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Validation of ESP Oil Wells Measured Parameters Using Simulation Olga Software

T A Ganat, M Hrairi*, MNA Hawlader

Department of Mechanical Engineering, International Islamic University Malaysia, P.O. Box 10,50728 Kuala Lumpur, Malaysia

*E-mail: meftah@iium.edu.my

Abstract. The significant challenge in the oil and gas industry is the concurrent measurement of commingled gas, oil and water production, either using three phase test separator or multiphase flow meter (MPFM). A major issue in these applications is the uncertainty of the measurements, due to different measurement operations conditions. A new computational approach has been generated to estimate oil well flow rate of 48 oil wells using Electrical Submersible pump (ESP) from D, G, and W oil fields located in North Africa. The idea is to close the wellhead wing valve and the ESP is kept running normally and the wellhead flowing pressure before shut-in the well and the build-up of wellhead flowing pressure after shut-in the well are measured. OLGA software has been used to make comparison with multiphase flow model available in the OLGA software against each nominated ESP oil well parameters obtained from measured field data. The objective was to verify the obtained shut-in wellhead pressure after closing the choke wing valve (WHPa) from the measured field data with the obtained shut-in wellhead pressure valve from the simulation model. In this paper the simulation results showed that the estimated WHPa are in agreement with the measured WHPa. The relative errors for individual oil field are within accuracy standard specification (typically +/- 10%). The overall relative errors are low and within acceptable uncertainty range, where the aggregate relative error for all wells was less than +/-4% which is considered acceptable. Therefore, the results have demonstrated that the new computational method can work under ESP oil wells conditions and has the ability to perform accurate results even when closing the wellhead wing valve for short time span.

1. Introduction

The need for multiphase flow measurements in the oil and gas production industry has been evident for many years. A number of such meters have been developed since the early eighties by research organizations, and meter manufacturers [1]. Currently the oil and gas industry use the three phase test separator or Multiphase Flow Meter (MPFM). A major issue in the application of using either of these techniques in the oil field is the uncertainty of the fluid measurements, due to different process and operations conditions (mainly at high water and gas fraction) [2].

In this paper, the use of multiphase flow models in OLGA software has been used. The purpose of using OLGA software is to compare multiphase flow models available in the OLGA software against the well parameters obtained from measured field data. This work was performed on a new computational method to estimate the flow rates of ESP oil wells, where the new method was applied on 48 ESP oil wells in North Africa oil fields [3]. The research idea is based on keeping the pump running and closing the wellhead wing valve for few minutes (continuously monitoring the limited

ESP shutting off pressure), and measure the wellhead flowing pressure before and after closing the well head valve, and record the total shut-in time period. Explicit physics concepts for estimation of the multiphase fluid flow rate in a vertical pipe were employed. The formulas deal with changes of fluid flow parameters along the vertical pipe in the well as a function of pressure and temperature variations with the depth.

Figure 1 shows the flow chart of the simulation model structure where the input parameters must contain many input fields. The latters are shown in the below OLGA board tabs (Figure 2).

Simulation model was performed for each individual ESP well from three different oil fields. The objective was to verify the obtained shut-in wellhead pressure after closing the choke valve from the measured field with the obtained shut-in wellhead pressure valve from the simulation model.

