Modeling of Horizontal Wells in Unconventional Reservoirs

The use of horizontal wells and hydraulic fracture completion practices has become the norm today, particularly in unconventional reservoirs. These wells and their completions present unique challenges to engineers' efforts to optimize and forecast well performance. Where to drill wells is generally not the issue. The primary decisions are orientation of the lateral(s), length of the lateral(s), vertical placement of the lateral(s) in the formation, number and size of the hydraulic fracture treatments, and well spacing.

All of these decisions revolve around the stimulated rock volume (**SRV**) created by the hydraulic fracture treatment. Proper understanding of the SRV creation and its interaction with the reservoir matrix and natural fracture systems is paramount. The geometry, extent and complexity of fractures within the SRV impact the fracture surface area available for interaction with the matrix.

The examples in this document show how proper characterization of the SRV can impact the predicted EUR for a well and how the SRV is impacted by the number and size of the frac stages, the well orientation and spacing.

Reservoir simulation, if properly employed, is the best tool available for addressing these issues. NITEC has developed unique technologies to address the evaluation of hydraulically fractured horizontal wells. These technologies utilize assisted history matching (NITEC's MatchingPro®), and a dual porosity reservoir simulator (Coats Engineering's SENSOR®) with special geomechanical modifications to the simulator. (These simulator modifications are currently only available in SENSOR.)

Many of these operational decisions (well orientation, well spacing, well length, fracture treatment size and number of stages) cannot be properly addressed with statistical methods or "conventional" modeling approaches. NITEC's modeling approach provides knowledge about the reservoir behavior of the hydraulic fracturing process and the reservoir's natural fracture/matrix system for the well(s) being studied. Unlike the conventional approach this information can then be used to investigate operational decisions for future wells planned in the same reservoir.

NITEC Modeling Approach

NITEC's technology dynamically integrates the stage by stage fracture treatment, the flowback period and the post-frac performance in the model calibration process. Fixed, preconceived assumptions about the SRV are not required. NITEC's proprietary technology develops the SRV for each stage (Figure 1) and the calibration process adjusts SRV, reservoir matrix and natural fracture properties to match the three flow periods – hydraulic fracture treatment, flowback and post-frac production.

The SENSOR finite difference simulator has been modified to take into account tensile and shear failure

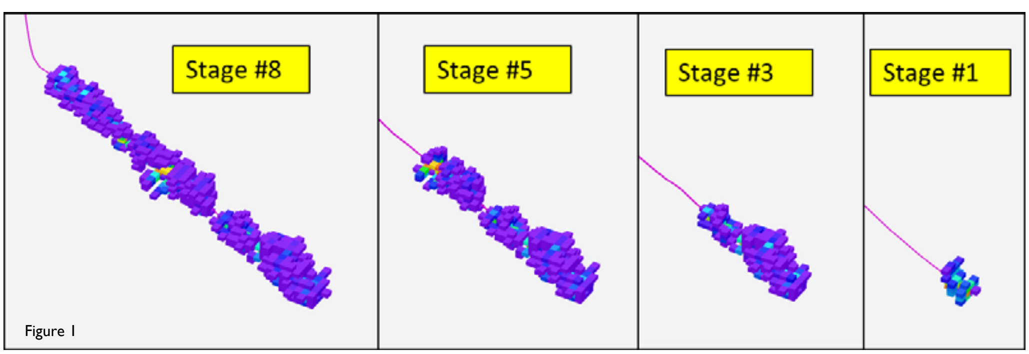


Figure 1

Provider of ***LYNX®*, *MatchingPro®*, *PlanningPro®*, and *ForecastingPro®*,** Software caused by increasing pore pressure sufficient to overcome the minimum stress. The user specifies effective stress thresholds in the model that, when overcome, generate shear and tensile failure in the model. Anisotropy is represented by the ability to specify in which direction the greatest transmissibility gains are generated consistent with the current principle stress orientation. The combination of these two mechanisms of shear and tensile failure generate the SRV as it is created in each frac stage.

Conventional Modeling Approach

The conventional approach to developing a predictive tool for hydraulically fractured horizontal wells using reservoir simulation has been to define certain information about the reservoir and the SRV (Figure 2) and then calibrate the model to the **post-frac** production/pressure performance. The fixed shape of the SRV may be based on service company data and/or microseismic test results. While a calibrated simulation model may result in a reasonable prediction of future performance of this modeled well, it is only unique for that well and cannot be reliably used neither to assess other areas of the reservoir nor other hydraulic fracture treatments, etc.

