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Effect of Frequent Well Shut-In's on Well Productivity: Marcellus Shale Case Study

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Abstract

Well operation is one of the key foundations for optimal production of hydrocarbons from unconventional shale plays. However, optimal production practices do not follow the versatility of "one size fits all" phenomenon. Completion strategy, Pressure-Volume-Temperature (PVT) properties and petrophysical properties vary from play to play. Hence, the well operating practices should be custom tailored to suit the completion and fluid properties.

In this paper, we propose optimal shut-in practices for dry gas shale reservoirs. We elaborated our study from a Marcellus shale dataset. Marcellus shale dry gas window has in place fluid properties that differ from liquid rich reservoirs like Eagle Ford and Wolfcamp shales. Therefore, production best practices borrowed "as-is" from liquid rich reservoirs and applied to dry gas reservoirs (or vice versa) may not affect the well ultimate recoveries in a positive manner and in some cases, may even reduce the expected ultimate recoveries (EUR's).

We show that the practice of "well conditioning", "resting" or "soak-in" i.e. shutting in the well for a significant time after hydraulic fracturing and before connecting to pipeline as well as frequent shut-in impedes the water unloading from the dry gas reservoirs. This leads to reduction in matrix permeability with an additional skin introduced by water imbibition.

Our methodology by simultaneously history matching gas rate, flowing bottomhole pressure (FBHP) and water rates in a reservoir simulator. We observe that after shut-in, water to gas ratio (WGR) decreases and gas rate increases. However, this increased gas rate is accompanied with higher declines in rates and pressures and ultimately leads to lower EUR's. The reduction in EUR in our case is modeled as a function of water saturation increase in the matrix due to imbibition. Thus, EUR in our study is a function of duration of shut-in and the time in well life at which the shut-in occurs.

Introduction

Production practices like shut-in in shales are one of the neglected areas of study areas in shales. Most of the production practices borrowed from either conventional reservoirs or other delineated shale plays are applied "as-is" on most reservoirs. There is very limited literature available on the topic of well shut-in's. Out of the few documented studies for conventional and unconventional reservoirs, the focus is on drawdown management and phase properties. This leaves behind a big portion of unconventional hydrocarbon reservoirs i.e. dry gas.

Hawkins (1988) studied the effect of shut-in on hydraulic fracture conductivity and found out that shut-in can lead to deposition of gel and breaker in the proppant pack and can reduce the proppant pack conductivity. The effect varied on the proppant mesh size and the chemicals (gel and breaker) used for hydraulic fracturing. There was little to no effect of reservoir temperature in this study. Guillory et al. (1995) carried out the similar experiment with brine and reported little to no reduction in permeability of proppant pack.

Al-mutairi et al. (2008) suggested that cyclic production scheme (CPS), can be beneficial for mature conventional oil fields by reducing the water production in these fields. For unconventional reservoirs, Crafton et al. (2013) used a statistical method to analyze 270 wells in Marcellus shale and found out that frequent shut-in and especially initial "soak-in" period is detrimental for well productivity.

Gupte (2016) summarized a simulation study showing that shut-in usually have the positive impact on well productivity but the effect is dependent on the fluid type in the study. Mittal et al. (2017) observed huge reduction in proppant pack conductivity and attributed it to proppant crushing and proppant embedment i.e. geomechanics, but did not quantify the effect of no-flow i.e. shut-in in core experiments.

Previous studies sent mixed results supporting our conjecture against "one size fits all" for well shut-in practices. We have tried to break down the problem into: fluid type and reservoir type and then built up our hypothesis. We then tried to model a typical well in Marcellus shale and tested our hypothesis with the help of a reservoir simulator.

Hypothesis

For the reservoir type, it is well known that due to low permeability of shales coupled with massive hydraulic fracturing, shale reservoirs behave completely different from conventional well-connected reservoirs (Law et al., 2002; Shuangfang et al., 2012; Mathur et al., 2016). Hence, the production practices applicable to conventional reservoirs may not be applicable to unconventional reservoirs.

For the retrograde condensate reservoir, it is almost rule of thumb to maintain the reservoir above dew point pressure to avoid near wellbore condensate blockage. Following the analogy, it is safe to assume that recharging of pressure in near wellbore region with a shut-in in an unconventional reservoir will lead to delay in near wellbore condensate blockage and will improve the recovery. There is some literature documented for "pore-proximity" effects in shale by Milad et al. (2014) and Jin et al. (2013). It suggests some PVT corrections for shale "nanopores" but does not change the overall fluid phase behavior.