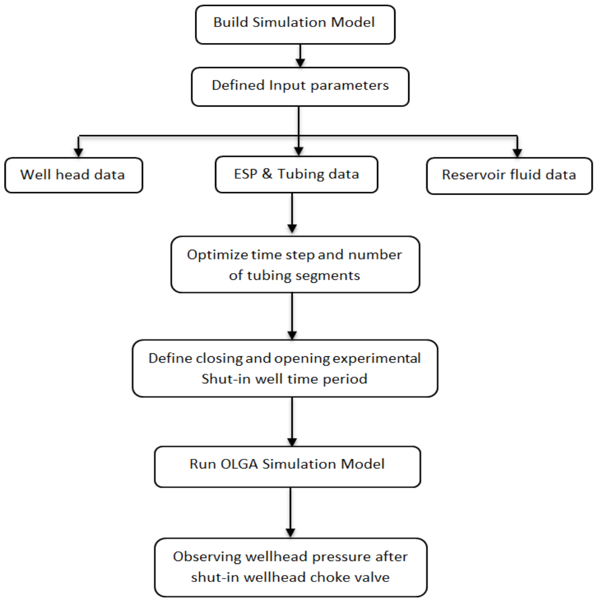

Figure 1. Flow chart of the simulation model structure

2. Software simulation

The OLGA simulator is one of the principal components in analysis of pipeline operations and production well operations. OLGA is a computational program developed to simulate multiphase flow in pipelines and pipelines networks, with processing equipment included. The program solves separate continuity equations for the gas, liquid bulk and liquid droplets, two momentum equations, one for the continuous liquid phase and one for the combination of gas and possible liquid droplets and one mixture energy equation, considering that both phases are at same temperature. The equations are solved using the finite volume method and semi-implicit time integration [4]. Successful design and operation of multiphase production systems rely on detailed understanding of flow behavior [5]. OLGA provides solutions through accurate modeling of true dynamics. Transient simulator provides an added dimension to steady-state analyses by predicting system dynamics such as time-varying changes in flow rates, fluid compositions, temperature, and operational changes [6].

From wellbore dynamics for any well completion to pipeline systems with all types of process equipment, simulator provides an accurate prediction of key operational conditions involving transient flow. The simulation model was run based on the field data gathered from D, G, and W oil fields. The aim of simulation was to find models that accurately predict the wellhead pressure after shut-in the wellhead valve for each single nominated ESP wells. The prediction results depend on the phase redistribution phenomenon and investigate the effect of changing simulation parameters. This was done by using same wells parameters and validating the modeling results against the measured well data.

2.1 The simulation parameter structure

The simulation model in terms of OLGA input file, file name of the optional restart file, specification of input variables, specification of output variables (trend/profile), and time interval between the major time steps are to be specified in an input parameter structure.

The simulator is controlled by defining a set of data groups consisting of a keyword followed by a list of keys with appropriate values. Each data group can be seen as either a simulation object, information object, or administration object. The input parameter structure must contain many input fields, these fields are shown in the below OLGA board tabs (figure 2).

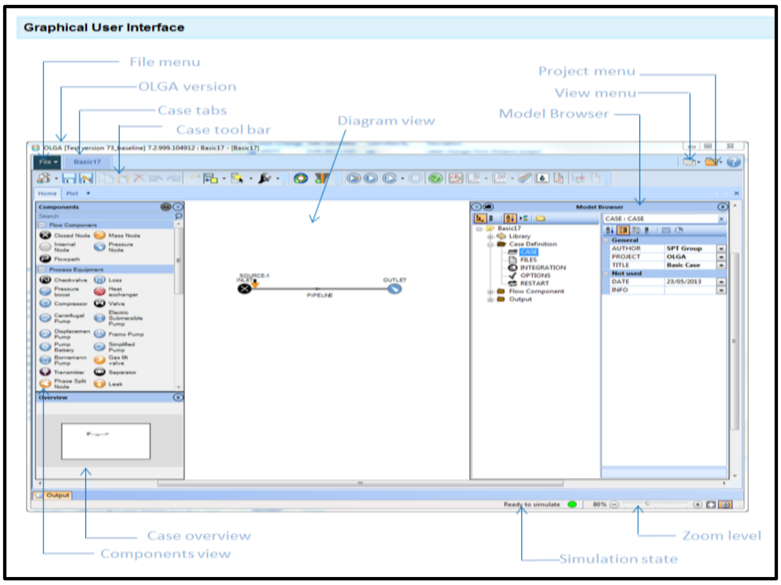

Figure 2. Olga input fields' board tabs.

The entire well path must be identified, (figure 3), using the input files such as well casing strings data and tubing string data, (figure 4), fluid properties data (PVT) using PVTI simulation, (figure 5), pump data, wellhead data, and reservoir data. Simulator requires a description of the fluid properties as a unique function of temperature and pressure. These can be given either as a fluid file, through specific component data given in a feed file (compositional tracking) or defined in the main file (black oil). Besides, a variable time step model is set up and simulator determines the major time steps. In this study, the well simulation design was built for each nominated ESP oil wells, using the measured field data available.

