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# Maximization of Oil Production in the Norne Field C-Segment: Well Placement Comparative Study

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***Abstract*—Maximum oil production can be obtained with more oil wells, but few optimal numbers of wells in good location reduces economic costs and increase recovery. In this work, The Norne field C-segment reservoir model in Eclipse® software is used to study the effect of well placement. Six producers (while the four injectors remain the same as those of the base case) for two different well placement scenarios, 1 and 2, are located manually after identifying grid blocks with high oil saturation from an updated geological model. Insignificant variation in oil recovery factors, 1.3%, is obtained for the base case and the two scenarios. However, after taking into account the well costs, gas and water injection costs under reasonable economic assumption, the NPV results shows that scenario 2 with the highest NPV is considered to be more favourable**.

***Keywords—Maximum Oil production, Well placement, Norne field C-Segment, Reservoir Simulation, Oil Recovery, Economic Analysis, Net Present Value.***

## I. INTRODUCTION

The Norne database in the Center of Integrated Operation in the Petroleum industry at the Norwegian University of Science and Technology (NTNU) has a license limitation but it is readily available for postgraduate research projects. Many academic projects, mostly simulation of chemical EOR processes to improve oil recovery from Norne field, have been carried out at the Center of Integrated Operation in the Petroleum industry at the Norwegian University of Science and Technology (NTNU) by utilizing the Norne database.

However, this work studies the effect of well placement for maximum oil recovery in the Norne Field C-segment. Determining the best location for new wells is a complex problem that depends on reservoir and fluid properties, well and surface equipment specifications, and economic criteria. Placing too many wells in oil reservoir is known to have tremendous effect in oil recovery but it has also cause increase in economic cost in the oil industry for many years now. Optimum well placement most of the time is done based on a deterministic (most likely) case. In this sense, the use of reservoir simulation allows the engineer to evaluate different placement scenarios.

A total number of ten wells; six producers and four injectors are placed in each scenario. In order to obtain maximum oil recovery, the producers are placed horizontally while injectors remain the same as those from the base case. The new well placements in the scenarios are identified with the suffix "P-H" for producers and "I-H" for injectors. Simulation results, the total oil produced for wells in each scenario from the start year 1997 to December 2015 are reported.

The Net present values for the three cases are then calculated taking into account the economic costs such as well cost, cost of gas and water injection. Sensitization was done on the oil price ($25, $35). The NPV results are discussed and the most economical well placement scenario is thus identified.

## II. THE NORNE FIELD AND ITS SIMULATION MODEL

The Norne field, one of the largest discovery on the Norwegian continental shelf in more than a decade with recoverable oil reserves of 450 Mbbl, has four main fault blocks of C, D, E and G segment. The Norne Main Structure (Norne C-, D- and E-segment, discovered in 1991) contains 97% of the oil in place. The Norne field is in Blocks 6008/10 and 6508/10 on a horst block in the southern part of the Nodland II area in the Norwegian Sea. The drainage strategies/drive mechanisms on the field are pressure depletion, gas injection, water injection and combine gas and water injection. Based on the framework, water and gas injection is recommended as the base mechanism for the C-segment field. The rocks within the Norne reservoir are Late Triassic to Middle Jurassic. The current geological model has five reservoir zones- Garn, Not, Ile, Tofte, and Tilje. Oil is found mainly in the Ile and Tofte formations, and gas is found in the Garn formation. The sandstones are at a depth of 2500m to 2700m. The porosity ranges from 25 to 30%, and permeability varies from 20md to 2500md. The data consist of near-, middle-, and far-stack 3D-seismic data acquired in 2001, 2003, and 2004.

The Norne field has been simulated by four different Eclipse black oil models, from oldest to newest [13, 14]. New simulation models are built when significant updates of the geological model are done, or if certain formation needs refinement. The reservoir model used in this work is the 2004 geological model with 3D three-phase full field black-oil model. The Norne full field model consists of 49080 active grid cells. DX & DY range between 80 – 100 m. The Norne C-segment coarsened grid model was separated from the rest of the field by keeping the C-segment coarsened model with 29x49x22 grid blocks active. Water compressibility of 4.67 x 10-5/bar at 277 bars and rock compressibility factor of 4.84 x 10-5/bar are used in the model. The formation volume factor used is 1.038 Rm3/Sm3 and the oil viscosity is 0.318 cp.

## III. WORK FLOW

This section explains the base case which is defined as the initial case obtained from Eclipse 100 simulation run from Statoil. The scenarios 1 and 2 are created based on the initial field reservoir conditions (rock and fluid properties) at 1997. New wells are placed manually on high oil saturation on the scenario cases and the results obtained on well placement and oil production will be compared for economic benefit.

### *A. Base Case*

The total number of wells located on the base case is 13, 9 producers and 4 injectors from the simulated model of the field from the duration of 1997 to 2006. More also, the work will predict production until 2015. In the base case the producing well and injection wells used a template name B, D, K and C respectively. Well locations on the base case are based on the following principles [15]:

- Water injectors are located at the flanks of the reservoir

- Gas injectors located at the structural heights of the reservoir.

- Oil producers located between gas and water injectors for delaying gas and water breakthrough.

- Oil producers are located at some distance from major faults to avoid gas inflow.

### *B. Drilling and Completion Strategy*

Three Well; B-2H, D-1H and D-2H, was drilled from the start-up in the C-segment field base case. These give plateau production in 2000. Two producers show good productivity and late gas break through. The last five were drilled continuously form the production start-up with a drilling time of 1-2 years until 2006. The four injectors are locations close to the edge of the simulation model rounding the in centre all the producers. The first injector well C-1H was drilled a year after the stat-up of the field 1997, and follow by the other four injectors all drilled in 1998. The water injection wells has 5.5” and 7” tubing. The injection pressures are dependent on the bottom-hole pressure required to flow the water into the reservoir formation.

The wells are completed in different formations depending on the drainage strategy. The water injectors are perforated below the oil-water contact, and the two gas injectors are perforated in layer one top Garn formation. The vertical production wells are generally perforated in the Ile 1, top of Tofte 3 and Tofte. The production wells are completed to delay gas and water breakthrough and to minimize the amount of well interventions required [16].

### *C. Well Placement for Scenario 1 and 2*

The objective was to place minimum number of wells to obtain same or higher recovery than the Statoil. A decision was made that 10 new wells will be placed taking well type, location and spacing in to consideration. In new well placement, the suffix “P” is used for producers and “I” is used for the injectors in both scenarios 1 and 2. The flow in the reservoir from the base case shows good recovery on both vertical and horizontal wells but high recovery is achieved with horizontal wells then the vertical wells. Since few wells will be placed to achieve high recovery, slant vertical wells and horizontal will be placed to decrease the drilling and operational cost.

### *D. Procedure*

The base case wells were all removed from the Schedule file and the field was left with no wells accepts general reservoir properties. The flow pattern was studied along with oil/gas water saturation. New schedule files from Eclipse were formed and well placed continuously for each year starting with the P-1H to P-6H wells. First, by using keyword WELOPEN all existing injection wells were stopped and then opened only when observed pressure drop during production which are in both scenarios. Well properties in COMPDAT and WELSPECS keyword were on defaulted except wellbore.

To achieve a successful placement both for Scenario 1 and 2, several numbers of simulation runs was carried out and 6 successful producers, P-1H, P-2H, P-3H, P-4H, P-5H and P-6H, all horizontally placed for Scenario 1, while 4 producers, the remaining 2 producers were left in the same position as in Scenario 1, were placed for Scenario 2. The producer placement and completion are carry out where there is only high oil saturation in the field after studying the direction of flow in the reservoir. The completions were targeted at the Ile and the Tofte formations which contain about 80% of the oil in Norne C-Segment.