Similar to retrograde condensate reservoirs, for oil reservoirs, same effect should take place. By pressure recharging of the near wellbore region, the bubble point in oil reservoirs can be delayed by re dissolving the solution gas in the oil. This helps in replenishing the reservoir energy and hence the recovery from the well.

In unconventional dry gas reservoirs, there is no shortage of reservoir energy due to fluid type and the reservoir is always saturated. As the reservoirs are completed with massive hydraulic fracturing, majority of the water is imbibed into the reservoir (Mehana and Fahes, 2016). Flowing back the wells helps in reducing the water that remains in the reservoirs causing a bottleneck on reservoir permeability. As gas is the saturated phase, addition of additional water may just impede the gas flow while pressure recharging from shut in providing no additional benefit like in case of retrograde condensate reservoir or an oil reservoir.

This effect coupled with polymer degradation may also alter the initial relative permeability curves of fractures and in some cases can also lead to water blockage as the fracturing water is not unloaded (Bertoncello et al., 2014). Settari et al. (2002), described the method to incorporate this effect in a reservoir simulator.

Based on previous literature survey and method of exclusion we propose that there may be a reduction in EUR due to frequent well shut-in in and especially during initial "soak in period" in case of unconventional dry gas reservoirs. In our study we have focused on increased water saturation in matrix blocks due to imbibition.

Methodology

Ejofodomi et al. (2011) carried out an elaborate reservoir characterization and simulation study to improve the production in Marcellus shale. Although, the purpose of our study is different from theirs, their work presents an elaborate dataset which is used in our study.

Figure 1 shows the equivalent stimulated rock volume (SRV) generated based on microseismic data from the study performed by Ejofodomi et al. (2011). We used the permeability of the SRV along with other parameters to obtain a history match during simulation.

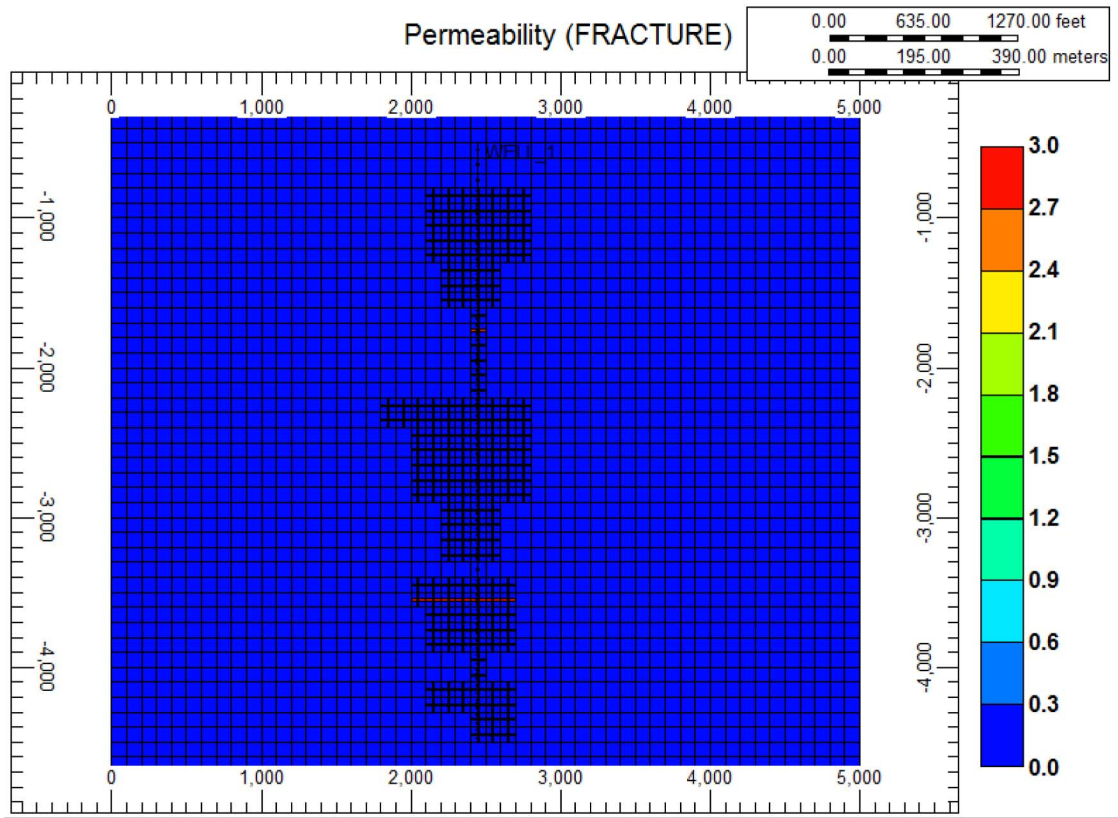

Figure 1—Simulator generated SRV. Color scale on the simulation study show the fracture permeability in mD before history matching. A smaller SRV is used than the actual microseismic as (Ejofodomi et al., 2011) used a variable permeability SRV and a smaller actual volume. We do not use enhanced permeability zones but a single smaller SRV and then reduce the permeability of the full SRV.