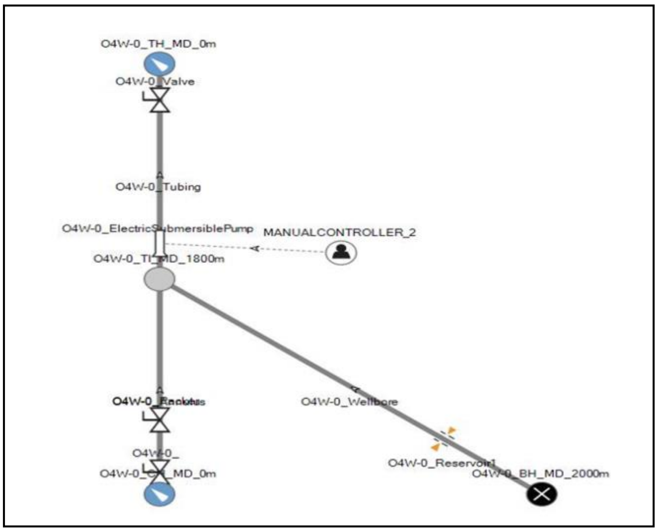

Figure 3. OLGA well structure model.

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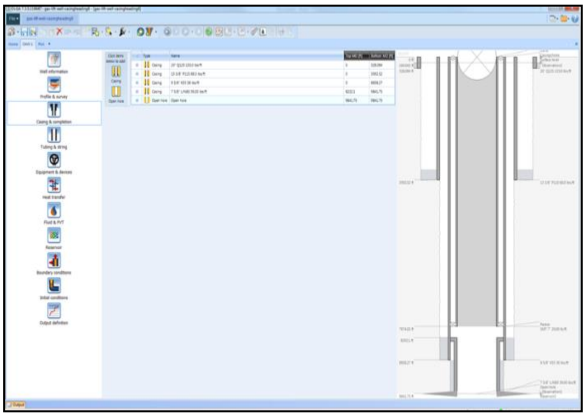

Figure 4.Well casing and tubing design profile.

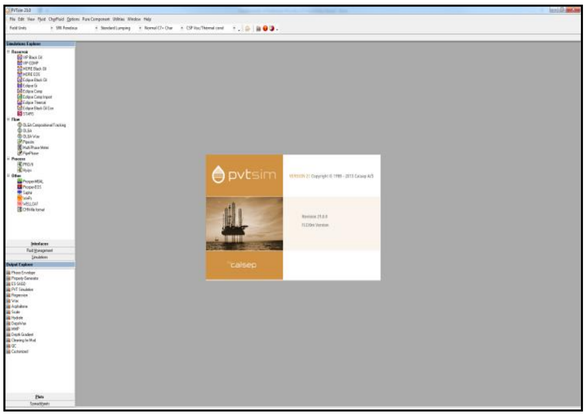

Figure 5. PVTI simulation model.

2.2 Simulation Viewer

The basic objective of multiphase flow visualization in the vertical well tubing is to imagine the multiphase flow phenomena and phase re-distribution during open and shut-in the wellhead choke valve and to prove that the new computational methodology process was made under same production conditions. Using OLGA software, one can evaluate and compare well result alternatives with the visualization of the fluid flow results with real time interaction. Also, one can understand the fluid flow inside the vertical riser pipe using the section plots. It will also allow getting values quickly and easily for critical parameters, such as pressure drop, liquid and gas volumes, and holdup fractions.

Figure 6 shows the 2D simulation viewer profile for multiphase flow in the vertical tubing string. The viewer shows the re-distribution phase phenomena when shut-in the wellhead choke valve where the gas phase dissolved back to the liquid phase, and shows the bubble point location depth before and after shut-in wellhead choke valve. It can be seen from figure 6 that the depth location of the bubble point pressure has been moved up to new bubble point location depth due to the dissolved gas and vapor phase into the liquid phase during shut-in the wellhead choke valve, and back to the original location depth after opening the choke valve again. This visualization demonstrated exactly what happened during shutting and opening wellhead choke valve process at the well site. The difference between the two bubble point location depths represents the amount of fluid volume pumped during shut-in the well as a function of total shut-in time period.

