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Title: Application and use of near-wellbore mechanical rock property information to model stimulation and completion operations

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Abstract

Numerical models of hydraulic fracture emplacement are calibrated using pumping data to understand the influence of near-wellbore, mechanical rock property variations on the stimulation and completion operations of a Middle Woodford, Arkoma Basin, well. Here, Poisson's ratio information is used to group the reservoir into stages and to minimize differences in minimum horizontal stress between entry points within a stage.

Pumping data confirms that hydraulic fracture initiation in stages with lower Young's Modulus values (YME) and higher Poisson's ratio (PR) require higher pressures. This suggests that the near-wellbore mechanical rock properties played an important contribution to reservoir-to-well connectivity in these formation intervals.

Processing and Analysis of Drilling Induced Vibrations

Mechanical rock properties information used to populate the reservoir model were obtained from the processing and analysis of bit vibrations while drilling. These vibrations are generated in reaction to the deformation and failure of the rock formation. Because they typically have higher frequency and are of lower amplitudes than torsional and lateral resonances, they are best viewed proximal to the bit.

Tri-axial measurements of near-bit, drilling induced vibrations are acquired at 1kHz and 12-bit resolution using a digital data logger (DDL); a memory tool that can record continuously for four days. A short, 12" bit sub is used to place the DDL directly behind the bit. Staggered deployments involving multiple DDL's can be used to accommodate longer drilling intervals.

Continuous, high-frequency (1kHz) measurements of drilling induced vibrations are processed using standard geophysical signal processing techniques to obtain the motion of the bit and forces acting on the bit. The acceleration data are processed in the frequency domain using half-second windows to obtain band-limited estimates of the displacement spectra and the acceleration spectra. This time-window may correspond to one to two turns of the bit, where the bit is understood to have advanced tenths of an inch over that period. This allows mechanical rock properties to be determined at unprecedented resolution.

The processing bandwidth is usually between 150-500 Hz. This frequency range is typically above the lower-frequency, higher-amplitude torsional and lateral resonances. The displacement of the bit is usually on the order of micrometers and the forces are typically several gravities or g's. The forces and notions are converted to stress and strain by observing the vibrations generated when cutting a formation with known mechanical properties, such as cement, to scale the data.

Measured depth is obtained by attaching the 1Hz surface drilling data to the processed acceleration data to identify periods of drilling versus non-drilling time. Data corresponding to non-drilling time are removed.

These data are processed using elastic stress-strain relationships to solve for the stiffness coefficients. For purposes of the modeling performed here, isotropic stress-strain relationships were used to invert for the stiffness coefficients (Cij's). According to the method, the axial and lateral measurements are treated as principle stresses and principle strains. The Cij's can be re-arranged into convenient and well-known forms to represent YME and Poisson's Ratio.

Application of Elastic Moduli to Improve Completion Efficiency

Under the conditions of hydraulic fracturing, rock failure can occur in tension, or shear along pre-existing planes of weakness. In either case the tensile strength of rock matrix is negligible compared to σ_{min}. (Baree, 1998)

For completion designs with multiple points of entry per stimulation treatment, the heterogeneity of initiation pressures between clusters, and interactions between the hydraulic fractures, results in unstimulated entry points, where small variations in the elastic moduli can be the determining factor in how many entry points are effectively stimulated. (Manchanda, R. Et al. 2016) This paper focuses on minimizing the difference in the minimum horizontal stress between entry points to be treated simultaneously in an attempt to increase the number of clusters that receive effective stimulation.

The minimum horizontal stress can be calculated from elastic moduli via the following equation from Warpinkski, N.R. et al. (1998):

$$\sigma_{min} = \frac{\nu}{1-\nu}(\sigma_{ob} - \alpha P) + \alpha + \sigma_t \quad (1)$$

Where σ_{min} is the minimum horizontal stress (psi), ν is Poisson's ratio, σ_{ob} is overburden stress (psi), α is a Poroelastic coefficient related to Biot's constant, P is the pore pressure of the reservoir fluid (psi), and σ_t is the tectonic stress.

Drill bit acceleration data collected and processed in the manner described above allows for a high-resolution description of Poisson's ratio, but does not give any information about the variation of overburden, pore pressure, or tectonic stress over the length of the wellbore. Therefore, some simplifying assumptions about overburden, the poroelastic coefficient, reservoir pressure, and tectonic stress are needed.

