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Geomodeling Guides Jonah Infill Wells

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LITTLETON, CO.–The Jonah Field in the Green River Basin in Sublette County, Wy., is one of the most prolific natural gas fields in the Rocky Mountain region, estimated to contain up to 15 trillion cubic feet of natural gas in a 32-square mile productive area.

The field is defined by the intersection of two subvertical shear fault zones that form a wedge-shaped structural block. To evaluate five-acre infill well development in various sections of the Jonah Field, reservoir characterization and simulation studies were performed to integrate geology, petrophysics, 3-D seismic and engineering data into technically sound 3-D geologic and engineering models.

The reservoir characterization and simulation work focused on three sections within the main field area. Detailed geomodels were built for each section, from which reservoir simulation models were then extracted. The studies included:

- Detailed petrophysical modeling for minerals, effective porosity and fluid saturations;
- Well- and seismic-based interpretations of internal markers within the Lance formation;
- Calibrating with cores and thin section images;
- Generating log-based vertical facies proportion curves;
- Generating a facies probability cube based on log facies and seismic information; and
- Constructing an integrated 3-D geomodel.

The multiwell simulation performed for this project attempted to address long-term well performance, including possible interference effects and optimal spacing. Pressure depletion seen at new infill wells was used to validate the characterization and simulation methodologies. This integrated characterization and simulation approach shows the importance of geologic controls on long-term recovery, and provides a method to assess optimal infill well spacing by area and improve economic development. Specific to Jonah Field, this approach demonstrates that differences in channel variability and thickness have a direct impact on gas recovery and optimal well spacing for different parts of the field.

FIGURE 1

Jonah Field Location and Study Areas

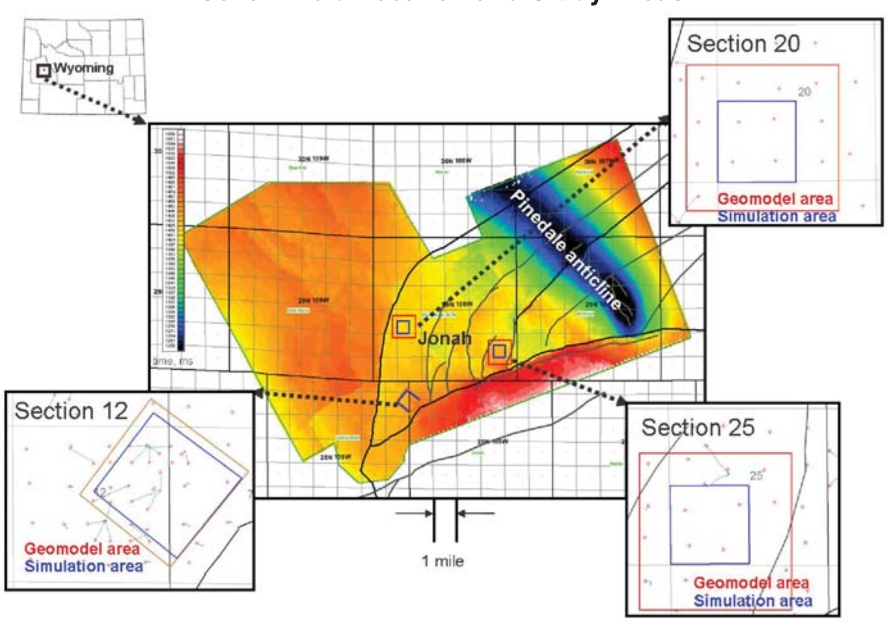


Figure 1 shows the locations of the three study areas at Jonah Field. Most of the production comes from overpressured and ultratight Lance Sandstones. The Lance formation is composed of braided to meandering fluvial channels intercalated with siltstones and mudstones. Median permeability of Lance Sandstones is ±0.01 milliDarcy and median porosity is ± 8 percent. Because of the low permeability, stimulation is required to achieve economical production rates. Overpressure is also critical for the economics of the field, since it helps to increase storage, preserve porosity and permeability, and increase relative permeability.

