DETERMINATION OF HISTORICAL FIELD DATA CUT-OFF TIME SUFFICIENT FOR RESERVOIR HISTORY MATCHING

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ABSTRACT

For reservoir history matching, simulated model output is conditioned to observed historical field data by modifying the model parameters so that the simulated data matches the history data. The matched model which is dependent on the historical data utilized for matching is used for reservoir production forecast. The vital question to be answered by reservoir engineers is the "waiting period" required to achieve sufficient historical data for matching. In this work an answer is provided for this waiting period.

This paper reports cut-off time for sufficient historical data necessary for reservoir history matching. The cut-off time was determined from several history matched scenarios. To calculate the cut-off time, reservoirs with known parameters and twenty five year production data were used as the base case models. Thereafter, simulation models of the actual reservoirs were built. Each simulated model was run for 6, 12, 18, 24 and 48 months, respectively, and the simulated production profile matched with their corresponding actual reservoir historical time data to achieve a matched model. For the six months historical data matching, it was noticed that all the simulated models output matched the base case model data. While for the 18 months historical data matching all the simulated except one fails to match the base case output.

This approach enabled the determination of historical data cut-off time that is sufficient for good history matching as follows: 1. observed historical data of 18 months are sufficient for a good history match if the simulated model is 75 percent and above close to the actual reservoir description. 2. If the simulated model is between 50 – 70% of the actual reservoir description more than 18 months data is required in order to obtain a calibrated history matched model that is reliable.

The 18 months calibrated model was utilized to predict twenty five years reservoir performance and the simulated model prediction compared favorable with the base case reservoir production profiles which were known.

INTRODUCTION

The goal of reservoir performance simulation is to build a reservoir model that is capable of predicting the actual reservoir performance by minimizing associated errors in reservoir simulation model. Minimization of the simulation model errors is achieved by performing reservoir history matching. History match process involves comparing the simulator output with observed field production data[2, 3, 5, 7, 14, 19, 21, 22]. When an acceptable match is obtained, the history matched model is then used to predict the reservoir future production performance.

The conventional approach for minimizing the difference between observed history data and simulation model result is to vary the model input parameters until a match with the history data is achieved. The fact is that more than one model can reproduce the real reservoir history data as a result, recent history matching approach involves constructing multiple reservoir simulation models and conduct history matching of simulated and observed data. When a match is obtained, the matched model(s) is used to forecast future reservoir performance. The major problem with this multiple realization technique is the increase in computation cost. While the technique main advantage is the ability to minimize the non-uniqueness of traditional history matching because a match with a single simulation model may have resulted from compensation errors of the various interacting parameters[17, 23].

It is well known that during the life of a reservoir, the pre-reservoir and post-reservoir performance evaluations are generally not equal. This inequality is because of the history matched model inability to accurately forecast reservoir performance. This inadequacy is due to a number of reasons. One of these reasons is having inadequate knowledge of the reservoir rock and fluid properties such that the resulting simulation model can not mimic the actual reservoir. Another vital reason is the utilization of observed field data collected over an insufficient historical duration for history matching.

Knowledge of the sufficient historical duration, most especially for a new field development, is as uncertain as describing the entire reservoir with parameters obtained from a single well. This work provides a method to determine the sufficient historical duration for collecting observed field data. The data collected over this appropriate period will enable the simulation model to better represent the actual reservoir. As a result, the resulting history match model can better predict future reservoir performance.

LIMITATION OF HISTORY MATCHING

It is a known fact that reservoir performance prediction obtained from reservoir simulation models can not be exact. This is generally accepted industry-wide and reported by numerous authors[1, 4, 6, 11, 12, 17, 23]. The process of constraining reservoir model with historical data which is referred to as history matching[2, 3, 4, 5, 7, 8, 9, 11, 14, 15, 16, 17, 19, 20, 21, 22, 23] involves the determination of a set of reservoir parameters that will make the simulator model output as close as possible to the observed history data.

There are three areas of interest in history matching which limit the ability of engineers to perform outstanding history matching. Firstly, the different approaches for constructing reservoir models for history matching. Secondly, the varied methods for generating appropriate misfit algorithm to calculate the difference between the model data and the historical data. And, thirdly the sufficient historical duration period. Numerous techniques have been proposed to solve the first two problems. On the other hand, the third problem has receive less attention probably because of the believe that a standard cut-off time may not be easy to attain.

During reservoir description process, reservoir engineers assign values to reservoir simulation model parameters using incomplete data such as data which were measured from a small portion of the reservoir to describe the entire reservoir[10]. The incomplete data limit reservoir simulation model capacity to accurately mimic the actual reservoir leading to error in the model output. The uncertainty associated with the reservoir input parameters lead to uncertainty in reservoir performance forecast. For example, the uncertainties associated with individual reservoir characteristics such as: hydrocarbon originally in place, aquifer size, sand continuity, shale continuity, permeability distribution, upscaling, mathematical model, and external factors (e.g. pump lifetime), all add up to give a resultant total uncertainty associated with the reservoir performance prediction[11, 12, 13, 23].

A number of methods have been reported for quantifying uncertainty associated with input parameters as well as the resulting total uncertainty in the reservoir simulation output[1, 4, 6, 11, 12, 13]. The standard principle common to all the techniques is to reduce uncertainty associated with the input parameter by conditioning the model with observed history data. This principle is a sound approach because the historical data are direct responses of the actual reservoir parameters. It is these actual reservoir parameters that history matching tries to estimate.

During reservoir history matching the reservoir simulation model is conditioned to the observed history data. To measure the extent of the conditioning, a mismatch between the reservoir model output and the history data is quantified. The mismatch quantification is performed using an objective function algorithm.

HISTORICAL DATA

Historical data are the observed field data measurement obtained from wellbore measuring equipments such has pressure gauges and flow meters. Theses data are; reservoir pressure, oil, gas and water production rates. These measured data are direct response of the reservoir and they provide useful information of the reservoir behavior. Assuming that the measurements were properly taken and the measuring equipment precision is standard, the next question is what is the appropriate waiting period (3, 6, 12, or 24 months) such that the historical field data can be used for history matching?

One of the major problems surrounding the waiting period is how long it will take for the fluid transient to reach the reservoir boundary. Consider a well close to a fault as show in figure 1, the time the effect of production at the well will reach the fault boundary is given by equation 1.

$$t_p = \frac{6752\phi\mu c_t d^2}{k} \qquad \text{1}$$

Equation 1 indicates that the waiting time for the transient pressure to reach the boundary is a function of reservoir rock and fluid properties as well as the reservoir size. Therefore the duration of observed history will vary from one reservoir to another. The variation is a function of reservoir rock and fluid properties, reservoir drive mechanism, type of production scheme, and number of producing wells and location of each well in the reservoir. These factors that control historical data waiting period are given in table 1.