It is assumed that overburden stress is a constant gradient with respect to depth for a given wellbore. The value of the gradient can be approximated by integrating the density log from a nearby offset vertical well. This allows the overburden stress to be expressed as follows.

$$\sigma_{ob} = \sigma_{obg} \cdot TVD \qquad (2)$$

Where σ_{ovg} is the overburden gradient (psi/ft) and *TVD* is the true vertical depth (ft).

The poroelastic coefficient is often a function of the bulk modulus, or correlated to density. (Nur, A. and Byerlee, J.D. 1971) Because horizontal wells in resources plays are planned to stay in the same target formation for the length of the lateral, and stage length in contemporary wells is often on the scale of 150-300 feet, it is assumed that any variance of the poroelastic coefficient is negligible in determining the variance of the minimum horizontal stress for a stage. Therefore, it is assumed that the poroelastic coefficient is constant along the wellbore.

For a single horizontal well optimization, the conventional assumption that pore pressure is a constant gradient with respect to depth is assumed to be sufficient. The value of the gradient can be approximated by analyzing a nearby Injection/Falloff Test. This allows the pore pressure to be expressed as follows.

$$P = P_{pg} * TVD \qquad (3)$$

As tectonic stress is difficult to measure accurately, it's importance must be assessed. As stage lengths typically only vary from 150' to 350', it is assumed that tectonic stresses do not vary within these relatively short lengths. Ultimately, the goal of the exercise is to minimize the difference of σ_{min} between entry points, and not to quantify σ_{min}, assuming $\sigma_t = 0$ will not affect the analysis.

Applying these assumptions equation 1 simplifies to:

$$\sigma_{min} \cong \frac{\nu}{1-\nu}\left(\sigma_{obg} \cdot TVD - \alpha \cdot P_{pg} \cdot TVD\right) + \alpha \cdot P_{pg} \cdot TVD \qquad (4)$$

By relying on offset logs and, when available, Diagnostic Fracture Injection Tests (DFIT) to fix the values of the overburden gradient, Biot's constant, pore pressure gradient, and using the measured Poisson's ratio as well as directional surveys, an approximation of minimum horizontal stress can be calculated along the well bore. The results of these calculations can be plotted as a log track along other measurements to aid engineers and geologists in understanding and optimizing the well.

By establishing cut off criteria for magnitude and duration of deviation of stress from a rolling average value, one can categorize the gross changes to stage completion treatments within similarly stressed rock. This strategy can be advantageous when perforation clusters are closely spaced, and the accuracy of placing perforation clusters is low. By using a stress criteria to pick each individual perforation cluster within a stage it is possible to minimize the stress differences between perforation clusters, and greatly improve perforation efficiency. These methods have been used previously, using sonic tools or correlations to other logging measurements to estimate elastic moduli.

Modeling Perforation Efficiency

As changes in elastic properties can be the dominant factor in how many entry points receive stimulation, (Manchanda, R. Et al. 2016) including the lateral variation of elastic properties in a fracturing simulation model should aid in estimating entry point efficiency. A method for estimating entry point efficiency is outlined below. Using vertical off set logs, or a type log, an initial earth model, representing the formations surrounding the study well, is created on a series. The wellbore survey data for the study well is plotted onto the earth model. The geosteering interpretation is used to shift the columns of the earth model grid to ensure that the modeled well bore is in the appropriate layer of the model in each cell of the grid. The elastic property data derived from drill bit accelerations is then incorporated into the earth model along the path of the wellbore. By incorporating the lateral variance of the elastic properties, it is possible to model the variance in initiation pressure more accurately for each cluster in a single treatment. Modeling the lateral variance of elastic properties also allows the model to predict the near wellbore effects of stress shadowing more accurately.

Once the model is built, and calibrated to pumping data, multiple perforation scenarios can be run. Any output that can be measured per initiation point can be used to establish a 'cut off' threshold to categorize any initiation point as effectively treated or not effectively treated.