The gross pay interval ranges between 2,800 and 3,500 feet. Significant changes of sandstone occurrence and thickness in closely-spaced wells provide strong evidence for a high degree of vertical and lateral depositional compartmentalization in the Lance formation. Strong compartmentalization translates into infill well performances that are highly variable and difficult to predict. For this reason, a reliable estimation of the facies distribution within the Lance is crucial to field development.

Facies Characterization

The workflow for characterizing any reservoir depends on the available data, the geological problem to be addressed, the time frame of the study, and the business question that such a study is intended to answer. For Jonah Field, a workflow was devised that aimed at characterizing facies using core data from different wells throughout the field, well logs from about 40 wells per study area, 3-D post-stack seismic data, and check shots to facilitate seismic/well calibration. Three to four months was a typical time frame for each study.

Characterizing the facies geometry focused on identifying pay and nonpay facies using core and well log data. Pay facies consist of single and multistory channels. Single-story channels correspond to sand bodies accumulated in point bars associated with meander belts aligned in a northwest-to-southeast direction. Nonpay facies consist of flood plains, fine-grained shaly sandstones, and thin sandstones. These last two facies are interpreted to be small crevasse splays and levees. Facies geometry was characterized using three methods to capture different scales and variability across each area:

- Local facies curves to capture the local facies variability at each well location;
- Vertical proportion curves to capture the global vertical facies variability for a whole area (a section, for instance); and
- Seismic-driven facies probability cubes to capture the spatial variations in facies distributions and to use as "soft constraint" when integrating all the facies information into a single geomodel (local facies curves and vertical proportion curves were treated as hard data when building the geomodel).

The starting point of the reservoir characterization workflow in all the areas of interest was petrophysical analysis and modeling. Well logs may contain erroneous values in different zones along the well bore that must be corrected before using them for further analyses. The result of the petrophysical modeling was a set of enhanced logs that were used for seismic well calibration, stratigraphic interpretation and facies classification. Other products of the petrophysical modeling were estimates of the volumes of shale, water saturation, porosity, and fractions of other minerals suspected to be present in the reservoir rocks. Well log-derived porosities were calibrated with core data.

Lithology and facies associations were the next steps after petrophysical analysis and modeling. Five lithologies were identified based on shale and density volume values for each depth: coal, shale, silty shale, shaly sand and clean sand. A set of rules designed to classify all lithologies was applied to all wells, and the results were carefully checked for misclassifications. Lithologic classification was also calibrated with core data.

Using these lithology logs, facies associations were performed depending on the dominant lithology and thickness of each interval. Three facies were identified depending on the thickness of the clean sand interval. From thickest to thinnest, these facies were multistory channels, single-story channels, and silty-sandy flood plains, respectively. The name "shaly flood plain" was used to refer to nonpay intervals where shales and/or coals were the dominant lithology.

Stratigraphic Correlations

Stratigraphic correlations and seismic interpretation are very difficult at Jonah Field because of rapid changes in lithology and strong compartmentalization within the Lance formation. A variety of seismic attributes were examined to delineate seismic events that were continuous within the different study areas. After interpreting "whatever looked continuous in any attribute" extracted from the seismic data, check shots and sonic logs were used to convert these events to depth, and as a framework to guide the stratigraphic correlation.

Stratigraphic correlations were performed using lithology and facies logs. After several iterations between stratigraphic correlations among different wells and careful seismic interpretation (usually performed in a line-by-line fashion), a set of seismic horizons and well markers were obtained that were totally consistent with one another. The seismic horizons were also used as a guide to pick additional well markers that were not visible in the seismic data.

Once the seismic-guided stratigraphic correlations were completed, the Lance interval for all wells in each study area was divided into a fixed number of layers within each stratigraphic interval. Layer thickness was variable, but averaged five feet. The total thickness of each facies for all wells was calculated for each layer, and the relative proportions of the different facies by layer were computed.

