FORMULATION OF IOR SCHEME IN A HETEROGENEOUS MATURE CARBONATE RESERVOIR USING RESERVOIR MODELING AND SIMULATION.

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Abstract:
Heera, the Indian Offshore oil field in Arabian sea, 60 km from Mumbai city is a geologically complex heterogeneous limestone reservoir of middle to late Eocene age. Bassein limestone constitutes the main pay for oil. Heera field is a complex reservoir characterized by facies heterogeneities in the vertical and horizontal directions. The field was discovered in September 77 and was put on production in November 1984. The field has been developed in phases. The production from this field reached to the level of 50000 bopd in December 1985 which subsequently reduced to 27000 bopd in June 1991. With initiation of water injection in September 1990, and with major inputs like drilling of additional horizontal wells, re-completion, side tracking etc. the production again increased to 53000 bopd in Aug.1996. Since then steady declined in production has been observed with current production rate of 43000 bopd. To enhance the over all recovery from this field, re-development project has been planned which focuses on strategy to enhance production with introduction of latest technology in drilling, well completion and state of art surface facilities including re-distribution of water injection pattern for better sweep and pressure maintenance.

A multidisciplinary approach to describe the reservoir and review production and injection history led to pinpoint the unexploited area. A geological model which integrated the legacy data was developed. The 3D reservoir simulation model was constructed with the objective of improving vertical as well as horizontal definitions within the reservoir to understand fluid flow dynamics and also to pinpoint high permeable layers responsible for early breakthrough. Geostatistical techniques were used to populate rock properties throughout the reservoir.

The re-development project envisages two prong strategy: brown field development through existing wells and green field development through new wells. Modular approach is planned to be taken during project implementation, which shall have flexibility for taking mid course correction if needed. It will give additional flexibility to adopt new/alternate technologies available during the course of implementation to improve productivity.

The major inputs planned are two unmanned platform and connected pipelines, state of art facilities at the unmanned platform, drilling of 21 new wells, 46 side track wells and related work over jobs including upgradation of existing compressor facilities.

This is one of the biggest re-development project in Western Offshore being undertaken with completion schedule of pre-monsoon 2010 at a total investment of about Rs.3,000 Crores. The overall recovery from the field is estimated to increase by 4% of OIIP. The paper highlights the impact of oil price on project economics and risk involved with respect to different unknown variables.

Key words:
Pre-stack depth migration (PSDM) Reservoir characterization, Reservoir Simulation, Modular approach, Uncertainty and Risk Analysis

Background:
Most of the world’s oil production comes from mature fields, and increasing production from these fields is a major concern for the E & P companies. From mid 1980 to 2003, low oil prices has reduced the opportunity to invest in brown field development. Additionally, new discoveries have been declining over the past few decades. Boosting oil recovery from mature fields needs bold investment decision and induction of new technologies.
Introduction:

The Heera field lies 75 km south west of Mumbai city in west coast of India in Arabian sea (Fig.1). The field is divided into a northern and large southern block, with better petrophysical properties, by an east-west oriented graben. In Heera about 1800 m of sediments have been deposited over Precambrian Basement. The Basal clastics of Paleocene age is present in some parts of the structure. The Basal clastics is overlain by a limestone sequence (Bassein limestone) deposited in a transgressive period. However, there exists ample evidence of erosion subsequent to deposition of Bassein (middle Eocene) and Mukta (lower Oligocene) limestone. Subsequent to the unconformity above Mukta, Heera was deposited in a transgressive phase. The Bassein limestone were deposited in a shallow marine environment. About 500 million bbl of oil reserves has been established in 5 stratigraphic horizons in the field (Fig. 2). Of these the middle Eocene Bassein limestone is the main productive horizon in this field. Due to thinning of Bassein limestone and low dip, the central part of the field and this area has been the subject of initial development.

These limestones mainly have Mukta and Bassein with the latter containing the bulk of the hydrocarbon. Mukta and Bassein zone are separated by an unconformity and the best permeability in Bassein is in the upper section which is attributed to leaching. Based on reservoir characteristics Bassein limestone is again subdivided into 4 layers (Fig. 3). The Bassein limestone, comprising vuggy limestone, is the major payzone. The development of this pay zone was greatly influenced by the topography existing at the time of deposition of the respective layers as well as degree of erosion at various places over the structure. These two factors are highly responsible for the non development of layers in some parts of Heera field. Although Mukta is present over whole of the Heera field, the gross thickness decreases from west to east (Fig. 4).

