

Evaluation of Deep Subsurface Resistivity Imaging for Hydrofracture Monitoring

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2. Abstract

This report describes the results of the first of its kind monitoring of a hydrofracture operation with electromagnetic measurements. The researchers teamed with oil and gas producer Encana Corporation to design and execute a borehole to surface monitoring of three fracture stages at a well pad in central Colorado. The field project consisted of an equipment upgrade, a survey design and modeling phase, several weeks of data collection, and data processing and interpretation.

Existing Depth to Surface Resistivity (DSR) instrumentation was upgraded to allow for continuous high precision recording from downhole sources. The full system can now collect data continuously for up to 72 hours, which is sufficient to measure data for 10 frac stages. Next we used numerical modeling and frac treatment data supplied by Encana to design a field survey to detect EM signal from induced fractures. Prior to modeling we developed a novel technique for using well casing as an antenna for a downhole source. Modeling shows that 1) a measurable response for an induced fracture could be achieved if the fracture fluid was of high salinity 2) an optimum fracture response is created when the primary source field is parallel to the well casing but perpendicular to the fracture direction.

In mid-July, 2014 we installed an array of more than 100 surface sensors, distributed above the treatment wells and extending for approximately 1 km north and 750 m eastward. We applied a 0.6 Hz square wave signal to a downhole current electrode located in a horizontal well 200 m offset from the treatment well with a return electrode on the surface. The data were transmitted to a recording trailer via Wi-Fi where we monitored receiver and transmitter channels continuously in a 72-hour period which covered 7 frac stages, three of which were high salinity. Although the background conditions were very noisy we were able to extract a clear signal from the high salinity stages.

Initial data interpretation attempts consisting of trying to directly invert collected data using a simple background starting model did not produce reasonable models. We next used a simulated data set to develop a constrained inversion workflow that places the downhole fracture in the correct location. Finally, we used a combination of forward and inverse models

to fit the collected data to a model that incorporated 3 frac stages.

This project provided a first-of-its-kind application of EM technology to map an induced fracture. The results demonstrated a clear anomaly during the operation that can be fit to a reasonable model of an induced fracture.

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4. Executive Summary

This report describes the results of the first of its kind monitoring of a hydrofracture operation with electromagnetic measurements. Existing tools allow us to track seismic activity associated with the fracturing or model a bulge but they cannot tell us where the fluids have gone, and this is key to the understanding of the process. EM technology can map and monitor the electrical resistivity of rock in the interrogated volume and can target regions of lower electrical resistivity associated with fracture porosity or volumes of low resistivity fluids or proppant.

For this project the researchers teamed with oil and gas producer Encana Corporation to design and execute a borehole-to-surface monitor of three fracture stages at a well pad in central Colorado. The field project consisted of an equipment upgrade, a survey design and modeling phase, several weeks of data collection, and data processing and interpretation. All activities were accomplished in full cooperation with the Encana team.

The first phase of the project was to upgrade existing proprietary Depth to Surface Resistivity (DSR) instrumentation to allow for continuous high precision recording from downhole sources. On the receiver side the upgrade consisted of redesigned capacitive electric field sensors, a new 32-bit multichannel lightweight data acquisition station, and Wi-Fi for continuous data transmission. This is connected to a centralized data collection station that receives input data from the distributed sensors. The new transmitter utilized on this job had been upgraded to include a multichannel switchable load source panel and a high precision current monitor. New downhole current electrodes were designed to allow for up to 20 amps of current to be grounded into the casing. The full system can collect data continuously for up to 72 hours on a single battery charge, which is sufficient to measure data for more than 10 frac stages.

In the next project phase we used numerical modeling and frac treatment data supplied by Encana to design a field survey and optimize it to detect EM signal from induced fractures. Prior to modeling we developed a novel technique for using well casing as an antenna for a downhole source. Here we apply an electrode downhole and use completion and logging data to calculate the current leakage into the formation along the casing. This new current function was then incorporated into a 3D resistivity forward and inverse model to predict the response

from the induced fractures. Modeling exercises that followed show that 1) a measurable response for an induced fracture could be achieved if the fracture fluid was of high salinity and 2) an optimum fracture response is created when the primary source field is parallel to the well casing but perpendicular to the fracture direction.