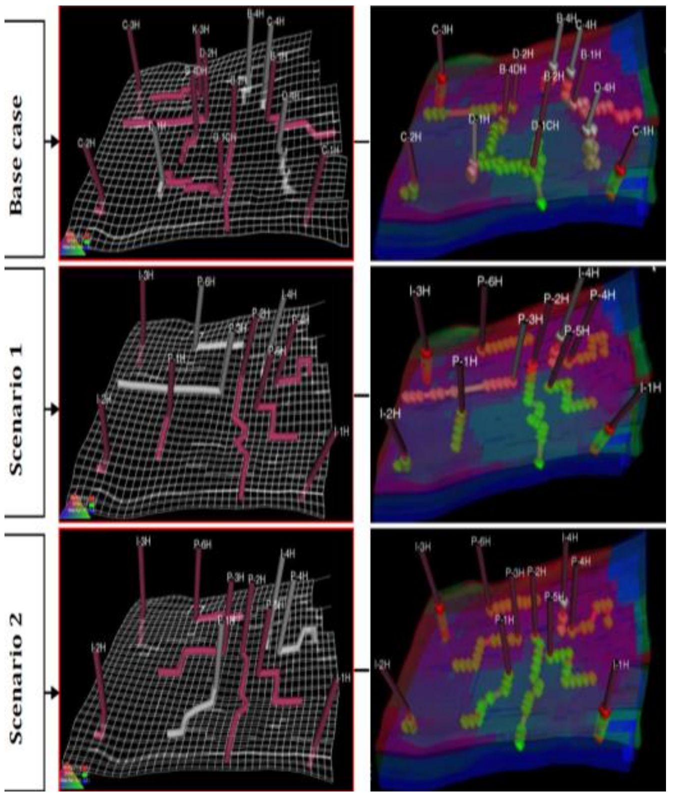


Fig 1: Wells trajectory from simulation run for the Base case, Scenario 1& 2

The location of injection wells depends on the factor such as reservoir structure, injected fluid type, and displacement mechanism. Therefore, all injection wells, I-1H, 1-2H, I-3H, and I-4H, in both scenario cases were left in the same location as in the base case. Injection wells are all vertical with perforation in the bottom for water injection and in the top for gas injection. Some of water injection wells are perforated throughout the reservoir. (See Figure 1 for the Wells trajectory from simulation run for the Base case, Scenario 1& 2 in the Norne Field C-Segment.).

To decrease simulation time restart file for first 9 years of production was made. Then for each case including the base case, additional 9 years of production were simulated using Eclipse® software. Results of simulation were extracted from RSM files and compared between each other. In this part of report cases are compared only by using value of recovery factor. For economic calculation following indexes were extracted with time step of one year: cumulative oil production, cumulative water and gas injected. Description of the scenario cases and recovery factor after additional 9 years of production will be explain in as we go further on this work.

*E. Production and injection constraints*

A slight variation in Production and injection constraints is used in the simulation cases. For the base case, maximum oil production rate for each oil producer is 7008 Sm3/day while the maximum oil production rate for each oil producer in scenario 1 and 2 is 8009 Sm3/day. Other production and injection constraints include;

- Maximum oil production rate for each oil producer is 7008 Sm3/day
- Maximum gas injection rate for each gas injector is 2600000 Sm3/day.
- Maximum water injection rate for each water injector is 3760 Sm3/day
- Maximum water-cut is 95%
- Maximum gas oil-ratio is 15675 Sm3/Sm3
- Maximum bottom-hole pressure is 376 bars

*F. Reservoir Simulation Results and Discussions*

The results obtained from simulation on base case field production and the scenario 1 and 2 well placement production and injection are presented and discussed. The results combine the initial production profile of the reservoir from 1997 to 2006 and the expected (forecast) production to 2015. Also the recoverable and unrecoverable reserves are summarised.

*a. Oil Production Results*

The Oil production in the base case from the year 1997 to 2006 is approximately 31.6 million Sm3. Oil production in case 1 is 34.3 million Sm3 and Scenario 2 is 36.7 million Sm3. Oil production forecast for the base case from 2006 to 2015 is estimated as 9.7 million Sm3. A total of 8.5 million Sm3 of oil is produced in this nine-year period in scenario 1 and 6.5 million Sm3 in scenario 2. The field oil production and the total oil production rate profiles for the three cases can be seen in Figure 2. The cumulative oil production rises from the base case to 41.3 million Sm3. The oil production for scenario case rises to 42.8 and 43.2 million Sm3 in scenario 1 & 2 cases. This shows that there is an increase of 1.5 to 1. 9 million Sm3 of oil production for the two cases when compared to the base case.

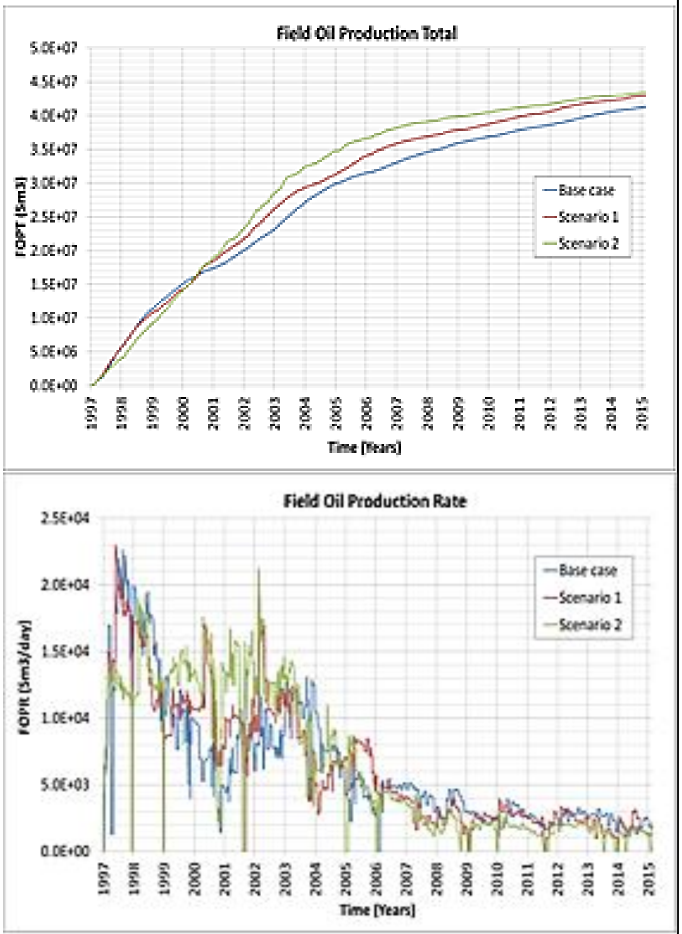


Fig 2: Field oil production rate and total field oil production profiles

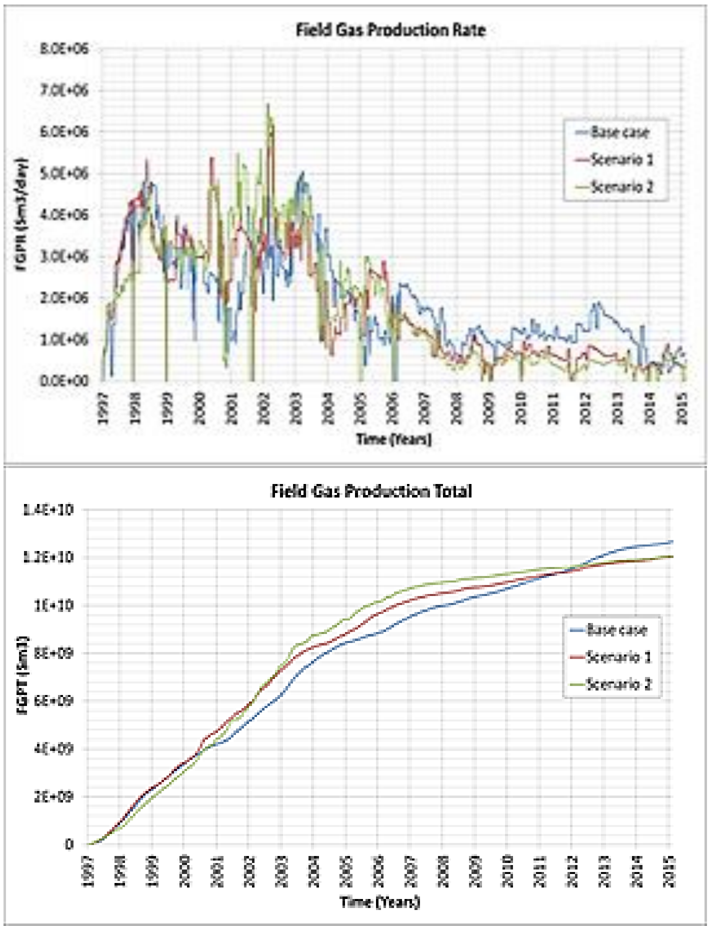


Fig 3: Field gas production rate and total field gas production profiles

*b. Gas Production Results*

The total volume of gas produced from the base case from 1997 to 2006 is 8.9 billion Sm3. However, the total produced gas for Scenario 1 is 9.7 billion Sm3 and scenario 2 produced 10.2 billion Sm3 of gas. The gas production forecast in the base case from 2006 to 2015 is 8.5 billion Sm3, while gas production for scenario 1 is 2.3 billion Sm3 and 1.8 billion Sm3 for scenario 2 case. The cumulative Gas production from 1997 to 2015 is therefore 12.7 billion Sm3 for the base case and 12.0 billion Sm3 for both Scenario 1 and 2. The production rate and total field gas production profiles can be seen in Figure 3.

