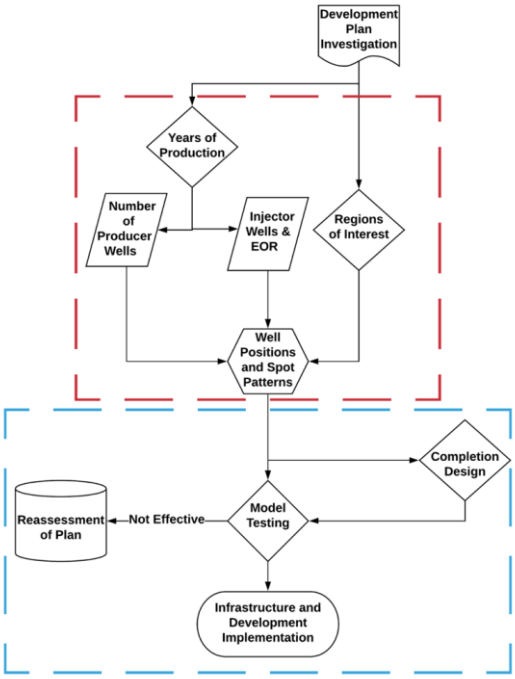


Fig. 5. Logic flow diagram of development scheme (2 phases containing 5 and 4 stages respectively).

The first phase is determining the years of production, number of producer wells, number of injector & EOR wells, regions of interest and well positions & spot patterns. The second phase is the model testing, completion design, optional reassessment of plan and infrastructure & development implementation. The different sections of Fig. 5 are described in the following paragraphs. The activities were conducted in a methodical downward system with the results of the previous step affecting the next step.

2.5.1. Years of production

The number of years of production is a difficult number to estimate and more often than not estimated years on oil and gas projects are incorrect. For instance, in the original development of the Volve field, production lasted 4 years longer than initially anticipated. Instead of giving an inaccurate estimate as to how long oil production may last before any redevelopment is actually conducted a minimum production time was estimated. The minimum timeline, T_m, is estimated as shown:

$$T_m = \frac{R_f \times N}{Q_{o(average)}} \tag{1}$$

where, the recovery factor (R_f) is 10%, the oil initially in place (N) is $22x10^6 m^3$ and average flow rate (Q_o) is $2000m^3/d$. This gives approximately 3 years. Note in the economics section, the payback time from first oil is calculated and thus gives a more precise minimum production time.

2.5.2. Number of producer wells

The number of producer wells proposed for the redevelopment is estimated as shown below:

$$N_{prods} = \frac{R_f \times H_p}{t \times B_{oi} \times Q_{oi}} \tag{2}$$

where N_{prods} is the number of producers, R_f is the recovery factor (0.1), H_p is the hydrocarbon pore volume ($26MMm^3$), t is the time in days which was stated as 3 years, B_{oi} is the initial oil formation volume factor (1.17 $resm^3/Stm^3$) and Q_{oi} is the estimated initial rate of production (200 m^3/D). This gives approximately 10 producing wells requirement for the redevelopment which is implemented as the number of producer wells in this redevelopment plan. Again, in the economics section this value is checked as to be economically feasible.

2.5.3. Injectors and EOR

The purpose of injectors was two-fold; to maintain pressure and to increase sweep efficiency. For pressure maintenance, a minimal number of water injector wells are required. 3 were used in the previous development with one converted to a producer later on. Thus, for the purpose of pressure maintenance 2 injector wells were implemented. Given the high recovery of 46% so far, some form of EOR would have to be implemented to increase recovery.

The importance of selecting the correct EOR method is huge, with around 90% of all conventional light oil discovered still in the ground and with current technologies only capable of producing an additional 12%, application of appropriate new technologies is paramount and Neuro-Fuzzy selection could pose a viable solution [15]. The Neuro-Fuzzy technique determines the suitability of an EOR

technique to a field, variables are considered based on degree of variance. Some variables are considerably more sensitive than others, for instance permeability would not be considered critical for injection of gases whereas gas is [16].

The main considerations discussed for EOR selection were CO_2 availability, infrastructure, reservoir characteristics, aquifer and natural fractures. Miscible CO_2 and steam projects account for 76% of EOR projects worldwide, with 21% made up of miscible hydrocarbon gases, polymers and combustion. The remaining 3% is made up of surfactants, microbial and miscible acid gas [15].

