Simulation of a Depleted Gas Condensate Reservoir for Storage of Natural Gas in Iran

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ABSTRACT

The northern part of the city located in higher elevations is of the main concerns in Tehran during winter which leads to the shortage in gas supply. To deal with this problem, National Iranian Gas Company (NIGC) decided to store gas in nearby natural reservoirs during hot season and produce it during cold season. Sarajeh gas condensate reservoir was considered for UGS to deal with gas demand.

In this study , we first present the significance of UGS, different types of reservoirs considered for UGS and its history. Next, using GEM software, a coarse grid model of the reservoir is built. Then, simulation and history matching of Sarajeh gas field are introduced and briefly discussed. Finally conclusions and recommendation for future work is presented.

Based on available information and those results generated by the model, this field could be a candidate for UGS plan. The results showed that two horizontal and one vertical gas production wells need to be drilled to achieve pressure drop in the reservoir and deliver 150 MMSCF of gas per day including production from former producers. Reservoir performance after history matching using depletion scenarios is predicted. Depletion last for 4.5 years. Ultimate recovery factor is 65% for gas and 40% for gas condensate. Following reservoir depletion to approximately 2400 psia, gas injection cycles in 6 months during hot season with the injection rate of 160 MMSCF per day and gas production cycles in 5 months in cold season with the rate of 175 MMscfD can start. Total gas volume stored in each cycles is approximately 0.84×10^{12} m^3.

KEYWORDS

Underground Gas Storage (UGS), Gas Injection, Depletion, History Matching, Reservoir Performance

1. INTRODUCTION

1.1 Background

Sarajeh gas field, discovered in 1959 by drilling exploration well Sj-2, is located 50 km southeast of Qom and 140 km far from Tehran. Total area of the field is 125 km^2. The presence of gas was confirmed in zone E of limestone Qom formation. Initial pressure and temperature of reservoir at datum depth of 5800 ft Sub-Sea were 5699 psia and 228° Fahrenheit. The dew point saturation pressure was reported to be 5561 psia. Qom formation is gas bearing formation with considerable amount of gas condensate in place.

A total of 8 wells have been drilled in Sarajeh structure. Wells Sj-2, 3 and 5 are gas producers and the rest are abandoned. Only wells Sj-3 and 4 in the field have fully perforated zone E of Qom formation but well Sj-4 was drilled out of water and gas depth.

First production started in 1960. Based on available production data, a total amount of 59.5 MMMSCF gas and 2.78 MMbbl of gas condensate have been produced till the end of 2003. Initial gas in place and recoverable gas are estimated to be 310.6 MMMSCF and 223.6 MMMSCF, respectively. According to the provided production data, 26.59% of recoverable gas reserves have been produced.

During 44 years of production, a total pressure drop of 1300 psia has happened across the field [1]. Therefore, the depletion rate is 45 MMSCF of gas production per 1psia pressure drop. *Importance, History and Classification of UGS Reservoirs* Nowadays, gas storage in different underground structures is considered as a policy to control fluctuations in consumption market especially in cold season in more populated areas. Growth in use of natural gas as a clean fuel has affected this concern in such a way that 243×10^{9} m^3 natural gas was stored in more than 554 UGS sites till 1995. Around 425 of these UGS sites are depleted hydrocarbon reservoirs, 82 are aquifers and 45

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are salt domes. UGS for the first time in 1915 was successfully commenced in Welland town, Ontario, Canada. The significance of UGS as a strategic plan [5] is introduced to achieve three important aims to: a) Control fluctuations in market due to seasonal issues, etc., b) Manage high demand in short term from few hours to many days and c) Reduce high cost of setting up production units and transfer lines with appropriate capacity to deal with high demand.

1.1.1 Classification of UGS

UGS reservoirs are classified as:

1- Depleted Oil and Gas Reservoirs
2- Natural Aquifers
3- Salt Domes
4- Abandoned Underground Mines such as Coal mines

Since Sarajeh reservoir is a partially depleted gas reservoir considered for UGS plan, therefore the main characteristics of a hydrocarbon reservoir as a candidate for UGS are briefly presented here [3].

1.1.2 Principles of UGS in Oil and Gas Fields

1) Appropriate porosity, ϕ
2) High permeability, K
3) Ideal Storage ability and enclosure considering cap rock[4].

Based on these criterions, Sarajeh gas reservoir with porosity of 6.5%, desired permeability of 20 md and ideal cap rock (based on hydraulic fracturing test) can store gas, hold it and therefore it is an ideal candidate for UGS reservoir .

2. Coarse Grid Modelling and Simulation of the Sarajeh Reservoir

A. 2.1 GEM Software

GEM software is one of CMG modules produced by CMG Company which is used to simulate hydrocarbon reservoirs utilising compositional modelling. In addition to GEM, CMG has two other modules named IMEX and Star which are used in Black Oil Simulation and Thermal Modelling, respectively. Each of these three modules has its own sub-program to input the data and display the results namely Grid Builder and Results. Grid Builder is used to set up grid model and Model Builder is used to input the other required data for modelling [8]. Win prop software is another CMG module used for reservoir fluid and hydrocarbon phase behaviour simulation. This software uses Peng-Robinson or Soave-Redlich-Kwong equation of states to define PVT properties of reservoir fluids.