The logs as well as core studies indicate the limestone to be a heterogeneous reservoir with permeability and porosity varying both vertically and laterally. Porosity and permeability both deteriorate towards the flank. Clear oil-water contact is not seen in most of the wells. However, free water level is interpreted as 1585 m.

Bassein reservoir oil has an API gravity of 39 degrees and a viscosity of 0.48 cp at reservoir pressure of 2150 psi and reservoir temperature of 101°C. The reservoir water viscosity is 0.25 cp. The reservoir is under saturated with a saturation pressure of 1850 psi.

The field has been delineated through 17 exploratory wells Production from the field commenced in November’84 following installation of HA platform.
Field Development History:

At different stages ONGC as well as consultant had prepared the development strategies based on the available geological model. In phase-I development, initially development wells of platforms HA, HB and HC were drilled. After reviewing the data of platform HA and HC which were drilled in 1984, two more platforms HD and HE were installed (Fig. 5). In the year 1985 consultant, CFP-TOTAL gave a development plan recommending additional five platforms in downdip direction. Based on this study ONGC formulated the plan for Phase-II development comprising of five platforms. Under this plan total of 10 platforms (2 in the North and 8 in the South) with 92 wells were envisaged. Pattern-cum-peripheral water injection was recommended for field implementation. In 1987 geological model was updated with additional well data. The simulation study recommended water injection of 85,000 bwpd through 45 injectors. (Fig. 6). In 1997-98 Phase-III development was commissioned solely to develop Mukta pay in crestal part. Under Addl Dev-part-I, one 12-slot HV platform was commissioned in 2003 in northern part of the field. Additional Development Part-II is under commissioning (Fig. 7 & Fig. 8)
Field Performance:

Commercial production from the Heera field started from November’84. The oil production is mainly from Bassein, Mukta & Panna formations. The location map of platforms and wells is shown in Fig. 9. The field produced under depletion drive for about six years till Sep.’90. By this time the reservoir pressure dropped to 1,300-1,375 psi from initial reservoir pressure of 2,150 psi and the field experienced sharp decline in production. During depletion mode of production there was no water cut indicating negligible aquifer influx/support. Water injection was initiated in Sep.’90. With increase in water injection, the production stabilized during 1992-93 with increase in water cut. Production increased further with the installation of gas lift during 1993-94 and reached to the level of 51,000 bopd with water cut of 25% in Aug.’96. The production and water injection performance of the field is shown in Fig. 10.

Currently the field is producing oil @34,230 bopd with 58% water cut and GOR of 120 v/v through 100 strings. The current water injection rate is 109,480 bwpd through 38 injection strings. The current area weighted average reservoir pressure is 1400 psi. The incremental voidage compensation is of the order of 112% and cumulative voidage compensation is about 69%. The cumulative oil production as on 01.04.07 is 36.335 MMt which is about 17.6% of OIIP in Proved category.

Number of pressure surveys have been carried out in the field. The current reservoir pressure scenario is given in Fig. 11 & 12. Water injection is in progress mainly through peripheral and pattern injection. Injection and production are mostly through commingled conventional completions. The Injector to Producer ratio is 1:2.2. At the commencement of water injection, the wells which were producers earlier were directly converted to injectors. In the northern part and western flank of Heera field the reservoir is tight. As a result the required quantity of water is not getting injected.

Effect of water injection is not uniformly felt in all parts of the field. In some areas with good injection support, the layers with relatively high permeability get the water injection effect early while the tighter ones continue under depletion mode. A considerable amount of pressure gradient exists from the periphery to the updip part of the reservoir. Higher pressures around the injectors indicate poor dissipation of injected water towards producing area.
Pilot experience on Brownfield Development:

Brownfield development is mainly reinterpretation, revisiting of old logs, optimization of surface networks and use of current drilling and completion philosophy from maximum reservoir contact area with past experiences of the field. Integration of total field experience and induction of new technology has shown the path of success through Brownfield development in Heera field.