There were four different EOR methods considered, these were: chemical, polymer, gas injection and water alternating gas (WAG). Both gas and WAG have a minimum pressure and temperature requirement (Minimum Miscible Pressure) which the reservoir exceeds. However, as the reservoir does have a high temperature and pressure (230ºF and 329 bar) this excludes polymer and quite a number of chemicals. Unfortunately, the chemicals that do operate effectively at these conditions tend to have a greater potential to be environmentally damaging. As a result, both polymer and chemical were excluded, with the only options remaining the aforementioned gas injection and WAG, both were tested in the model and WAG was considerably more effective, thus it was the method used going forward.

2.5.4. Regions of interest

Based on investigating the region potential for oil production, five (5) out of the twelve (12) regions were isolated. These were regions 1, 2, 3, 4, 6. Their positions are shown (Fig. 6).

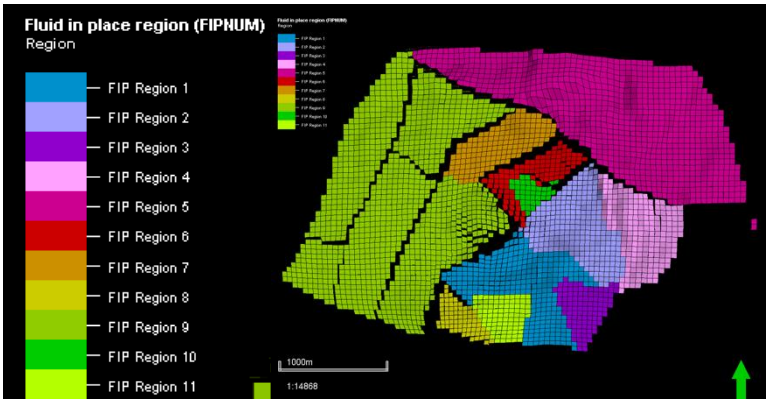


Fig. 6. Volve field by FIPNUM region.

Eleven (11) regions colour-coded with the key to the left and the map to the right. Regions are based on similar fluids in place. (Made in Petrel)

2.5.5. General well position and spot pattern

The spot pattern is a dual periphery as displayed with the orange triangles demonstrating producer locations and red rectangles demonstrating WAG/injector well locations (Fig. 7).

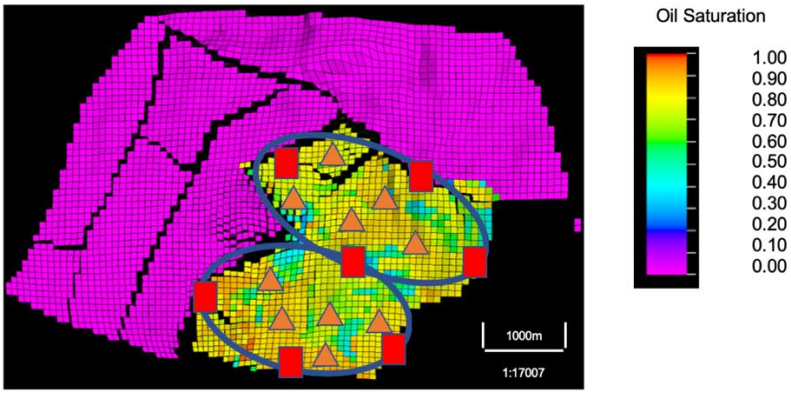


Fig. 7. Oil Saturation across the field.

Orange colour triangles represent producer well location and red rectangles represent WAG/water injector positions. A peripheral injection pattern was used. (Made in Petrel) The reason for the wells being placed in these general areas is because these are the regions of interest highlighted in the previous section and in Fig. 6.

2.5.6. Specific well locations and case development

Specific well locations were allocated by running the base case which was the original development well location. The most effective wells were noted and then, new wells were made with similar but improved trajectory as to those from the original development. This is an improved reactivation of the original development. Then series of redevelopment cases were created with new wells, with new well locations being optimised by changing locations. This took the form of 10 producer wells and 7 injectors. The final case (case 7) was an amalgamation of the most effective reactivated original wells and the effective new wells. The different cases are explained (Table 6).

Table 6. Case number, name and description.