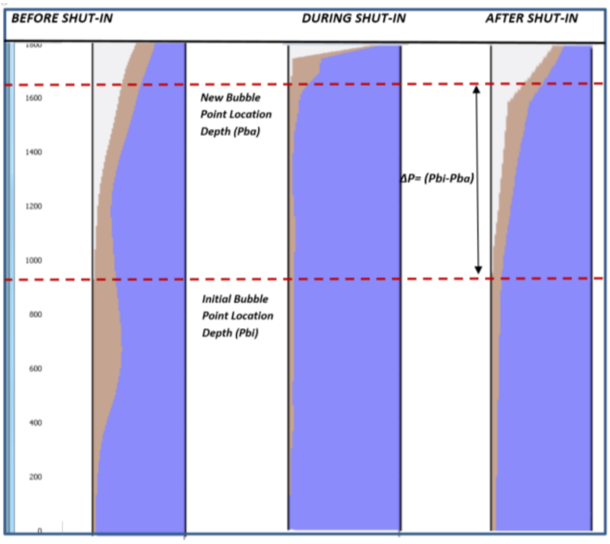

Figure 6. 2D vertical well cross section pipe using OLGA viewer profile showing bubble point location depth before and after shut-in the well.

2.3 Simulation Results

The series of simulation results that were carried out reflect the nominated wells production performance and yields many possible values for the outcomes of interest. The 48 ESP oil wells simulation results were compared and validated with field measured data. The results were very encouraging, where the verified WHPa was very close to the measured WHPa for each well. Tables 1, 2 and 3 and figures 7, 8, and 9 show the comparison results of OLGA simulation values of WHPa with experimental values of WHPa for all the ESP wells in D, G, and W oil fields, respectively. The result shows small values of average relative error of ± 10%, with a high R^2 of 99.06%, 99.44%, and 96.51%, respectively, indicating that the measured shut-in wellhead pressure values onsite for most of the ESP oil wells are satisfactory.

Table 1. WHPa Comparison between the measured and simulation data for D oil field.

well Name	Calculated WHPa (Psia)	Measured WHPa (Psia)	Absolute Error (Psia)	Relative Error (%)
B56	170	172.45	-2.45	-1%
B70	230	240	-10	-4%
B121	160	159.62	0.38	0%
B119	160	153.35	6.65	4%
B50	250	241.53	8.47	4%
B88	160	166.5	-6.5	-4%
B14	270	278.59	-8.59	-3%
B151	230	235	-5	-2%
B164	170	176.33	-6.33	-4%
B51	310	322.33	-12.33	-4%
Q89	150	146.36	3.64	2%
Q21	150	147.45	2.55	2%
Q53	150	148.05	1.95	1%
Q14	130	131.194	-1.194	-1%
Q100	130	130.65	-0.65	0%
Q12	150	146.126	3.874	3%
Q85	150	147.53	2.47	2%
Q82	150	156.38	-6.38	-4%
Q78	150	147.62	2.38	2%
Q76	160	153	7	5%

Table 2. WHPa comparison between the measured and simulation data for G oil field.

well Name	Calculated WHPa (Psia)	Measured WHPa (Psia)	Absolute Error (Psia)	Relative Error (%)
E89	200.53	190	10.53	6%
E210	134.12	120	14.12	12%
E211	122.28	120	2.28	2%
E286	106.86	100	6.86	7%
E192	114.63	110	4.63	4%
E327	119.52	110	9.52	9%
E325	112.54	110	2.54	2%
E197	117.55	110	7.55	7%
E208	107.06	110	-2.94	3-%
E226	115.88	110	5.88	5%
E284	132	120	12	10%
E258	92.64	90	2.64	3%
E326	104.49	100	4.49	4%
E227	158	150	8	5%
4_E3	310.71	300	10.71	4%

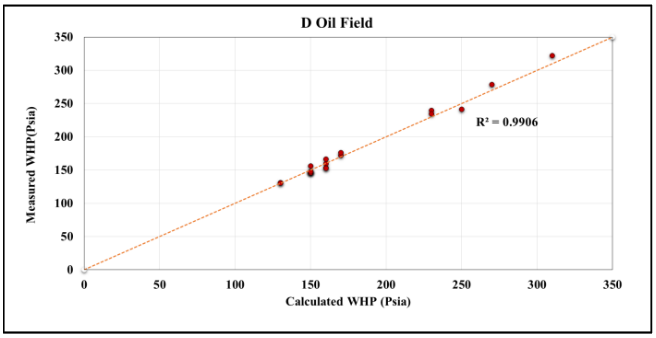

Figure 7. Comparison between the measured WHPa and simulated WHPa for D oil field.