2.2 Description of the model

2.2.1 Static Model

Roxar's Irap-RMS was used to create three dimensional (3D) geological model of the Sarajeh field. Structural model of the Sarajeh field is based on the latest underground contour map (UGC map) of the top of zone E. AutoCAD was used to digitize the map; the results were then imported to the GEM software with dxf format. Due to lack of appropriate UGC map of other zones, surfaces related to the top of the other zones in the field were created based on well data. Isochors and Isopach maps for each zone also created. Model Builder of GEM has following parts.

2.2.2 Description of the reservoir

Input data including all information of UGC map of each formation top in the reservoir, thickness of layers, reservoir depth, type of reservoir, selection of simulating model, calculation of shape factor, fracture dimension, permeability of matrix and fracture and overall parameters related to reservoir characteristics are loaded to the model.

The field was modelled using dual porosity option and girding was based on corner point- orthogonal coordinate system with 40 blocks in I-direction, 15 blocks in J-direction and 5 layers in K-direction. Kazemi and Gilman method was used to calculate shape factor. Formation tops and thickness of layers were provided by Roxar's Irap-RMS software and imported to the GEM. Because of use of dual porosity option in the simulation, the total number of blocks are two times higher that the total number of blocks with single porosity model. The method of girding, depth of blocks and their location with respect to each other are based on UGC map of top of formation E. Grid model of reservoir in two dimensional (2D) and 3D are coordinate system are displayed in Figures-1 and 2.

Due to lack of aquifer data and information, modelling was done with considering weak aquifer effects.

2.2.3 Fluid Properties

In this part, all thermodynamic properties of fluids such as reservoir temperature, PVT table for gas, fluid densities, water and gas compressibility, viscosity, and all other fluid properties were added to the model for flow simulation.

2.2.4 Rock-Fluid Properties

This section contained all data related to different reservoir rocks and their characteristics such as Capillary pressure-Saturation-Relative Permeability curves.

2.2.5 Initial Condition

Initial reservoir pressure at datum depth of 5680 ft sub-sea level was 5699 psia and initial gas-water contact (GWC) was 10498 ft sub-sea level.

2.2.6 Numerical Control Methods

The terms related to the control of numerical calculation and execution time based on user preference were presented in this part.

2.2.7 Well Data

Well grouping, date of production start up, preferred dates for output data generation, well selection and types (injection or production wells), well location, well data, production and injection layers selection, limiting parameters for maximum bottom hole pressure (BHP), opening and shutting down the wells at desired times and opening again were all loaded in this section. The created model contained three gas producing wells which have been on production since 1960.

2.3 History Matching

History matching in numerical simulation is an appropriate tool to assess the accuracy of the model and consists of simulating the performance of the field in the past and comparing the results with actual field performance. Therefore, it is the process of adjusting the simulator input in a way as to achieve a better fit to the actual reservoir performance.

2.3.1 History Matching Method

There is not a standard method for history matching. Regarding geological structures, reservoir drive mechanism, total number of wells, production history and scenarios each field is unique and differ from other fields. First step in every simulation is picking the critical parameters which need to be matched and the key wells. To some extent , the recognition of these parameters depends on drive mechanism of reservoir. For instance, in water drive reservoirs, the strengths of aquifer and its pressure support to the oil/gas layer and in solution gas drive reservoirs, water-gas relative permeability are considered as critical parameters.

2.3.2 Results of History Matching

Once the simulation is executed using the GEM software, history matching of the results with actual performance of the reservoir was commenced. The first production from the reservoir commenced in late 1960 and field has been producing for 44 years. The effort was to fit the static pressure and production rate generated by numerical model with actual field data. In this part, considering the output data, the results of different simulation by adjusting critical parameters such as fracture permeability, transmissibility multiplier and fracture spacing were compared with actual data and the best fit with actual data was achieved. Fracture spacing was changed in different directions and the results were investigated carefully. Finally, fracture spacing of 30 ft in all directions was considered.

Using the best fit parameters in the model, volume of initial gas in place calculated as 290 MMMSCF. After modifying the model with adjusted parameters for best fit results and considering reservoir drive mechanism, the history of gas pressure at datum depth (Figures 3-5), produced gas rate (Figures 6-8) and produced condensate rate (Figures 9-11) were matched. Also, field water cut, gas recovery factor and average reservoir pressure at datum depth generated by the model and displayed in Figures 12-14.