*c. Water production Results*

The total water produced from the base case is 7.3 million Sm3. An approximately 6.1 million Sm3 of water is produced in scenario 1 and 3.7 million Sm3 in scenario 2 case. Water production forecast for base case in 2006 to 2015 is 16.0 million Sm3. A total of 15.5 million Sm3 of water is produced in this nine-year period in scenario 1 and 14.1 million Sm3 in scenario 2. The production rate and the total water production profiles from 1997 to 2015 can be seen in Figure 4. The cumulative water production rises from the base case to 23.3 million Sm3. For scenario 1, it rises to 21.6 million Sm3 and 17.8 million Sm3 for scenario 2 case.

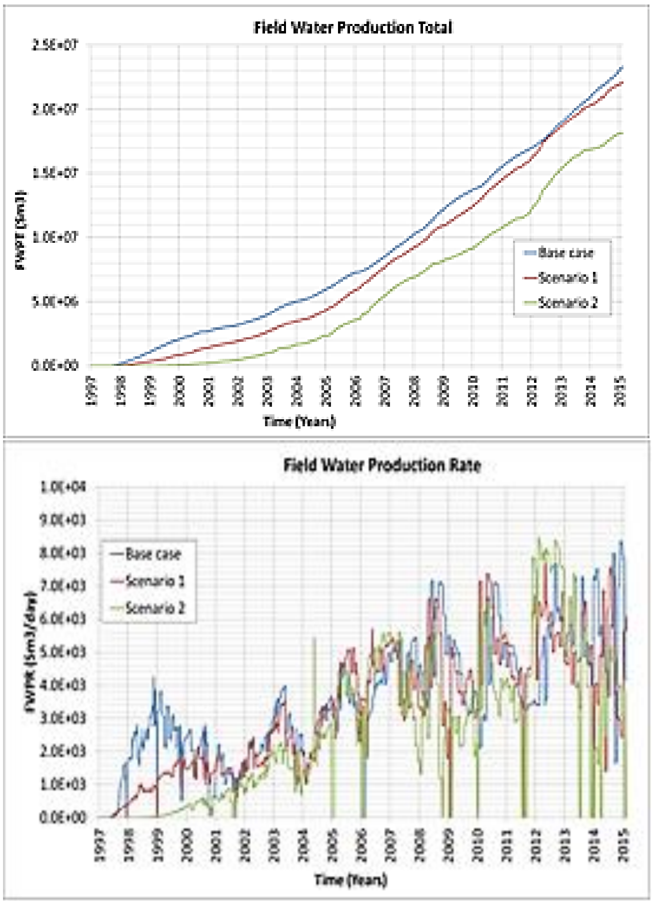


Fig 4: Water production rate and total field water production profiles

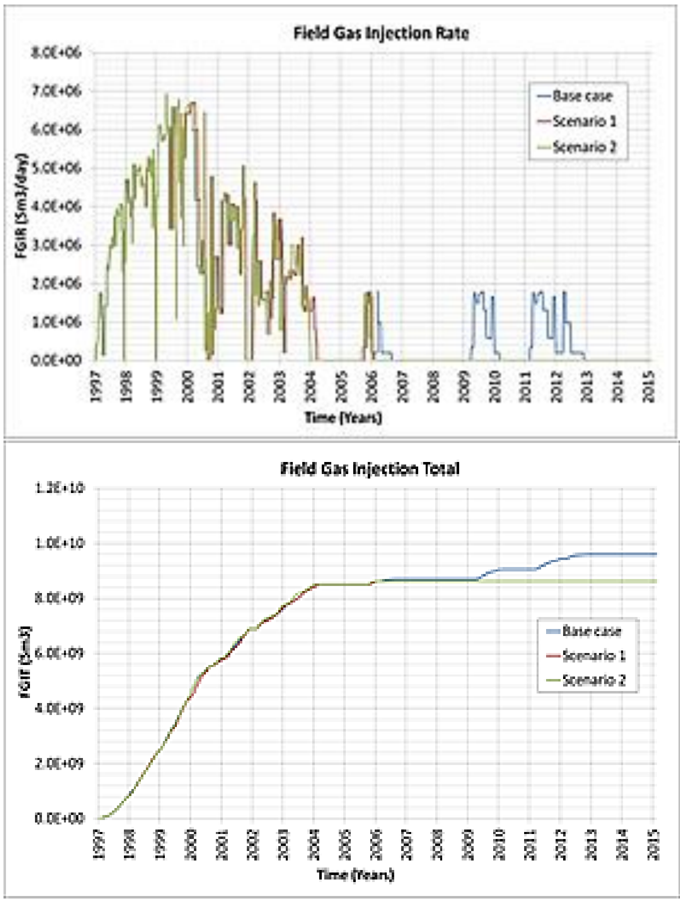


Fig 5: Field gas injection rate and total gas injection profiles

### *d. Gas injection and water injection*

To improve the recovery of oil in the C-segment reservoir, the total volume of 8.63 billion Sm3 gas was injected in the base case and the same volume was also injected in scenario 1 and 2 from 1997 to 2006. From 2006 to 2015, gas injection to maintain pressure in the base case is 10 million Sm3 volume of gas, whereas the gas injection volume for each of the two scenarios are less than 1 million Sm3. Figure 5 presents the gas injection rate and the total field gas injection profiles for the three cases.

Water injection from 1997 to 2015 in the base case is 79million Sm3. Injected water estimated in scenario 1 & 2 from 1997 to 2015 is 81.2 million Sm3 for each case. Figure 6 shows the water injection rate and the total field water injection profiles for the three cases.

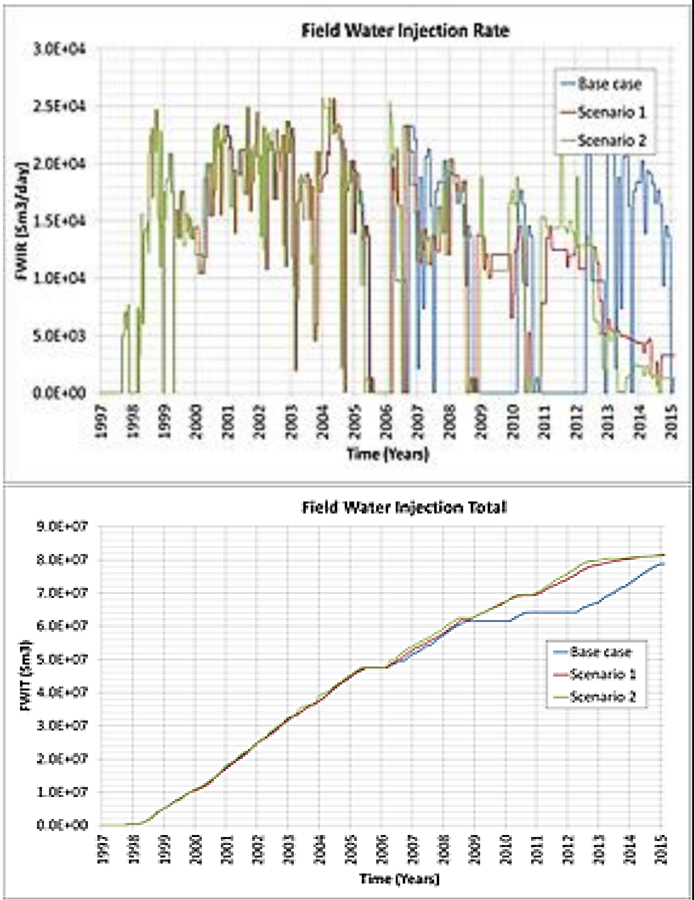


Fig 6: Field water injection rate and the total water injection profiles

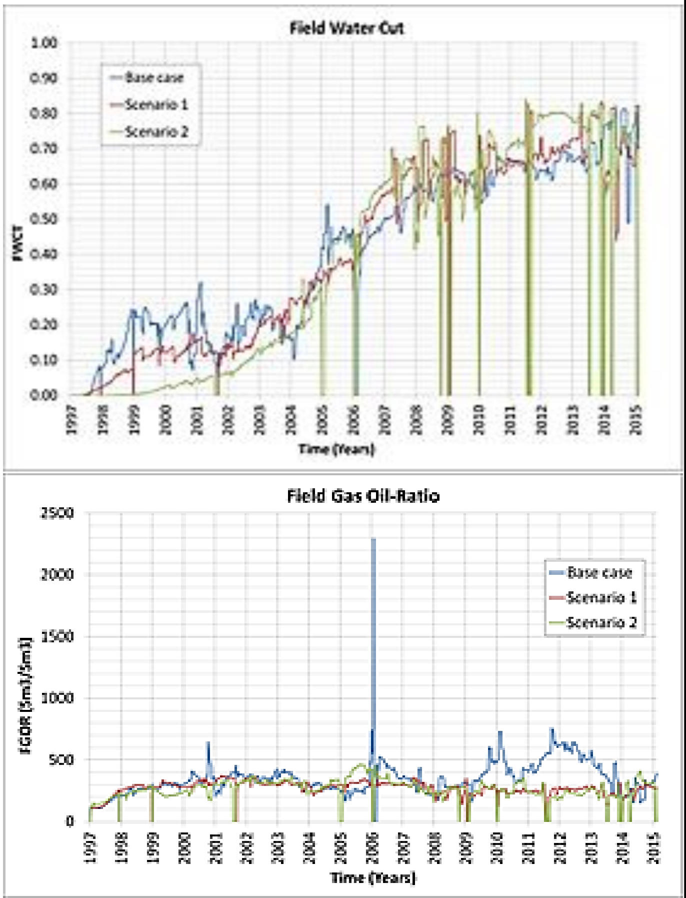


Fig 7a: Field Water-cut and Gas-Oil Ratio profile

*e. Oil Recovery*

Oil recovery factor for the base case is 21.4%, Scenario 1 has 23.2% oil recovery factor and Scenario 2 is 24.9%. From 1997 to 2015, the forecasted oil recovery factor for the base case increased to 28.0% while oil recovery factor is 29.0% for scenario1 and 29.3% for scenario 2. (See figure 7a); The field water-cut, GOR. Oil recovery efficiency and the field reservoir pressure profiles for the three scenarios are also presented in figure 7b,