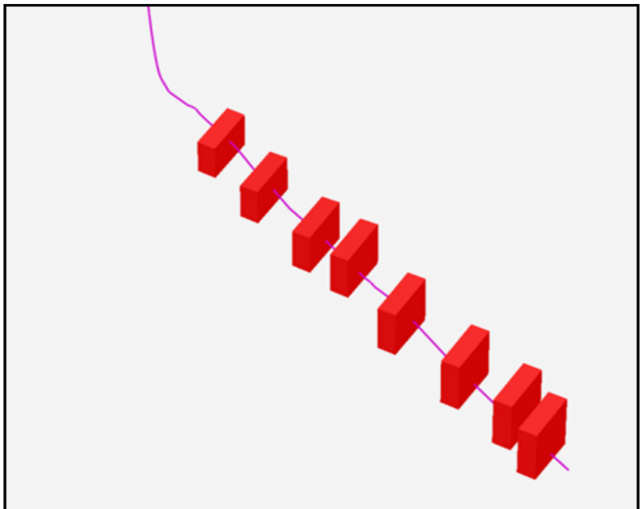


Figure 2

This conventional approach ignores some key data from the well(s) – the hydraulic fracture treatment (stage volumes and pressures) and the associated fluids produced during the flowback period. Hence, the impact of fracture treatment fluid in the reservoir on post-frac production is not accounted for. It is a solution unique to this well only and cannot be reliably used to assess other areas of the reservoir and the effectiveness of alternative fracture treatments.

Bakken Example

The following example is from a well in the Bakken formation. It compares the conventional modeling approach for developing a "representative" simulation model to NITEC's integrated modeling approach.

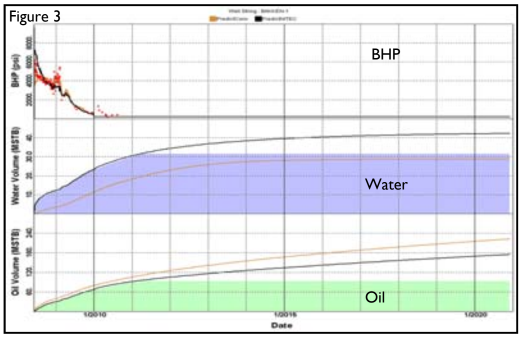
The problem:

- A horizontal well with 1.5 years of post-frac oil, water and gas production performance
- A cased and perforated 7500' lateral
- An 8 stage hydraulic fracture treatment
- A 40' thick productive formation

Comparison of Predicted Performance

The impact of the SRV calibration on predicted well performance will be discussed first, as the differences in the predicted performance are key to assessing the viability of the two modeling approaches. A separate white paper titled *"History Matching Hydraulically Fractured Horizontal Wells*" describes the calibration process and differences in the two final calibrated (history matched) models. Suffice it to say that good history match solutions were achieved for each modeling approach subject to the limitations associated with each model.

The two calibrated simulation models were set up to predict the future performance of the well starting January 1, 2010. Approximately one year of historical performance data was available for the well beyond this date. The well in each model was produced at a constant 215 psia bottom hole flowing pressure for the duration of the prediction run. The simulation was made for a ten year period. As the oil production rates at the end of the ten year period were approximately 20 STB/D in both models, this can be assumed to be an approximation of the EUR for the well.



NITEC: Black

Conventional: Brown

History: Solids

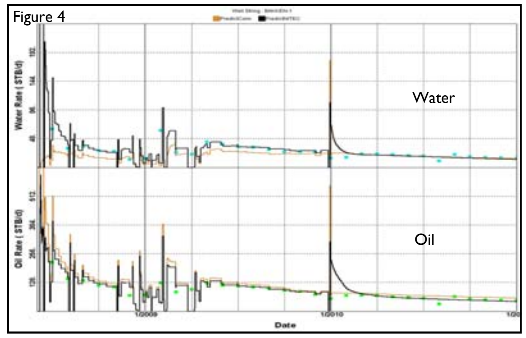
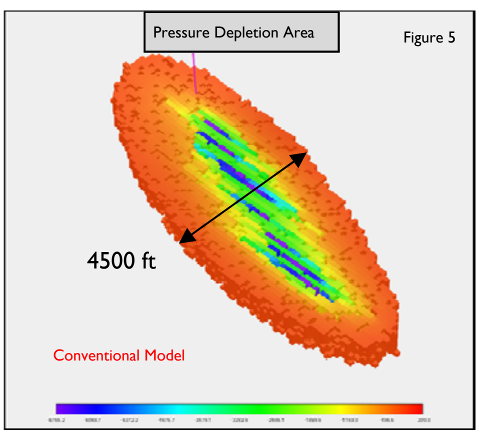