2.4. Field Depletion Prediction

Production prediction is the last step in hydrocarbon field development studies. The aim is to define the field production performance under different production scenarios and also find ultimate recovery for economical estimates of the project costs. Production prediction program depending on the size of the field (small or giant field), the significance of the project and timing may differ from few days to many months. In this study, the production prediction with the aim of depletion to 165 bar (injection pressure) defining the best production strategy was commenced. The considered depletion scenario is as follows: drilling two new horizontal and one vertical well and bringing them to production with former producers for fast depletion of the reservoir and consequently commencing gas injection. Usually in any production scenario, there are some limitations which must be considered for production prediction. In this scenario, following limitations were imposed on each well: 1) Maximum production rate from each well, 2) Maximum BHP and 3) produced Water- Gas Ratio (WGR) [10].

2.4.1 Wield Depletion Plan

In this scenario, for best depletion plan of the reservoir, two new horizontal producers named as SH-1, SH-2 with approximately 450 meter horizontal leg and one new vertical producer named as SJ-9 were drilled in the crest of the field in addition to former producer wells SJ-2, SJ-3 and SJ-8 which have been on production for years. The well locations are based on gas solubility at the end of depletion, distance to the nearby wells and geological setting of the field. In production program, horizontal wells were added to the model with two months time difference for drilling and finally the field was depleted with 6 production wells to get to the desired pressure to commence gas injection for UGS plan. Figure 15 shows the 3D display of the model including producing well locations. Maximum well production rate was for each well was 50 MMSCF per day and maximum produced WGR was 30 bbl water per 1 MMSCF produced gas. Minimum FBHP was set to 500 psia. Total field rate was considered to be 150 MMSCF per day and was kept constant for one year. Afterwards, because of water production and also FBHP drop to less than 500 psia, production decline followed till 2008 and average reservoir pressure at datum depth came closer to injection pressure of 165 bar and recovery factor of 65% was achieved. The period of reservoir depletion based on model results is approximately 4.5 years. Figures 16-19 display the field gas rate, average reservoir pressure at datum depth, produced WGR, and recovery factor during reservoir depletion.

2.5 Injection and Production cycles

Gas injection rate of 160 MMSCF per day for injection cycles and production rate of 175 MMCSF per day for production cycles were selected. Injection cycles were last for 6 months during hot season and production cycles were last for 5 months during cold season. In injection cycles, maximum injection rate in each well was 40 MMSCF per day and maximum BHP was set to 5000 psia. In production cycles, maximum production rate in each well was 50 MMSCF per day and minimum FBHP was set to 500 psia. Gas injection in first cycle will be commenced in April 2008 and production will be started in December 2008 and these cycles were repeated for 4 cycles. Figure 20 displays filed gas production rate during depletion and production cycles and Figure 21 shows changes in field average pressure during depletion scenarios and also production and injection cycles across the field.

3. Conclusions, Recommendations for Future Work and References

At the end, conclusions are presented and recommendations for future work are outlined and finally a list of references used in this study are given.

3.1 Conclusions

1. Compositional model was used to set up the model. Two-phase flow of water and gas was considered in the reservoir and dual porosity and permeability option was

used for fractured reservoir modelling. Orthogonal corner point geometry system was used to set up 3D geological model containing $40\times15\times5$ blocks

2. Initial gas in place using the model with adjusted parameters was estimated to be 290 MMMSCF.

3. The results of simulations showed that two horizontal and one vertical gas production wells needed to be drilled to achieve pressure drop in the reservoir and deliver 150 MMSCF per day including production from existing three gas producer wells.

4. Reservoir performance after history matching using depletion scenarios was predicted and depletion last for 4.5 years. Ultimate recovery factor for gas is 65% and for condensate is 40%.

5. Based on available information and those generated by the model, this field could be a candidate for UGS plan. After reservoir depletion to approximately 2400 Pisa, gas injection cycle with the injection rate of 160 MMSCFD and gas production cycle with the rate of 175 MMSCFD can start. Injection cycle would be in 6 months during hot season and production cycles would be 5 months in cold season and total gas volume stored in each cycles would be approximately 0.84×10^{12} m^3.

3.2. Recommendations for future work

1. To define the strength of the aquifer and contribution in pressure support and production and also monitoring the Water-Gas Contact (WGC) changes it is necessary to measure water pressure in lower layers.

2. With respect to unknown parts on the east of the field, some appraisal wells are recommended to be drilled for further information on reservoir behavior.