SUFFICIENT HISTORICAL TIME DETERMINATION

To demonstrate the methodology for estimating sufficient historical time we utilized the reported 5^{th} and 6^{th} SPE comparative solution projects. In this report, the 5^{th} and 6^{th} projects are referred to as test case 1 and 2, respectively and GEOQUEST black oil simulator (ECLIPSE100) was used to simulate the reservoirs.

The test case 1 reservoir is a multiphase flow in heterogeneous single-porosity medium. The reservoir consists of three layers and was modeled with 7×7×3 Cartesian grids figure 2. Numerical dispersion problems resulting from the coarseness of the grid is ignored. A single producing well located at one corner of the reservoir (i=7, j=7 and k=3) was perforated in the third layer and the well produced at a maximum oil rate of 12,000 STB/D without pressure support.. The well shut-in criteria were minimum BHP of 1,000 psi, limiting WOR and GOR of 5 STB/STB and 10 MSCF/STB, respectively. The simulation model input data are given in tables 2 and 3. This original SPE model with twenty five years production history data was taken as the base case reservoir.

To determine sufficient historical data necessary for an acceptable history matching the following five steps were performed:

1. The base case model was run for 2, 6, 12, 18, 24, and 48 months, respectively (see Tables 4, 5, 6 and 7)
2. The base case model production output; BHP, GOR, WCT and COP were recorded as the field measured history data.
3. Thereafter, the base case model permeability distribution were perturbed for 1%, 10%, 20%, 30%, 75% and 90% of the initial value and run for the same number of months as in step one. The perturbed model production output; BHP, GOR, WCT and COP were recorded as the simulated production data.
4. History matching of both the observed field data and the simulated production data was performed for 2, 6, 12, 18, 24, and 48 months, respectively.
5. Run twenty five years production prediction for each of the perturbed models and also run the base case model for twenty five years. Thereafter plot their twenty five years cumulative oil production output.

The second test case was a dual-porosity reservoir. The reservoir is a fractured reservoir model built to simulate natural depletion, gas-injection and water injection, respectively. The reservoir consist of five layers with varying permeability and with a single production well located at grid block I = 10. The injection well is located at grid block I= 1 and was perforated in layers 1, 2 and 3 while the production well was perforated in layers 4 and 5. The production well was constrained to a maximum drawdown pressure of 100psi and maximum production rate of 1,000 STB/D. Table 8 outlines the reservoir data. This reservoir model is used as the base case model which act in this report as the actual reservoir that provide measured historical data. To utilize the model for determination of sufficient historical data necessary for reliable history matching we carried out the aforementioned steps 1 through 5.

DISCUSSION OF RESULTS

For the two test cases, when the six months historical data were graphed all the perturbed models matched the field observed data for cumulative oil production, and field water-cut as depicted in figures 3 and 4. When a calibrated simulation model is obtained with six months historical data matching there exists a high degree of uncertainty if the calibrated model is used to make reservoir performance forecast as evident in figure 5.

Figure 5 and 6 show when the models were used to make performance predictions. In spite of the fact that with six months historical data all the different simulation models matched the observed field data but it is only the 75% simulation model that can actual give a close reservoir performance prediction of the actual reservoir.

A gradual deviation of all the perturbed models matching the history data is noticed as the historical duration increases. As depicted in the 12 months historical data matching, all the perturbed models below 30% fail to match the history data such that these models can be neglected at this stage see figures 7 and 8. This is even more pronounced with the 18 months historical data matching.

The inability of the 50% perturbed model to match the historical data is noticeable for the 12 months historical data matching but more pronounced in the 18 months matching as show in figures 9, 10 and 11.

For the 18 and 24 months historical data matching, the 75% perturbed model gave better close match to the history data compare to all other models see figures 12 through 14. From the aforementioned evaluations, we concluded that 18 months historical data is sufficient to determine if a simulation model will be effective for reservoir performance prediction as further supported by figures 15 and 16.

CONCLUSIONS

From the findings of this research, it is concluded that for the reservoirs under investigation, observed historical data of 18 months are sufficient for a good history match if:

1. The model is 75% and above close to the actual reservoir.
2. The model is between 50 – 70% of the actual reservoir more than 18 months data is required.

This means that a good reservoir simulation model of the real reservoir will be obtained after 18 months of producing the actual reservoir. As a result, reservoir prediction determined from a history matched model that is based on 18 months historical data is reliable for field development.

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NOMENCLATURE

t_p = production time, hr
μ = viscosity, cp
Φ = porosity
k = permeability, md
d = distance
c_t = total compressibility, psi^{-1}

Table 1
Factors Controlling Historical Data Waiting Period

1. Production rate
2. Number of wells
3. Position of the wells in the reservoir
4. Reservoir size
5. Reservoir rock properties
6. Fluid properties
7. Drive mechanism

Table 2
Reservoir Layer Data

Layer	Thickness (feet)	Porosity (fraction)	Horizontal Perm. (mD)	Vertical Perm. (mD)
1	20.0	0.3	500.0	50.0
2	30.0	0.3	50.0	50.0
3	50.0	0.3	25.0	25.0

Layer	Initial S_o	Initial S_w	Initial P_{oil} (psia)	Elevation (feet)
1	0.8	0.2	3984.3	8335
2	0.8	0.2	3990.3	8360
3	0.8	0.2	4000.0	8400

Table 3
Reservoir Model Data

Grid Dimension	Areally:7 x 7 in 3 layers
Water Density	62.4 lb/cuft
Oil Density	38.53 lb/cuft
Gas Density	68.64 lb/cuft
Water Compressibility	3.3×10^{-6} psi^{-1}
Rock Compressibility	5.0×10^{-6} psi^{-1}
Water Formation Volume Factor	1.00 RB/STB
Water Viscosity	0.70 cp
Reservoir Temperature	160 ^oF
Separator Conditions (Flash Temperature and Pressure)	60 ^oF 14.7 psia
Reservoir Oil Saturation Pressure	2302.3 psia
Oil Formation Volume Factor (above bubble point pressure)	-21.85×10^{-6} RB/STB/PSI
Reference Depth	8400.0 ft
Initial Pressure at Reference Depth	4000.0 psia
Initial Water Saturation	0.20
Initial Oil Saturation	0.80
Areal Grid Block Dimensions	500 ft x 500 ft
Reservoir Dip	0
Trapped Gas, Corresponding to Initial Gas Saturation	20%
Wellbore Radius	0.25 ft
Well KH	10000.0 md/ft
Well Location; Grid Cell Center	Production well: I = 7, J = 7 (Completed in Layer 3)

Table 4
Base Case Reservoir Description and Simulation Output

Base Case 6 Months			
TIME	FGOR	FPR	FWCT
(DAYS)	(MSCF/STB)	(PSIA)	
0	0	3993.75	0
1	0.5728	3981.823	2.28E-06
4	0.5728	3946.034	3.74E-06
13	0.5728	3838.561	5.84E-06
30	0.5728	3635.205	9.35E-06
60	0.5728	3274.432	1.52E-05
90	0.5728	2902.931	2.08E-05
120	0.5728	2529.859	2.60E-05
150	0.527151	2286.751	3.51E-05
180	0.512511	2240.178	4.02E-05
	Permx	Permy	PermZ
Layer1	500	500	50
Layer2	50	50	50
Layer3	200	200	25