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Table 3. WHPa comparison between the measured and simulation data for W oil field.

Well Name	Calculated WHPa (Psia)	Measured WHPa (Psia)	Absolute Error (Psia)	Relative Error (%)
A33	202.34	200	2.34	1%
A125	209.86	200	9.86	5%
A64	242.64	250	-7.36	-3%
A29	251.5	270	-18.5	-7%
A23	335.35	300	35.35	12%
A135	303.36	300	3.36	1%
A126	176.32	170	6.32	4%
A12	305.15	300	5.15	2%
A108	225.12	210	15.12	7%
5J5	270.12	270	0.12	0%
J52	261.52	260	1.52	1%
5J4	249.52	250	-0.48	0%
5J7	312.17	300	12.17	4%

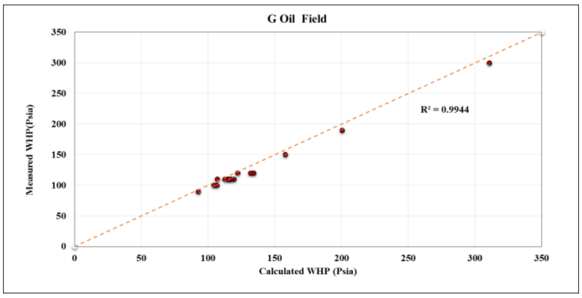

Figure 8. Comparison between the measured WHPa and simulation WHPa for G oil field.

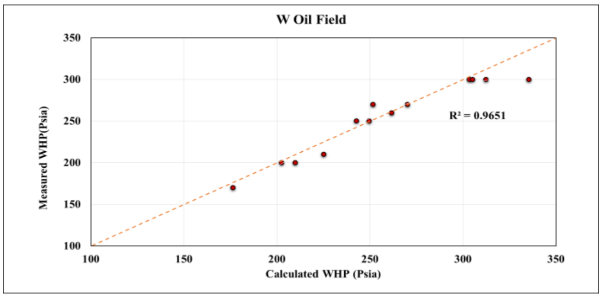

Figure 9. Comparison between the measured WHPa and simulation WHPa for W oil field.

At an average relative error band of ±10%, 100%, 87%, and 85%, of total number of ESP oil wells in D, G, and W, oil fields respectively, had correctly predicted shut-in pressure values.

Generally, it is important to know, how much the measured value is likely to deviate by using different method. All cross plot figures have showed a quite good correlation around the actual values. The results of the simulations were encouraging in terms of model performance.

Figures 10, 11 and 12 display the estimated relative error results in wellhead pressures after shut-in the choke valve from experimental measurements verses simulation calculations for all wells in D, G, and W oil fields respectively. These figures show the stability of estimating the wellhead shut-in pressure. It has been noticed that most investigated wells showed good relative error results.

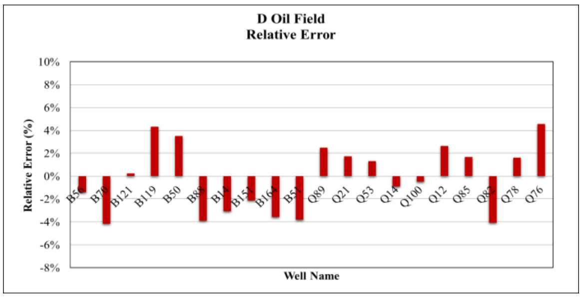

Figure 10. The measured WHPa accuracy for D oil field.