Case Study

A well drilled in the Woodford formation in the Arkoma basin gathered full waveform bit acceleration data while drilling. Using the methodology described above, the waveforms were processed to generate elastic properties curves. The Poisson's ratio curve was combined with wellbore survey data, offset logs, and a nearby injection-falloff test to create a curve approximating σ_{min}. An analysis of the planned perforation strategy led to a grouping criteria of grouping stresses by looking for changes in stress that were greater than 200 psi and persisted for 40 feet or longer. By applying these criteria to the well data, 28 distinct stress zones were identified. Integrating this information with the gamma ray track generated from MWD tools, and an interpretation of the geosteering allowed the authors to plan 20 hydraulic fracture stimulation stages with each stage's perforations targeting similar rock.

Each of these stages was planned with 4 perforation clusters. To estimate perf efficiency, the authors used offset logs to create a simple earth model (Figure 1), incorporated geologic structure and geosteering data into the model (Figure 2), and integrated the lateral measurement of elastic properties into the model (Figures 3 and 4). Multiple perforation configurations were simulated and evaluated. 'Cut off' values were chosen for pounds of sand and baseline conductivity; these cut offs were used to categorize perforation clusters as either effectively treated, or not effectively treated. Modeled cluster treatment efficiency varied from 54% to 73%. While no further diagnostics were run to confirm the accuracy of the model, this well presented an interesting verification of the relative values of the elastic moduli.

Two hydraulic fracture treatment stages were placed in rock with a large difference in elastic moduli between the stages (Figure 5). Stage A was placed in rock with a higher Poisson's ratio and lower Young's modulus than the average stage in this well. Stage B was placed in rock with a lower Poisson's ratio and higher Young's modulus than the average stage in this well. From the model, it was expected that stage A would not generate as much width as stage B, and that stage A would treat at a higher pressure than stage

B. The pumping data from these stages is in line with the expectations from the model; stage A treated at a higher pressure than stage B (Figure 6).   The character of these pressure plots, as analyzed via the model's simulation and Nolte-Smith plots, suggests that the relative width prediction is also accurate.

Conclusions

When near-wellbore variations in mechanical rock properties are used to create high-resolution, laterally variable reservoir models, a better understanding of the pumping program in relation to the various formation intervals becomes possible, and perhaps predictable. This approach provides conceivably new bearings for stage lengths and number and locations of perforations in the context of near-wellbore reservoir characterization for stimulation and completion operations.

The significant advancement provided by this approach are a much lower acquisition cost and higher resolution of data.   The lower acquisition costs allow elastic moduli data to be gathered on a greater number of wells. The higher resolution data allows for interesting applications in fracture modeling.

Gathering high resolution drillbit acceleration data provides a low-cost method to acquire elastic property data along wellbores. With knowledge of the variance of elastic properties along a wellbore, geologists and engineers can better group completion stages and perforations in similar rock. By grouping stages and perforations in similarly stressed rock, more perforations should receive effective stimulation. Integrating elastic properties into a 3D fracture propagation model improves accuracy of modeling fracture initiation the near wellbore effects of stress shadowing.