Figure 3 shows the cumulative water and oil production for the historical period and at the end of the 10 year prediction. The cumulative oil production for the prediction was

- Conventional approach 221.9 MSTB
- NITEC Approach 174.6 MSTB

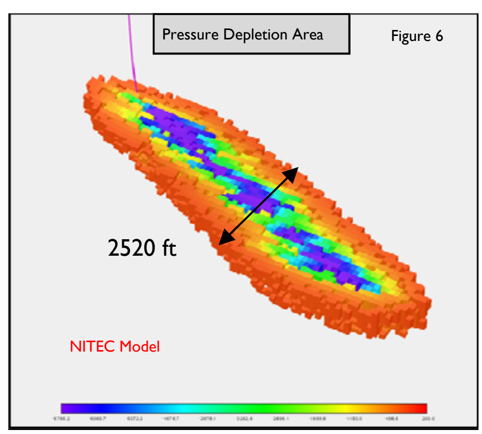
The conventional model approach appears to provide an overly optimistic forecast of the oil recovery. When the accuracy of the oil production match during the historical period is taken into account, the conventional approach cumulative oil production at 10 years should be adjusted to 206.9 MSTB. (*The conventional model overproduced oil during the history match period by 15 MMSTB.*) This results in a difference between the models of 32.3 MSTB; 18.5 percent more oil compared to the NITEC model approach.

The production profiles (Figure 4) for the two model predictions (historical period and the first 2 years of prediction) show that the conventional approach produces at a higher oil production rate after the first few months. This is due to the different fracture characterization that results from accounting for the frac treatment, flowback and post-frac production in the NITEC calibration process versus modeling only the post-frac production period in the conventional approach.



The pressure change in the fractures at the end of the 10 year prediction period for the two models are shown in Figures 5 and 6. The cells shown in these figures represent areas of the model where the pressure has changed by greater than 200 psia in the fractures from initial conditions at the time shown. (Red areas are at near-initial pressure. Blue areas have experienced significant pressure reduction.) All other cells in the model are not shown.

Figure 5 for the conventional model approach shows that depletion in the fractures is occurring near the wellbore. The matrix (not shown) is similar. However, the areal extent of the depletion in the fractures (and the matrix) is relatively large.



Similar review of the pressure in the fractures (Figure 6) for the NITEC model approach indicates that depletion in the fractures near the wellbore is more extensive. However, the maximum areal extent of the depletion is much less in the NITEC model approach (~ 2520 ft) than the conventional model (~4500 ft). These differences impact the oil production response during the prediction period for each model.

It is fair to conclude that these different depletion areas at the same time in the prediction will have an impact on the ultimate oil recovery for a given well spacing. Accordingly, the smaller depletion area in the NITEC model suggests that closer spacing may be required to deplete the reservoir in a given time period.

Sensitivity Studies

One of the strengths of the NITEC modeling approach is the ability to conduct sensitivity studies on the impact of operational parameter changes (well length, orientation, number of fracture stages, volumes in each stage, etc.) on the predicted performance as an aid in optimizing and planning alternative development scenarios. **This type of analysis cannot be reliably performed with the conventional modeling approach**, as the predefined SRV and the associated fracture and matrix parameters are based on a specific fracture treatment, for a specific well configuration, and the reservoir properties at that location.

Increased Frac Volume: The impact of higher frac volumes (gals/ft) per stage was investigated. A case with twice the fluid volume (twice the injection rate) during each of the fracture stages and a case with four times the volume were simulated.