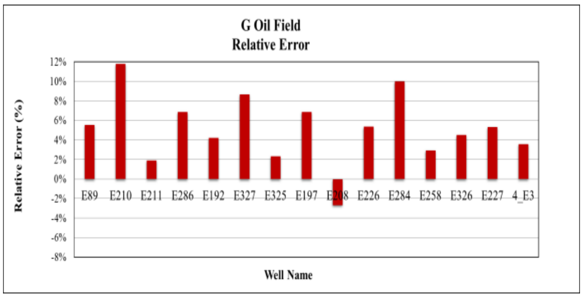

Figure 11. The measured WHPa accuracy for G oil field.

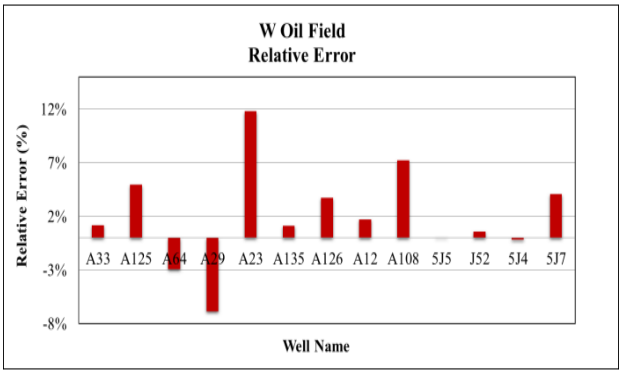

Figure 12. The measured WHPa accuracy for W oil field.

Figure 10 shows that 100% of the total number of oil wells in D oil field had correctly predicted shut-in pressure values where the error was within the specified target accuracy of ±10%. 95% of data had an accuracy of less than ±5%. However, there was a trending small spread of errors during verification of these accuracies.
Figure 11 shows that 87% of the total number of oil wells in G oil field, had correctly predicted shut-in pressure values where the error was within the specified target accuracy of ±10%, while 13% had shut-in pressure values are more than ±10%. Here, 60% of data had an accuracy of less than ±5%. However, there was a trending small spread of errors during verification of these accuracies.
Figure 12 shows that 85% of the total number of the oil wells in W oil field, had correctly predicted shut-in pressure values where the error was within the specified target accuracy of ±10%, while 15% had shut-in pressure values are more than ±10%. Here again, 69% of data had an accuracy of less than ±5%. However, there was a trending small spread of errors during verification of these accuracies.
In general, 96% of the total 48 oil wells had predicted the shut-in wellhead pressure correctly, within ±10% relative error, whereas 4% of the wells recorded shut-in pressure data accuracy of less than ±12%.
Figure 13 shows the histogram construction for all relative error measures (±), which records the overall shut-in wellhead pressure accuracy for all ESP oil wells. The histogram demonstrated that the inclusive average relative error of ± 4% is more accurate, and represents 25% of the data set, while the rest of the data are flocculating between 0% and 12% average relative error.

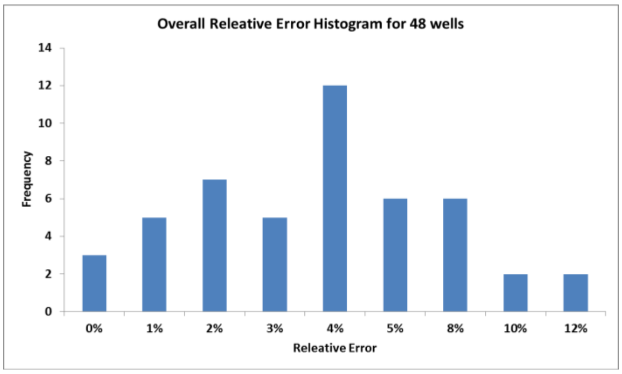

Figure 13. Overall relative Error Histogram for all ESP wells.

3. Conclusion

The estimation of the 48 ESP oil wells flow rate using the new computational approach has been generated and validated with measured flow rate data in the case study oil fields. The measured WHPa was investigated using OLGA simulation Software.
The simulation results showed that the estimated WHPa are in agreement with the measured WHPa. The relative errors for individual oil field are within the accuracy standard specification (typically +/-

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10%). The overall relative errors are low and within acceptable uncertainty range, where the aggregate relative error for all wells was less than +/-4% this accuracy considered acceptable. Therefore, the results have demonstrated that the new computational method can work under ESP oil wells conditions and has the ability to perform accurate results even when closing the wellhead wing valve at short time span.

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