Figure 2 shows the gas rate, water rate and flowing bottomhole pressure (FBHP) ratio from the well. We observe that after extended shut-in the rate increases with a higher decline, the pressure is recharged but shows higher decline, and water to gas ratio (WTG) can be easily deduced to be declining. Figure 2 also shows two shut-in periods i.e. first shut-in after approximately a week of flowback and then an extended shut-in after approximately 120 days. The first shut-in is the "soak-in" period and the second shut-in is the extended shut-in. As the water rate did not increase significantly after extended shut-in, we can rule out a re-fracturing operation or adjacent well fracturing operation.

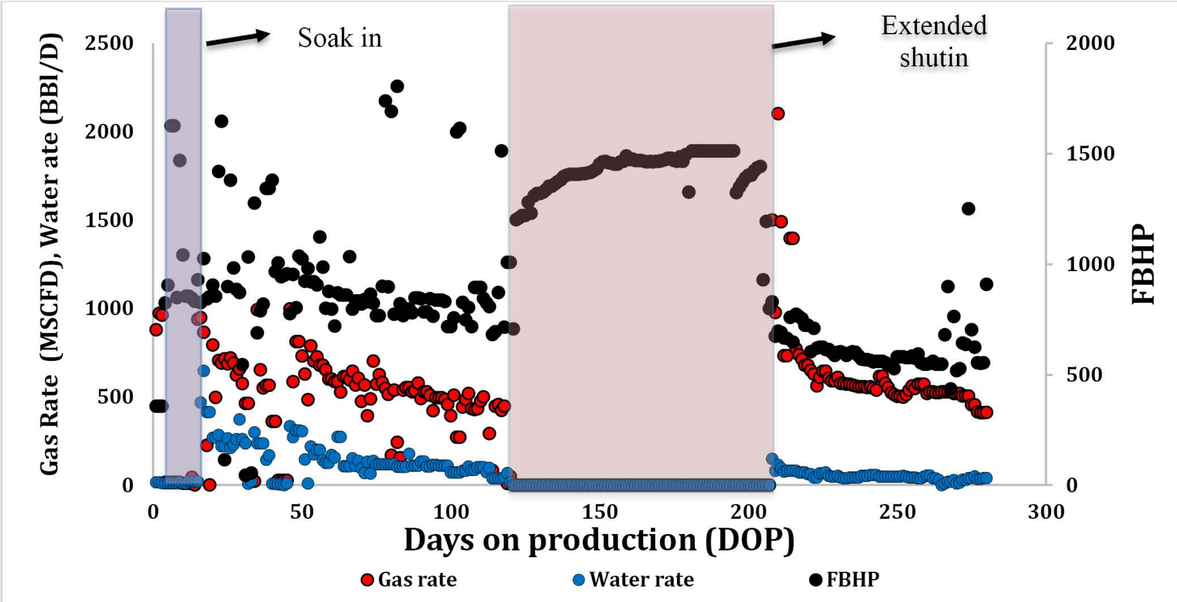

Figure 2—Gas rate, water rate and flowing bottomhole pressure (FBHP) along with two shut in periods. The first shut in is the initial "soak in" period shown in purple followed by the second shut in which is the extended shut-in which is shown in orange square box. Data is digitized from (Ejofodomi et al., 2011).

To show the well productivity trends including both rates and pressures, we plotted the well productivity index in Figure 3, obtaining a typical PI plot for a shale well. The productivity index is calculated as qg / (Pi – Pwf). Where, q_g is the gas rate, Pi is the initial reservoir pressure (calculated from post- frac pressure gradient) and P_{wf} is the flowing bottomhole pressure. We observe that the PI starts from a higher value and then stabilizes (constant PI) for a significant time. With enough production history, the PI declines further as the fractures start shutting down completely.