Under Brownfield development and as a prelude to IOR scheme of Heera field, a pilot project, HR platform in the western flank of the field was taken up as a pilot project for work over jobs during 2005-06. Main objective of this pilot was to sidetrack the existing poor producers towards the un-drained/better saturation areas and to drill horizontal drain holes utilizing latest available drilling technologies.

HR, a 12-slot platform, is situated in the down dip part of the Heera field. Initially the oil production started with 3000 bopd from 5 producers. After adding three new wells (two multi laterals and one horizontal) and installation of gas lift, production peaked to 8500 bopd by 1996. Thereafter the
production started declining and from 1998, there was a continuous decline in oil production with increase in water cut.

Out of 12 wells of the platform, 11 wells were taken up for work over jobs during 2005-06. All the wells were re-located to suitable locations within Bassein pay zone. Eight wells were converted to horizontal oil producers and three wells were completed as water injector with drain holes. Use of state of the art drilling technology (SRDH) made it possible to achieve precise placement of drain holes with low horizontal drift through high doglegs. Before the well intervention the production from the platform was about 2000 bopd with av. water cut of 63 % and GOR of 190 v/v. After relocating and converting them into drain holes, the oil production increased to more than 7640 bopd with significant reduction in water cut to 26 %. Presently the platform is producing oil @ 4920 bopd at 56 % water cut. The cumulative oil gain from this platform is 0.306 MMt. The performance of HR platform is shown in Fig. 13.

![Fig. 13 Performance of HR platform](image)

**Challenges & Opportunities :**

The well spacing in the field is non-uniform and large (~ 225 acres/well). Over all recovery from the field is of the order of 17 % of OIIP in proved category. Currently the field encounters major problems of increase in water cut due to preferential movement of water through high permeability streaks, sub-optimal production from existing wells, large well spacing and pressure sinks in some of the areas. The field, at its current stage of exploitation, offers significant flexibility for revitalization plan under IOR. Identification of bottlenecks/constraints imposed by existing infrastructure such as existing locations vs target locations, existing capacity vs new required capacity etc. necessitates a optimal IOR proposal to remove them and to maximize and optimize reservoir exploitation.

**IOR Scheme :**

**3-D Seismic data and mapping**

Pre-stack depth migration (PSDM) was carried out to visualize the structure more clearly vis a vis the fault frame work. The fault framework was re-looked into and a number of new faults with varying throws were identified. These faults are distributed all over the Heera field and are having trend of east-west, north-south and northeast-southwest. Numbers of east-west trending faults were identified in the main block of the Heera field. These faults are having a throw of about 2-6 m and may be playing some role in the fluid dynamics of the field. The pre-stack depth migrated data has clearly brought out the structural trend of the field.

**Well Log Correlation**
The raw well logs were loaded to the OPENWORKS and the markers H3CGG, H3G, H3A, H3B, H4 and H5 were picked on the individual well logs. The concept of subdivision the Bassein Formation into B1, B2, B3 and B4, used in the earlier study was not followed. Hence the Bassein formation has been taken as one single unit. 31 Exploratory and 140 Development wells were taken up for processing and used in the present model.

**Permeability Distribution**

Laboratory generated data of permeability on number of core plugs was collected and a correlation was established between core derived porosity and permeability. Also some cross plots were derived from core data to find out the relationship between $s_{wi}$ and porosity ($\Omega$) with respect to different permeability, relationship between $s_{wi}$ and $s_{cr}$ etc. Based on these correlations permeability was calculated from log derived porosity with $s_{wi}$ of the wells.

**Simulation Study**

The model was built-up for simulation study considering 75 cells in I-direction and 145 cells in J-direction with 17 model layers.

**Model Layering**

The thickness of the zones are in the order of 20-70. To have better resolution and accuracy in model output these zones were subdivided in 17 layers.

**Model Inputs**

Geocellular model was prepared incorporating the reprocessed log and 3-D seismic data. The permeability distribution through out the grids was generated based on laboratory data, log derived porosity and saturation values using standard transform. Well wise monthly allocated oil, water and gas data upto March’06 was used as inputs for history matching.