The DSR system was fielded at the Colorado site in mid-July, 2014. We installed an array of more than 100 surface sensors, distributed above the treatment wells and extending for approximately 1 km north and 750 m eastward. The grid was not uniform due to access issues, but it did cover all surface positions above the fracture. The data were connected to a recording trailer via Wi-Fi where we monitored 120 receiver and transmitter channels. Data were continuously recorded in a 72-hour period which covered 7 frac stages, three of which were high salinity.

We applied a 0.6 Hz square wave signal to a downhole current electrode located in a horizontal well 200 m offset from the treatment well with a return electrode on the surface. More than 2 terabytes of field data were recorded and processed during this experiment. Although the background conditions were very noisy we applied a series of techniques to extract a small but clear signal due to the frac stages.

Because the frac signal was a very small percentage of the collected data we knew that data interpretation would be challenging. Initial data interpretation attempts consisted of trying to directly invert collected data using a simple layered background starting model and the results produced models that fit the data well but did not produce reasonable models. In fact, inversion fit the data by placing structures near the source and receiver position instead of the at the fracturing intervals. We next used a simulated data set to develop a constrained inversion workflow that places the downhole fracture in the correct location. To our knowledge this is the first successful inversion of this type. Finally, we used a combination of forward and inverse models to fit the collected data to a model that incorporated 3 frac stages.

While we feel that this project was groundbreaking in its scope and vision and we are proud of the accomplishments it was not possible to complete all tasks as proposed or answer all questions that arose.

5. Report Details

5.1 Introduction

Hydraulic fracturing (frac'ing) has enabled commercial production from unconventional (low permeability) reservoirs. However, frac'ing is more expensive than the conventional methods used to produce gas and oil, and frac'ed wells exhibit a much faster decline in production than conventional wells. Furthermore, there are environmental concerns with the amount of water that is needed, pollution of groundwater reservoirs, the triggering of earthquakes, and the release of methane into the atmosphere. A key concern of the general public is hydrofracturing out of the formation and into the groundwater table.

Unconventional wells exhibit highly variable production in a given area and often the majority of gas or oil produced comes from only a few of the fracturing stages. As a result, more extensive fracturing operations are performed than are really needed, resulting in excess proppant being pumped into the formation. These inefficiencies indicate that the eventual destination of the injected fluids used in reservoir stimulation is poorly understood.

The objective of this project was to quantify how well an in-situ measurement of a hydraulic fracturing operation, using the new method of Depth to Surface Resistivity (DSR) imaging, could be related to the changes in rock properties and fluid propagation that occur as a result of the fracturing. Electromagnetic data were processed to quantify the EM signal and compared with simultaneously acquired microseismic data to establish both the benefit of the EM data alone and combining them with microseismic data.

5.2 Experimental Methods

We are applying the Depth to Surface Resistivity (DSR) method to image the electrical resistivity of fracture volumes after hydraulic fracturing operations. The increased porosity due to fracturing and the addition of saline as a fracture fluid dramatically decreases the electrical resistivity of the fractured rock thereby allowing it to be imaged with electrical resistivity methods. DSR data are collected continuously during fracture operations and analysis is performed on the field differences due to the formation changes.

During DSR surveys, a transmitter is used to inject current into the earth via a pair of electrodes

– in this case a deep casing source (DCS) and surface return electrode. The current generates surface EM fields that are characteristic of the electrical properties of the subsurface. In order to measure changes in resistivity, the current applied, and the variations of the surface EM fields must be accurately measured. The researchers have a proprietary current monitoring system and sensors for this purpose. A hydrofracturing stage involves a series of unique events particular to the host geology that cannot be repeated and reproduced. Thus, all sensors must be in place and running in advance of the frac'ing process. As part of this project the researchers built additional electric-field sensors and adapted a data acquisition system (DAS) from the seismic survey industry that has the ability to send data over a Wi-Fi array to a central location in near real time to ensure the continued integrity of the data.