The higher volumes during each frac stage result in a larger and more intensely fractured SRV in each prediction which results in higher production rates early in the post-frac life of the well. This is quantified in the TEX parameter which represents the intensity of the fractures determined by the surface area created in the matrix due to fracturing. Figure 7 is the SRV for the 2 times base volume case. Figure 8 is the base case.

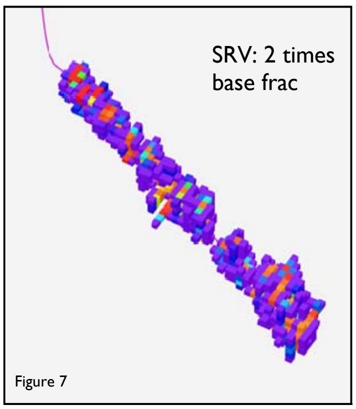


Figure 7

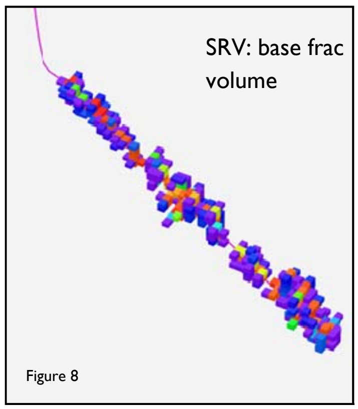


Figure 8

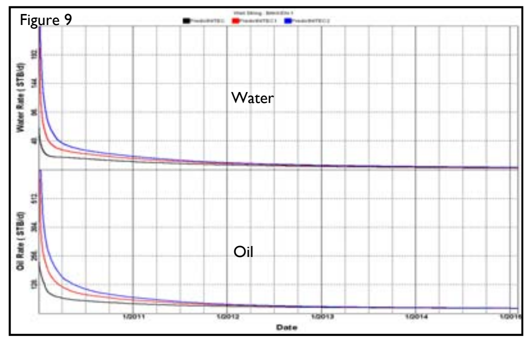


Figure 9

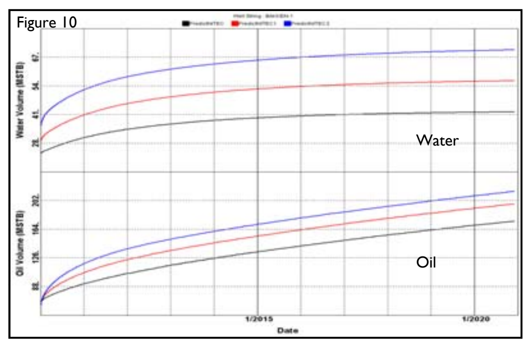


Figure 10

The production rate plot (Figure 9) for the first five years for each of the higher frac volume cases shows the rates are significantly higher in the first 2-3 years. Economic analysis will determine whether the cost of the larger fracture treatment is warranted by the increased rate and higher ultimate recovery (Figure 10).

Decrease Number of Stages: The impact of decreasing the number of fracture treatment stages was investigated. The original 8 stage fracture treatment was decreased to 6 stages and 4 stages in two separate simulation runs. The total volume of fracture fluid was the same (larger volume per stage relative to original case) in all cases. A comparison of the cumulative production performance is shown in Figure 11.

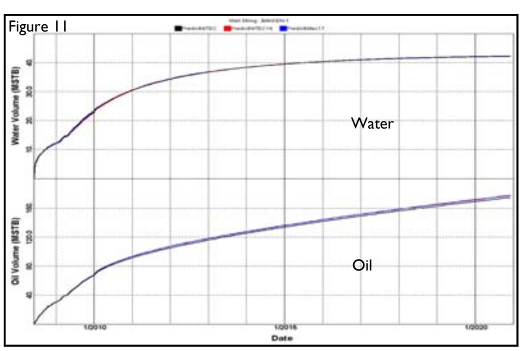
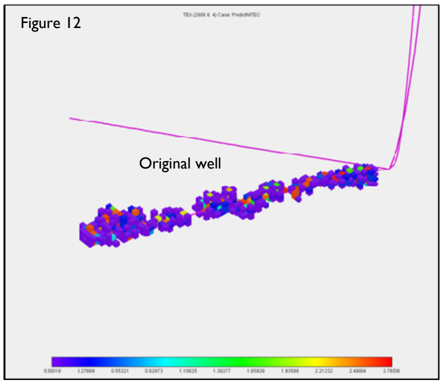


Figure 11

It is clear that the number of frac stages has no impact on the cumulative production if the total volume in the combined stages is the same. This is as we would expect.

