Monitoring Hydraulic Fracture Flowback in the Permian Basin Using Surface-Based, Controlled-Source Electromagnetics

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Abstract

We used a new, large-scale, surface-based, controlled-source electromagnetics (CSEM) approach to map the locations of frac fluid during flowback following a three-well hydraulic fracture stimulation in the Permian Basin. CSEM records and analyzes electric field signals induced in the electrically conductive frac fluids by a surface-based transmitter. For this study, we placed a grounded dipole transmitter directly above the central horizontal well of three parallel neighboring wells. The transmitted signal was a broadband pseudo-random binary sequence. To record the frac fluid response signal, we placed an array of 161 receivers on the surface covering the three horizontal wells. We recorded the induced, response signals of the flowback fluids in three-hour intervals (three on, three off) for 228 hours. The CSEM recording started eleven days after flowback began on the central well and four days after flowback began in the two outer wells. From this time-lapse recording we captured the spatial and temporal change in electrical conductivity within the fractured reservoir, allowing us to infer the location of flowback fluid and its movement. During the stimulations chemical tracers had been included in the frac fluid. Analysis of the tracers captured during flowback agreed well with the mapped fluid locations and movement found in the CSEM data.

Introduction

Flowback monitoring and its interpretation offer another valuable tool for frac and reservoir engineers. This understanding is especially critical in developing and managing unconventional reservoirs. Here, the stimulation responses are not simple, more and more evidence show complex fracturing and complex fracture networks (e.g., Rassenfoss, 2018). Characterizing a fracture network or networks in shale (i.e., an unconventional reservoir) is a challenging task. It is complicated by multiphase and complex flow regimes, non-static permeability and porosity, natural fracture and flow systems, heterogeneities and complex stress, changing stress with production, liquid loading, and a host of operational concerns (Zolfaghari et al., 2016). In the past, to determine hydraulic fracture properties, operators used production data in a variety of models to manage wells and reservoirs. Garnering production data can take months or even years delaying, for
example, upgrades to well and stimulation designs and designing infill drilling (Williams-Kovacs, Clarkson, & Zanganeh, 2015). In contrast, a flowback occurs during the transition between stimulation and bringing the well online. Understanding the flowback provides significant improvements in determining early production rates enabling estimates of the effective size of stimulations, distinguishing key reservoir properties, and predicting long-term production rates (Jacobs, 2016). In addition, there can be direct savings if, for example, flowback interpretation identifies an underproducing play in time to redirect funds into a more lucrative play before infill drilling (Williams-Kovacs et al., 2015).

Flowback monitoring divides into two broad categories: (1) wellbore techniques and (2) far-field techniques (Williams-Kovacs & Clarkson, 2014). Wellbore techniques include chemical and radioactive tracers, fiber-optic methods (e.g., distributed temperature sensing and distributed acoustic sensing), and quantitative flowback analyses. Far-field techniques include microseismic mapping and tiltmeter mapping. Adding to far-field techniques, we introduce large-scale, surface-based, controlled-source electromagnetics (CSEM).

CSEM is a well-established and proven technology within the geophysics community (Goldstein & Strangway, 1975 and Streich, 2016). As the name implies, CSEM is an electromagnetic technique that measures localized changes in the reservoir conductivity caused by the presence of a conducting fluid (i.e., frac fluid). Instead of trying to map noisy or distended fractures (i.e., microseismic or tilt), CSEM images the frac fluids through their electrical conductivity contrast with the surrounding rock. CSEM’s distinct advantages include using an on-demand, controlled-source, and the fact that this method is not intrusive and does not interfere or impede the normal operations on the well. Large-scale, multi-receiver, surface-based CSEM, as described here, is new to hydraulic fracture and flowback monitoring.

**Method: Surface-Based, Controlled-Source Electromagnetics**

CSEM maps the electric field created by a conductivity contrast. It is most sensitive to large conductivity-resistivity contrasts between the target, here frac fluids, and its resistive host rock. Surface-based CSEM hydraulic fracture or flowback monitoring, as used here, works on the principle that the electrically conductive fluid filled fracture networks perturb the inductive response of the well casing. The fracture networks act like loops of wire in different sizes and orientations that vary in electrical conductivity with fluctuations in frac fluid concentration. As the frac fluid invades the host rock (i.e., during stimulation) or as it leaves the host rock (i.e., during flowback), the size, shape, and extent of the fracture network changes, altering the characteristics of the induced electromagnetic field. By recording and subsequently mapping these changes we can infer the spatial and temporal extent of stimulation and flowback fluids. During active injection, areas of significant signal variation indicate where frac fluids have penetrated the host rock. We can use CSEM to map the extent and movement of frac fluids for individual frac stages. We also detect fluid-invaded natural fractures and fluid-filled pathways plus those created during active injection (Hickey et al., 2019).