5.2.1 Current monitoring system

The current monitoring system is shown in Figure 1. Its main function is to record two continuous ultra-precise measurements of applied current. It also makes a continuous measurement of device temperature to ensure the device is within its operational temperature range. The data are digitized using the same system used in the data recorders. These data are synchronized to GPS time and are passed to a computer to be monitored in near real time.



Figure 1. Current monitoring system

5.2.2 Data acquisition system

During this project we integrated a first stage input board, which takes the analog difference of

two pairs of electric-field sensors, filters and amplifies the signal, and passes the output to an analog-to-digital converter (ADC), with an existing DAS from a new vendor. The resulting system, shown in Figure 2, synchronizes the data to GPS time and can send data to a central location over a Wi-Fi array. The system has two upgrades from the base unit. The first upgrade allows equipment to be placed in areas where GPS access cannot be maintained. All units were fitted to be used with VHF (very high frequency) radios that, in the absence of GPS connection, will automatically link to a master radio, and only the master radio must maintain GPS lock. The second upgrade was to use a higher quality precision voltage reference for the ADC with a 0.05% variance specification and better temperature stability, important for an outdoor application in various types of weather.



Figure 2. New data acquisition systems

5.2.3 Electric-field sensors

The researchers use proprietary sensors to measure the surface electric field. The sensors couple capacitively to potentials in the earth so, unlike standard galvanic electrodes, they do not have to be buried and are not affected by near-surface groundwater content and temperature. This model features a refined circuit design that improves its sensitivity, a new form factor that makes it easier to hold and place, improved manufacturability, and a color chosen for improved visibility. Figure 3 shows an older sensor next to the latest version.

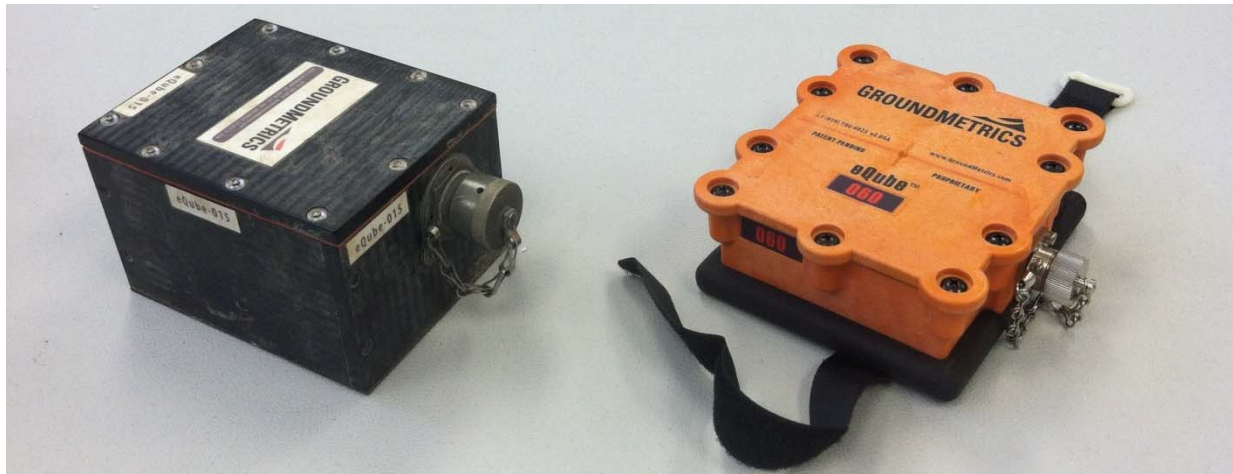


Figure 3. Old (left) and new (right) version of proprietary electric-field sensors

5.3 Results and Discussions

5.3.1 Task 1 – Project Management Plan

The initial project management plan was completed and accepted by the program manager.