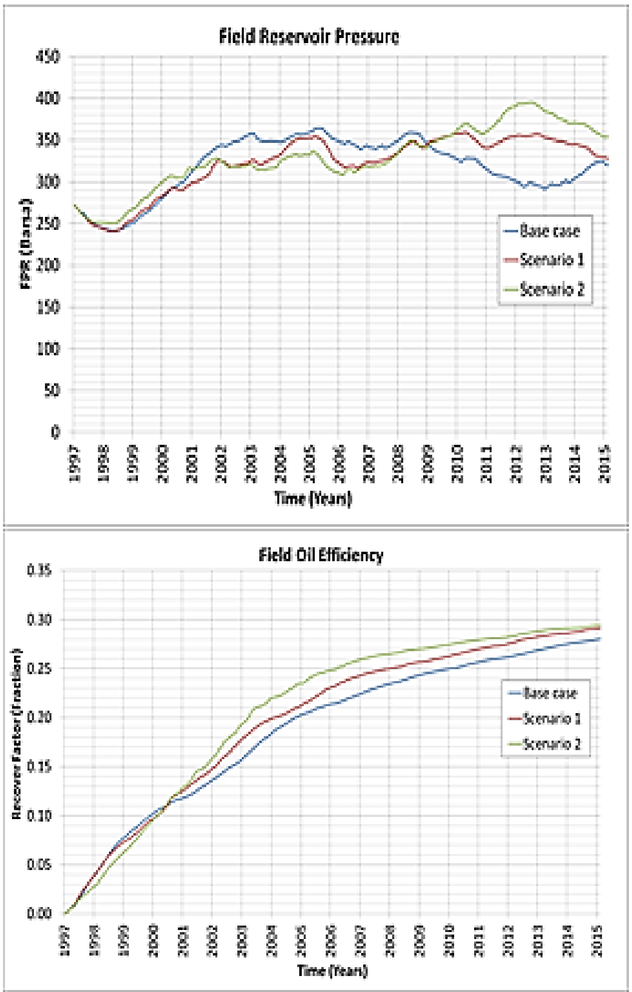


Fig 7b: Field reservoir pressure and the recovery factor profile

### G. *Recoverable and Unrecoverable reserves*

Originally, oil in-place in the simulations model is estimated as 147 million Sm3 and gas in place as 230 billion Sm3 in 1997. The recoverable oil reserves, the recoverable gas reserves and the unrecoverable reserves for the three cases, from1997 to 2015, are presented in table 1.

Table 1: Reserves of Oil and Gas in the C-segment Field from 1997 to 2015

| Description | Units ($Sm^3$) | Base case | Scenario 1 | Scenario 2 |
|---|---|---|---|---|
| Oil in Place, STOIIP | * $10^6$ | 147.6 | 147.6 | 147.6 |
| Gas in Place (free & Solution) | * $10^9$ | 229.9 | 229.9 | 229.9 |
| Recoverable Oil Reserves | * $10^6$ | 41.4 | 43.0 | 43.4 |
| Recoverable Gas Reserves | * $10^9$ | 3.06 | 3.35 | 3.37 |
| Unrecoverable Oil reserved | * $10^6$ | 106.2 | 104.6 | 104.2 |

## IV. ECONOMIC ANALYSES

### A. *Net Present Value (NPV)*

Present value of money compares the value of a certain amount of money today to the value of that same amount in the future and vice versa, taking into consideration inflation and returns. Net present value (NPV) is the difference be-tween the present value of cash inflow and the present value of cash outflow. Given an investment opportunity, NPV is used by an organization to analyze the profitability of the project or investment and to make decisions with regards to capital budgeting. It is sensitive to the future cash inflows that an investment or project will yield [17].

Table 2: Economic assumptions for NPV calculation

| Economic Parameter | Cost (USD) |
|---|---|
| **Vertical well** | |
| Cost of drilling a vertical well | 17000000 |
| Capital expenditure (CapEx) per vertical well | 1700000 |
| Operating Expenditure (OpEx) per vertical well | 800000 |
| **Horizontal wells** | |
| Cost of drilling a horizontal well | 20000000 |
| Capital expenditure (CapEx) per horizontal well | 2000000 |
| Operating Expenditure (OpEx) per horizontal well | 1000000 |
| **Fixed parameters** | |
| Fixed Capital expenditure | 200000000 |
| Fixed Operating expenditure per year | 5000000 |
| **Other operational costs were not taken into consideration:** | |
| Cost of Gas injection Per MScf | $12 |
| Cost of water injection Per Mbbl | $8 |
| Discount rate | 8% |
| Inflation rate | 8% |
| Oil price | $25 and $35 |

Thus, the objective is to calculate the net present value over the life of the reservoir and this is achieved after generating the results of the reservoir simulation. In carrying out this analysis, a number of assumptions are made. The economic parameters assumed can be seen in Table 2 below.

The calculation of NPV is possible after extracting results to a user friendly Excel Spread sheet program from the simulation output file. Annual oil production, summation of oil produced from the wells in a year for each case, represents a single value. NPV takes more consideration of the economics of the project period, starting with the first year of production 1997-2006 until the forecast production period 2015 (See Table 3).

The base case will be compared with other Scenario case. The NPV formula used is given below;

**Formula:**

$$NPV = \sum_{t=0}^{n} \left( \frac{CF_t}{(1+d)^t} \right) \quad (1)$$

Where: $CF_t$ = Cash Flow of a period "t"

$dt$ = Discount rate for period "t"

$n$ = Last period of economic horizon

Cash flow is cash inflow minus cash outflow. The main elements required for a cash flow analysis are: Revenue, R= Production x Price, and Expenditure, E = Operating expenditure (OPEX) + capital expenditure (CAPEX). The investment Decision is if NPV > 0, the Project is accepted or NPV < 0, the Project is rejected. This means the project with the highest NPV is favorable.

In any petroleum project, the price of crude oil is very important. Oil prices changing with respect to time, in the fore-casting of oil price, inflation needs to be factored into the estimates. Hence, inflation is used to calculate current price value of 1997 to 2015. The assume oil prices based on 1997 are $25 as low price, $35 as high price. The rate of inflation is stated as a percentage. This represents the rate of changes of prices between the current and previous year. Thus, Inflation;

$I = P_o(1 + R)^n$ (2)

Where, $I$ is an inflation index

$P_o$, Initial oil Price (based on 1997)

$R$, inflation rate per annum

$n$ , the number of years

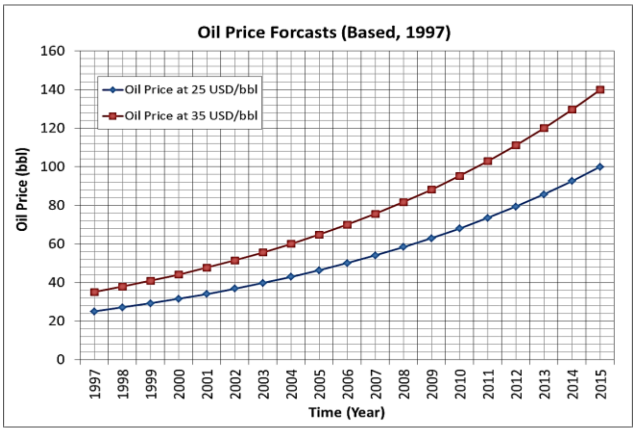


Fig. 8: Forecast Oil price for NPV calculation (assume Oil price based on 1997)

Using the above equation, the result for the forecast oil price is presented in Figure 8.