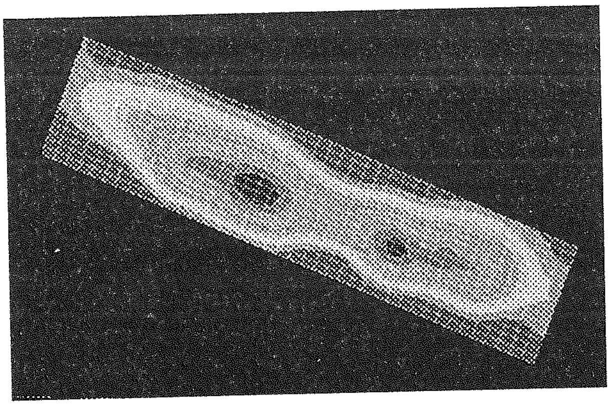

Figure-1 2D model and areal grids structure

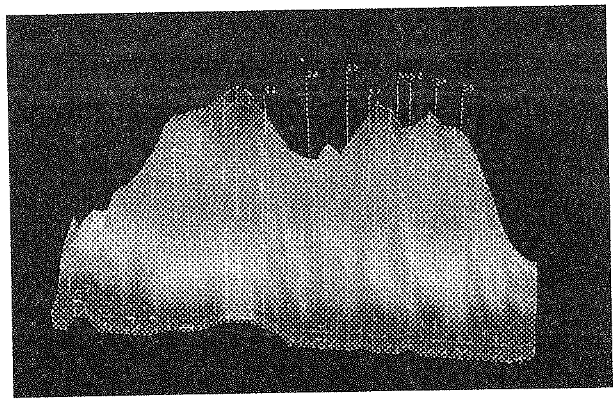

Figure-2 3D model including well locations

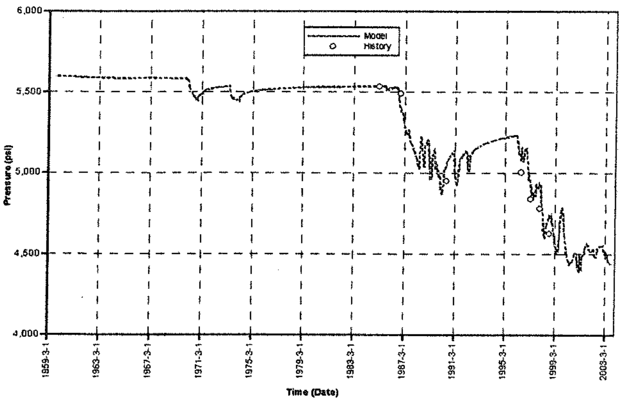

Figure-3 History Matching of Gas Pressure at Datum Depth, Well SJ-2

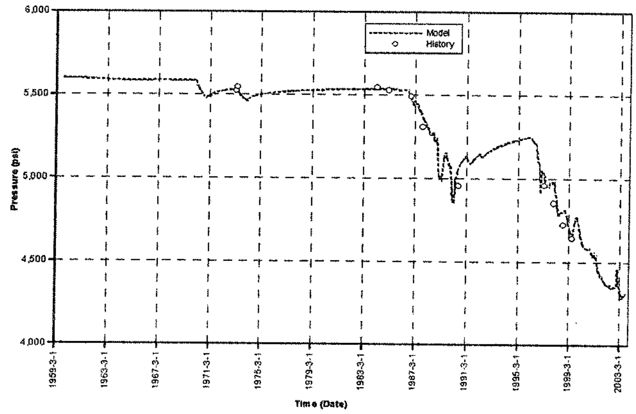

Figure-4 History Matching of Gas Pressureat Datum Depth, Well SJ-3

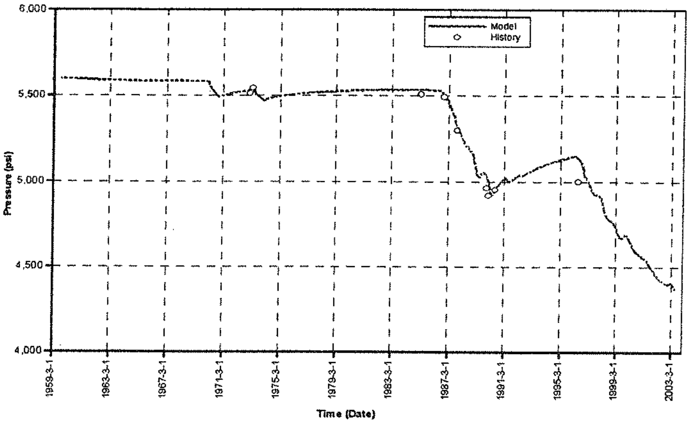

Figure-5 History Matching of Gas Pressure at Datum Depth, WellSJ-5