The results of this process are shown in Figure 2. These curves are known as "facies proportion curves" and are used to estimate and constrain the relative amounts of each facie in each layer of the

FIGURE 2

Facies Proportion Curves

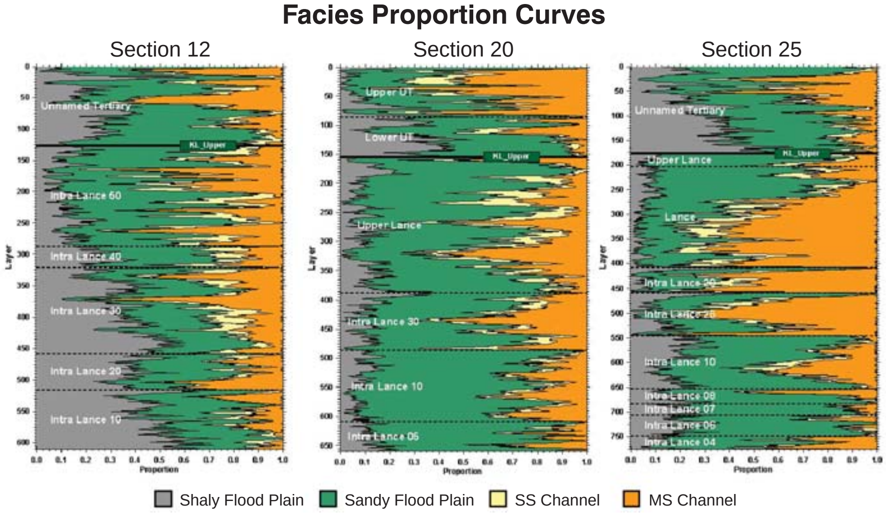
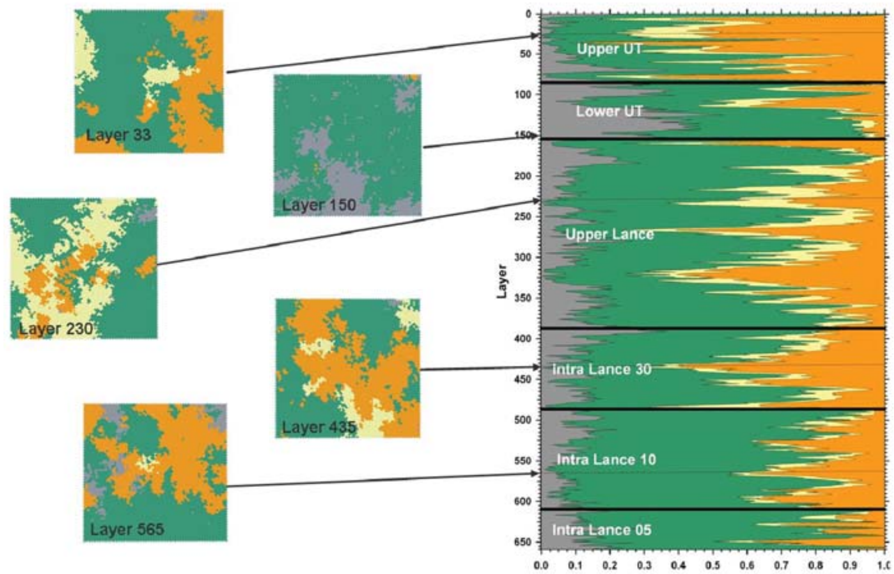


FIGURE 3

Facies Distribution in 3-D



geomodel. From left to right, the plot for each section shows the relative proportion of shaly flood plains, sandy flood plains, single-story channels, and multistory channels, respectively. The numbers at left indicate stratigraphic layer numbers, each averaging five feet in thickness. Each plot summarizes the facies information of approximately 40 wells in each section.

