Integrated Sensor Diagnostics (ISD) – Subsurface Insight for Unconventional Reservoirs
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Authors: Mike Mayerhofer, Eric Holley

Introduction
Apart from identifying and targeting sweet spots, the top four technical issues that developers of ultra-low-permeability unconventional assets face, as shown in Figure 1, are:

1. **Well spacing** – Discovering the optimum parallel lateral spacing
2. **Fracture spacing** – Identifying the optimum fracture spacing per unit of lateral length
3. **Horizontal well landing depth** – Finding the optimum landing depth and staggered or stacked well placement
4. **Completion timing** – Evaluating the impact of development timing between adjacent completions

Although there are other technical factors that directly impact the net present value (NPV) of large, unconventional development efforts over time, generally, these four issues are considered to be the main drivers that materially and significantly affect the fiscal performance of exploration and production (E&P) operators.

Figure 1: The Unconventional Challenge

There are two methods by which an operator can elect to approach the above issues. First, conventional production engineering – i.e., statistical examination of design of experiments (DOE) and associated production results, as well as decline curve analysis – may be employed, as it has been for many years, in higher-permeability projects. Unfortunately, this method is not appropriate for ultra-low-permeability (unconventional) delineation and development scenarios where drilling and completion (D&C)
costs typically range between $6 million and $15 million per lateral well, and where such production engineering efforts may require examining dozens (or hundreds) of wellbores and five years to 15 years to complete. As a result, many developers opt to embrace some particular degree of up-front diagnostics during an acreage delineation period and, subsequently, use those results to deal with the above factors and issues.

Pinnacle, a Halliburton service is introducing integrated sensor diagnostics (ISD) as a key component of Halliburton’s CYPHER® Seismic-to-Stimulation Service. This provides the necessary insight for accelerating the learning curve in unconventional development by characterizing and quantifying the created – and effectively producing – hydraulic-fracture footprint used in calibrated reservoir models and reservoir performance forecasting tools. In addition, ISD enables real-time adjustments and improvements during the fracture treatment and pad completion. This includes pumping diverting agents, as part of Halliburton’s AccessFrac® NWB technology, to increase the fracture contact area with the reservoir, which improves access to, and deliverability from, the reservoir.

**Integrated Sensor Diagnostic Technologies**

Rigorous reservoir modeling of unconventional assets has been very challenging, primarily due to the assumptions that are made with respect to total exposed hydraulic-fracture surface area, fracture spacing, and reservoir-system permeability, which are not generally constrainable. The advent and introduction of hydraulic-fracture diagnostic technologies, including downhole and surface microseismic fracture mapping; near-wellbore distributed temperature sensing (DTS); distributed acoustic sensing (DAS); distributed strain sensing (DSS); and downhole and surface microdeformation technologies, along with diagnostic fracture injection tests (DFITs), have radically changed this approach (Figure 2). It is now possible to constrain the reservoir model assumptions to relatively small ranges – thus allowing engineers to more accurately characterize the reservoir and fracture system. Fracture, geomechanical, and reservoir models developed using Halliburton’s CYPHER service are, therefore, more tightly constrained by the results obtained from the ISD service, which provides more reliable models for forward prediction of well spacing and completion optimization information. The capability of the reservoir model to perform

![Figure 2: Integrated Sensor Diagnostic (ISD) Technologies](image)
unstructured gridding is also extremely valuable for interpreting fracture and drainage patterns for ultra-low-permeability reservoirs. Having this capability through CYPHER service further emphasizes the need for diagnostic evaluation as inputs into these models (Figure 3).

The implementation of fiber-optic technologies yields detailed near-wellbore results crucial to fully understanding fluid injection along a wellbore. Vital outputs can be determined regarding cluster efficiency in cemented wellbores and fracture entry points in the case of openhole uncemented completion systems when temperature changes and acoustic profiles during the injection and thermal-recovery periods (i.e., the time following the injection) are applied. Volumetric distribution of fracturing fluid entry and completion issues, such as areas of unsuccessful isolation along the casing or annulus, can all be identified through DTS and DAS technologies. Utilizing Pinnacle’s proprietary thermodynamic and acoustic modeling software, the percentage of fluid exiting each cluster and/or the quantity of flow associated with a failed isolation plug or packer may be estimated. Such information enables the engineer to visualize and characterize the fracture system, such as the number of fractures generated at the wellbore, which fractures dominate, and the amount of fluid pumped into the previous zone due to inter-stage communication. Near-wellbore fiber-optic technologies and advanced modeling of the fiber-optic results can answer all of these questions.