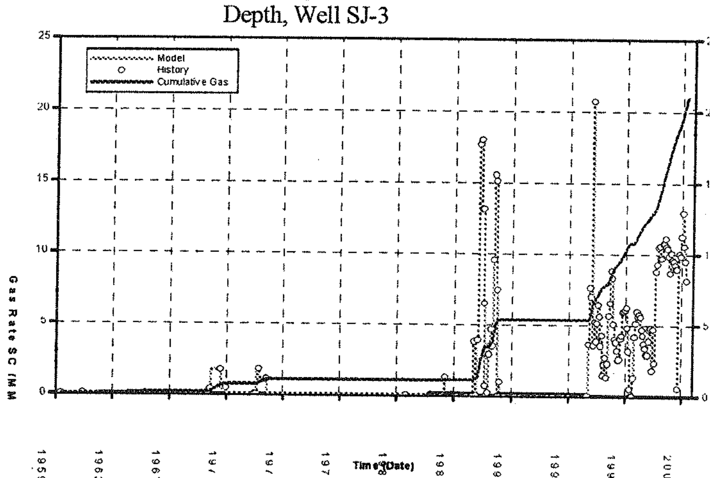

Figure-6 History Matching of Gas Production Rate, Well SJ-2

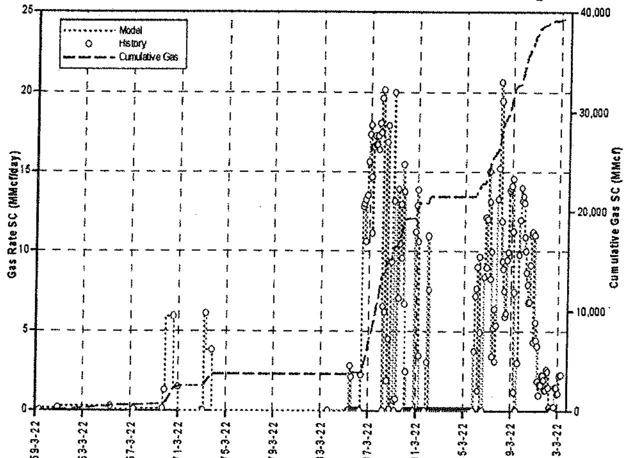

Figure-7 History Matching of Gas Production Rate, Well SJ-3

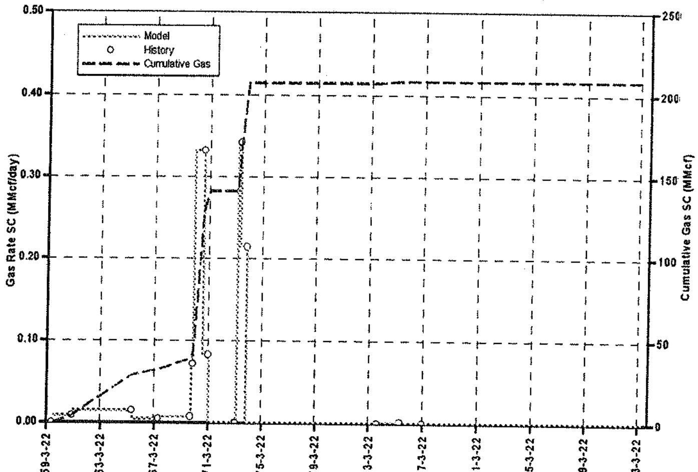

Figure-8 History Matching of Gas Production Rate, Well SJ-5

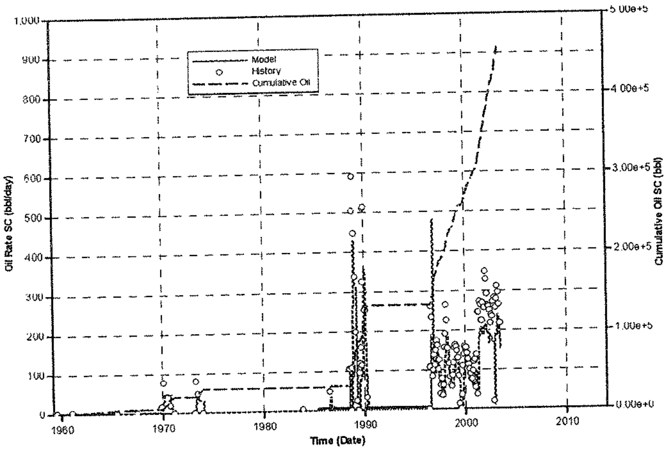

Figure-9 History Matching of Condensate Production Rate, Well SJ-2

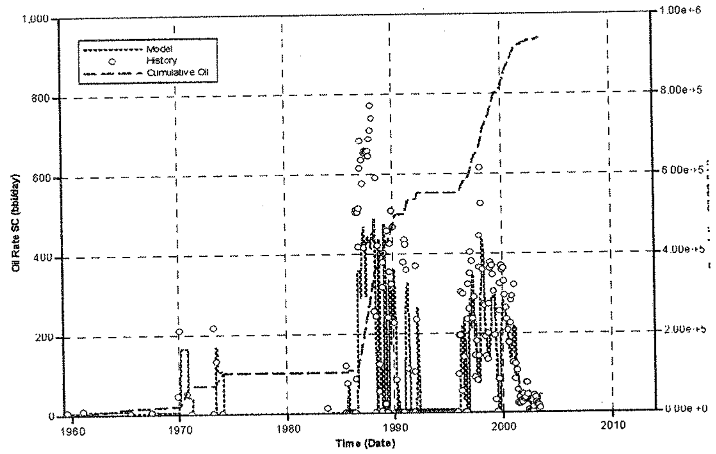

Figure-10 History Matching of Condensate Production Rate, Well SJ-3