For economic calculation, the oil production is converted from standard cubic feet (Sm3) to barrel (bbl). The conversion factor is given in table 4. A detailed economic analysis is carried out in excel sheet. Tables 5 through 9 at the Appendix present the cost of gas and water injection, well cost and total expenditure for base case wells and the new well case scenario 1 & 2. NPV calculation for all cases is shown in Tables 10 through 12, lastly NPV results summary for the three cases at different oil price value presented in Table 13. Figure 9 shows the NPV comparisons for the three cases at the price regimes under study.

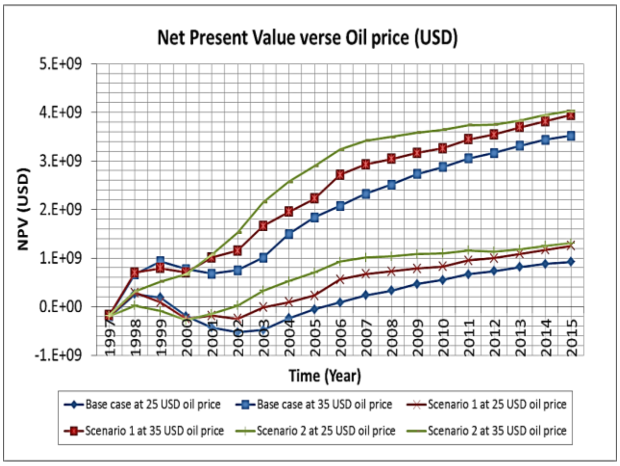


Fig. 9: Summary of NPV comparisons for base case and the two scenarios at various Oil price values

The Net present value for the three project for the base case, scenario 1 & 2 at low oil price; $25, slightly high oil price; $35, is presented below in Table 14.

Table 14: The Net Present Value

| Present Value (PV) | Oil price at 25 USD (mill) | Oil price at 35 USD (mill) |
|---|---|---|
| Base case | 918 | 3,516 |
| Scenario 1 | 1,254 | 3,945 |
| Scenario 2 | 1,307 | 4,026 |

The NPV show values in relative to the oil prices, the higher the oil price, the higher the NPV. Base on economic decision, all cases are considered since there is no negative NPV. However, the NPV for the base case is less when compare to scenario 1 & 2; the NPV of scenario 1 is less than that of scenario 2. The best case is thus scenario 2.

## V. CONCLUSION

The Norne field is the largest discovery on the Norwegian continental shelf in more than a decade with recoverable oil reserves of 450 Million bbl, and has four main fault blocks of C, D, E and G segment. Maximum oil production can be obtained with more oil wells, but few optimal numbers of wells in good location reduces economic costs and increase recovery. The Norne field C-segment reservoir model in Eclipse® software is used to study the effect of well placement. Six producers (while the four injectors remain the same as those of the base case) for two different well placement scenarios, 1 and 2, are located manually after identifying grid blocks with high oil saturation.

Oil recovery factor for the base case is 21.4%, Scenario 1 has 23.2% oil recovery factor and Scenario 2 is 24.9%. From 1997 to 2015, the forecasted oil recovery factor for the base case increased to 28.0% while oil recovery factor is 29.0%

for scenario1 and 29.3% for scenario 2. The cumulative Gas production from 1997 to 2015 is therefore 12.7 billion Sm3 for the base case and 12.0 billion Sm3 for both Scenario 1 and 2. From 1997 to 2015, the cumulative water production rises from the base case to 23.3 million Sm3. For scenario 1, it rises to 21.6 million Sm3 and 17.8 million Sm3 for scenario 2 case. Water injection from 1997 to 2015 in the base case is 79 million Sm3. Injected water estimated in scenario 1 & 2 from 1997 to 2015 is 81.2 million Sm3 for each case.

From the economic analyses, the NPV for the base case is less when compare to scenario 1 & 2; the NPV of scenario 1 is less than that of scenario 2. The best case is thus scenario 2.

ACKNOWLEDGMENT

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## VI. APPENDIX

Table 3: Cumulative Oil Production for Base case and Scenario Cases (in Sm3 and bbl)

| Year | Cum. Oil Prod.(Sm³) Base case | Cum. Oil Prod.(Sm³) Scenario 1 | Cum. Oil Prod (Sm³) Scenario 2 | Cum. Oil Prod.(bbl) Base case | Cum.Oil Prod.(bbl.) Scenario 1 | Cum. Oil Prod.(bbl) Scenario 2 |
|---|---|---|---|---|---|---|
| 1997 | 384337 | 293356 | 306413 | 2417481 | 1845209 | 1927340 |
| 1998 | 6139044 | 6308123 | 4387918 | 38614586 | 39678094 | 27600002 |
| 1999 | 5329219 | 4553771 | 5052367 | 33520788 | 28643220 | 31779388 |
| 2000 | 3635180 | 3916340 | 5358832 | 22865282 | 24633779 | 33707053 |
| 2001 | 2114810 | 3966190 | 4352620 | 13302155 | 24947335 | 27377980 |
| 2002 | 2795720 | 3204060 | 4477600 | 17585079 | 20153537 | 28164104 |
| 2003 | 3356280 | 4413450 | 5021370 | 21111001 | 27760601 | 31584417 |
| 2004 | 3837120 | 2867970 | 3623370 | 24135485 | 18039531 | 22790997 |
| 2005 | 2507320 | 2188040 | 2310810 | 15771043 | 13762772 | 14534995 |
| 2006 | 1465200 | 2557960 | 1838920 | 9216108 | 16089568 | 11566807 |
| 2007 | 1700750 | 1583690 | 1505740 | 10697718 | 9961410 | 9471105 |
| 2008 | 1449620 | 1009530 | 877030 | 9118110 | 6349944 | 5516519 |
| 2009 | 1299620 | 988210 | 703930 | 8174610 | 6215841 | 4427720 |
| 2010 | 894290 | 793770 | 627940 | 5625084 | 4992813 | 3949743 |
| 2011 | 1046370 | 1033440 | 660850 | 6581667 | 6500338 | 4156747 |
| 2012 | 754400 | 759330 | 439670 | 4745176 | 4776186 | 2765524 |
| 2013 | 1024350 | 984500 | 702160 | 6443162 | 6192505 | 4416586 |
| 2014 | 908990 | 697280 | 568860 | 5717547 | 4385891 | 3578129 |
| 2015 | 664020 | 654230 | 415130 | 4176686 | 4115107 | 2611168 |
| | 41306640 | 42773240 | 43231530 | 259818766 | 269043680 | 271926324 |

Table 4: Conversion Factor [18]

| Nomenclature | | | Units |
|---|---|---|---|
| *CapEx* | Capital Expenditure | *rcf* | Reservoir cubic feet |
| *OpEx* | Operating Expenditure | *res.bbl* | Reservoir barrel |
| *3D* | Three Dimensions | *rm3* | Reservoir cubic metres |
| *NPV* | Net Present Value | *scf* | Standard cubic feet |
| *Np* | Cumulative Oil Produced | *sm3* | Standard cubic metres |
| | | *Mscf* | 1000 scf |
| **Subscript** | | *MMscf* | 1000000 scf |
| *o* | Original | *stb* | Stock tank barrel |
| *i* | Initial | *$ (USD)* | Dollars |
| *g* | Gas | bbl | Barrel |
| *w* | Water | bcf | Billion Cubic Feet |
| | | d | Day |

**Conversion Factor**

| | | | |
|---|---|---|---|
| 1 Sm3 Oil | = | 1.0 | Sm3o.e. |
| 1000 Sm3 Gas | = | 1.0 | Sm3o.e. |
| 1 Sm3Condensate | = | 1.0 | Sm3o.e. |
| 1 tonne NGL | = | 1.9 | Sm3o.e. |
| 1 Sm3 Crude Oil | = | 6.29 | barrels |
| 1 Sm3 Crude Oil | = | 0.84 | tonnes Crude Oil |
| 1 Sm3 Gas | = | 35.314 | Scf |