Case	Name	Description
1	Base case	Production Prediction Based on original development
2	Reactivated well trajectory case	Similar wells as the base case with improved trajectory and modernised rules
3	Redevelopment case A	Newly created well locations, 10 vertical producers and 7 water injectors
4	Redevelopment case B	Same wells as Case 3 with 10 producers and most effective 2 water injectors
5	Redevelopment case C	Same wells as Case 3 with 10 producers, 1 water injector and 6 WAG wells
6	Redevelopment case D	Same as Case 5 with 3 ineffective producers replaced by more productive well locations
7	Double periphery (final case)	A merger of Cases 6 and 2, with the peripheral spot pattern as Case 6 and the inclusion of the most effective producers from Case 2

The logic flow diagram (Fig. 8) describes how these cases were formed, starting with the base case and from the base case the Reactivated Well Trajectory Case was formed. Then starting from scratch from the development scheme plan a new case was formed with new wells (Case 3). This was improved creating development plans B, C and D. From here Case 7; The Double Periphery Final Case was born from the best parts of Case 2; Reactivated Well Trajectory Case and Case 6; The Redevelopment Case D.

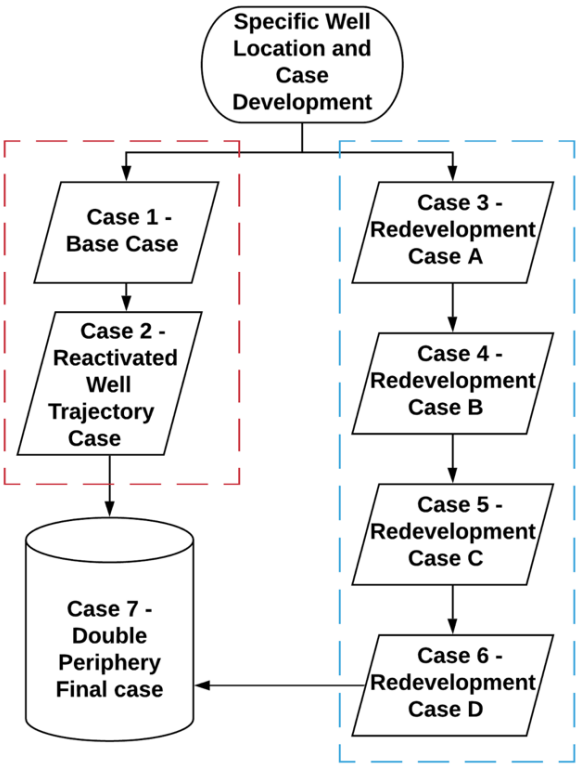


Fig. 8. Logic flow diagram of well location and case development.

The case development is broken into 2 paths the first highlighted in red draw inspiration from the original development and the second in blue draw inspiration from the new development. The trail of thought used a double path to come to the final case. The first highlighted in the red box (cases 1 and 2) used the reactivated and improved versions of the original development plan well positions. The second path (cases 3-6) were based on completely new wells from research into the geology and properties of the reservoir. With each successive case from 3-6 being an improvement on the previous. Case 7 then connects cases 2 and 6, in essence this is the amalgamation of the best parts of cases 2 and 6, using the most effective wells from case 2 and combining them with the spot pattern and effective wells from case 6.

2.5.7. Summary of cases

A summary of the 7 cases is illustrated (Table 7).

Table 7. Summary of redevelopment cases.

Case	Vert Wells	Horz/Deviated Wells	Total Wells	R_f
1	1	6	7	52.0%
2	1	6	7	53.2%
3	17	0	17	49%
4	12	0	12	50.0%
5	17	0	17	51.5%
6	17	0	17	52.6%
7	11	6	17	56.0% (58% year 4)

On examination of Table 7, it may appear that in fact cases 1 or 2 are a lot more attractive, as they gain a reasonable recovery factor with a significantly smaller number of wells. However, it must be stressed that both cases 1 and 2 could not produce economically after the 3-year timeline and would have to be shut down. Case 7 on the other hand could keep producing economically for 4+ years. The economic comparison of these is described in the economics section. It may also appear unusual that cases 1 and 2 both achieve a higher recovery factor than cases 3, 4 and 5 whilst using less wells. The reason for this is due to the positioning and trajectories of the previous development wells were clearly superior to the positioning and trajectories in these cases.

2.5.8. Final case

Case 7 – Double Periphery Final Case. The final wells are described (Table 8).

Table 8. Development wells for Case 7.