5.3.2 Task 2 – Model the DSR Signal of a Fracture Network

Before collecting field data, it was important to estimate the range of surface electric fields for a typical fracture network in order to optimally position equipment. Much development to codes and modeling techniques was required to complete this work, which was completed in two basic steps: a) project the change in rock resistivity as a result of hydrofractures. We assumed that the fracturing fluid is more conductive than the host rock and forms a connected conducting anomaly. The calculation is of the reduction in resistivity (= increase in conductivity). And, b) project the change in electric field at the surface due to the change in rock resistivity resulting from hydrofracturing.

5.3.2.1 Task 2.1 Project the change in electrical resistivity due to hydrofractures

The goal of this task was to determine the electrical resistivity distribution of a formation that includes induced fracture volumes. The fractured volumes themselves are complex structures initiated by hydrofracture operation at the wellbore that connect to a natural fracture network or create new fractures along planes of weakness. We see an example of this in the seismic image below.

Figure 4 shows plan views and side elevation views of published microseismic images for a commercial fracturing project. The images comprise a connected series of subvolume (voxel) images showing seismic energy is released during the fracturing process. Figure 4 shows two roughly parallel fractures of lateral extent 160 m and 140 m, and height 220 m and 215 m corresponding to a total fracture thickness of 2.3 cm, or an average thickness of 1.15 cm per fracture. However, it should be noted that the voxels in Figure 4 are 8 m (25 ft) cubes, and near to the casing, there could be multiple fractures within each voxel, thereby reducing the thickness per fracture.

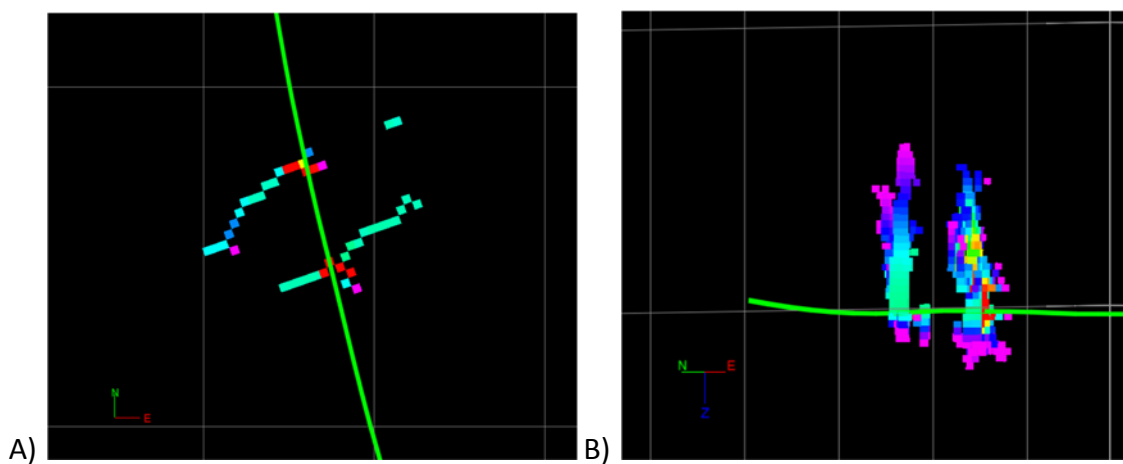


Figure 4. Typical microseismic fracture images for a commercial fracturing project in the Marcellus shale. A) Plan view. B) Side elevation. Individual image voxels are 8 m x 8 m x 8 m.

The change in electrical resistivity in an induced fracture is caused by the creation of porosity due to the induced fracture operations as well as the addition of a water based fracture fluid into rock pores filled with oil and gas. The electrical resistivity of the fractured volume can change dramatically if highly saline frac'ing fluid is used.