Table 5: Cost of Gas injection (in USD/Sm3 and USD/Scf)

| Year | Total Gas Injected (Sm³) Base case | Total Gas Injected (Sm³) Scenario 1 | Total Gas Injected (Sm³) Scenario 2 | Costs of Gas Injection (USD/Scf) Base case | Costs of Gas Injection (USD /Scf) Scenario 1 | Costs of Gas Injection (USD /Scf) Scenario 2 |
|---|---|---|---|---|---|---|
| 1997 | 27068270 | 25636610 | 31295750 | 955888887 | 905331246 | 1105178116 |
| 1998 | 1047243730 | 1048675390 | 1035985250 | 36982365081 | 37032922722 | 36584783119 |
| 1999 | 1657076000 | 1670657000 | 1667069000 | 58517981864 | 58997581298 | 58870874666 |
| 2000 | 2170290000 | 2154696000 | 2349805000 | 76641621060 | 76090934544 | 82981013770 |
| 2001 | 948453000 | 950466000 | 853363000 | 33493669242 | 33564756324 | 30135660982 |
| 2002 | 1043499000 | 1050320000 | 974221000 | 36850123686 | 37091000480 | 34403640394 |
| 2003 | 873764000 | 866945000 | 879802000 | 30856101896 | 30615295730 | 31069327828 |
| 2004 | 716852000 | 715147000 | 718664000 | 25314911528 | 25254701158 | 25378900496 |
| 2005 | 25959000 | 27662000 | 0 | 916716126 | 976855868 | 0 |
| 2006 | 123771000 | 118666000 | 118666000 | 4370849094 | 4190571124 | 4190571124 |
| 2007 | 70404000 | 0 | 0 | 2486246856 | 0 | 0 |
| 2008 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2009 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2010 | 353277000 | 0 | 0 | 12475623978 | 0 | 0 |
| 2011 | 1120000 | 0 | 0 | 39551680 | 0 | 0 |
| 2012 | 391197000 | 0 | 0 | 13814730858 | 0 | 0 |
| 2013 | 147179000 | 0 | 0 | 5197479206 | 0 | 0 |
| 2014 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2015 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 9597153000 | 8628871000 | 8628871000 | 60366092370 | 54275598590 | 54275598590 |

Table 6: Cost of Water Injection (in Sm3 and bbl)

| Year | Total Water Injected (Sm³) Base case | Total Water Injected (Sm³) Scenario 1 | Total Water Injected (Sm³) Scenario 2 | Costs of Water Injection ($/bbl) Base case | Costs of Water Injection ($/bbl) Scenario 1 | Costs of Water Injection ($/bbl) Scenario 2 |
|---|---|---|---|---|---|---|
| 1997 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1998 | 465521 | 465521 | 465521 | 2928125 | 2928125 | 2928125 |
| 1999 | 5434252 | 5475522 | 5443252 | 34181448 | 34441036 | 34238058 |
| 2000 | 5611987 | 5567587 | 5948987 | 35299398 | 35020122 | 37419128 |
| 2001 | 7059300 | 7062430 | 7098850 | 44402997 | 44422685 | 44651767 |
| 2002 | 6964340 | 7095900 | 6801140 | 43805699 | 44633211 | 42779171 |
| 2003 | 7200530 | 7069010 | 7180550 | 45291334 | 44464073 | 45165660 |
| 2004 | 5658350 | 5638240 | 6676880 | 35591022 | 35464530 | 41997575 |
| 2005 | 7411840 | 7431910 | 6687070 | 46620474 | 46746714 | 42061670 |
| 2006 | 1810130 | 1713130 | 1501380 | 11385718 | 10775588 | 9443680 |
| 2007 | 4607690 | 5533470 | 6328420 | 28982370 | 34805526 | 39805762 |
| 2008 | 5881330 | 4980280 | 5208850 | 36993566 | 31325961 | 32763667 |
| 2009 | 3385690 | 4678230 | 3205540 | 21295990 | 29426067 | 20162847 |
| 2010 | 0 | 4371820 | 4214260 | 0 | 27498748 | 26507695 |
| 2011 | 2701040 | 2204000 | 2700120 | 16989542 | 13863160 | 16983755 |
| 2012 | 0 | 4260820 | 5545750 | 0 | 26800558 | 34882768 |
| 2013 | 4032220 | 4394590 | 4532530 | 25362664 | 27641971 | 28509614 |
| 2014 | 5640200 | 2068220 | 1045800 | 35476858 | 13009104 | 6578082 |
| 2015 | 4973990 | 1207780 | 590300 | 31286397 | 7596936 | 3712987 |
| | 78838410 | 81218460 | 81175200 | 495893599 | 510864113 | 510592008 |

Table 7a: Well cost and total expenditures for Base case, Scenario 1 & 2 wells

| Year of well Placement | Nos of Vertical well | CapEx. for Vertical wells + Cost of drilling Vertical well | CapEx. + Drilling costs for Vertical and Horizontal wells | Nos. of Vertical well* OpEx. per Vertical wells (USD) | OpEx. + Drilling costs for Vertical and Horizontal |
|---|---|---|---|---|---|
| 1997 | 1 | 18700000 | 60700000 | 800000 | 2800000 |
| 1998 | 3 | 52700000 | 54700000 | 2400000 | 2400000 |
| 1999 | 3 | 52700000 | 74700000 | 2400000 | 3400000 |
| 2003 | 0 | 1700000 | 23700000 | 0 | 1000000 |
| 2004 | 0 | 1700000 | 23700000 | 0 | 1000000 |
| 2006 | 1 | 18700000 | 20700000 | 800000 | 800000 |
| Total | 8 | 146200000 | 258200000 | | 11400000 |
| Numbers of wells and Expenditures in Scenario-1 wells | | | | | |
| 1997 | 1 | 18700000 | 20700000 | 800000 | 800000 |
| 1998 | 1 | 18700000 | 80700000 | 800000 | 3800000 |
| 1999 | 3 | 52700000 | 74700000 | 2400000 | 3400000 |
| 2003 | 0 | 1700000 | 23700000 | 0 | 1000000 |
| Total | 5 | 91800000 | 177800000 | | 9000000 |
| Numbers of wells and Expenditures in Scenario-2 wells | | | | | |
| 1997 | 0 | 1700000 | 23700000 | 0 | 1000000 |
| 1998 | 1 | 18700000 | 40700000 | 800000 | 1800000 |
| 1999 | 3 | 52700000 | 74700000 | 2400000 | 3400000 |
| 2001 | 0 | 1700000 | 23700000 | 0 | 1000000 |
| 2002 | 0 | 1700000 | 23700000 | 0 | 1000000 |
| 2003 | 0 | 1700000 | 23700000 | 0 | 1000000 |
| Total | 4 | 78200000 | 210200000 | | 9200000 |

Table 7b: Cont. on Well cost and total expenditures for Base case, Scenario 1 & 2 wells

| Year of well Placement | Nos of Horizontal well | CapEx. for Horizontal wells + Cost of drilling Horizontal well | CapEx. + Drilling costs for Vertical and Horizontal wells | No. of Horizontal well *OpEx. Per Horizontal wells (USD) | OpEx. + Drilling costs for Vertical and Horizontal |
|---|---|---|---|---|---|
| 1997 | 2 | 42000000 | 60700000 | 2000000 | 2800000 |
| 1998 | 0 | 2000000 | 54700000 | 0 | 2400000 |
| 1999 | 1 | 22000000 | 74700000 | 1000000 | 3400000 |
| 2003 | 1 | 22000000 | 23700000 | 1000000 | 1000000 |
| 2004 | 1 | 22000000 | 23700000 | 1000000 | 1000000 |
| 2006 | 0 | 2000000 | 20700000 | 0 | 800000 |
| Total | 5 | 112000000 | 258200000 | | 11400000 |
| Numbers of wells and Expenditures in Scenario-1 wells | | | | | |
| 1997 | 0 | 2000000 | 20700000 | 0 | 800000 |
| 1998 | 3 | 62000000 | 80700000 | 3000000 | 3800000 |
| 1999 | 1 | 22000000 | 74700000 | 1000000 | 3400000 |
| 2003 | 1 | 22000000 | 23700000 | 1000000 | 1000000 |
| Total | 5 | 86000000 | 177800000 | | 9000000 |
| Numbers of wells and Expenditures in Scenario-2 wells | | | | | |
| 1997 | 1 | 22000000 | 23700000 | 1000000 | 1000000 |
| 1998 | 1 | 22000000 | 40700000 | 1000000 | 1800000 |
| 1999 | 1 | 22000000 | 74700000 | 1000000 | 3400000 |
| 2001 | 1 | 22000000 | 23700000 | 1000000 | 1000000 |
| 2002 | 1 | 22000000 | 23700000 | 1000000 | 1000000 |
| 2003 | 1 | 22000000 | 23700000 | 1000000 | 1000000 |
| Total | 6 | 132000000 | 210200000 | | 9200000 |