Well	Type	Case Origin	Horizontal/Vertical
P-F-11B	Producer	Case 2	Horizontal
P-F-12	Producer	Case 2	Vertical
P-F-15C	Producer	Case 2	Vertical
P-F-15D	Producer	Case 2	Horizontal
P-F-1C	Producer	Case 2	Horizontal
P-F-5	Producer	Case 2	Vertical
R-2-P-11	Producer	Case 6	Vertical
R-8-P-12	Producer	Case 6	Vertical
R-2-P-13	Producer	Case 6	Vertical
R-6-I-1	WAG	Case 6	Vertical
R-4-I-2	WAG	Case 6	Vertical
R-4-I-3	WAG	Case 6	Vertical
R-1-I-4	WAG	Case 6	Vertical
R-1-I-5	WAG	Case 6	Vertical
R-1-I-6	Water Injector	Case 6	Vertical
R-3-I-7	Water Injector	Case 6	Vertical

This final case combines the best parts of Case 6 and the Reactivated Well Trajectory Case (Case 2). This was the most productive case fielding a recovery factor of 56% after 3 years and a recovery of 58% after 4.

3. Outputs

Figures 9-12 display the oil production rate, pressure, water injection rate and water production rate against time respectively. Figure 13 displays the recovery factor against time for Case 7; the double periphery final case.

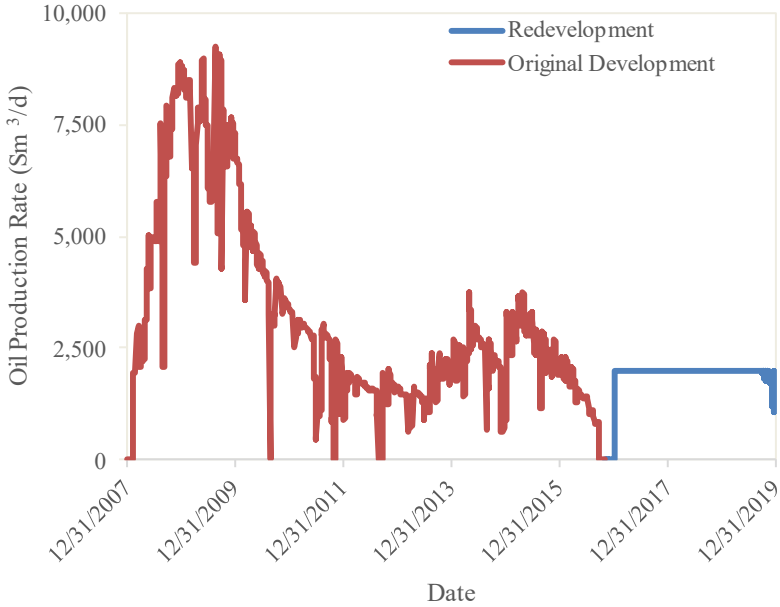


Fig. 9. Oil production rate versus time for Case 7.

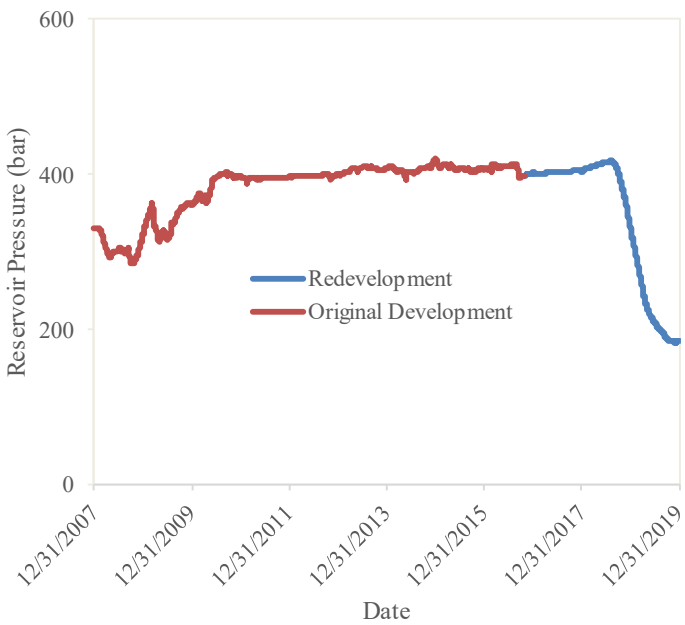


Fig. 10. Reservoir pressure versus time for Case 7.