Table 5
1% Reservoir Description Perturbation

1%			
TIME	FGOR	FPR	FWCT
(DAYS)	(MSCF/STB)	(PSIA)	
0	0	3993.75	0
1	0.5728	3992.667	1.61E-06
4	0.5728	3989.562	4.67E-06
13	0.5728	3980.926	8.98E-06
30	0.5728	3965.781	1.27E-05
60	0.5728	3940.67	1.55E-05
90	0.5728	3916.537	1.71E-05
120	0.5728	3893.097	1.82E-05
150	0.5728	3870.162	1.89E-05
180	0.5728	3847.622	1.95E-05
	Permx	Permy	PermZ
Layer1	5	5	0.5
Layer2	0.5	0.5	0.5
Layer3	2	2	0.05

Table 6
30% Reservoir Description Perturbation

30%			
TIME	FGOR	FPR	FWCT
(DAYS)	(MSCF/STB)	(PSIA)	

0	0	3993.75	0
1	0.5728	3981.825	4.55E-06
4	0.5728	3946.014	8.36E-06
13	0.5728	3838.521	1.19E-05
30	0.5728	3635.045	1.55E-05
60	0.5728	3273.753	2.08E-05
90	0.5728	2902.881	2.58E-05
120	0.52391	2577.909	3.73E-05
150	0.51046	2366.895	4.65E-05
180	0.520919	2273.761	5.14E-05
	Permx	Permy	PermZ
Layer1	150	150	15
Layer2	15	15	15
Layer3	60	60	7.5

Table 7
90% Reservoir Description Perturbation

90%			
TIME	FGOR	FPR	FWCT
(DAYS)	(MSCF/STB)	(PSIA)	
0	0	3993.75	0
1	0.5728	3981.823	2.44E-06
4	0.5728	3946.025	4.01E-06
13	0.5728	3838.552	6.16E-06
30	0.5728	3635.196	9.67E-06
60	0.5728	3274.408	1.55E-05
90	0.5728	2902.921	2.10E-05
120	0.5728	2529.849	2.62E-05
150	0.523139	2287.649	3.60E-05
180	0.509729	2240.616	4.15E-05
	Permx	Permy	PermZ
Layer1	450	450	45
Layer2	45	45	45
Layer3	180	180	22.5