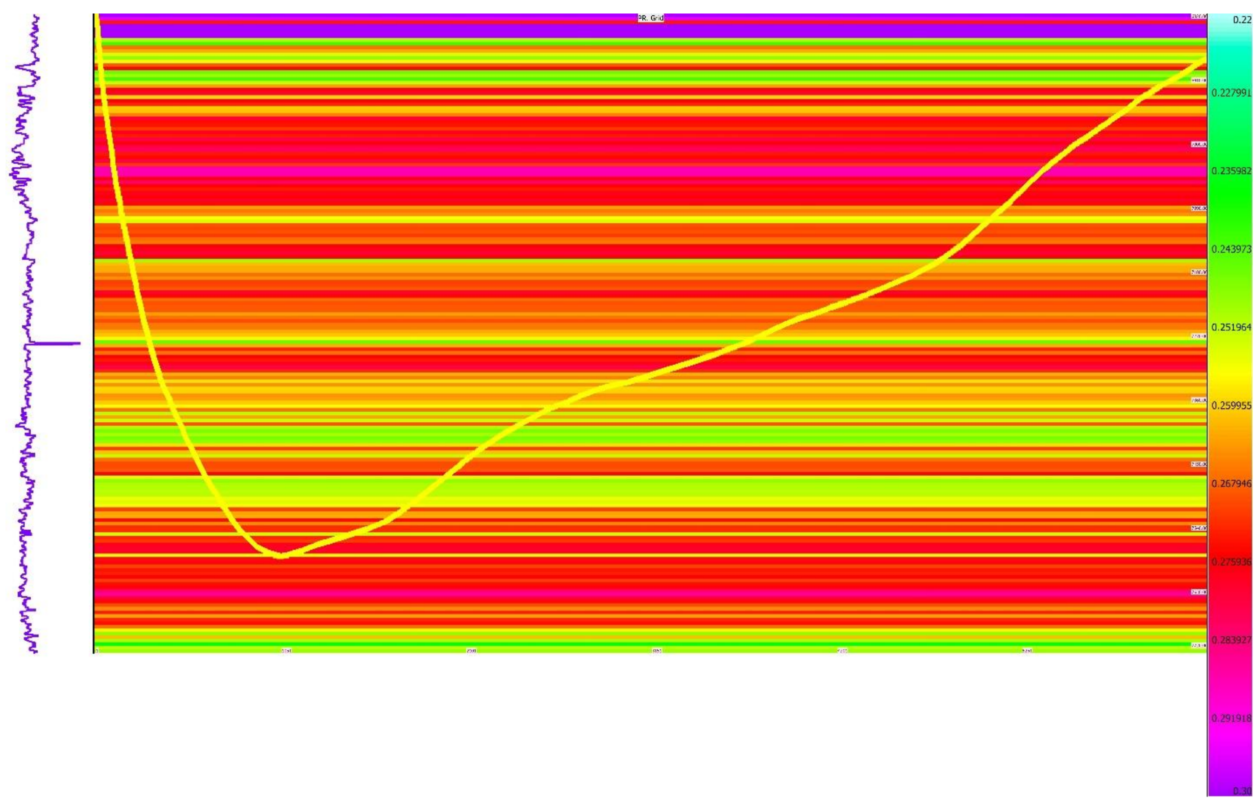

Figure 1: 2D projection of stress in 3D model created from offset vertical logs

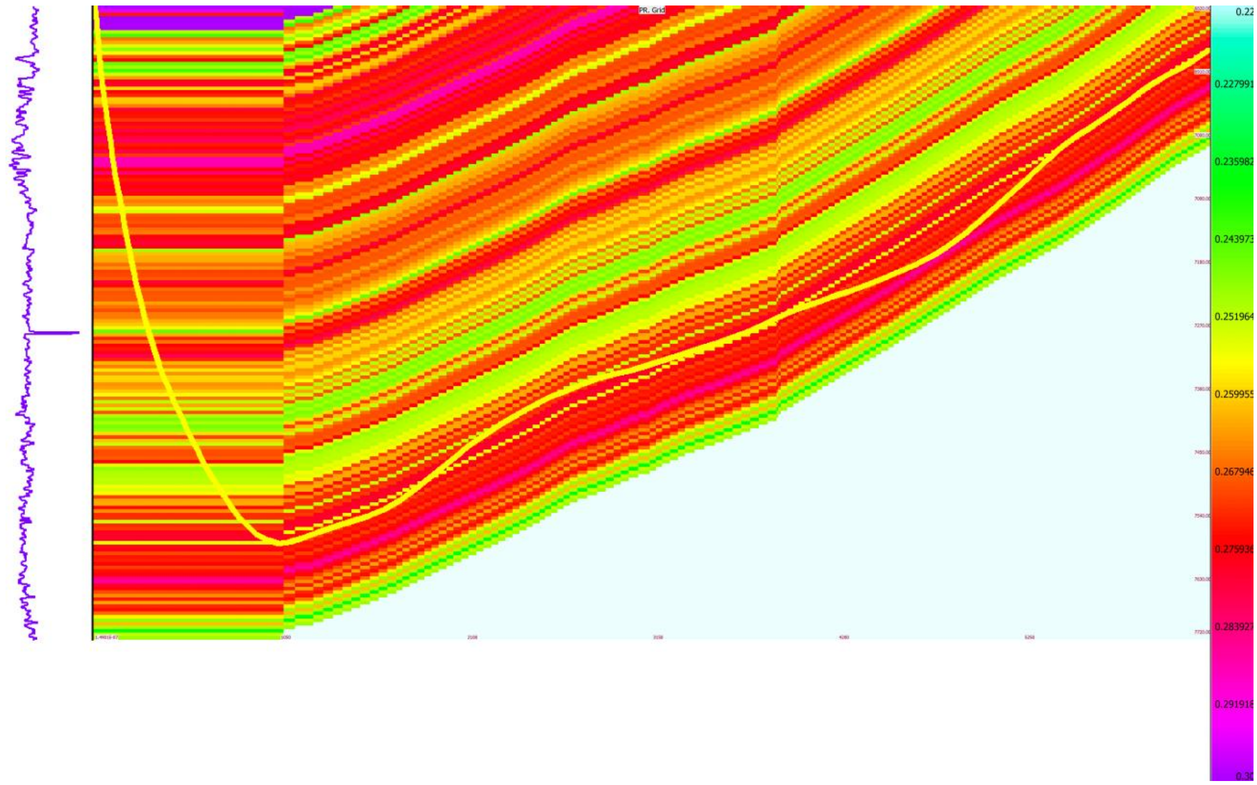