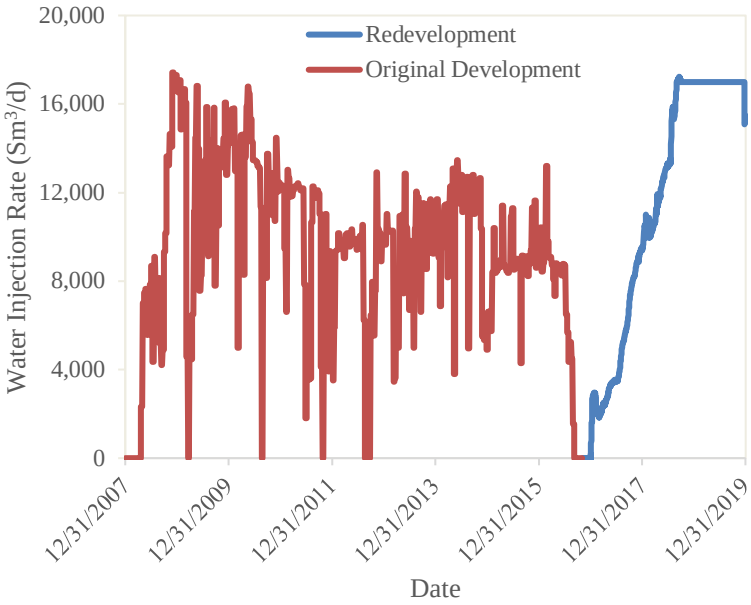


Fig. 11. Graph of water injection rate against time for Case 7.

From 31/12/2007 to 31/12/2019 water injection rate is displayed with the orange representing original development and blue redevelopment.

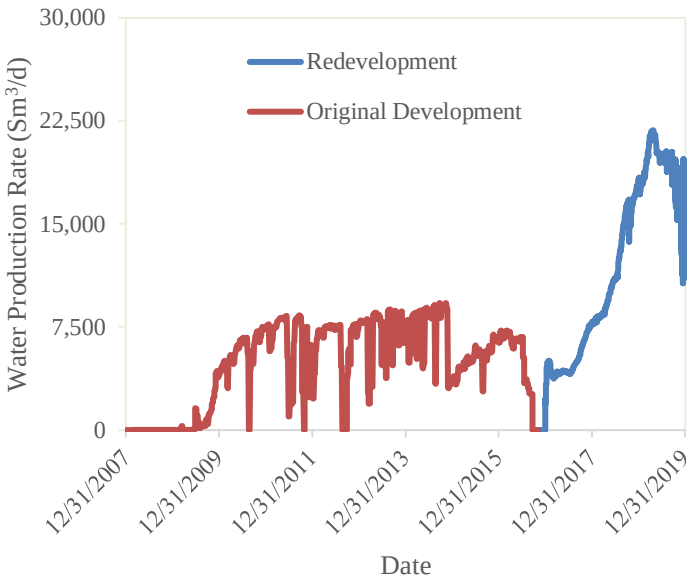


Fig. 12. Water production rate against time for Case 7.

From 31/12/2007 to 31/12/2019 water production rate is displayed with the orange representing original development and blue redevelopment.

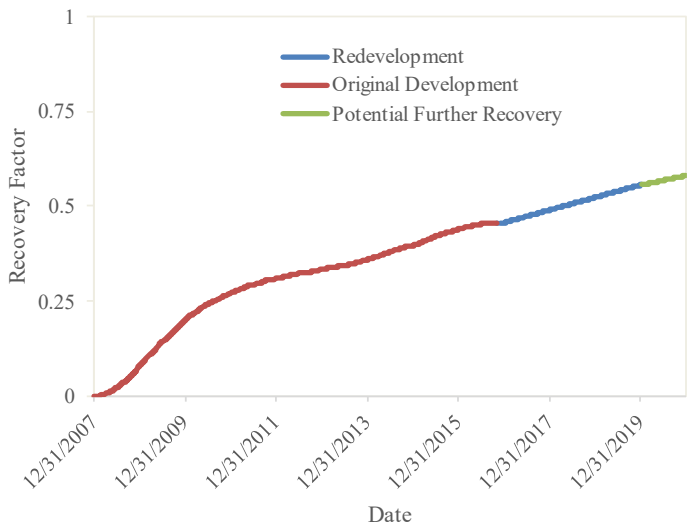


Fig. 13. Recovery factor against time.

From 31/12/2007 to 31/12/2020 recovery factor is displayed for Redevelopment (blue), Original Development (orange) and Potential Further Recovery (grey). Figure 14 illustrates the gas flow rate against time and Fig. 15 illustrates the liquid flow rate against time.