While fiber-optic technologies help characterize near-wellbore activity associated with pumping fluid into the reservoir, far-field monitoring enables an engineer to understand and characterize the generated fracture system away from the wellbore (Figure 4). Microseismic technology is used to gain an understanding of the generated fracture geometry, including fracture half-length and fracture height, as well as fracture azimuth and complexity. While microseismic mapping can provide a qualitative estimate of potential fracture complexity, surface microdeformation monitoring (FracNet℠) delivers more detailed measurements of fracture complexity, such as volumetric distribution along multiple fracture azimuths and orientations. FracNet also determines fluid distribution between horizontal and vertical components of the fracture system. The newly introduced stimulated reservoir characterization (SRC) evaluation, which is utilized along with the hydraulic deformation index (HDI) obtained from FracNet, provides additional insight as to where the majority of hydraulic-fracture deformation was generated and may provide a proxy for the potentially propped stimulated reservoir area (SRA).

A more recent Pinnacle technology, FracHeight℠ service, has allowed operators to more accurately determine the hydraulic fracture height. FracHeight℠ service combines downhole microdeformation and microseismic mapping by using a single vertical array configuration. This setup provides more reliable height measurements, as it combines a deformation-based height measurement with traditional microseismic.
Calibrated Fracture Model
The true value of ISD is that it honors the results of diagnostic measurements, applying them directly to fracture and reservoir model inputs. Hydraulic-fracture models can be either planar or non-planar (i.e., complex) in nature. Halliburton’s CYPHER process utilizes either type of model, depending on which is more applicable when the diagnostic measurements are considered. It also provides an unstructured gridding solution to create a more realistic output of the results. A calibrated fracture model is valuable as a baseline for fracture conductivity distribution along the hydraulic fractures (Figure 5) and provides the created “hydraulic-fracture footprint” that is input into reservoir models (Figure 6). As a result, the model provides a crucial link between the diagnostic measurements and the calibrated reservoir model, allowing operators to optimize their unconventional development.

A calibrated fracture model must honor all diagnostic results, including far-field fracture geometry, fluid distribution along the wellbore, and fracture treatment pressure data for each stage. Other critical inputs typically include a geomechanical earth model and reservoir properties obtained from petrophysical modeling, cores, and DFITs.

Calibrated Reservoir Model
Addressing the top four technical issues from an NPV standpoint typically involves history matching of existing properties with a discrete fracture reservoir model that is based on the hydraulic-fracture footprint obtained using ISD. To accurately perform a reservoir model history match and create a calibrated reservoir model, production from the completed well(s) must be obtained. By constraining the reservoir model production rate to the actual rate of production, a mass balance in the reservoir is maintained, and the resulting modeled flowing pressure and actual flowing pressure are history matched. While this method of reservoir history matching applies to the production of a given well and to a characterized fracture system generated during the completion, a major assumption is made: the
generated fracture system characterized during the completion defines the fracture system as effective during production drawdown. Production profiling suggests that not all perforation clusters or entry points of a given well and their associated fractures will effectively contribute to overall production. Certain sections of the well may have a better production rate than other sections, despite having created fractures similarly along the wellbore. This could be a function of a number of factors, including variations of reservoir quality, damage mechanisms, and/or effective drawdown pressure at individual clusters (for e.g., heel stages producing more than toe stages).
To further refine the reservoir model, an understanding of production along the lateral is critical. Fiber-optic sensing results can provide the production contribution along the completed lateral at any point during the production phase. This production profiling along the well enables engineers to identify which sections of the well are actually producing hydrocarbons and compare these results to the generated fracture system characterized during the completion (Figure 7). This level of knowledge about production and the connection to fracture system characterization provides an understanding of the overall completion effectiveness and success. Capturing production along the lateral, by reducing and/or eliminating production from poorly contributing stages and clusters while increasing the inflow from more productive stages, will result in a more unique calibrated reservoir model for a given well or pad of wells.

Figure 7. Production Profile Per Stage and Associated Production Decline

In today's unconventional development, well spacing has dramatically decreased and operators are experimenting with stacked and/or staggered well patterns to enhance production and reserve recovery. In addition, older wells (i.e., vintage wells) that are currently producing are frequently offset by new drilling, which can have a detrimental effect on the vintage well (i.e., well bashing) and/or reduce the efficiency of the new well completions due to asymmetric fracture growth toward the depleted area. Fiber-optic technology can better define the degree and location of cross-well communication or lack thereof. By performing strategic shut-ins of offset wells, the well containing the fiber-optic cables can be used to diagnose the degree of communication and the location of such communication by observing changes in production along the lateral as a result of the offset well shut-in. This information further constrains the calibrated reservoir model and productive fracture footprint. This is especially important when diagnosing varying degrees of horizontal and vertical communication between staggered or stacked horizontal wells, as well as communication with vintage wells.