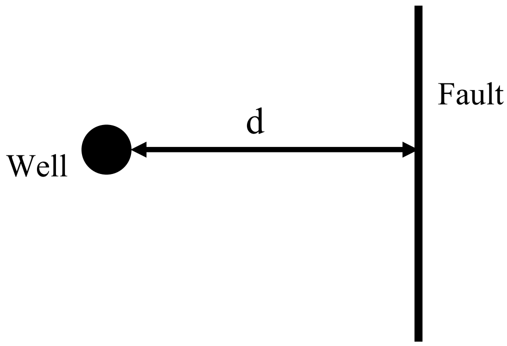

Figure 1 - Distance of a Sealing Fault from a Producing Well

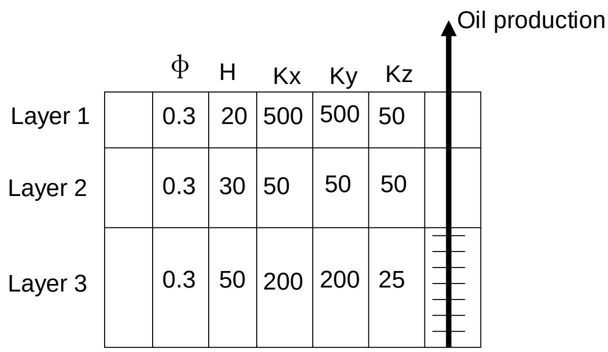

Figure 2: Test Case 1 Reservoir

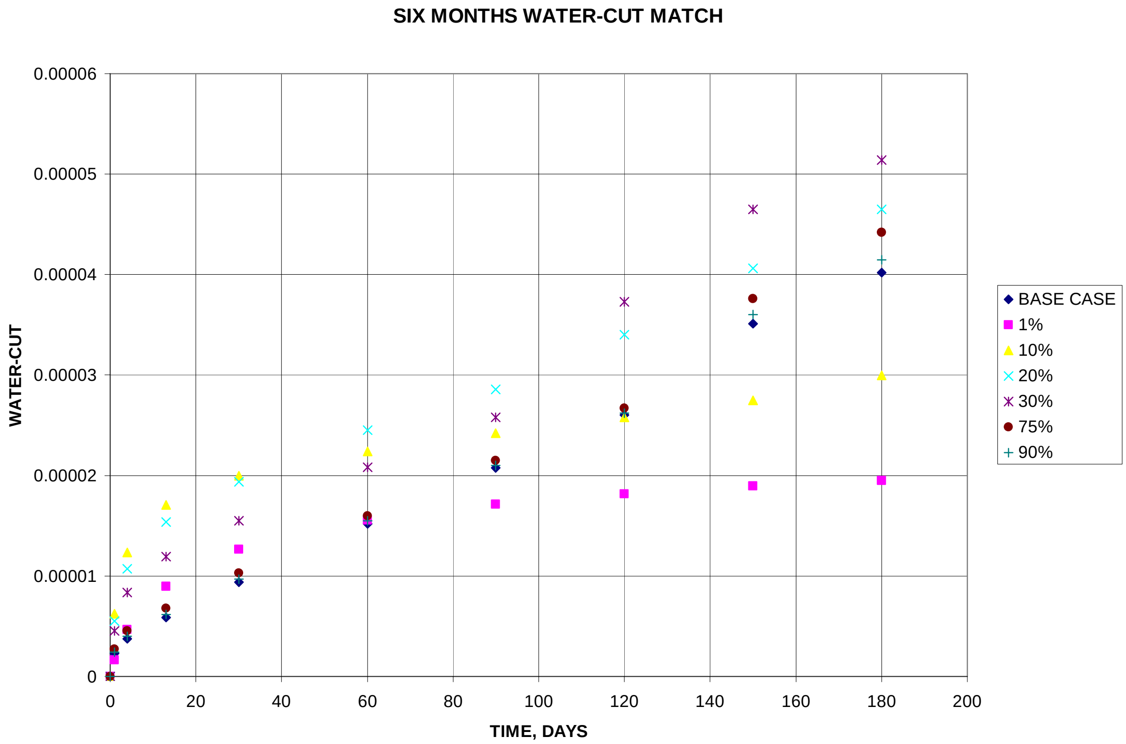

Figure 3 - Test Case 1, Six Months Historical Data Matching

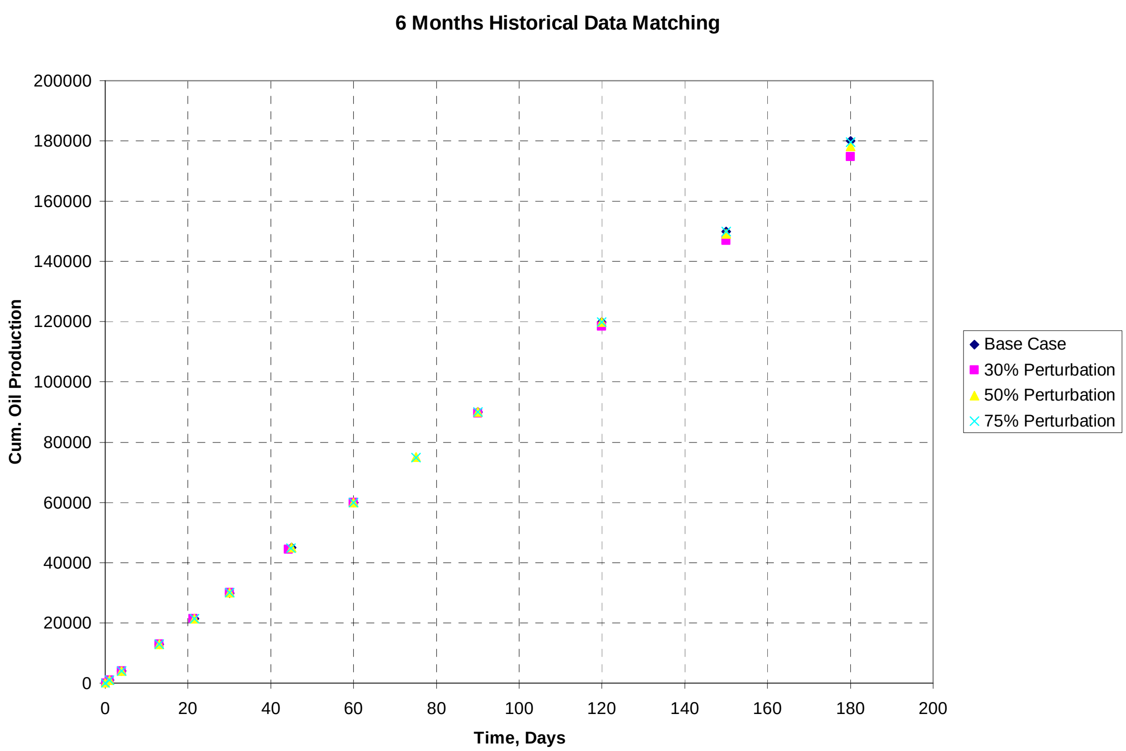