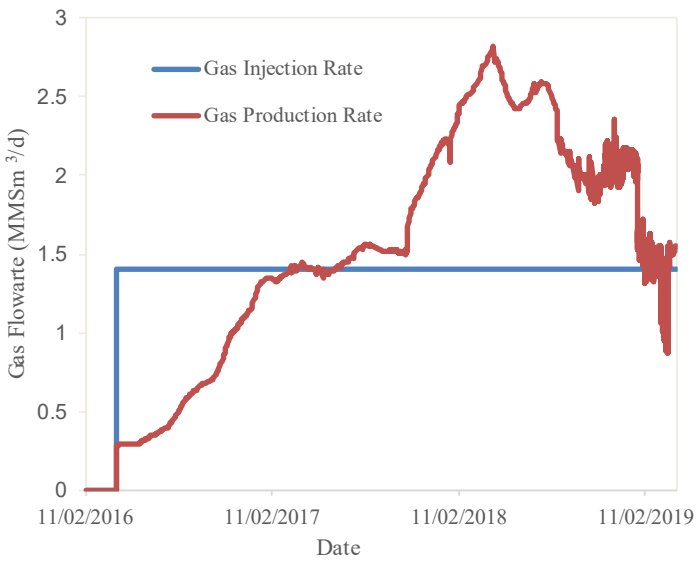


Fig. 14. Gas flow rate against time.

From 31/12/2007 to 31/12/2019 gas flow rate is displayed with the orange representing gas production rate and blue gas injection rate.

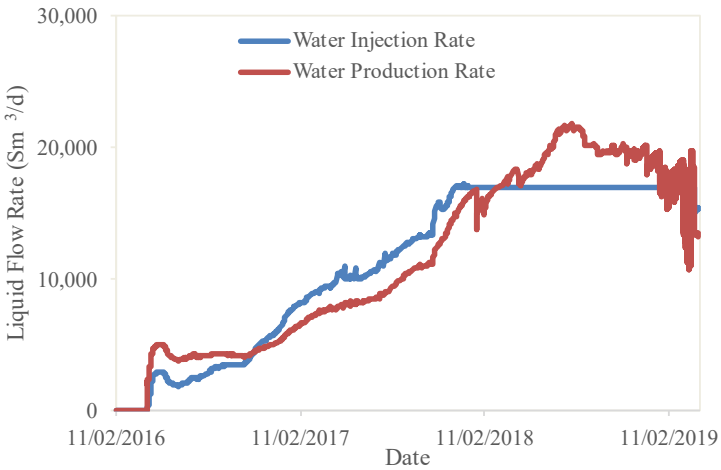


Fig. 15. Liquid flow rate against time.

From 31/12/2007 to 31/12/2019 water flow rate is displayed with the orange representing water production rate and blue water injection rate.

4. Results and Discussion

4.1. Redevelopment case

The redevelopment case with the best technical success was Case 7 with a recovery factor at 56% with a year extension bringing the recovery up to 58%. This was the summation of 47 different simulations and 65 well choices. The main reason for this choice its high recovery.

An additional advantage of this case it was developed so that it has a surplus production of gas and water to injected. The reason why this is, is because it used a more efficient use of water and gas from its efficient WAG regime. The additional 10 wells in case 7 compared to case 2 are significant, Table 9 shows the comparison between these cases (Table 9).

Table 9. Case 7 summary compared to Case 2 summary.

	Case 7 - Double Periphery Final	Case 2 - Reactivated Well Trajectory
Producer Wells	10	6
Water Injector Wells	2	1
WAG Wells	5	0
Horizontal Wells	3	3
Vertical Wells	14	4
Recovery Factor	56% (58% in 4 years)	53.2%
Total Oil Produced (Sm^3)	2,298,500	1,700,000
Total Gas Produced (Sm^3)	$1.8x10^9$	$0.269\ x10^9$
Total Gas Injected (Sm^3)	$1.5x10^9$	0
Total Water Produced (Sm^3)	$1.3x10^7$	$1.26x10^7$
Total Water Injected (Sm^3)	$1.3x10^7$	$1.4x10^7$

4.2. Redevelopment facilities

Although there was substantial water production how reinjection, at times there is a deficit to be made up by drilling a well into the nearby aquifer in the Utsira formation. Systems will be available for the dumping of water if the injection system is down. Almost all of the injected gas is from produced gas. However again a pipeline is recommended to import gas when there is a deficit and export when there is a surplus. It is a complex process to inverse the flow in the pipeline however there are facilities on both onshore and on the facility which are designed for this.