**Method: Field Operations**

Our field method, large-scale, multi-receiver, surface-based CSEM, differs from typical CSEM surveys described by Streich (2016). For our CSEM surveys, we use a grounded dipole as the source on the surface directly above the horizontal well. Placing the transmitter directly above the horizontal casing takes advantage of the “Casing-as-Antenna Effect” (Commer, Hoversten, & Um, 2015). Induced currents in the casing allow it to effectually become a secondary source, amplifying the primary source signal and
increasing its strength. A direct signal from the surface would induce a very weak electromagnetic field in the frac fluid at the typical depths of unconventional reservoirs. However, because of the signal-strengthening, casing-as-antenna effect, the frac-fluid will generate signals that are readily recordable at the surface.

In the case of monitoring flowback from multiple, closely spaced wells, we place the transmitter above the center-most well. We then build a surface array of receivers covering all the wells. By contrast, when monitoring an active injection, we typically only have the array over the stimulated well.

For both flowback and injection, each receiver has two horizontal, perpendicular antenna arms; each arm records one orthogonal electric field component induced in both the wellbore or wellbores and the frac fluids. Note that throughout the operation the wellbore signals do not change and are removed from the recorded data during processing, enabling us to identify and analyze the signal from the fluid alone.

**Method: Signal**

Using 3-D finite-element CSEM modeling based on the method described in Badea et al., 2001 and Stalnaker et al., 2006, we model each reservoir before the stimulation, identifying the frequencies with the highest signal-to-noise ratio. We then focus our processing and imaging on these specific ranges. We also use the modeling to select the length (i.e., duration) of the transmitted signal: a broadband pseudo-random binary sequence (PRBS). The PRBS, in addition to other factors, determines the bandwidth and fluid response resolution in the frequency domain (Hickey et al., 2015).

**Method: Analysis**

We image both flowbacks and injections using the same method. We record and quality check data in the time domain, then transform the data into the frequency domain. We use proprietary, in-house software. Time-domain data quality control checks consist of identifying and eliminating receivers with corrupted data before transforming into the frequency-domain using a windowed Fast Fourier Transform (FFT). Before imaging a hydraulic fracture stage, we subtract the initial few minutes of data recorded before active injection of that stage. For flowback imaging, we subtract the initial few hours of recording before flowback. This initial data is called “pre-frac” or “pre-flowback” and subtracting removes the background signal from the reservoir rock, unwanted fluid zones, and the well casing. With the pre-frac or pre-flowback data removed, the remaining signals are solely due to changes in the fluid filled fracture networks with variable amounts of noise (M. S. Hickey, et al., 2015b). CSEM monitoring is subject to various noise sources both inherent and cultural, and we take steps to prevent, eliminate, or at least reduce them both during data collection and during processing (Streic et al., 2011). We determine a noise threshold based on summing frequency responses, the number of frequencies summed, and the background noise present at the site. A signal is significant if its peak strength is at least two times greater than the background pre-frac or pre-flowback signal (M. S. Hickey et al., 2017). For typical hydraulic fracture operations, we image the data stage by stage; for flowbacks, we image first over shorter, discrete time windows and later over the complete flowback dataset. On site, we use a range of proprietary procedures and filters during active recording to further reduce noise and better focus the signals from the frac fluids.
Case Study: Operations

Recently we used large-scale, multi-receiver, surface-based CSEM, to investigate a flowback following a three-well hydraulic fracture stimulation in the Permian Basin. (Note: some information on this operation and findings have been withheld at the request of the operator.) For this study, we placed a grounded dipole transmitter directly above the central horizontal wellbore and an array of 161 receivers covering the three horizontal wells (Figure 1). Each receiver has a 200-ft antenna with two orthogonal arms. The lateral of the central well (Well 15) is about 500 ft below the two outer wells (Well 22 and Well 23) and lies in a different geologic formation. We recorded the flowback response (i.e., induced electromagnetic field perturbations due to the flowback fluids) in three-hour intervals (three on, three off) over 13 days, a total of 228 hours. The CSEM recording began eleven days after flowback began on the central well and four days after flowback started in the two outer wells. From this time-lapse recording we inferred the spatial and temporal fluid flow within the fractured reservoir. During the three stimulations, chemical tracers had been added to the injected fluid. Tracer data was then collected for the three wells over a period of six days; three of these days coincide with the first three days of CSEM monitoring. Figure 2 shows bar graphs of measured tracer concentration from all three wells. A group of unique tracers were added to the frac fluid and were changed every 5 stages. This allowed us to determine the most actively flowing portions of the reservoir over the first three days of CSEM monitoring.