Figure 4 - Test Case 2, Six Months Historical Data Matching

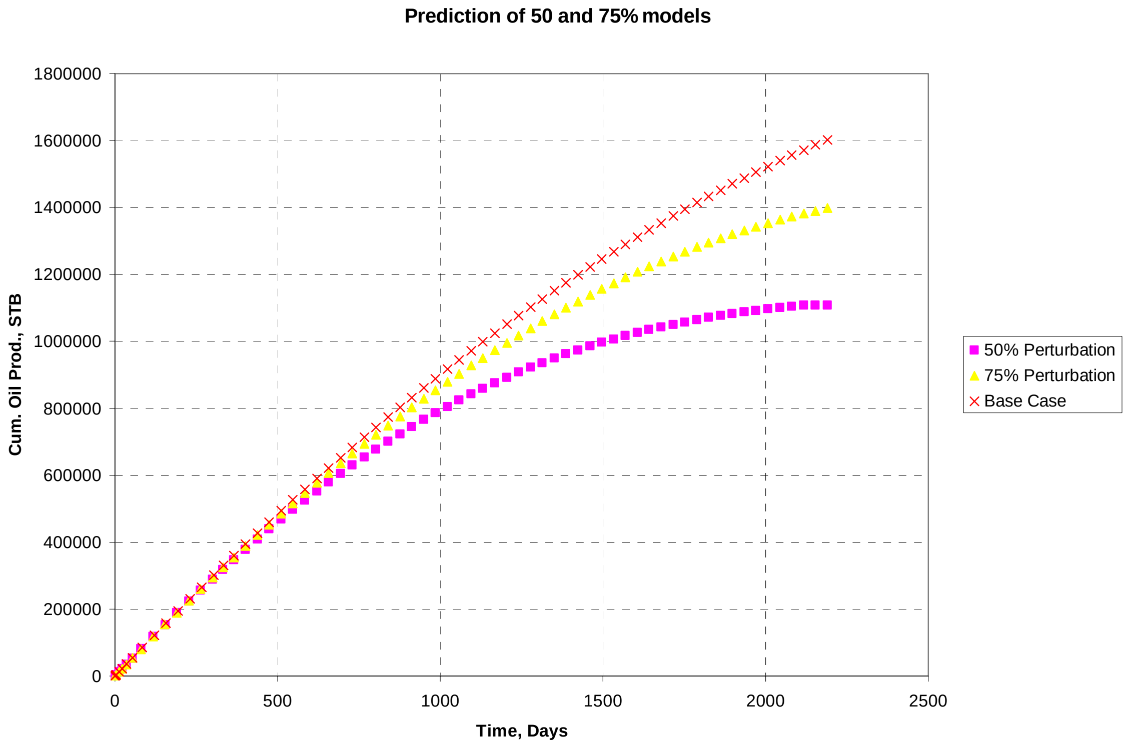

Figure 5 - Test Case 1, Base Case and Two Simulated Models Predictions

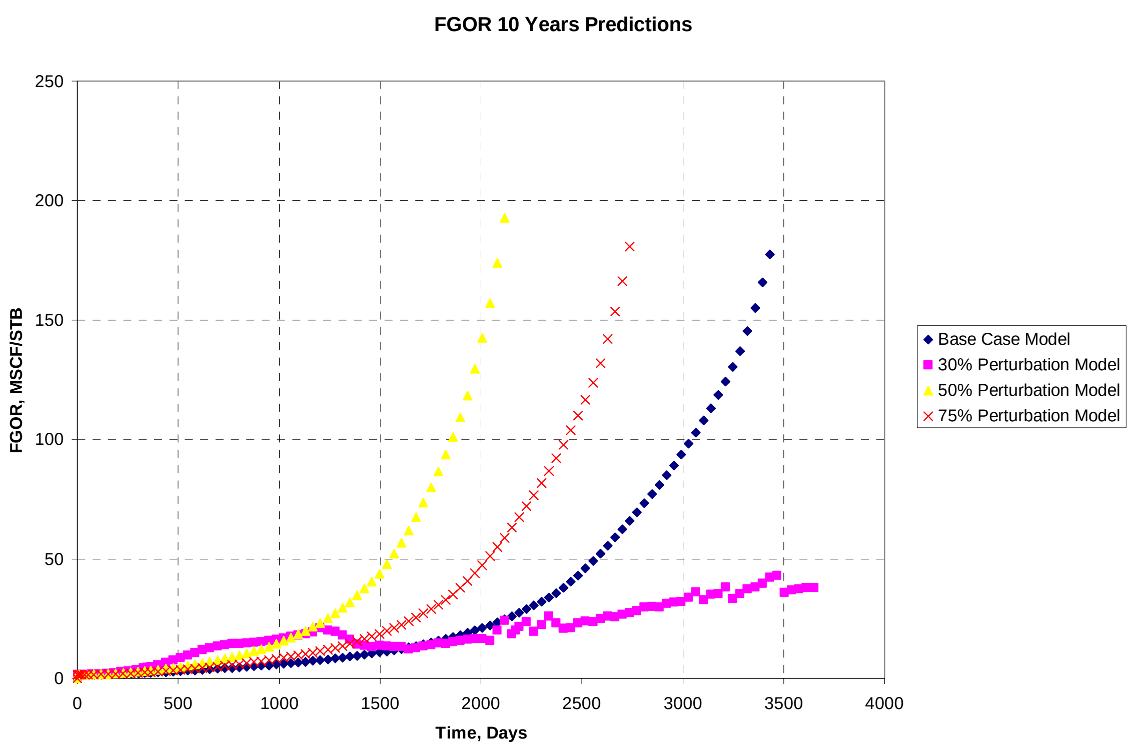

Figure 6 - Test Case 2, Base Case and Three Simulated Models Predictions

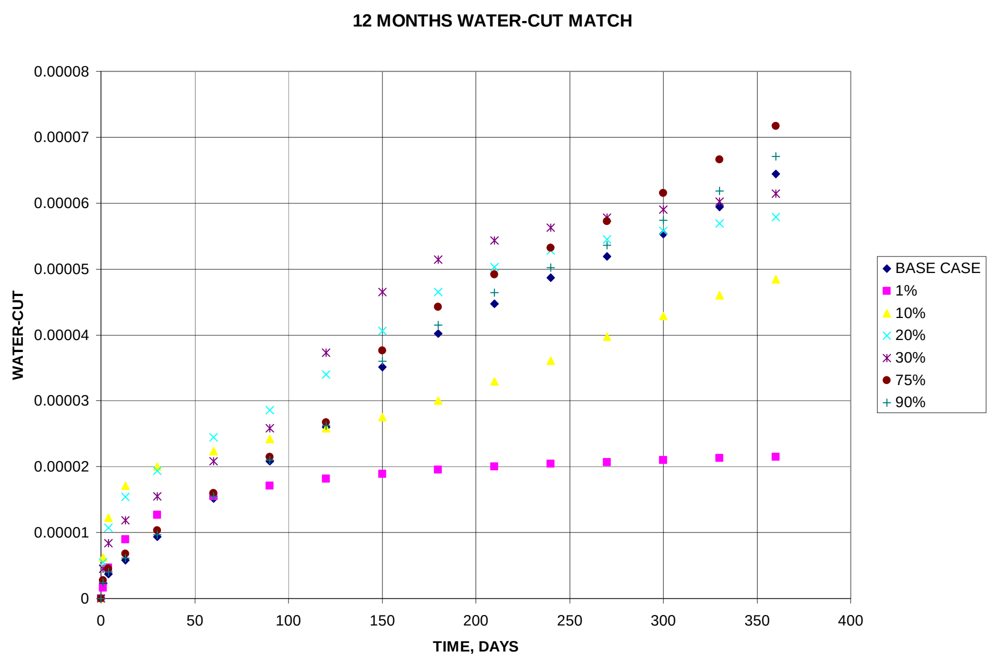