It has been determined that using a jack-up rig with processing facilities, with oil exported by shuttle via storage tanks is the best option. Similar to the first development which was successful to Equinor. The facility will be leased and capable to be positioned at desired location, drill producer and injector wells, process reservoir fluid, inject water and gas, export product oil to shuttle, accommodate all personnel (120 approx.) [14]

The facility will be capable of processing reservoir fluids in the form of separation and oil stabilization, gas compression, gas export, water treatment and injection. Power generation is from the gas turbines. [14]

Product quality oil is exported to a storage ship with the load capacity identical to the production capacity of 9,000 Sm^3/d. This vessel is moored to a buoy 2 to 3 km from the facility and has a capacity of 1,000,000 STB with an unloading capacity of 6,000 Sm^3/h. The measurement of oil will take place both from the facility and the tanker [14]. Several chemicals are to be used to deal with potential fluid problems. The operation of the facility will be up to the contractor however the operator has a duty to monitor.

4.3. Economics

CAPEX and fixed OPEX is calculated based on the previous development (Table 10) (2005NOK = 0.1537 2005USD) (2005USD = 1.32 2020USD) [17].

Table 10. CAPEX Estimations [11].

	Cost million 2005 NOK	Cost million 2020 NOK	Cost million 2020 USD
Platform Rental and Underwater Equipment	499/y	76.70/y	101/y
Platform Operation and Maintenance	222/y	34.12/y	45/y

The total facility cost is estimated at being $303 million for the Platform Rental and Underwater Equipment, $135 million for the Platform Operation and Maintenance. This gives a total of $438 million

The fuel prices are based on projections from the EIA in May 2020. With the cost of gas at $3.25 per mmscf and oil price between 2021-2024 at $70. [2] The effectiveness per well is also illustrated (Table 11).

Each well is viable as the revenue from each well's production exceeds the cost of drilling. An economic overview of the redevelopment is highlighted (Table 12).

Table 11. Cost benefit analysis of producer wells.

	Oil Produced (Sm^3)	Revenue (million USD)	Viable
P-F-11B	370,000	163	Yes
P-F-12	270,000	119	Yes
P-F-15C	179,000	79	Yes
P-F-15D	300,000	132	Yes
P-F-1C	470,000	207	Yes
P-F-5	160,000	71	Yes
R-2-P-11	157,500	70	Yes
R-2-P-5	93,500	41	Yes
R-2-P-13	93,500	41	Yes
R-6-P-1	205,000	91	Yes
Total	2,298,500	1014	Yes

Table 12. Economic summary of Volve redevelopment.

	Annual mill USD	3 Year Total mill USD
Drilling	----	426
Platform Rental and Underwater Equipment	101	303
Platform Operation and Maintenance	45	135
Export Cost	0.12	0.36
Gas Injection	---	0.17
Water Injection	---	17
Additional 4th Year Cost*	---	146*
Decommissioning	---	30
Total Cost	---	911.53+146*
Oil Production	338	1014
Gas Production	---	0.21
Additional 4th Year Production Potential*	---	200*
Total Income	---	1014.21+200*
Net Revenue	---	102.68+54*

*A further 2% recovery in the 4th year could bring in an additional $200 million, bringing an additional $54 million after the $146 million platform costs. This would be the recommendation as it would increase the net revenue by approximately 50%.

With a discount rate (r) at 6% this gives an NPV at $106 million, an IRR of 27% and a UTC at $60.8/bbl. Assuming first oil is struck a year after project conception the payback time would be halfway through the third year (2 and a half years from first oil). Comparing this approach with the production prediction approach (case 2) is shown in table 13.

Table 13. Economic comparison of Cases 2 and 7.

	Case 2 – Production Prediction	Case 7 – Double Peripheral Final
Cost 3 Years mill USD	657	912
Income 3 Years mill USD	750	1,014
Net Revenue 3 Years mill USD	93	102
Cost 4 Years mill USD	803	1,058
Income 4 Years mill USD	830	1,214
Net Revenue 4 Years mill USD	17	156

Although there is comparable economic success after 3 years with only $9 million difference, from four years and further case 7 is by far the most profitable. This affirms that case 7 is the prudent technical choice over 4 years, however in terms of the recommended choices by the authors it would have to be Case 2. This was a difficult recommendation to make, however the facts remain that Case 2 utilizes 10 less wells leading to a much-reduced decommissioning cost and equally vital a far significant impact on the local environment. The energy landscape is changing, and it is important to make sensible steps to be on the right side of that, thus it would be recommended to utilize Case 2 over 3 years and then stop production.