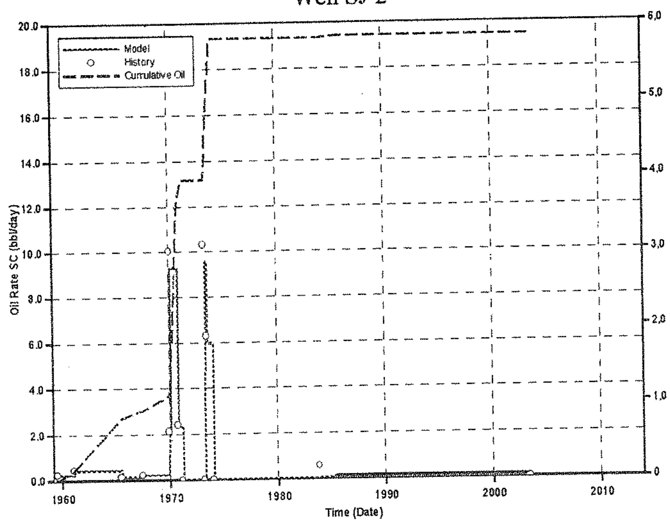

Figure-11 History Matching of Condensate Production Rate,

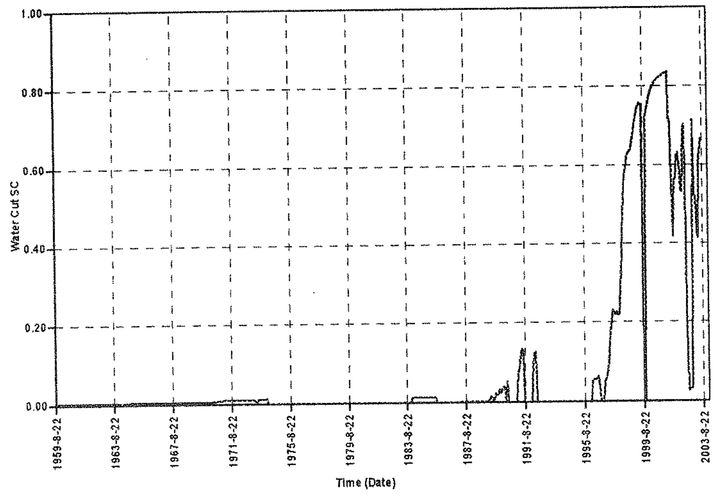

Figure-12 Field Water Cut

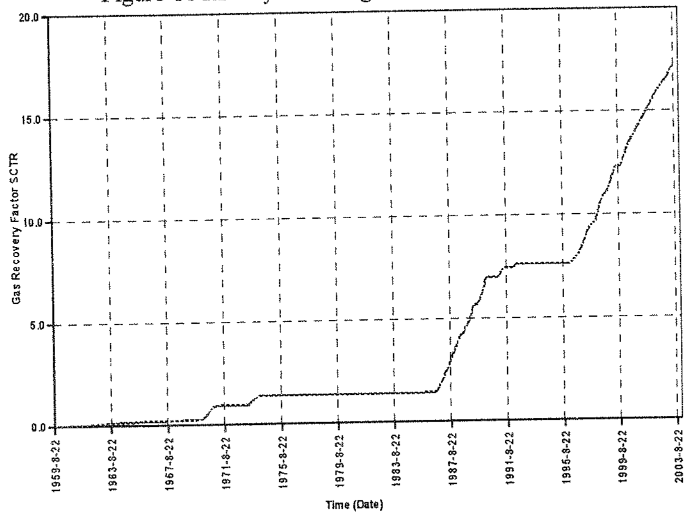

Figure-13 Gas Recovery Factor

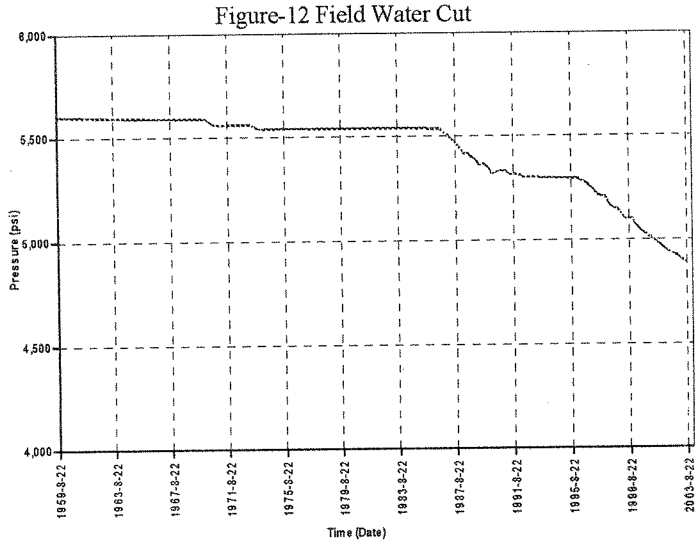

Figure-14 Average Reservoir Pressure at Datum Depth

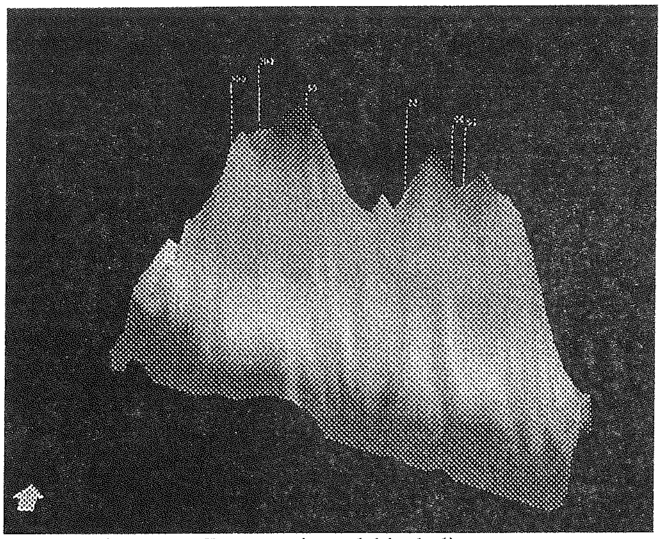

Figure-15 3D reservoir model including two new Horizontal and one new Vertical Wells