Although the fractures themselves are typically very thin, (i.e. 1-8 mm in width), the cumulative effect of the operations is significant. Fractures are usually made in clusters, approximately 10 fractures for every meter of wellbore and up to 6 of these clusters are generated per "stage", or every 100 m of well bore. The net effect is a quasi-continuous connection to the formation from discrete fracture clusters, roughly 15 m apart. In addition, the volume of added material can be quite large. A typical well uses up to 4 million gallons of water ($\sim 10,000\text{m}^3$) during fracture

operations, and an equivalent weight of sand or ceramic proppant. A typical fracture stage may constitute 500-1000 m³ of sand and water.

Modeling this arrangement with standard EM code can be challenging. No existing code can model mm size fracture structure together with km scale field structures. Our approach is to use “Effective Medium Theory” to upscale these small structures into meter scaled volumes that can be modeled (Berryman and Hoversten, 2013; Heagy et al. 2014).

With Effective Medium Theory the electrical characteristics of the fractured volume can be captured by considering an equivalent anisotropic volume with properties calculated via volumetric averaging relations. A number of these relations are available and the correct one for every situation varies with geology. An example of this upscaling is shown in Figures 5 and 6. Here we see that 10, 4 mm highly conductive (2500 S/m) fractures over a 10-meter region are equivalent to a single 15 S/m anisotropic slab.