Figure 2: Geologic Structure incorporated into earth model

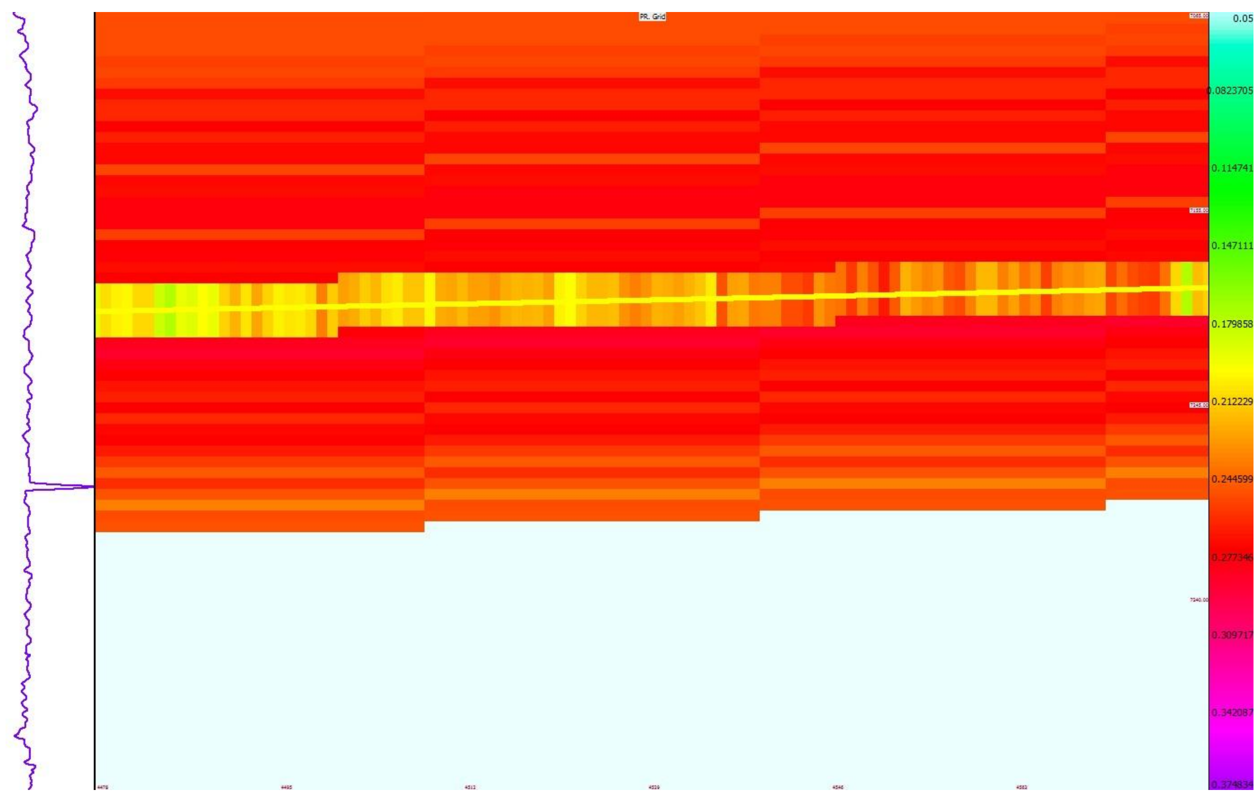

Figure 3: Detail of model showing effect of incorporating drillbit geomechanics into the model