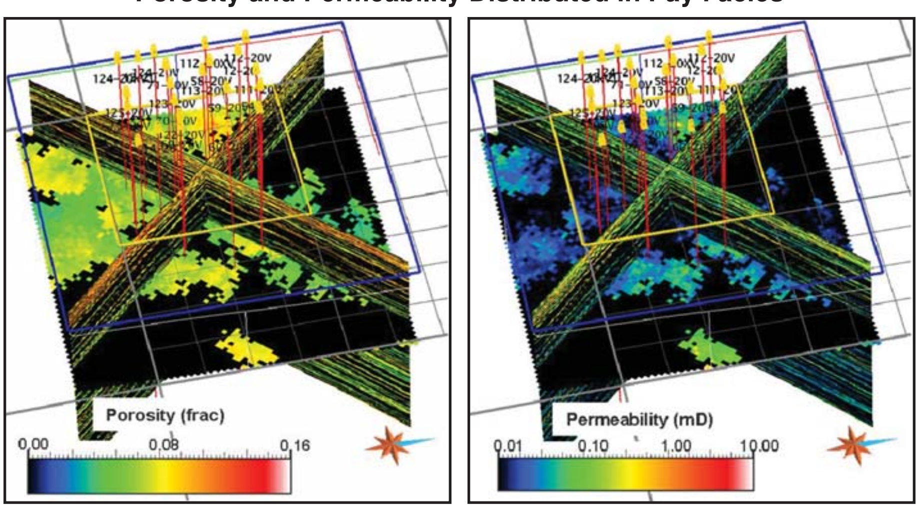
Note how the variability and thickness of facies are different from one area to the next. In terms of spatial variability, section 12 is the most variable, followed by sections 20 and 25. In terms of net-to-gross ratio of pay versus nonpay intervals, section 25 shows the higher values, followed by sections 20 and 12, respectively. In other words, channels in section 25 show more continuity and higher net-to-gross ratios than channels in the other two sections. These differences in channel variability and thickness have a direct impact on the gas recovery for the different sections.

Seismic data and well log data are complementary in the way they sample the spatial variability of the reservoir. Even though individual facies curves at well locations and vertical proportion curves from a group of wells sample details of the vertical variability within the reservoir, they are not adequate to capture horizontal variability. On the contrary, 3-D seismic data provide a better idea of the horizontal variability than well log-derived information, but sample vertical variability poorly compared to log data. For this reason, information derived from 3-D seismic data amplitudes also was used to constrain the spatial variability of facies in the interwell regions.

Acoustic impedance derived from seismic data was found to be qualitatively correlated with facies information at well locations and was used to estimate, in a probabilistic sense, the presence of facies in the interwell regions of the reservoir. These 3-D facies probability cubes derived from 3-D seismic data were later used as soft constraints along with the well-derived facies information to guide the facies distribution in the geomodel. Rock physics analysis of well logs shows that seismic attributes other than acoustic impedance alone derived from 3-D prestack data are better indicators of the presence of channels in the Lance formation. However, these attributes were not available at the time these studies were performed.

FIGURE 4

Porosity and Permeability Distributed in Pay Facies



3-D Facies Distribution

Facies information derived from well and seismic data was used to constrain the facies distribution in the geomodel. The first step in the geomodeling consisted of defining stratigraphic tops (constrained by geologic and geophysical integration), which were gridded to create the structural surfaces using seismic horizons as a guide. Second, a high-resolution 3-D stratigraphic grid was constructed to model the fine-scale vertical heterogeneity of the reservoir. After the grid was built, indicator-based simulation techniques were used to distribute facies in 3-D.

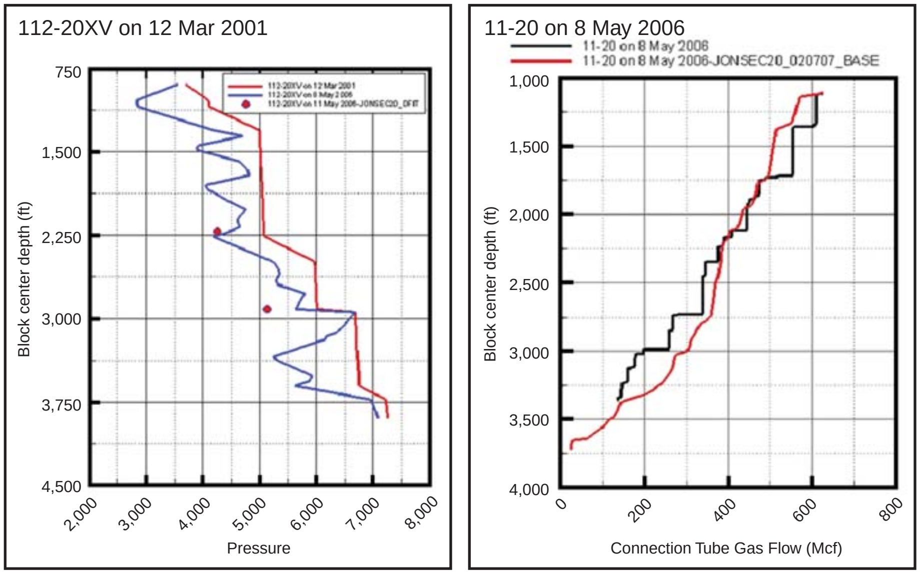
Figure 3 shows the result of the 3-D facies distribution in selected layers of the model for one of the study areas. The image at right is the vertical proportion curve, while the diagrams at left are areal slices for particular stratigraphic slices. Notice how the facies distribution honors the facies proportions calculated from well data and reflects the heterogeneous nature of the fluvial environment.