Figure 7 - Test Case 1, Twelve Months Historical Data Matching

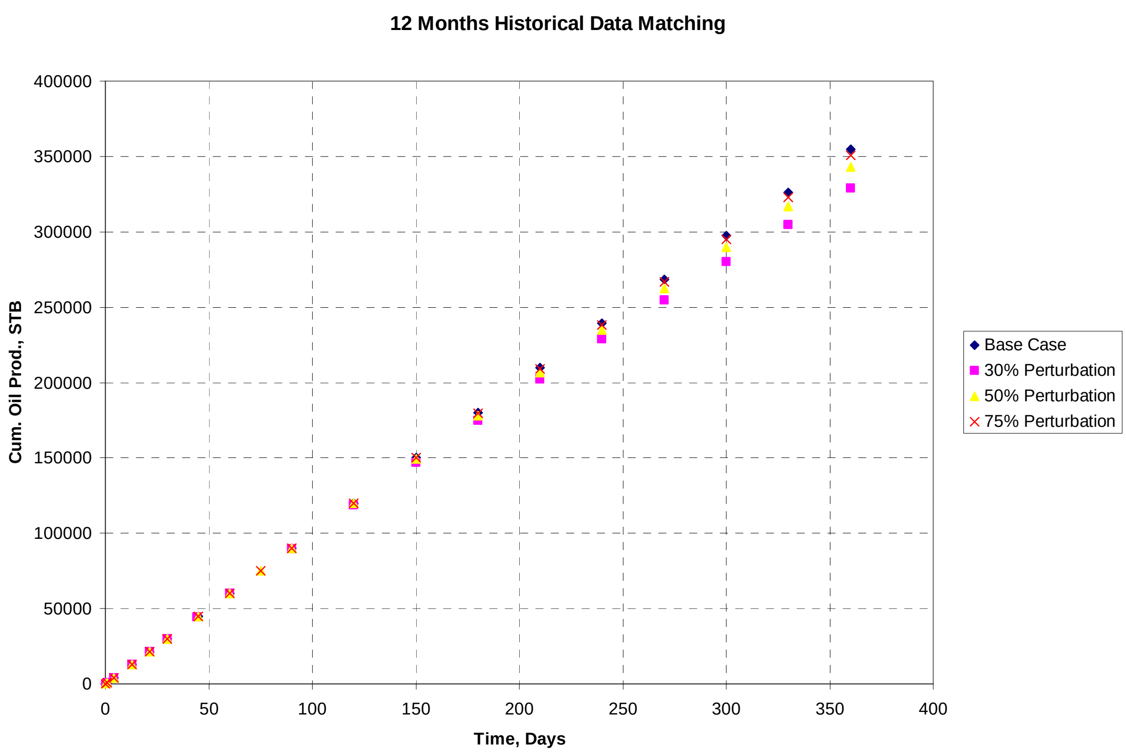

Figure 8 - Test Case 2, Twelve Months Historical Data Matching

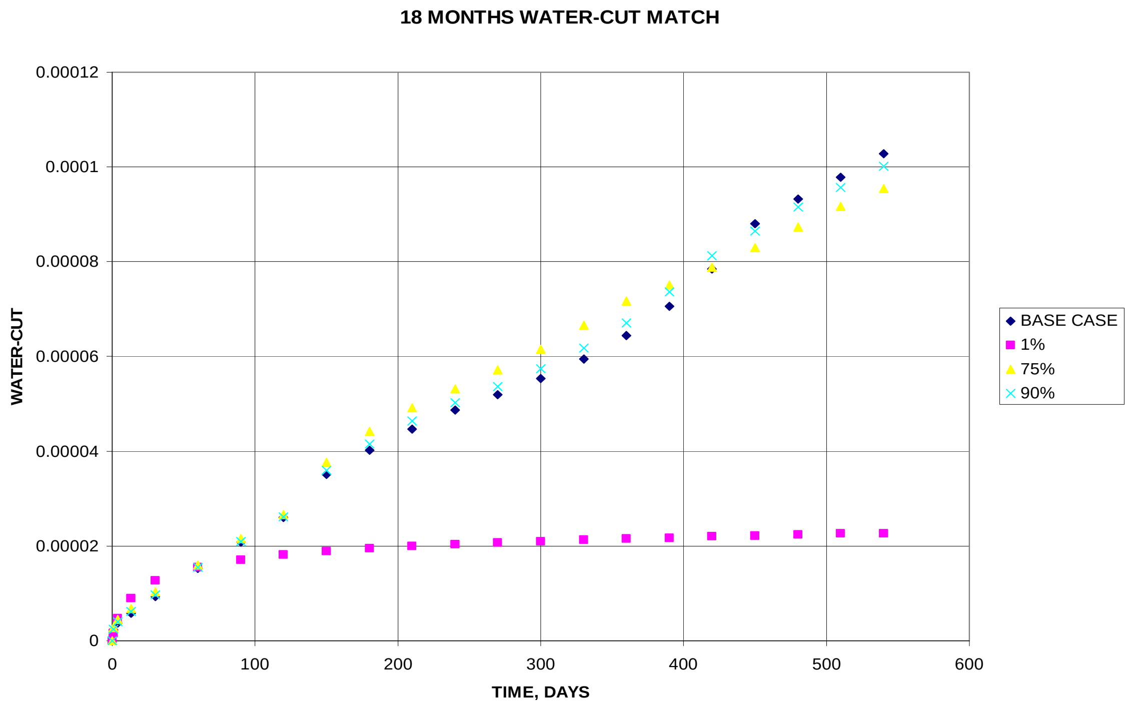

Figure 9 - Test Case 1, Eighteen Months Historical Data Matching

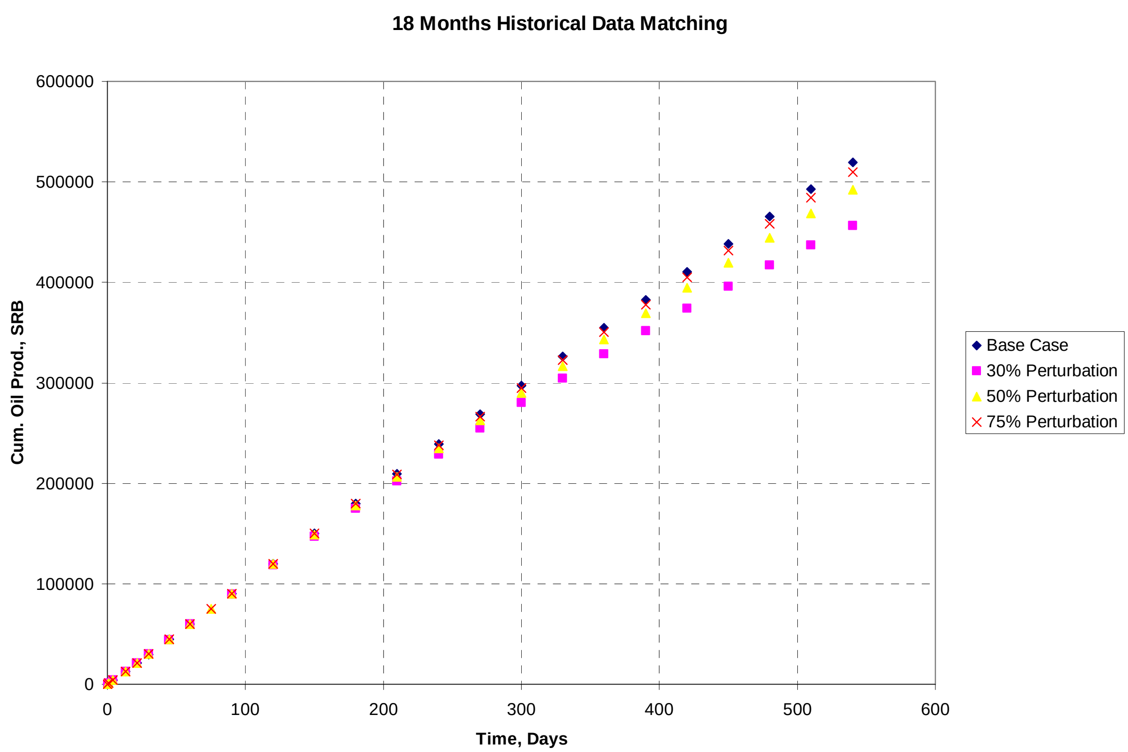

Figure 10 - Test Case 2, Eighteen Months Historical Data Matching