Well Orientation: The well orientation was changed to test the impact on production performance. The original well and the modified well orientations are shown in Figures 12 and 13. Figure 12 shows the fracture intensity parameter (TEX) for the original well orientation and the modified case (Figure 13) after the hydraulic frac treatment. The reservoir properties in the area simulated were not changed.

The character of the SRV is not significantly different in the two well orientations, although the EURs are quite different between the two wells.



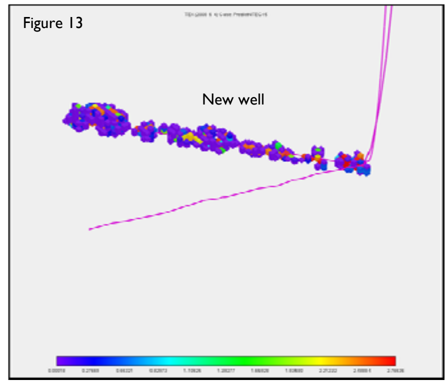
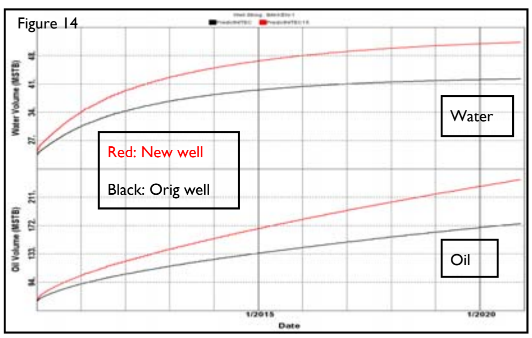
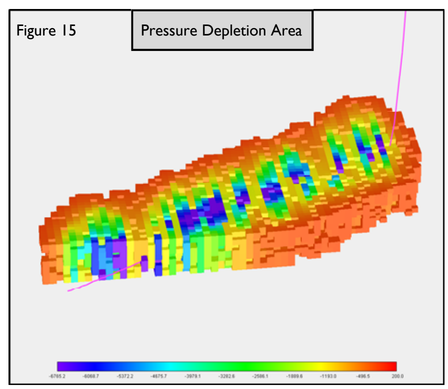


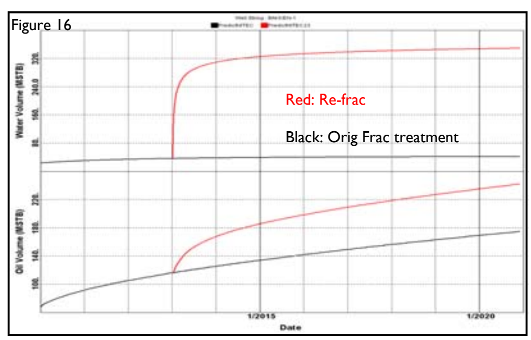
Figure 14 compares the prediction performance of the two well orientations. The SRV in the new orientation appears to benefit the performance of the well. This is likely because the new orientation is closer to being perpendicular to the principle stress direction than the original orientation; hence better communication is established with the natural fracture system.

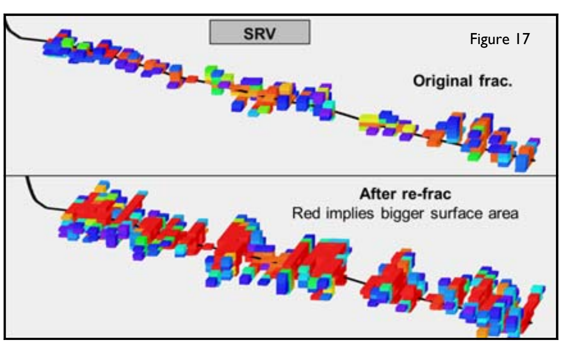
The delta pressure from initial conditions in the fractures to the end of the 10 year prediction is shown in Figures 15. (Red areas are at near-initial pressure. Blue areas have experienced significant pressure reduction.) This can be compared to the pressure depletion in the fractures for the original well orientation shown in Figure 6.





Re-fracture Treatment: The model was used to investigate the impact of re-fracturing the well approximately three years after the initial completion. A single stage frac treatment using **20** times the original frac volumes was simulated. An excessive volume was used to emphasize the possible impact on well performance.