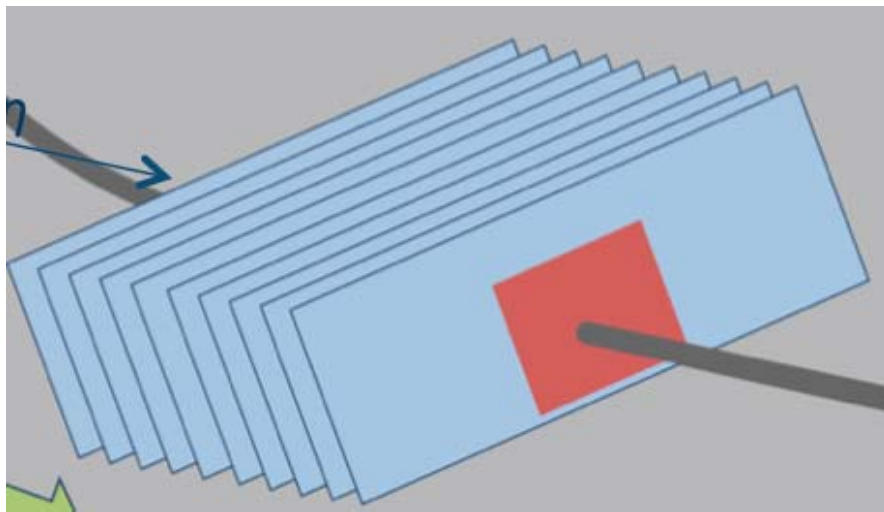


Figure 5. Schematic representation of a series of parallel induced fractures

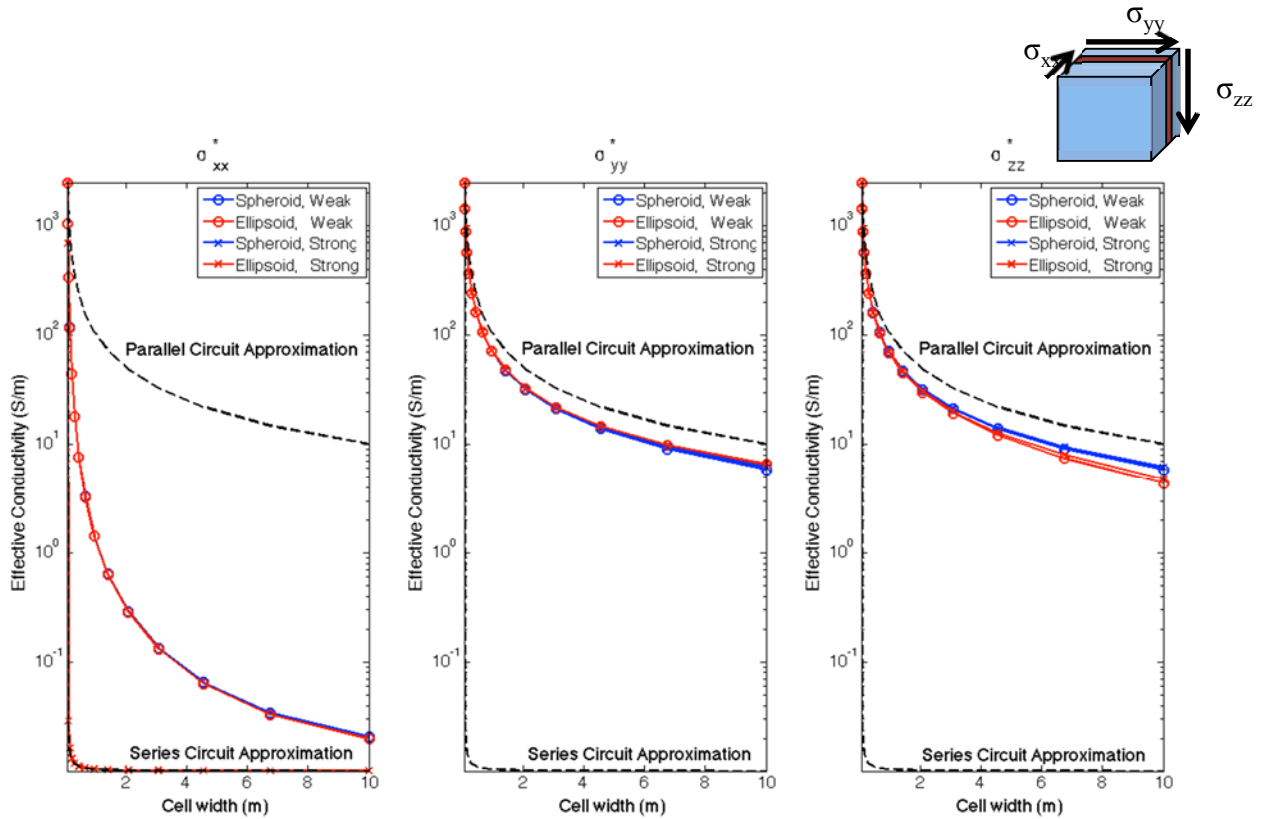


Figure 6. Calculation of the effective conductivity of a slab that is equivalent to a series of 10 individual fractures

For this project the fracture stages are 31 m long and spaced 15 m apart. There are 6 clusters per each stage and in each stage roughly 650 m^3 of salt water is injected. We can anticipate a porosity gain of roughly 5% (of the rock volume) due to the fracturing. For this project we note that three of the fracture stages use highly saline brine ($\sim 70,000$ ppm), the resistivity of this fluid is roughly 0.02 ohm-m . For the full 30 m stage we therefore calculate an equivalent resistivity of 1 ohm-m , from a background of 25 ohm-m .

The goal of Task 2.1 was to relate the fractures to a change in electrical resistivity that could be used to predict the electric field produced by the fracture at the surface. The relations above allow us to calculate the effect of an equivalent fractured volume without calculating the response of each individual fracture.

5.3.2.2 Task 2.2 Calculate surface EM signal due to fractures for DSR via a horizontal well

For this program we needed to model a signal produced by a 3D fracture in the vicinity of a horizontal casing. Historically, the presence of conducting casings in boreholes has been considered a problem for traditional EM surveys and such surveys have been arranged to avoid placing sources or receivers close to casings. However, the great majority of boreholes are completed with electrically conducting casing so the problem had to be addressed.

In our case we view the steel casing as an opportunity to place a source closer to the region of interest, although we understand that formation current from a source deployed into a metallic casing is complex, reflecting current flowing into the pipe as well as current “leaking” into the formation. Although we can calculate the external fields from such a source by incorporating the well casing into the model, this approach is extremely computer resource intensive due to high casing conductivity, which requires many small cells for an accurate solution. For most cases it is cost prohibitive.