Porosity was distributed using facies-dependent variograms and sequential Gaussian simulation, while also honoring log data at the wells and porosity statistics per facie. Figure 4 shows the result of the porosity and permeability modeling. Porosity and permeability in nonpay facies was set to zero (black coloring). Water saturations were populated utilizing a core and log-derived bulk volume water approach to distribution. Porosity was distributed separately for each facies, honoring individual statistics and variograms. Permeability was distributed using a core-derived porosity/permeability cloud transform.

Notice that variations in permeability

FIGURE 5

Simulated versus Measured Pressure Depletion/Production



do not mimic variations in porosity. The reason for these differences is that the relation between these two parameters in the geomodeling was based on a nonlinear statistical relation as defined by the cloud transform. The fine-scale model was then upscaled to preserve the vertical heterogeneous channel distributions and property variations. For both the geomodel and the simulation model, aerial grids were on the order of tens of feet.

Multiwell Simulation

The multiwell simulation performed for this project attempted to address long-term well performance, including well interference effects and optimal spacing. Only minimal upscaling of the geologic model was undertaken for simulation in order to preserve the complex architectural elements. In this case, it was important to maintain detailed geologic descriptions throughout the model area rather that using coarse grids with near-well refinements, as is commonly applied. The biggest concern was long-term interference effects, rather than short-term detailed rate profiles, as would be required for optimizing hydraulic fracture treatments.

The base input model was a result of averaging three geostatistical realizations. We applied the assumption of irreducible initial water saturations as determined from bulk-volume water relationships by facies. The presence of water has a significant impact on gas in place and effective gas permeability. In addition to using a gas permeability cloud transform based on core data to assign initial permeability values, core-measured permeability was adjusted for overburden effects, water saturation and gas slippage. These effects resulted in nearly an order-of-magnitude reduction in permeability compared to core data.

Furthermore, laboratory-measured compaction data was used to account for permeability loss as pore pressure was reduced. This has important implications on long-term recovery. For pressure initialization, separate pressure regions were assigned according the defined stratigraphic intervals, with initial pressures determined from the regional overpressure gradient (1.16 psi/foot). The models were validated by matching tubing-head pressures while honoring historical gas rates.

We also compared the models to historical production data acquired by production logging tools and initial pressure profiles at infill wells. The figure at left in Figure 5 shows that the simulated depletion data at a recent infill well (blue versus red line) is similar in magnitude to the measured pressure depletion (symbols). Measured production inflow (the black line on the figure at right) also was approximated by the simulator (red line). The pressure data were determined from diagnostic fracture injection tests or other direct pressure measurements. Many new infill wells show some level of pressure depletion. This has significant implications for optimal well spacing and was considered important data for model validation.