The SRV is shown in Figure 17. The incremental cumulative oil production over the base case (Figure 16) is significant. The cumulative water production is also significantly increased as the second frac treatment fluid volumes are produced, essentially during the first year after the refrac treatment. Actual re-frac data should be used to calibrate the model.

Perforated Interval: The impact of the number of perforation on the SRV and the predicted performance was investigated. The density of the perforations over the entire wellbore was reduced by 50 percent. The resulting SRV (Figure 19) is somewhat smaller relative to the original fracture treatment (Figure 18). The predicted performance (Figure 20) is also significantly impacted with the oil production being lower for the lower density perforation case.

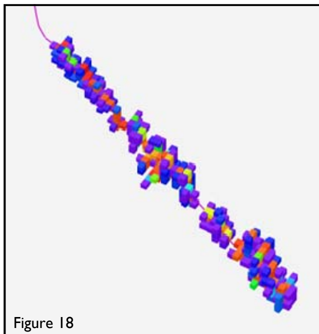


Figure 18

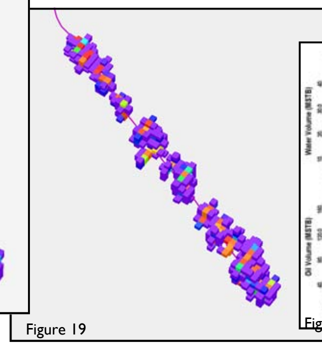


Figure 19

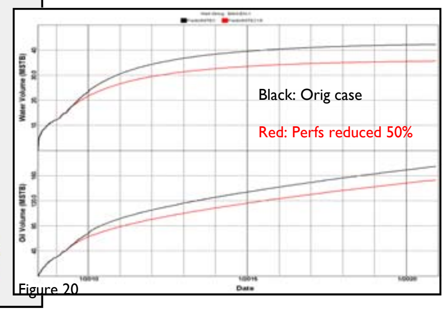


Figure 20

Spacing: The impact of a specific fracture treatment on well spacing was investigated. Well 1 was hydraulically fractured and produced for 34 months. The area of pressure depletion for Well 1 is shown in Figure 21. Well 2 was drilled and completed approximately 1200 ft from Well 1. Well 2 was hydraulically fractured with the same number of stages as Well 1. The SRV for Well 2 and the area of pressure depletion for Well 1 are shown in Figure 22. Both wells were then produced for 2 years. Figure 23 shows that the pressure sinks for the two wells are interfering at the end of the prediction period. These results are informative for a fracture treatment and well performance in an undisturbed area of the reservoir and in an area that has had some pressure depletion.

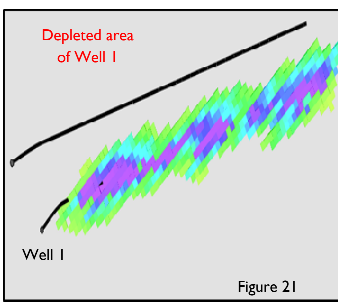


Figure 21

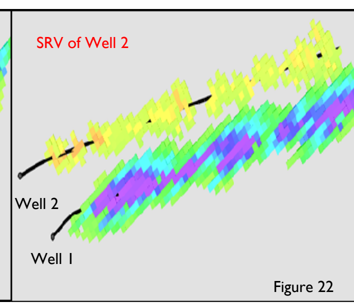


Figure 22

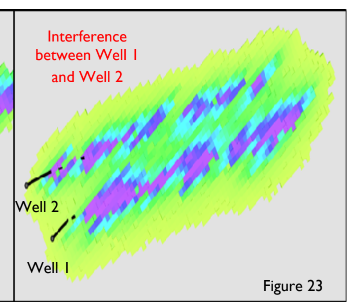


Figure 23

Summary

- **A poorly calibrated SRV in the predictive simulation model can significantly impact production forecasts.**
- **The NITEC modeling approach precludes predefining SRV parameters in the simulation model which prevents bias in the prediction results.**
- **Utilization of frac treatment, flowback and post-frac production in the model calibration process allows the simulation model to be easily used to investigate production sensitivities to frac treatment parameters, well configurations, orientation and spacing.**
- **The knowledge gained in the calibration process can be applied to other areas of the reservoir and future wells.**

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