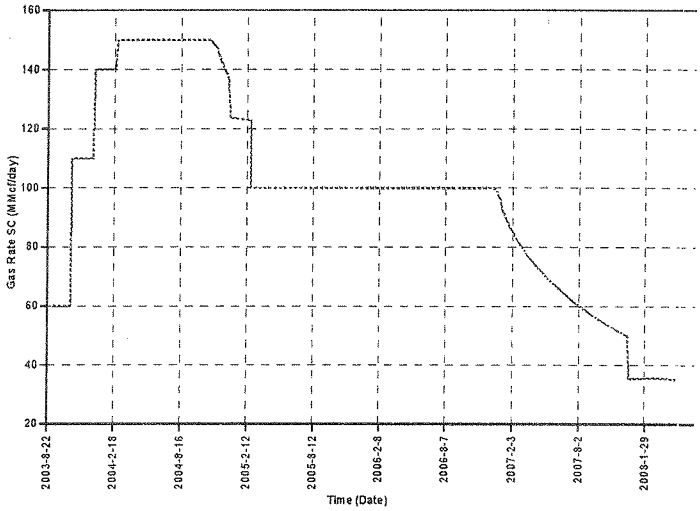

Figure-16 Field Gas rate during Depletion

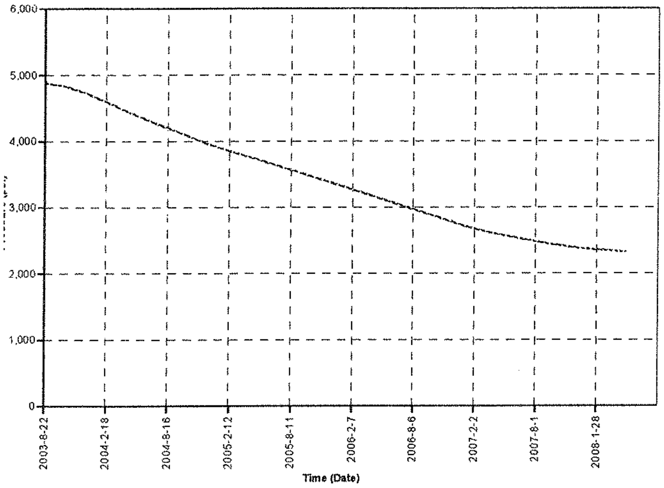

Figure-17 Average Reservoir Pressure at Datum Depth during Depletion

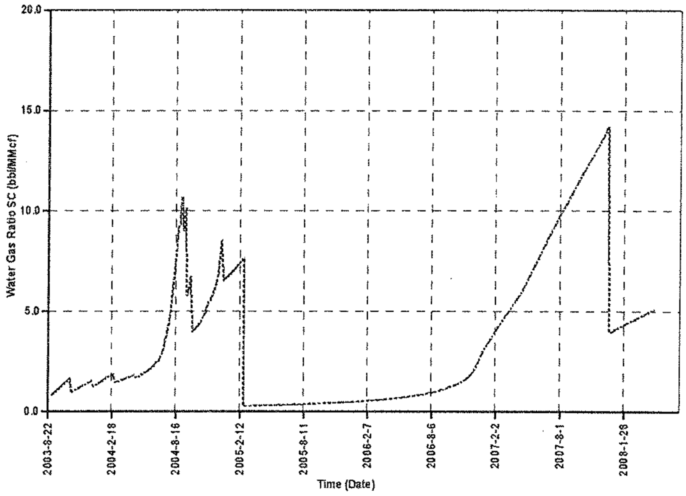

Figure-18 Field Water- Gas Ratio during Depletion

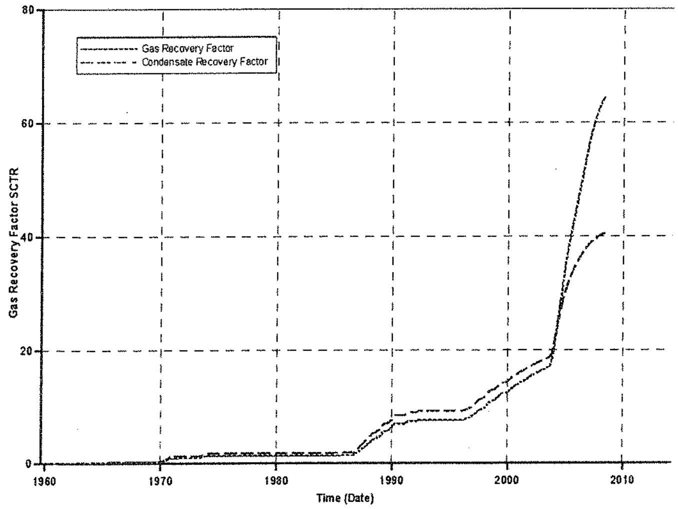

Figure-19 Gas and Gas Condensate Recovery Factor during Production