Table 12a: Net Present Value Calculation for Base Case

NPV for Base Case with Oil Price at 25 USD

| Year | Year | Cum. Oil Production (bbl) | Oil Price at 25 (USD/ bbl) | Revenue (USD) | CapEx = Fixed CapEx + CapEx per well + Well cost (USD) | OpEx | |
|---|---|---|---|---|---|---|---|
| | | | | | | Fixed OpEx + OpEx per well (USD) | Total Cost of Gas +Water injection (USD) |
| 1997 | 0 | 2417481 | 25.0 | 60437025 | 260700000 | 7800000 | 11470667 |
| 1998 | 1 | 38614586 | 27.0 | 1042593809 | 54700000 | 7400000 | 467213378 |
| 1999 | 2 | 33520788 | 29.2 | 977466164 | 74700000 | 8400000 | 975667363 |
| 2000 | 3 | 22865282 | 31.5 | 720091759 | 0 | 5000000 | 1202094639 |
| 2001 | 4 | 13302155 | 34.0 | 452435872 | 0 | 5000000 | 757148007 |
| 2002 | 5 | 17585079 | 36.7 | 645956250 | 0 | 5000000 | 792647073 |
| 2003 | 6 | 21111001 | 39.7 | 837512643 | 23700000 | 6000000 | 732603892 |
| 2004 | 7 | 24135485 | 42.8 | 1034099490 | 23700000 | 6000000 | 588507110 |
| 2005 | 8 | 15771043 | 46.3 | 729777489 | 0 | 5000000 | 383964382 |
| 2006 | 9 | 9216108 | 50.0 | 460576063 | 20700000 | 5800000 | 143535931 |
| 2007 | 10 | 10697718 | 54.0 | 577389243 | 0 | 5000000 | 261693923 |
| 2008 | 11 | 9118110 | 58.3 | 531503510 | 0 | 5000000 | 295948526 |
| 2009 | 12 | 8174610 | 63.0 | 514626453 | 0 | 5000000 | 170367921 |
| 2010 | 13 | 5625084 | 68.0 | 382452805 | 0 | 5000000 | 149707488 |
| 2011 | 14 | 6581667 | 73.4 | 483290781 | 0 | 5000000 | 136390953 |
| 2012 | 15 | 4745176 | 79.3 | 376312519 | 0 | 5000000 | 165776770 |
| 2013 | 16 | 6443162 | 85.6 | 551847544 | 0 | 5000000 | 265271061 |
| 2014 | 17 | 5717547 | 92.5 | 528875687 | 0 | 5000000 | 283814864 |
| 2015 | 18 | 4176686 | 99.9 | 417252947 | 0 | 5000000 | 250291177 |

NPV for Base case with Oil Price at 25 USD

| Year | Year | Total Expenditure (CapEx + OpEx) (USD) | Cash Flow (USD) | Present Value (PV) (USD) | Net Present Value (USD) |
|---|---|---|---|---|---|
| 1997 | 0 | 279970667 | -219533642 | -219533642 | -219533642 |
| 1998 | 1 | 529313378 | 513280431 | 475259658 | 255726016 |
| 1999 | 2 | 1058767363 | -81301199 | -69702674 | 186023342 |
| 2000 | 3 | 1207094639 | -487002879 | -386598587 | -200575245 |
| 2001 | 4 | 762148007 | -309712135 | -227647665 | -428222910 |
| 2002 | 5 | 797647073 | -151690823 | -103238225 | -531461135 |
| 2003 | 6 | 762303892 | 75208751 | 47394271 | -484066864 |
| 2004 | 7 | 618207110 | 415892379 | 242669209 | -241397655 |
| 2005 | 8 | 388964382 | 340813107 | 184130717 | -57266938 |
| 2006 | 9 | 170035931 | 290540133 | 145342401 | 88075463 |
| 2007 | 10 | 266693923 | 310695320 | 143912049 | 231987512 |
| 2008 | 11 | 300948526 | 230554984 | 98881081 | 330868593 |
| 2009 | 12 | 175367921 | 339258532 | 134724231 | 465592824 |
| 2010 | 13 | 154707488 | 227745317 | 83741480 | 549334304 |
| 2011 | 14 | 141390953 | 341899828 | 116403571 | 665737875 |
| 2012 | 15 | 170776770 | 205535748 | 64793440 | 730531315 |
| 2013 | 16 | 270271061 | 281576483 | 82189491 | 812720806 |
| 2014 | 17 | 288814864 | 240060823 | 64880987 | 877601793 |
| 2015 | 18 | 255291177 | 161961771 | 40530776 | 918132569 |
| Total | | | 2725782929 | 918132569 | |

Table 12b: Cont. on Net Present Value Calculation for Scenario 1 Case

NPV for Scenario 1 with Oil Price at 25 USD

| Year | Year | Cum. Oil Production (bbl) | Oil Price at 25 (USD/bbl) | Revenue (USD) | CapEx = Fixed CapEx + CapEx per well + Well cost (USD) | OpEx | |
|---|---|---|---|---|---|---|---|
| | | | | | | Fixed OpEx + OpEx per well (USD) | Total Cost of Gas +Water injection (USD) |
| 1997 | 0 | 1845209 | 25.0 | 46130215 | 220700000 | 5800000 | 10863975 |
| 1998 | 1 | 39678094 | 27.0 | 1071308546 | 80700000 | 8800000 | 467820069 |
| 1999 | 2 | 28643220 | 29.2 | 835236283 | 74700000 | 8400000 | 983499263 |
| 2000 | 3 | 24633779 | 31.5 | 775786663 | 0 | 5000000 | 1193252192 |
| 2001 | 4 | 24947335 | 34.0 | 848514350 | 0 | 5000000 | 758158553 |
| 2002 | 5 | 20153537 | 36.7 | 740303959 | 23700000 | 6000000 | 802157694 |
| 2003 | 6 | 27760601 | 39.7 | 1101314603 | 0 | 5000000 | 723096132 |
| 2004 | 7 | 18039531 | 42.8 | 772914663 | 0 | 5000000 | 586772651 |
| 2005 | 8 | 13762772 | 46.3 | 636848243 | 0 | 5000000 | 385695982 |
| 2006 | 9 | 16089568 | 50.0 | 804078042 | 0 | 5000000 | 136491555 |
| 2007 | 10 | 9961410 | 54.0 | 537648432 | 0 | 5000000 | 278444210 |
| 2008 | 11 | 6349944 | 58.3 | 370144409 | 0 | 5000000 | 250607690 |
| 2009 | 12 | 6215841 | 63.0 | 391313620 | 0 | 5000000 | 235408534 |
| 2010 | 13 | 4992813 | 68.0 | 339464338 | 0 | 5000000 | 219989982 |
| 2011 | 14 | 6500338 | 73.4 | 477318754 | 0 | 5000000 | 110905280 |
| 2012 | 15 | 4776186 | 79.3 | 378771719 | 0 | 5000000 | 214404462 |
| 2013 | 16 | 6192505 | 85.6 | 530379174 | 0 | 5000000 | 221135769 |
| 2014 | 17 | 4385891 | 92.5 | 405696916 | 0 | 5000000 | 104072830 |
| 2015 | 18 | 4115107 | 99.9 | 411101165 | 0 | 5000000 | 60775490 |

NPV for Scenario 1 with Oil Price at 25 USD

| Year | Year | Total Expenditure (CapEx + OpEx) (USD) | Cash Flow (USD) | Present Value (PV) (USD) | Net Present Value (USD) |
|---|---|---|---|---|---|
| 1997 | 0 | 237363975 | -191233760 | -191233760 | -191233760 |
| 1998 | 1 | 557320069 | 513988477 | 475915256 | 284681497 |
| 1999 | 2 | 1066599263 | -231362979 | -198356464 | 86325033 |
| 2000 | 3 | 1198252192 | -422465530 | -335366758 | -249041725 |
| 2001 | 4 | 763158553 | 85355796 | 62739058 | -186302667 |
| 2002 | 5 | 831857694 | -91553735 | -62309934 | -248612601 |
| 2003 | 6 | 728096132 | 373218471 | 235190945 | -13421656 |
| 2004 | 7 | 591772651 | 181142013 | 105694625 | 92272968 |
| 2005 | 8 | 390695982 | 246152262 | 132988408 | 225261376 |
| 2006 | 9 | 141491555 | 662586487 | 331458206 | 556719582 |
| 2007 | 10 | 283444210 | 254204221 | 117745740 | 674465322 |
| 2008 | 11 | 255607690 | 114536719 | 49122836 | 723588158 |
| 2009 | 12 | 240408534 | 150905087 | 59926486 | 783514644 |
| 2010 | 13 | 224989982 | 114474355 | 42091983 | 825606627 |
| 2011 | 14 | 115905280 | 361413474 | 123047208 | 948653834 |
| 2012 | 15 | 219404462 | 159367257 | 50239206 | 998893040 |
| 2013 | 16 | 226135769 | 304243405 | 88805750 | 1087698790 |
| 2014 | 17 | 109072830 | 296624085 | 80168280 | 1167867070 |
| 2015 | 18 | 65775490 | 345325676 | 86417415 | **1254284485** |
| **Total** | | | **3226921781** | **1254284485** | |