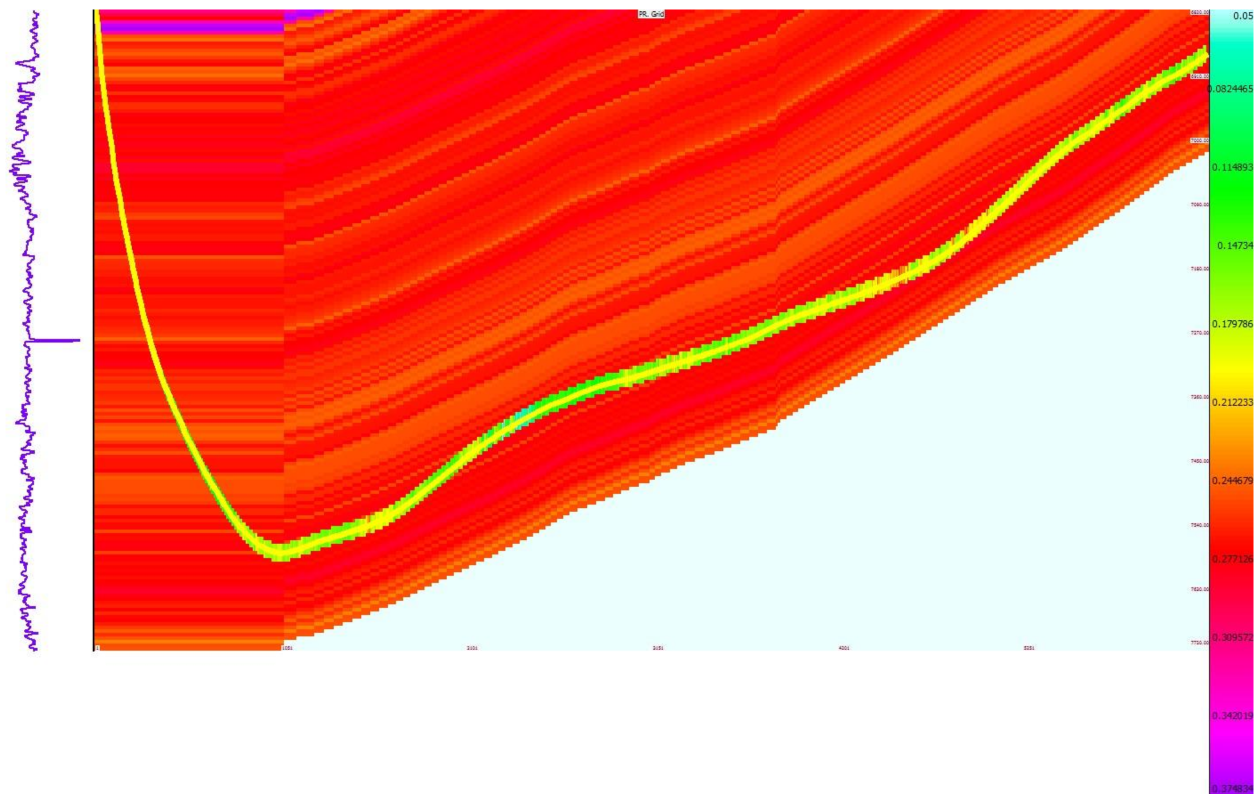

Figure 4: Image of model with geologic structure and detailed elastic properties along the wellbore.