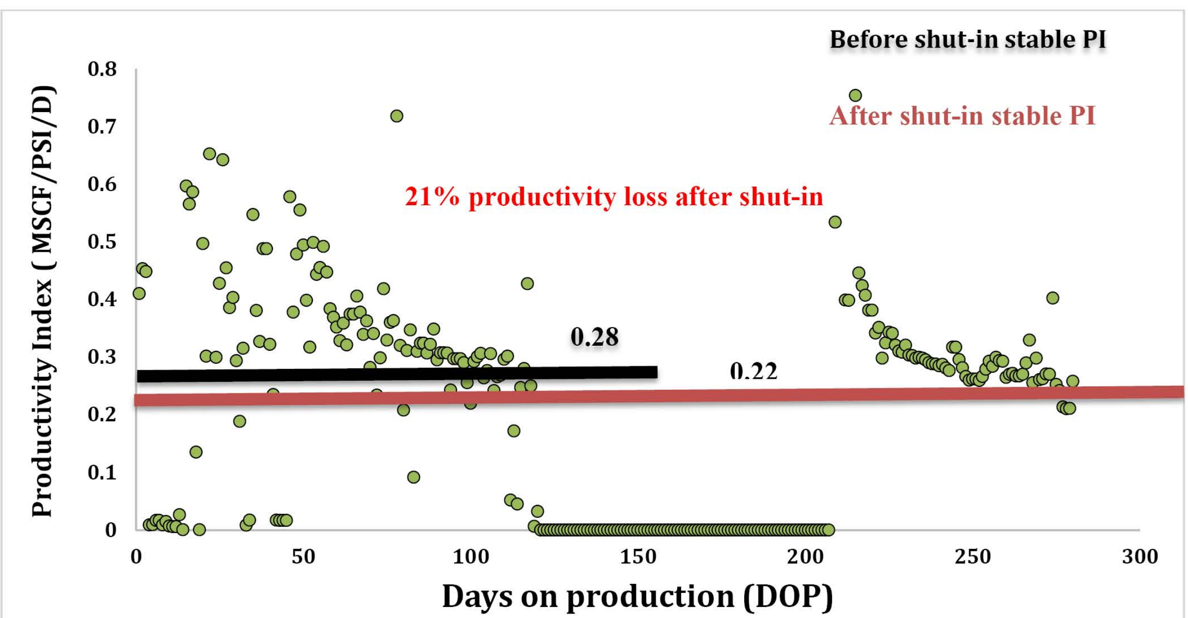

Figure 3—Stable PI for before and after the shut-in period. There is a significant reduction of 21% in well productivity after a shut-in of 90 days. After 120 days of production, this effect should be even greater in the "soak-in" period where the well is shut-in after fracturing

The stable PI explains a major portion of the production. In Figure 3, the two stable PI values before and after can be seen. Before shut-in value can be seen in the bold black curve and the post shut-in PI is seen in bold orange curve. It is evident from the PI plot that the stable PI is marginally decreased from ~ 0.28 MSCF/PSI/D to 0.22 MSCF/PSI/D. However, the percentage decrease in PI from the base value is 21% which is a significant reduction.

We divided our study in two parts:

a. First, we see the effect of an extended shut-in 3 months into well life by history matching the production with and without shut in. In this stable portion of the production, we tune our relative permeability curves to be used in the study by matching the water rates.
b. Then we interpolate the history matched model with the use of a neural-net based proxy model to see the effect of a "soak-in" period. This method is required as we have a week of flowback production and it is always better to interpolate rather than extrapolate the data.

We choose this methodology over statistically comparison from multiple wells as the reservoir simulation gives more insights into the physics of the problem and provides the "knobs" required to perform this kind of study.

Sensitivity Analysis and History Matching (HM)

Table 1 summarizes the model parameters used in our study. We use the microseismic generated SRV and then use different parameters sensitive to fluid rates. For this, we first run a sensitivity analysis. We have used a dual porosity model with natural fractures, matrix and hydraulic fractures in our study. We increased the water saturation in the matrix blocks and decreased the water saturation in natural fractures to simulate imbibition process.

Table 1—Reservoir parameters used to build the simulation model. The petrophysical properties are borrowed from Ejofodomi et al. (2011) study.

Parameter	Initial	HM
Porosity	0.1	0.12
Water Saturation (matrix)	0.2	0.32
Water Saturation (Fracture)	0.2	0.2
Matrix permeability	100 nD	60 nD
Complex fracture effective permeability	10 mD	1.2 mD
Zone Thickness	300	300

To see the effect of matrix water saturation on well productivity we run a separate sensitivity on our model by changing the matrix water saturation. The results are summarized in Figures 4, 5, 6 and 7. From Figure 4, we conclude that the proxy model generated from sensitivity analysis for productivity index (PI) can be used for prediction as most points lie near to 45-degree line indicating good QC for the proxy model. Figure 5. shows the tornado plot from sensitivity analysis, here we observe that the PI is affected strongly and negatively with increasing water saturation of both matrix and natural fractures.