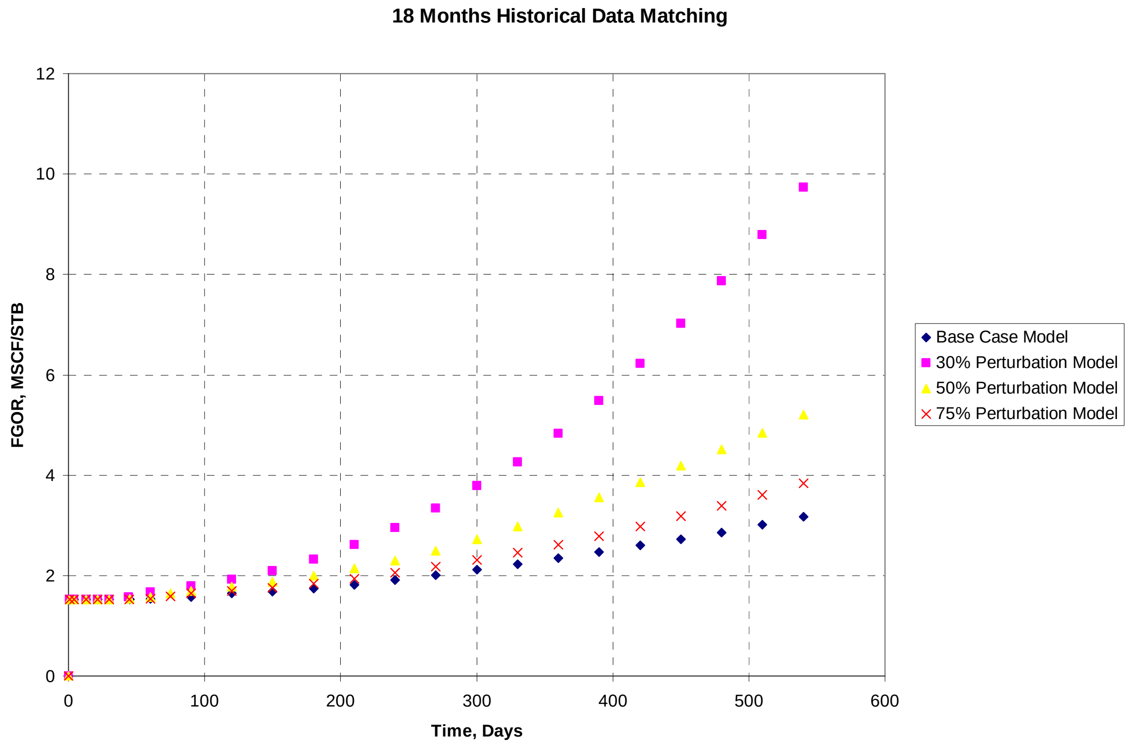

Figure 11 - Test Case 2, Eighteen Months Historical Data Matching

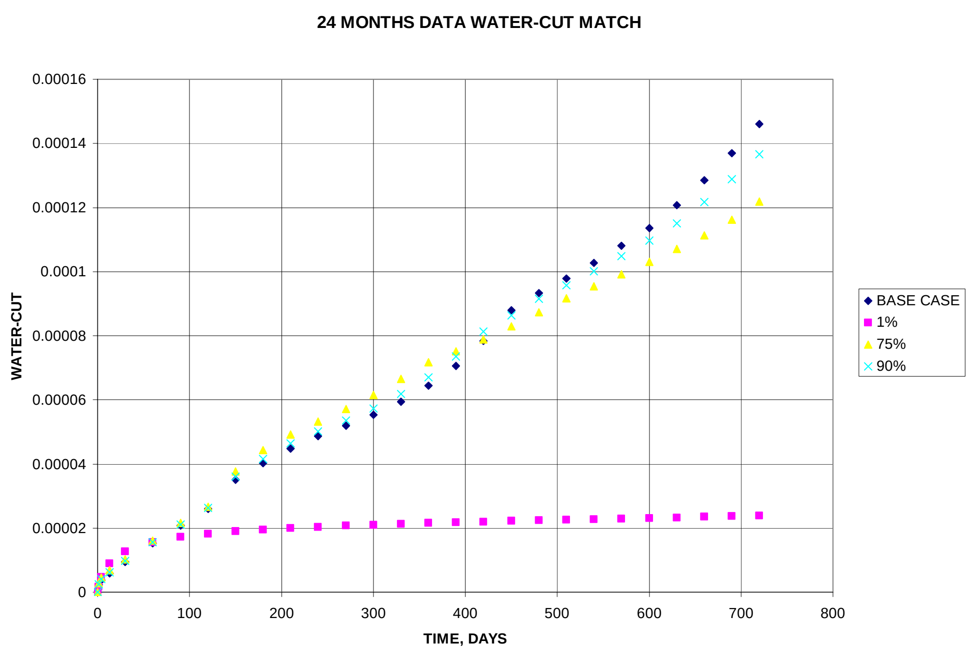

Figure 12 - Test Case 1, Twenty Four Months Historical Data Matching

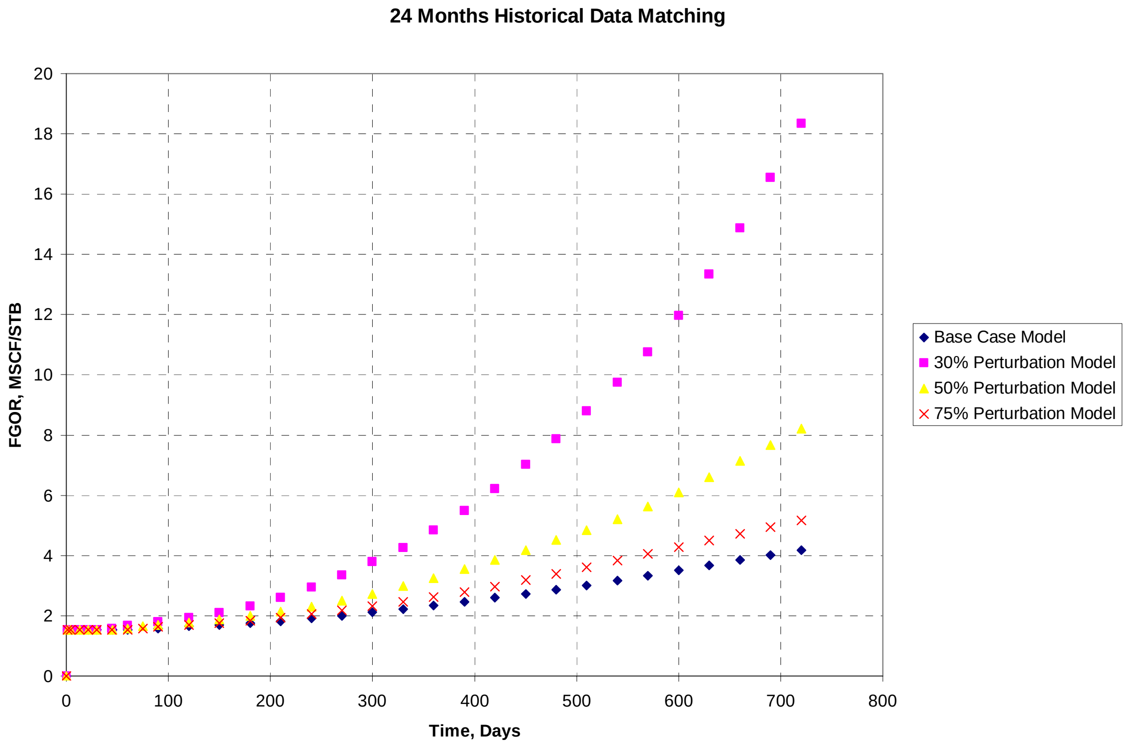

Figure 13 - Test Case 2, Twenty Four Months Historical Data Matching