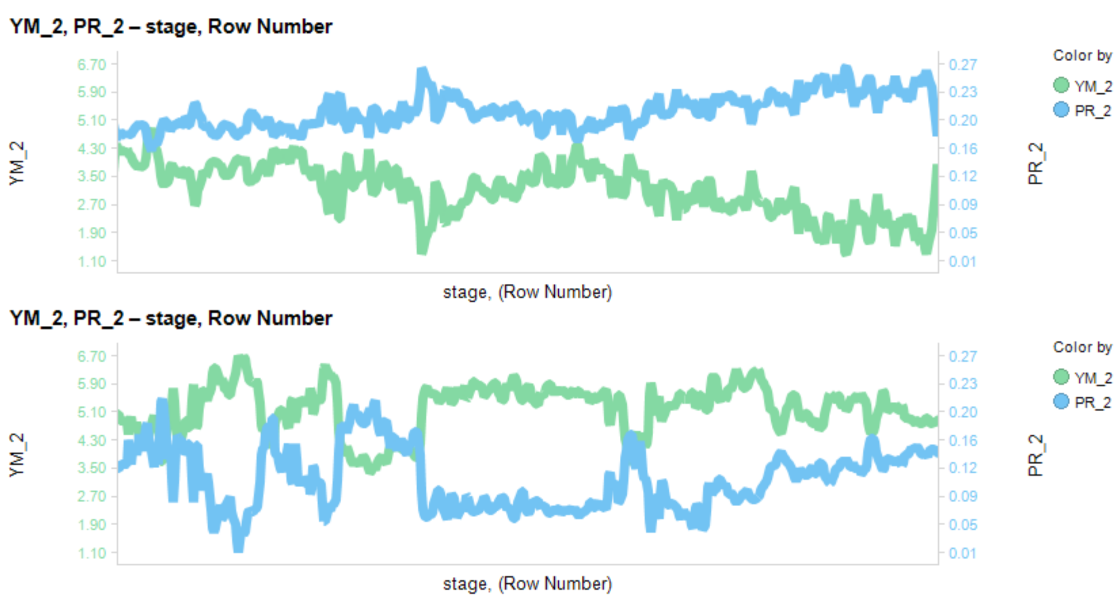

Figure 5: Comparison of Elastic properties of two stages

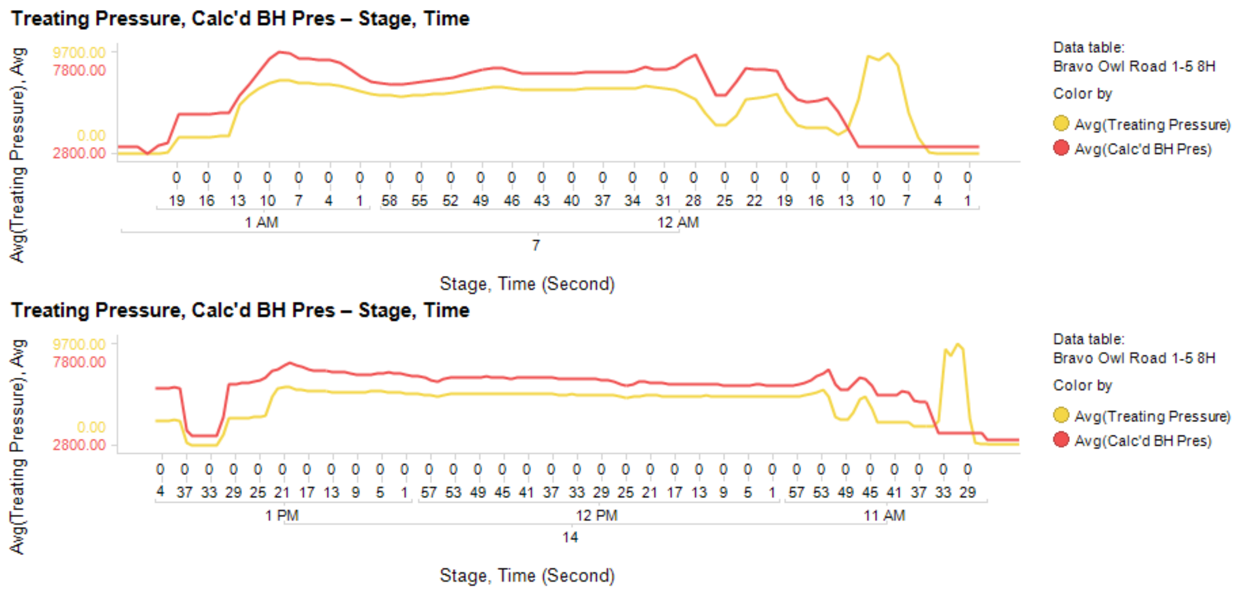

Figure 6: Comparison of pressure plots of two stages

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