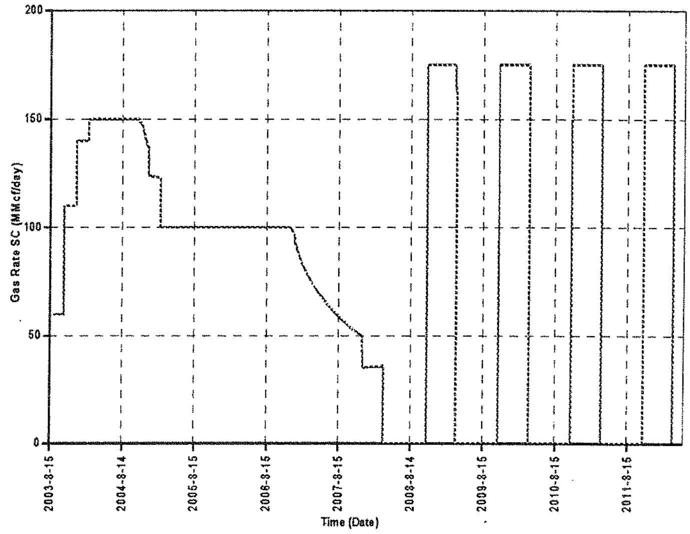

Figure-20 Gas Production Rate during Depletion and Production Cycles

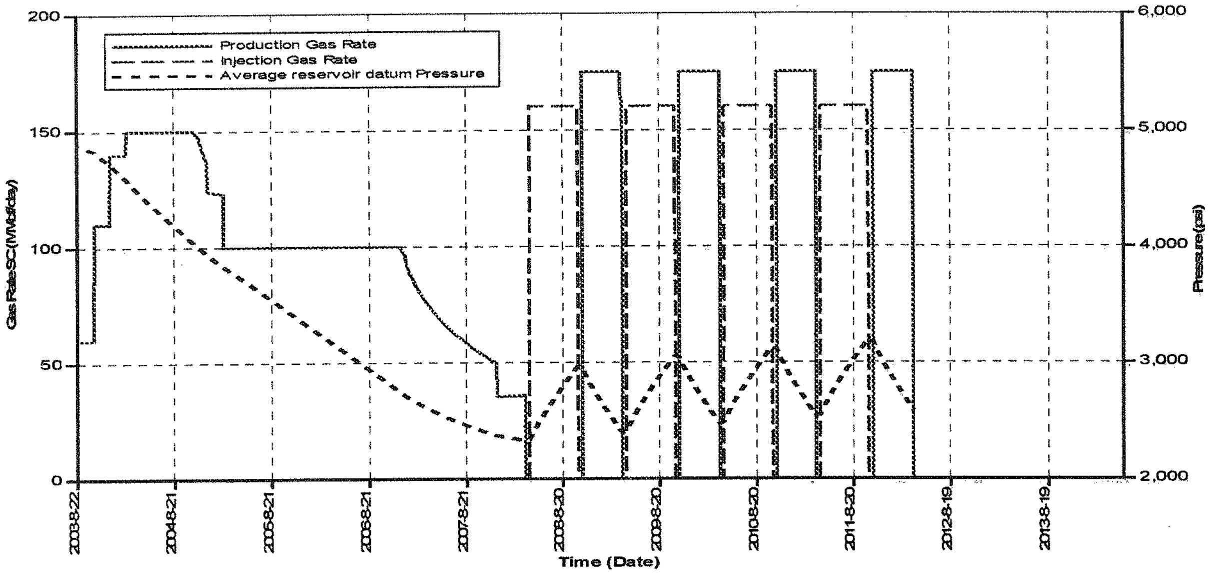

Figure-21 Field Average Pressure at Datum Depth, Gas Injection and Production Rate during Depletion and Production/Injection Cycles, respectivel

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