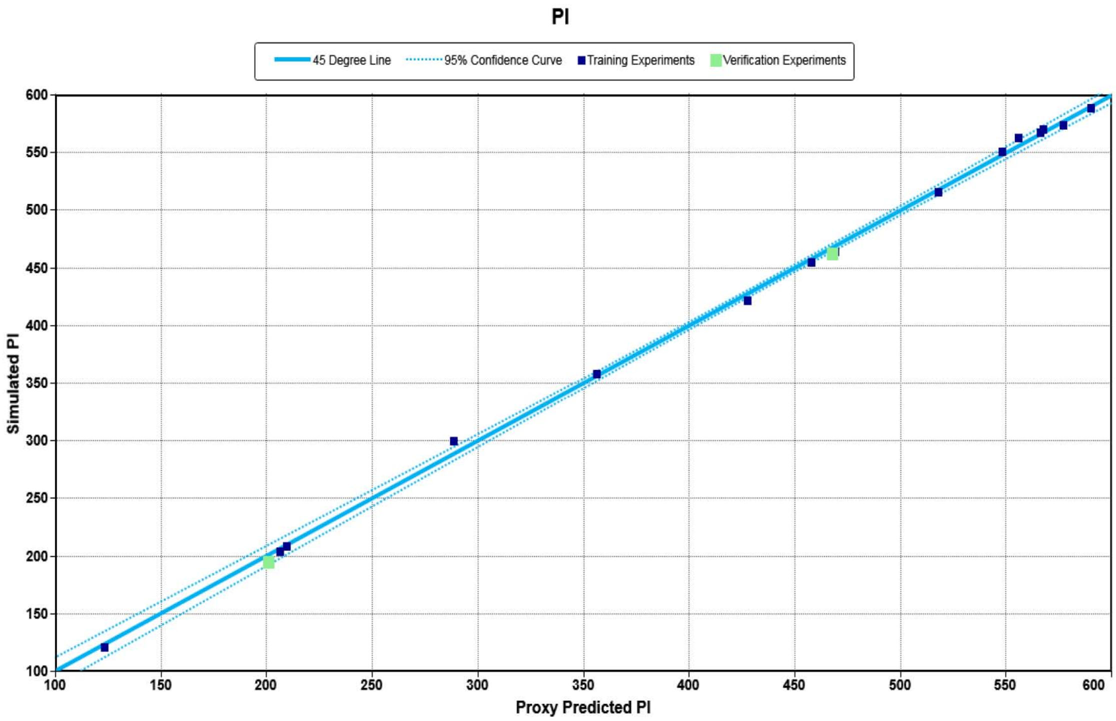

Figure 4—Prediction QC plot for proxy model

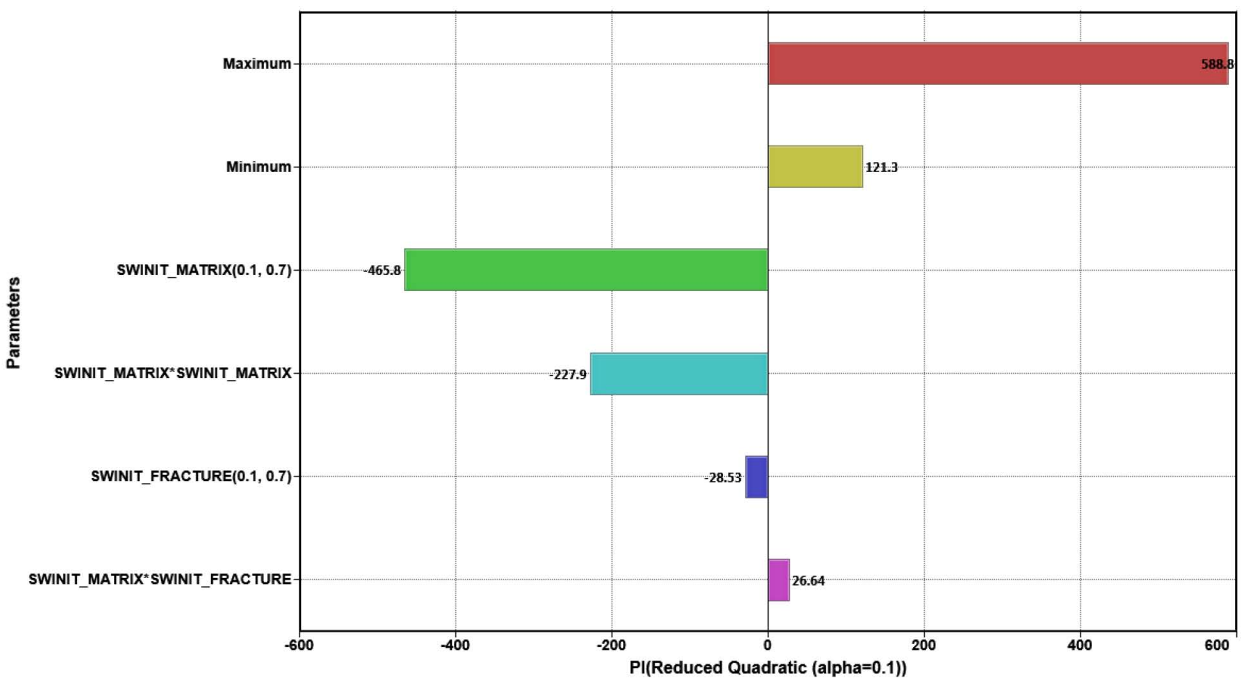

Figure 5—Tornado plot from sensitivity analysis

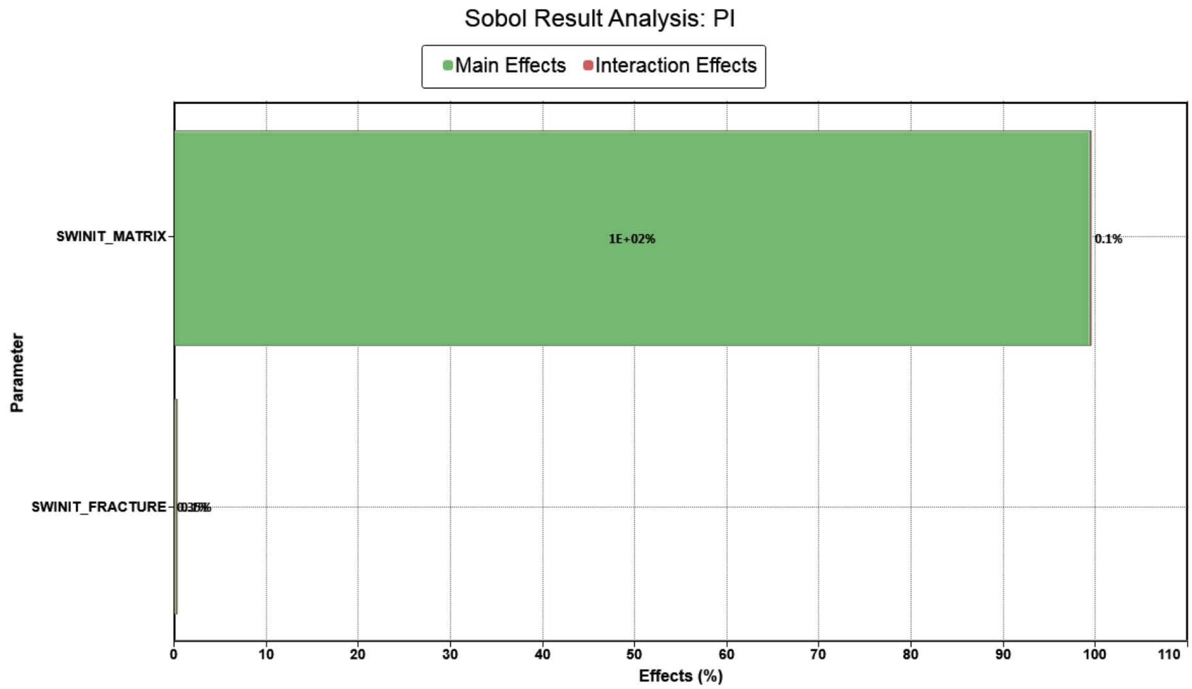

Figure 6—Sobol analysis

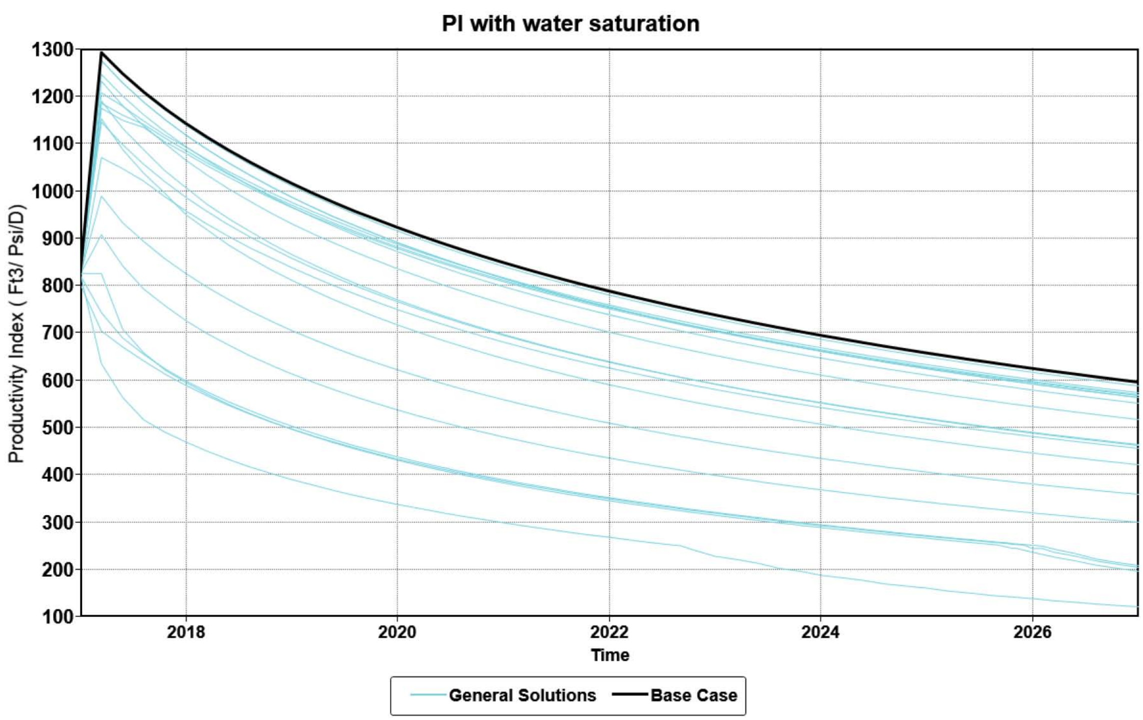

Figure 7—PI with time and varying water saturation. It is evident from the sensitivity analysis that increasing matrix water saturation affects the well productivity and hence EUR greatly and negatively.

Figure 6. Quantifies the effect of water saturation with the help of Sobol analysis and shows that the matrix water saturation effect on PI is 98%, while the fracture water saturation effect is 2% with little to no statistical interaction. This is due to low fracture porosity and hence less storage capacity. Hence, fracture permeability can be neglect for PI calculations. Finally, Figure 7. Shows the ultimate PI trends and it is evident that PI decreases as matrix water saturation increases.

Figure 8. Shows the combined history matching results from case a) soak-in, b) extended shut-in, and c) actual and simulated water rates. We created a proxy model from before shut-in case and ran a "what-if" analysis with respect to water saturation. Table 2 shows the results from the analysis and corresponding gas EUR's for the cases. All the EUR's in our case is based on a 10 year well life.