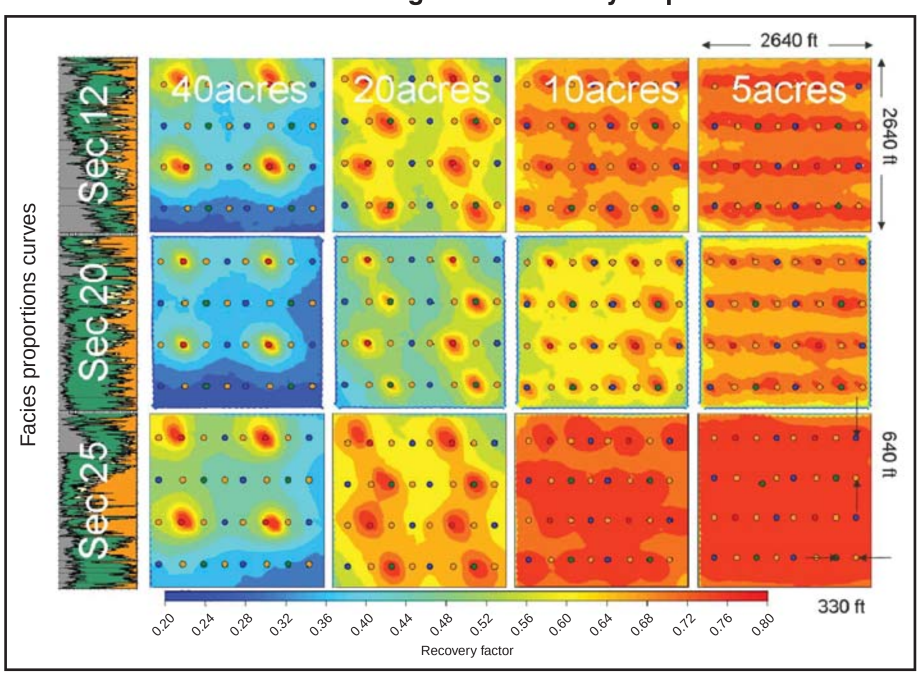
Predicting Well Performance

After validating the model, forecasts were performed in which the simulator estimated future gas rates using tubing-head or bottom-hole pressure constraints. Simulated recovery factors and rate profiles provided information about well interference at five-, 10-, 20- and 40-acre spacing by running a selected number of predictions using existing and uniform well pattern locations. The simulations show that while per-well recovery is reduced when going from 40- to five-acre spacing, total field recovery is increased as well spacing is reduced.

For example in section 20, five-acre wells produce 6.5 percent more gas at an economic limit compared to 10-acre wells and the recovery time frame is re-

FIGURE 6

Simulated Long-Term Recovery Maps



duced, but per-well recovery drops from 2.6 billion to 1.4 billion cubic feet. As mentioned, permeability loss from rock compaction was shown to have a significant effect on long-term recovery. Model comparisons show the importance of maintaining the geologic detail when trying to access long-term recovery. The more continuous multistorage channels in section 25 result in more efficient long-term drainage with five- and 10-acre wells compared to sections 12 and 20.

Figure 6 shows comparisons of long-term recovery for uniform well spacing. Well spacing is elongated to allow for elliptical drainage in a northwest-to-southeast direction based on maximum stress and depositional geometry. The left column shows the Jonah section number on top of the facies proportion curve, with well spacing varying from 40 to five acres moving from left to right. Blue represents 20 percent recovery of original gas in place, while red represents 80 percent recovery.

The Lance interval shows large variations in the proportion of pay intervals across the field, as illustrated by the detailed reservoir characterization of the three separate areas described in this article. These variations will have a considerable impact in the development plans and economic forecasts. Successful reservoir characterization of this kind of geologically complex reservoir depends to a large extent on how all the diverse information is applied in a way that is both consistent and complementary. Details are important and numerous iterations between disciplines may be required to ensure data consistency.

The simulations show that matches to historical gas rate decline were consistent with the integrated static and dynamic data, providing confidence in the methodologies applied. The models incorporate well completion information and also are consistent with production logs and infill well pressure depletion data. The simulations indicate significant variability in incremental long-term recovery when downspacing to five acres, and these comparisons show the importance of an integrated approach and detailed models for accessing long-term recovery.

Some model areas showed nearly 10 percent incremental recovery with five-acre development, compared to minimal incremental recovery in other areas. This is largely a result of differences in continuity and the number of multistorage channels, demonstrating that permeability and hydraulic fracture effectiveness are not the only issues with regard to infill drilling in tight gas reservoirs. More standard methodologies such as decline curve analysis can provide misleading results in determining optimum well spacing. ❒

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