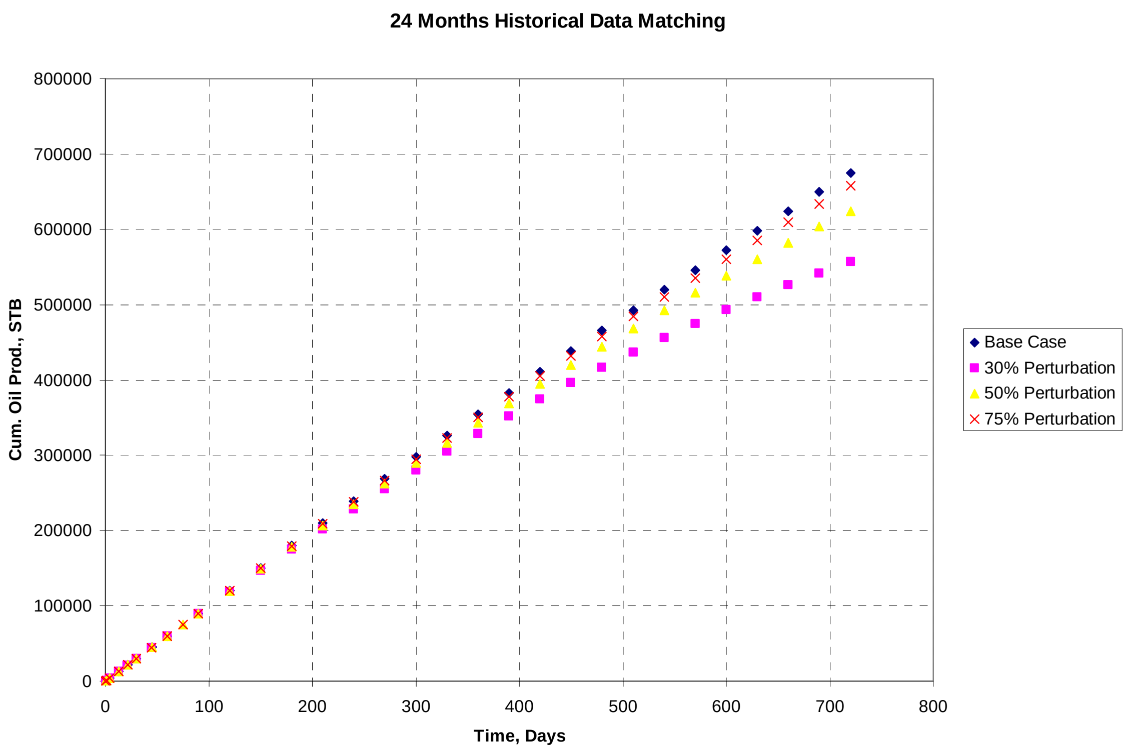

Figure 14 - Test Case 2, Twenty Four Months Historical Data Matching

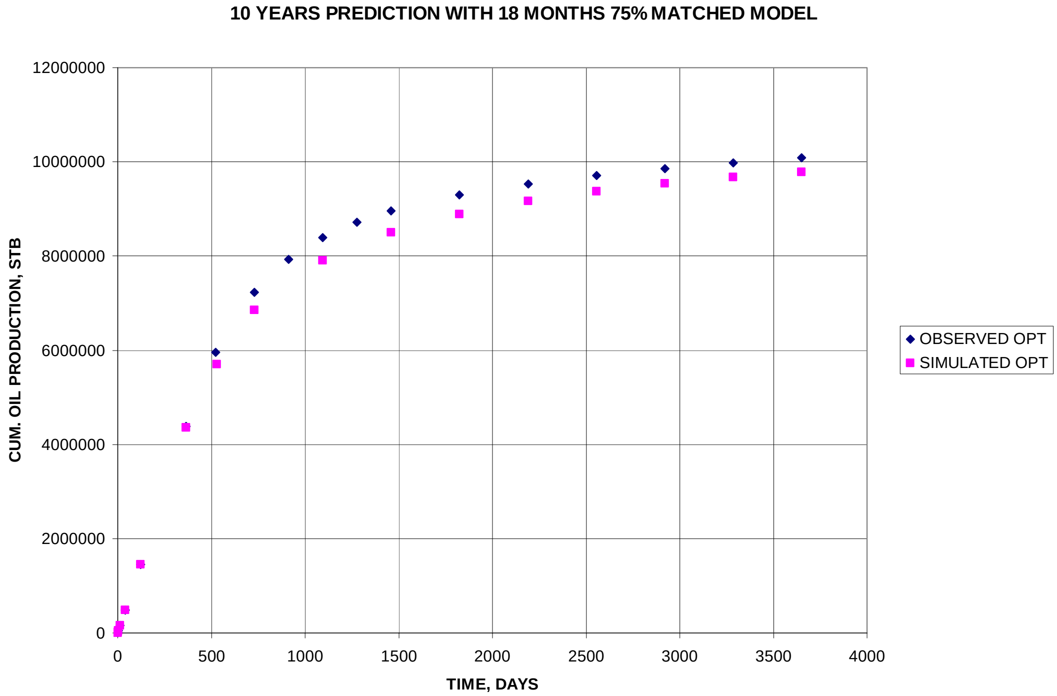

Figure 15 - Test Case Reservoir Performance Prediction

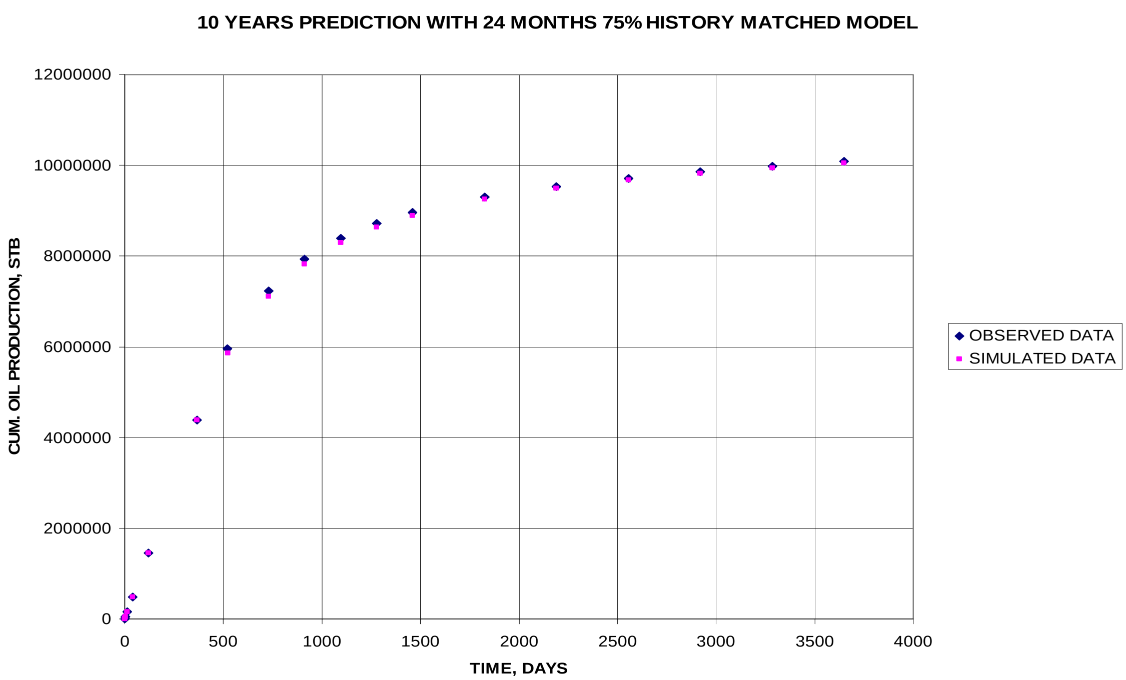

Figure 16 - Test Case 1 Reservoir Performance Prediction