**History Match**

Well wise monthly oil production and water injection rates were given for running the numerical model with the objective to match GOR, water cut and pressure recorded during the period of history matching. Several history match runs were made to fine tune the reservoir model. During history matching several parameters like horizontal/vertical permeability, saturations and transmissibility were altered, where ever felt necessary. The actual and model field performance is shown in fig. After the overall performance match, the scope was extended to platform wise and well wise match on Water cut and pressure. In general, of all the platforms and most of the wells show very good to good match (Fig. 14).
Performance Prediction

After achieving the satisfactory history match with actual field performance the model was used for performance prediction and optimisation of existing development. The inputs in terms of in-fill drilling were considered based on the current oil and water saturations. Emphasis was given for proper pressure maintenance through redistribution of injection water so as to maintain the GOR to the optimum level and achieve maximum oil recovery.

The present IOR plan envisages two prong strategy viz. Brown field development through existing wells and Greenfield development through new wells. Under Brownfield development, the major focus are enhancing the production from sub-optimally producing wells by sidetracking to a better saturation area, relocation/replacement of injectors for proper distribution of injection water for pressure maintenance & better sweep, and under Greenfield development, drilling of additional wells and reduce the well spacing.

The field is currently producing oil @33000 bopd through 91 wells. Under Brownfield development, wells which are producing sub-optimally and have potential are taken up for enhancing the production by sidetracking them towards better saturation areas and completing them as multilaterals/drainholes for enhancing the production. Similarly, offending injectors and injectors having poor injectivity are identified for relocation and profile modification. Water injection is planned to be enhanced by drilling additional injectors, relocating some of the existing conventional injectors and converting them into drainholes. Massive hydrofracturing is also planned in some of the poor injectors that are not getting addressed through sidetrack-drainhole. In all 37 producers and 19 injectors were considered in the present scheme.

Existing empty slots are planned to be drilled early in the life of the project, to obtain the economic advantages of early revenue. Also, these resources are to be used as low risk opportunities to test technologies in geologically high risk areas. New drilling and completion technology will be inducted early in the project life to derive maximum economic benefit.

Under Greenfield development several simulation runs were made under different boundary conditions. Infill locations were optimise and the following were planned:

- Drilling of 6 wells from existing vacant clam-on slots.
- Installation of one 12-slots platforms and one 9-slots platform
- Drilling of 5 ERD horizontal wells and 13 horizontal / multilaterals

The producers and injectors to be drilled from the new platforms are shown in (Fig.15). With implementation of IOR scheme the incremental oil & gas gain is estimated to be 8.4 MMt and 1.72 BCM. The overall recovery from Heera fields is estimated to be 30 % of proved OIIP. The oil recovery from the main pay Bassein is estimated to be 34 % of proved OIIP. Fig. 16 compares the profiles under Base case & IOR scheme.
Innovative Technology

There is continuous look out for opportunities to maximize oil production from the field. Meticulous planning is being done to utilize available resources and work over jobs with rig, jobs without rig by deploying mast and well stimulation jobs and new technology tools such as SRDH, MRDH are being carried out to improve productivity. In view of above mentioned efforts field production has increased than envisaged production and also restricted the reservoir decline.

- Drilling technology has significant implication in achieving higher productivity per well as well cost optimization.

- Rotary steering drilling of shale section, use of LWD, MRDH/SRDH, Whip-stock, Extended Reach Wells with horizontal drain holes, multilateral completions, activation through surge plug, glycol mud system to drill Alibaugh shale sections are some of the new technological initiatives undertaken in Neelam field under brown field development. Initial field response to most of these technologies has been encouraging in terms of improving well productivity, reducing operational risk and also drilling cost.

Project Evaluation:

In order to evaluate the project, the standard industry practice relies on discounted cash-flow techniques. The investment decision is manly on the basis of how large is the net present value of the project.

Financial analysis has been carried out considering the oil prices between USD 30 to 70 per bbl and gas price of Rs. 3200 per 1000 m³ and at an exchange rate of 1 USD = Rs. 46. The incremental projected production profile has been considered for economic evaluation. Further, 96.5% of oil and 10% for gas have been considered for revenue purpose to take care of the transportation losses. The discounting rate adopted is 10%.

- The viability analysis has been carried out on completion cost basis considering an escalation of 6% p.a. in Capital cost and Operating cost has been escalated @ 8% p.a.
- All calculation has been carried out in post-tax scenario.
Abandonment cost has been considered @20% on facilities cost except pipeline cost. A provision for the same has been made as per the prevailing abandonment policy during the economic life of the field.