Once the reservoir model has been fully calibrated, production forecasts can be made to assess the drainage pattern from each well. Figure 8 provides an example of where the effectively draining hydraulic-fracture footprint is too small to adequately drain all reserves between the three wellbores. This implies that well spacing must be reduced to capture all reserves (shown on right side of Figure 8). Conversely, if the fracture footprint is too large for a given well spacing, and strong well interference is
The optimized well and fracture spacing should always be based on overall economic criteria, not just on reserve recovery.

Value of Information for Well and Fracture Spacing Optimization: An Example

The following example illustrates the economic benefits and value of an accelerated learning curve when implementing the ISD approach for a hypothetical three-well pad with variable well spacing in an unconventional liquids reservoir. For this example, the middle well (i.e., the No. 1H well) was completed first, using four perforation clusters per stage that are spaced 80 ft apart, with a 160-ft gap between fracture stages. Figure 9 shows the predicted effective drainage area after five years of production, using a reservoir model calibrated with ISD results. Cluster efficiency for the toe-most stages of the pad was not ideal, as one or two of the four clusters of most stages did not generate a hydraulic fracture, as shown in the producing fracture footprint or drainage area after five years of production. As fiber-optic measurements are performed in real time, it is possible to remediate the sub-optimal completion efficiency as a completion progresses by altering the limited-entry approach and pumping diverting agents, such as Halliburton’s AccessFrac NWB, on the heel-most stages. In this example, adding diverter improved overall fluid distribution at the lateral heel, improving drainage by increasing the fracture initiation per lateral foot.

Based on the data acquired from the No. 1H stimulation, the No. 2H well was redesigned with consistent 80-ft fracture spacing along the entire lateral, and the cluster efficiency improvements implemented on the heel side of the No. 1H well were utilized across the entire No. 2H completion. The drainage pattern demonstrates the obvious improvement in drainage and reserves recovery along the lateral. The incremental five-year cumulative oil production benefit for the No. 2H well is approximately 220,000 bbl per well. Using an average oil price of $50 per bbl equates to $11 million in additional production revenue per well after five years, or $48 million in additional production revenue per section after five years, offset by an increased completion cost (based on the higher number of stages and diversion) of less than $1 million.
While the fracture spacing was greatly improved for the No. 2H well, the 1,200-ft well spacing between wells 1H and 2H is too large, given the drainage area forecast for the two wells. Therefore, the next well to be completed, the No. 3H well, was drilled approximately 750 ft away from the No. 1H well, rather than 1,200 ft away. The combined improvement of better fracture spacing along the wellbores and reduced well spacing is approximately 2 million cumulative bbl per section after five years. Using an average oil price of $50 per bbl, this equates to additional production revenue of roughly $100 million per section after five years. Assuming 10 million dollars per well in drilling and completion costs, the well cost normalized to production ($/BOE) goes from $30/BOE before ISD down to $21/BOE using the lessons learned from ISD. That is a total 30 percent reduction in $/BOE for the asset. Upgrading to a large development program with hundreds of wells illustrates the value and opportunity for improvement that ISD provides.

**Summary**

Integrated sensor diagnostics (ISD) allows operators to address the four main challenges faced in the unconventional market through proven diagnostic and engineering practices:

1. **Well spacing** – Discovering the optimum parallel lateral spacing
2. **Fracture spacing** – Identifying the optimum fracture spacing per unit of lateral length
3. **Horizontal well landing depth** – Finding the optimum landing depth and staggered or stacked well placement
4. **Completion timing** – Evaluating the impact of development timing between adjacent completions

This solution provides oil and gas operators the ability to substantially improve their unconventional development. The unique combination of diagnostic technologies significantly improves the characterization and quantification of the created and effectively producing hydraulic-fracture system, which, in turn, provides the needed constraints for a more reliable well performance forecast and model optimization. Through ISD, the learning curve is expedited substantially, allowing for improved asset performance and overall reduction in $/BOE early in the development life cycle.

Introducing ISD into your asset development can reduce overall $/BOE by 30 percent by improving overall recovery and production efficiency. Applying the ISD learnings to an acreage can have significant financial implications that directly impact the economic feasibility of an asset. Our proven ISD experience has illustrated legacy inefficiencies in unconventional resource development, and has provided a reliable map forward for improved asset returns.

**Figure 9. Value of Information for ISD Example**
Increase in well IP after optimizing completion design from ISD results

Increase in five-year production revenue per section after optimizing well spacing by 35% and fracture spacing, using ISD results

Increase in five-year production revenue per section after optimizing fracture stage spacing by 40%, using ISD results

AN EXAMPLE: ISD provides insight into optimal well and fracture spacing, improved horizontal landing depth, and improved completion timing. One example showed the following:

30% reduction in $/BOE over five-year production, using ISD results