The carbon consideration of this redevelopment is, like with any oil and gas development something that has to be considered. Assuming a value of 2.71 tons CO_2/m^3 of oil, the amount of CO_2 released due to the redevelopment is 4.61 million tons in 3 years. Efforts were made throughout this development to bring about a reduced emission project with limiting environmental damage. This included the EOR choice of reinjected reservoir gases in a WAG format, avoidance of any potentially excessively damaging chemicals and the location itself, as the North Sea would not be considered an environmentally sensitive area when compared to others (National Parks, Arctic, etc.).

4.4. Comparison between DM supported field development and conventional reservoir modelling

Given the clear successes of utilising DM in the field development it is prudent to compare this to simply conducting a field development without this innovative technique. This is done by comparing the recommended option (Case 2) with the base case option. The results are very clear with the exact same amount of CAPEX and OPEX an additional 1.2% of recovery is achieved. This means that using conventional reservoir modelling 1.42×10^6 Sm^3 of oil is produced, 180,000 Sm^3 less than using DM. This reduces profits by approximately $80,000,000. This clearly indicates the advantages of DM provided the system developed is at a cost of less than this figure.

5. Conclusions

This study was a brownfield development of Volve field, a Norwegian oil field. The data pack was huge and with this considerable size investigating manually would be unmanageable. Thus, a bespoke DM algorithm was planned and applied. This data was analysed and used to create the reservoir model, in tandem perhaps the most effective development scheme was fashioned, and an inclusive strategy was set out.

The DM successfully reduced the data set to 0.2% of the initial size extracting only the data instrumental for the study. The 11 steps development plan investigated the previous development and the reservoir, the successful completion of which permitted the scheme to be advanced. This culminated in the enhancement and simulation analysis which presented each of the cases investigated in this study.

The results identified the best scenarios based on 7 options. Resulting in the best technical case using 2 water injectors, 5 WAG injectors, and 10 oil producers (3 of which were horizontal). Giving a recovery factor of 56% in 3 years with 58% if extended for a further year. Due to environmental considerations and impact on

the seabed the recommended choice was the Case 2 utilizing 6 producers and 1 water injector. This gave a recovery of 53.2% over 3 years at which stage the wells will be shut in.

A jack-up rig with processing facilities is planned for drilling and fluid processing with a shuttle for export. The project is estimated to cost $657 million and make $750 million netting a profit of $93 million. The unique selling point of this case was its minimal footprint on the local environment as well as a lower carbon and capital intensity. After 3 years the NPV is $93 million, IRR is 57%, UTC is $52.8/bbl. and payback is 2 and a half years from first oil.

Nomenclatures

B_o	Oil formation volume factor	----
C	Concentration	kg/m^3
(γ_o)	Oil gravity	----
(γ_g)	Gas gravity	----
R	Gas-oil ratio	scf/stb
J	Connections to wells	bbl/d/psi
K	Permeability	mD
K_v	Vertical permeability	mD
K_h	Horizontal permeability	mD
K_r	Relative permeability	----
L, H, W	Length, height, width	m
H_p	Hydrocarbon pore volume	m^3
V	Volume	m^3
$V_{Standard}$	Volume at standard Conditions	Sm^3
N	Original oil in place	m^3
P	Pressure	Pa
Q	Fluid flow rate	m^3/s
r	Radius	m
R_f	Recovery factor	%
s	Saturation	----
S	Skin factor	----
S_{wi}	Initial water saturation	----
T	Transmissibility	mD-ft./cp
t	Temperature	K
TVD	True vertical depth	m

Greek Symbols

μ	Viscosity
φ	Porosity

Abbreviations

CAPEX	Capital Expenditure
CPU	Central Processing Unit
DM	Data Mining

EIA	Energy Information Administration
ED	Microscopic Sweep Efficiency
EOR	Enhanced Oil Recovery
Ev	Macroscopic Sweep Efficiency
FDP	Field Development Plan
FIPNUM	Fluid In Place Number
GOR	Gas Oil Ratio
HCPV	Hydrocarbon Pore Volume
IRR	Internal Rate of Return
KDD	Knowledge Discovery in Databases
MBAL	Mass Balance
Mo	Moveable Oil
NOK	Norwegian Krone
NPV	Net Present Value
OIIP	Oil Initially in Place
OPEX	Operational Expenditure
PVT	Pressure Volume Temperature
STB	Stock Tank Barrels
STOIIP	Stock Tank Oil Initially in Place
TVD	True Vertical Depth
USD	United States Dollars
UTC	Unit Technical Cost
WAG	Water Alternating Gas

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