A summary of results of analysis by considering the above for incremental oil of IOR project is given below and shown in Fig. 17-20.

<table>
<thead>
<tr>
<th>OIL PRICE (USD/bbl)</th>
<th>GAS PRICE (Rs. Per 1000 m³)</th>
<th>NPV (Rs. Cr)</th>
<th>IRR (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>30</td>
<td>3200</td>
<td>163.01</td>
<td>13.29%</td>
</tr>
<tr>
<td>35</td>
<td>3200</td>
<td>609.14</td>
<td>24.79%</td>
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<tr>
<td>40</td>
<td>3200</td>
<td>1062.66</td>
<td>43.86%</td>
</tr>
<tr>
<td>50</td>
<td>3200</td>
<td>1938.96</td>
<td>Indeterminate</td>
</tr>
<tr>
<td>60</td>
<td>3200</td>
<td>2811.48</td>
<td>Indeterminate</td>
</tr>
<tr>
<td>70</td>
<td>3200</td>
<td>3683.99</td>
<td>Indeterminate</td>
</tr>
</tbody>
</table>

It can be seen that project meets the hurdle rate of 10% even at oil price of USD 30 per bbl and gas price of Rs. 3200 per 1000 m³ (~ USD 70 per 1000 m³).

Uncertainty And Risk Analysis

Based on the future forecast of oil price the project evaluation assume that the oil price will be in the range of USD 70 per bbl in future. The forecast of oil price is the main area of uncertainty for investment decision making process even though the cost of drilling, cost of facilities and the operational cost provides additional areas of uncertainty. The DCF-NPV technique does not account for the volatility of oil price. The NPV only states that the project under evaluation will give certain profit if the oil price does not change. In view of this sensitivity analysis for the project has been carried out with oil price of USD 70 / bbl and gas price of Rs. 3200 per 1000 m³ (~ USD 70 per 1000 m³) at different unknown variables like CAPEX, OPEX and the production forecast. With OPEX and Production profile remain unchanged, the project can withstand 300% increase of CAPEX. On the other hand with CAPEX and OPEX remain unchanged the project is economically viable even with 65% change in production profile. The results of both these variants are shown in Fig. 20 through 23. Several other variants with different combinations were worked out.
A typical combination of CAPEX increase by 50%, OPEX by 25% and the production forecast is off by 50% gives the desired hurdle.

Recovery Factor

The base case of development envisages overall recovery factor of about 25% by 2030. The overall low recovery is mainly due to very low recovery achieved in other than Bassein layers of the field. However, with implementation of IOR scheme and other efforts the overall recovery factor of the main pay Bassein is expected to be about 28% of OIIP by 2030.

Conclusions

1. Fine grid simulation with detailed geological model has helped to identify the bypassed oil. The infill locations are optimized based on the current oil saturation. It is expected to improve overall recovery factor by 5% over the current estimates of about 28%.

2. A multi-discipline approach utilizing micro correlation of layers, classical reservoir engineering and water cut analyses have been effectively used to identify areas of remaining oil potential. The success of the study is shown by arresting the field production decline and maintaining oil rate at relatively constant levels. The impressive oil gain was possible due to innovative approach and utilizing latest technology for medium and short radius drilling.

3. The Hall's plot along with classical reservoir engineering plots helps to identify the bad injectors. This will in turn help in redistribution of water injection to achieve better areal and vertical sweep.

4. With the help of matrix analysis of different variables the work over jobs of platform wells have been prioritize.

5. The pilot success of Brownfield development helped us to plan the future Brownfield development in which sub-optimal wells will be taken up initially for relocation in better oil saturation area. All the wells will be drilled horizontal/multi laterals/drain holes for getting better productivity.

6. Detailed financial analysis has been carried out for the project evaluation. DCF – NPV techniques are used to analyse the different field development plans and provide to the company the input for decision making process. Uncertainty and risk analysis was carried out with different unknown valuable CAPEX, OPEX and the production forecast.

7. With the current level of oil price, it is the right opportunity to take major investment decision for Brownfield as well as greenfield development even with steep rise in facility and drilling cost.

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