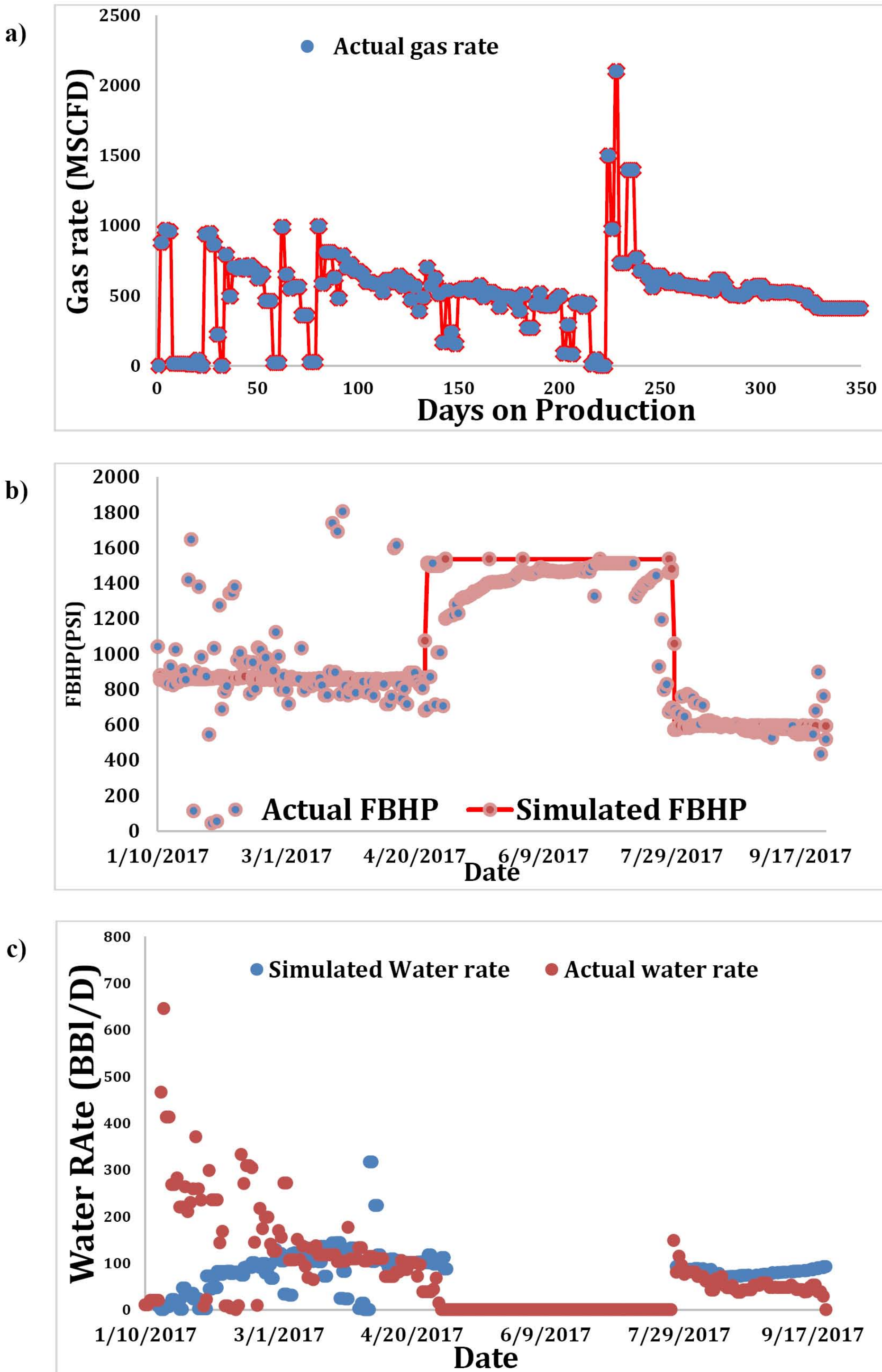

Figure 8—a) Actual and simulated gas rates, b) Actual and simulated FBHP, c) Actual and simulated water rates

Table 2—EUR sensitivity with initial water saturation with the help of a neural net-based proxy model for "soak-in" period. As the water saturation in matrix increases, the loss in productivity is also increased. The reported losses are based on the extended flow period based HM model, which is interpolated between flowback and "soak-in" period.

Matrix water saturation	Gas EUR	% EUR reduction
0.32	1.8	HM case (extended flow period)
0.335	1.56	13.33% (extended shut in case)
0.35	1.50	17%
0.40	0.98	46%
0.45	0.86	52%
0.50	0.65	64%

Results and Conclusions

In Table 2, the case for extended shut in is shown. To generate this case, we first produce the well with a constant rate to produce equivalent cumulative volumes before shut-in. Then, history match the production after shut-in by changing the water saturation to match the gas rates and declines as well as pressures.

This result along with extended shut in is plotted to show the full well history in a single plot. But, for forecasting, two different stems are used and reported as HM extended flow and HM extended shut in.

Our study shows that with an increment in water saturation in the matrix blocks due to shut-in, causes permeability reduction, and hence reduction in well productivity. The duration of shut-in and the time of the well life in which shut-in occurs plays an important role. The initial flowback is critical to unload the water. Shut in later in well life have lesser impact than initial shut-in.

The wells can suffer a productivity loss from 17% to 64% depending on the water imbibed in the reservoir and the corresponding increase in water saturation in the matrix blocks for "soak-in" case. For extended shut-in case, the EUR loss in our case is 13.33%, but we expect it to decrease if the shut-in happens later in well life.

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Nomenclature

FBHP – Flowing bottomhole pressure
PI – Productivity Index
Soak-in – Initial shut-in after flowback
Extended shut-in – Long shut-in due to well operation

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