Table 12c: Cont. on Net Present Value Calculation for Scenario 2 Case

NPV for Scenario 2 with Oil Price at 25 USD

| Year | Year | Cum. Oil Production (bbl) | Oil Price at 25 (USDbbl) | Revenue (USD) | CapEx = Fixed CapEx + CapEx per well + Well cost (USD) | OpEx | |
|---|---|---|---|---|---|---|---|
| | | | | | | Fixed OpEx + OpEx per well (USD) | Total Cost of Gas +Water injection (USD) |
| 1997 | 0 | 1927340 | 25.0 | 48183491 | 223700000 | 6000000 | 13262137 |
| 1998 | 1 | 27600002 | 27.0 | 745200063 | 40700000 | 6800000 | 462442394 |
| 1999 | 2 | 31779388 | 29.2 | 926686967 | 74700000 | 8400000 | 980354957 |
| 2000 | 3 | 33707053 | 31.5 | 106152949 | 0 | 5000000 | 1295125191 |
| 2001 | 4 | 27377980 | 34.0 | 931185982 | 23700000 | 6000000 | 718842064 |
| 2002 | 5 | 28164104 | 36.7 | 1034557719 | 23700000 | 6000000 | 755077050 |
| 2003 | 6 | 31584417 | 39.7 | 1253012520 | 23700000 | 6000000 | 734157210 |
| 2004 | 7 | 22790997 | 42.8 | 976494107 | 0 | 5000000 | 640527408 |
| 2005 | 8 | 14534995 | 46.3 | 672581529 | 0 | 5000000 | 336493362 |
| 2006 | 9 | 11566807 | 50.0 | 578052508 | 0 | 5000000 | 125836295 |
| 2007 | 10 | 9471105 | 54.0 | 511185112 | 0 | 5000000 | 318446094 |
| 2008 | 11 | 5516519 | 58.3 | 321563253 | 0 | 5000000 | 262109332 |
| 2009 | 12 | 4427720 | 63.0 | 278743786 | 0 | 5000000 | 161302773 |
| 2010 | 13 | 3949743 | 68.0 | 268545342 | 0 | 5000000 | 212061563 |
| 2011 | 14 | 4156747 | 73.4 | 305229233 | 0 | 5000000 | 135870038 |
| 2012 | 15 | 2765524 | 79.3 | 219317769 | 0 | 5000000 | 279062140 |
| 2013 | 16 | 4416586 | 85.6 | 378274292 | 0 | 5000000 | 228076910 |
| 2014 | 17 | 3578129 | 92.5 | 330978585 | 0 | 5000000 | 52624656 |
| 2015 | 18 | 2611168 | 99.9 | 260856926 | 0 | 5000000 | 29703896 |

NPV for Scenario 2 with Oil Price at 25 USD

| ar | Year | Total Expenditure (CapEx + OpEx) (USD) | Cash Flow (USD) | Present Value (PV) (USD) | Net Present Value (USD) |
|---|---|---|---|---|---|
| 97 | 0 | 242962137 | -194778646 | -194778646 | -194778646 |
| 98 | 1 | 509942394 | 235257669 | 217831175 | 23052529 |
| 99 | 2 | 1063454957 | -136767990 | -117256507 | -94203978 |
| 00 | 3 | 1300125191 | -238595704 | -189404962 | -283608940 |
| 01 | 4 | 748542064 | 182643918 | 134248732 | -149360208 |
| 02 | 5 | 784777050 | 249780670 | 169996527 | 20636318 |
| 03 | 6 | 763857210 | 489155311 | 308250820 | 328887138 |
| 04 | 7 | 645527408 | 330966700 | 193115890 | 522003028 |
| 05 | 8 | 341493362 | 331088167 | 178876635 | 700879663 |
| 06 | 9 | 130836295 | 447216213 | 223719449 | 924599111 |
| 07 | 10 | 323446094 | 187739017 | 86959490 | 1011558602 |
| 08 | 11 | 267109332 | 54453921 | 23354353 | 1034912955 |
| 09 | 12 | 166302773 | 112441013 | 44651873 | 1079564828 |
| 10 | 13 | 217061563 | 51483779 | 18930479 | 1098495307 |
| 11 | 14 | 140870038 | 164359195 | 55957903 | 1154453210 |
| 12 | 15 | 284062140 | -64744371 | -20410126 | 1134043084 |
| 13 | 16 | 233076910 | 145197383 | 42381732 | 1176424816 |
| 14 | 17 | 57624656 | 273353929 | 73879080 | 1250303895 |
| 15 | 18 | 34703896 | 226153030 | 56594576 | **1306898471** |
| **tal** | | | **2846403202** | **1306898471** | |

Table 13a: Summary of Net Present Value Result for Base case

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Table 13a: Summary of Net Present Value Result for Base case

NPV (USD) for Base case

| Year | Cum.Oil Prod.(bbl) | Base case at 25 USD Oil price | Base case at 3 USD Oil price |
|---|---|---|---|
| 1997 | 2417481 | -219533642 | -195358832 |
| 1998 | 38614586 | 255726016 | 666046681 |
| 1999 | 33520788 | 186023342 | 931551882 |
| 2000 | 22865282 | -200575245 | 773606117 |
| 2001 | 13302155 | -428222910 | 678980001 |
| 2002 | 17585079 | -531461135 | 751592564 |
| 2003 | 21111001 | -484066864 | 1010096847 |
| 2004 | 24135485 | -241397655 | 1494120904 |
| 2005 | 15771043 | -57266938 | 1835962049 |
| 2006 | 9216108 | 88075463 | 2073465530 |
| 2007 | 10697718 | 231987512 | 2324354754 |
| 2008 | 9118110 | 330868593 | 2514416933 |
| 2009 | 8174610 | 465592824 | 2730887262 |
| 2010 | 5625084 | 549334304 | 2870879583 |
| 2011 | 6581667 | 665737875 | 3053099827 |
| 2012 | 4745176 | 730531315 | 3165345027 |
| 2013 | 6443162 | 812720806 | 3311966133 |
| 2014 | 5717547 | 877601793 | 3434022591 |
| 2015 | 4176686 | 918132569 | 3516320225 |

Table 13b:Cont. on Summary of Net Present Value Result for scenario 1

NPV (USD) for Scenario 1

| Year | Cum.Oil Prod. (bbl) | Scenario 1 at 25 USD Oil price | Scenario 1 at 35 USD Oil price |
|---|---|---|---|
| 1997 | 1845209 | -191233760 | -172781674 |
| 1998 | 39678094 | 284681497 | 699914526 |
| 1999 | 28643220 | 86325033 | 787990258 |
| 2000 | 24633779 | -249041725 | 698961286 |
| 2001 | 24947335 | -186302667 | 1011173695 |
| 2002 | 20153537 | -248612601 | 1150399135 |
| 2003 | 27760601 | -13421656 | 1663196085 |
| 2004 | 18039531 | 92272968 | 1949286022 |
| 2005 | 13762772 | 225261376 | 2219902146 |
| 2006 | 16089568 | 556719582 | 2712256036 |
| 2007 | 9961410 | 674465322 | 2929615877 |
| 2008 | 6349944 | 723588158 | 3042238150 |
| 2009 | 6215841 | 783514644 | 3164323045 |
| 2010 | 4992813 | 825606627 | 3256343161 |
| 2011 | 6500338 | 948653834 | 3444393744 |
| 2012 | 4776186 | 998893040 | 3542394807 |
| 2013 | 6192505 | 1087698790 | 3693125607 |
| 2014 | 4385891 | 1167867070 | 3817152799 |
| 2015 | 4115107 | 1254284485 | 3944721281 |

Table 13c: Cont. on Summary of Net Present Value Result for Scenario 2 case

NPV (USD) for Scenario 2

| Year | Cum. Oil Prod. (bbl) | Scenario 2 at 25 USD Oil price | Scenario 2 at 35 USD Oil price |
|---|---|---|---|
| 1997 | 1927340 | -194778646 | -175505249 |
| 1998 | 27600002 | 23052529 | 318325949 |
| 1999 | 31779388 | -94203978 | 518863326 |
| 2000 | 33707053 | -283608940 | 666528897 |
| 2001 | 27377980 | -149360208 | 1074557427 |
| 2002 | 28164104 | 20636318 | 1526194993 |
| 2003 | 31584417 | 328887138 | 2150289986 |
| 2004 | 22790997 | 522003028 | 2571315849 |
| 2005 | 14534995 | 700879663 | 2895542433 |
| 2006 | 11566807 | 924599111 | 3234929949 |
| 2007 | 9471105 | 1011558602 | 3416600486 |
| 2008 | 5516519 | 1034912955 | 3495120026 |
| 2009 | 4427720 | 1079564828 | 3584049096 |
| 2010 | 3949743 | 1098495307 | 3642477001 |
| 2011 | 4156747 | 1154453210 | 3740002369 |
| 2012 | 2765524 | 1134043084 | 3747247486 |
| 2013 | 4416586 | 1176424816 | 3833795082 |
| 2014 | 3578129 | 1250303895 | 3943455455 |
| 2015 | 2611168 | 1306898471 | 4026161708 |