Case Study: Results

In the CSEM flowback results presented here we subtracted the first three-hours of data from the complete dataset. This allows us to image the change in the flowback response over the course of the entire monitoring operation. Figure 3 shows six, time-sequential frames of the flowback response taken over the entire monitoring period. Note that because we subtracted pre-flowback at the start of the monitoring period, the response appears to grow over the first few days of monitoring. We do not interpret this as fluid appearing in various regions of the reservoir, but instead it indicates areas of the most significant change from the initial conditions. As changes build over time, much of the monitored portion of the reservoir shows a flowback response. The imaged response intensity corresponds to the degree of change from the
initial monitoring time. Note that some regions show a response at one time and no response later, or a decreased response toward the end of the monitoring period. The response turning on/off or increasing/decreasing represents changes in the electrical conductivity and spatial extent of the fracture networks.

Because flowback began on Well 15 eleven days before we began monitoring, and 7 days before flowback on the outer wells, we believe the bulk of the signal response is due to Wells 22 and 23. The main reason for this interpretation is that the measured water flowback rate for Well 15 (Figure 4a) had decreased significantly and leveled out when our monitoring began. By that time Well 15 was producing mostly gas (Figure 4b). Comparison of the tracer data with the CSEM results shows good agreement, with the stages having the greatest tracer content also showing greater signal intensity.

Well 22 tracer data show that the most active stages were 6-10 and 16-20, which corresponds with the CSEM results (Figure 3). However, the tracer data on this well does not explain the higher intensity response in stages 11-15. For Well 23, stages 11-15 show the most significant concentration of tracers, which corresponds to the stages of the highest CSEM signal. Stages 6-10 on Well 23 also show a significant response despite the lower tracer concentration. It is important to keep in mind that tracer data do not span the entire CSEM monitoring period and only cover to the second frame (Day 3) in Figure 3.

Figure 2. Tracer recovery plots for the three monitored flowback wells. Each plot is broken up from left to right (heel to toe) into five-stage sections, the blue line indicates the average tracer concentration per stage grouping.
Figure 3. Snap shots of the CSEM flowback data spanning the 13-day monitoring period and with pre-flowback data removed. Wells highlighted and stages are shown for comparison to Figure 2.

Figure 4. (A) Shows water production and (B) gas production for the three wells over the course of the CSEM flowback monitoring. Monitoring of gas does not begin on Wells 22 and 23 until the fourth day of observation.
The significant increase in signal intensity, primarily on Well 22, between days 5 and 6 of CSEM monitoring (Figure 5) is also important. This correlates with the increased water recovery between the fifth and sixth days of monitoring (Figure 4a). Well 23 sustained generally steady decrease in water production over the monitoring period. Yet, Well 22 showed decreased flow early followed by an increase after which it decreased steadily like Well 23. What caused this decrease then increase is not known. However, this variation is seen in the CSEM signal. Figure 6 shows six more frames of the flowback response, this time over 26 hours. Over this period, change occurs in the CSEM response around some individual stages (small colored dots), and overall during the 26 hours. The response decreases and then increases again. This highlights how during this study, CSEM tracks both large-scale and small-scale fluctuations in the reservoir.

**The Future**

The study of hydraulic fracture flowbacks using large-scale, multi-receiver, surface-based CSEM is a new approach in the flowback monitoring toolkit. However, there is still more information to be gained through study of the relationship between the recorded signal and the changing properties of the flowing reservoir.

- The water/gas ratio of the measured flowback fluids and how it affects the phase or amplitude of the electric field response.
- Effects on the signal intensity due to increasing salinity of flowback fluid over time.
- Effects of the liquid/gas phase changes near the wellbore.
- Possible temperature effects on the signal intensity due to the cooling and warm-back of the host rock near fracture locations.
- A more detailed investigation into quantitative flowback analysis techniques using wellhead pressure and flow-rate.
- Determining the possible effect on the CSEM signal caused by the before breakthrough and after breakthrough transition, and the associated flow regimes.
There are also many interesting problems facing hydraulic fracturing flowback operations that could be observed and addressed in future CSEM flowback surveys:

- Communication between closely spaced wells and/or parent-child wells (i.e., “frac hits”),
- Identifying the most effective perforations on a stage-by-stage basis,
- Examining stress shadows and their effect on fluid flowback,
- Tracking and characterizing non-sequential flow along the well
- Deciding whether it is possible to distinguish between frac fluids and formation fluids.

**Discussion**

We have shown the results of the first ever time-lapse monitoring of hydraulic fracturing flowback using large-scale, surface-based CSEM. The results correlate to tracer data and demonstrate the potential of this method to map producing zones, production fairways, and recompletion zones at well scale and on a stage by stage basis. As onshore operators infill acreage and increase density of development drilling, understanding the interaction and performance of wells has become paramount. Knowing where frac fluid has been placed and from where the fluid ultimately returns gives operators an additional tool for effective reservoir management. By imaging changes in the fluid-filled fracture networks, large-scale surface-based CSEM is a new, non-intrusive tool that holds great potential for monitoring the fracking and flowback of unconventional reservoirs.
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References


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