Our approach is to first calculate the current distribution from a source deployed in a steel casing using the method of Schenkel and Morrison (1994) and then modify two codes to allow for the calculation of 3D EM fields using this complex current source.

The Schenkel method uses the following relation to compute the casing and leakage current from a downhole source, where I_{cas} is the casing current I_{inj} is the leakage current and L_c is the conduction length, a measure of how quickly the current leaks from the casing into the formation. We show this schematically in Figure 7.

$$I_{cas}(z) = I_0 \exp(-z / L_c) \quad I_{inj}(z) = \frac{-1}{L_c} \exp(-z / L_c)$$

$$L_c = \sqrt{\rho_{formation} \sigma_{case} A_{case}}$$

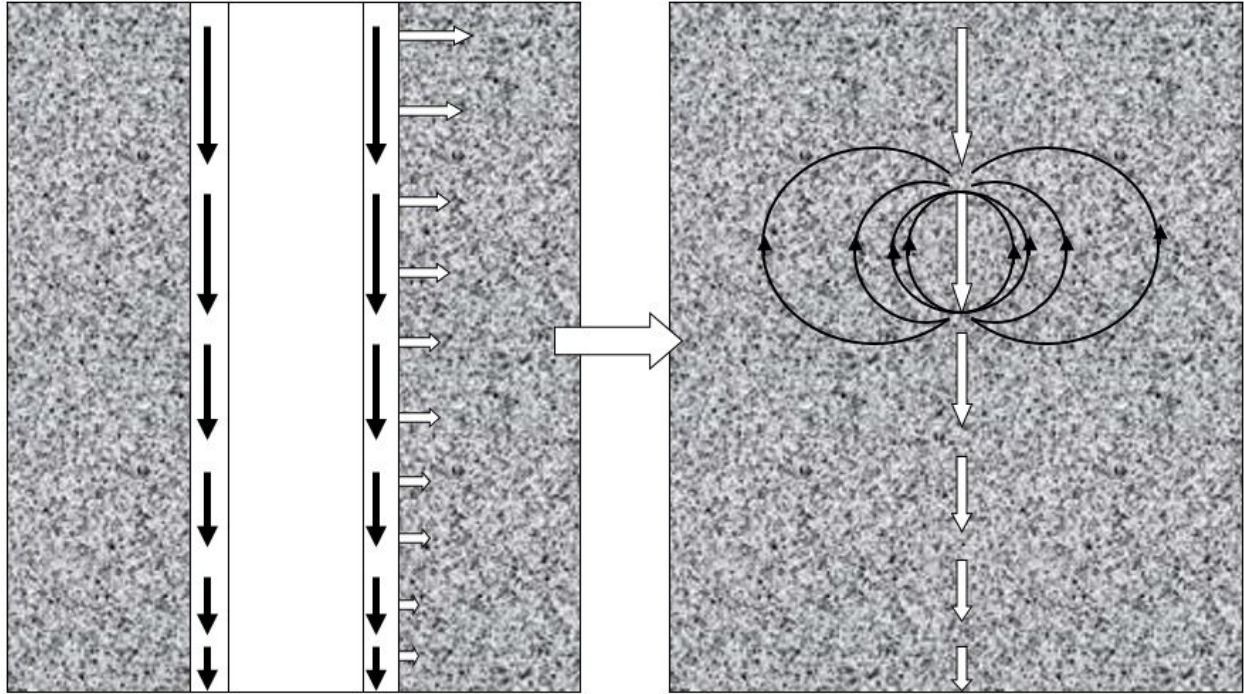


Figure 7. Representation of a conducting casing carrying an electric current (left) as a series of equivalent current dipoles in the host medium (right). The current in the casing is shown by the black arrows and varies along the length of the casing due to current flow from the casing into the medium which is illustrated by white horizontal arrows. In the right figure, the current flowing in the medium for one of the equivalent dipoles is illustrated by the black curved lines.

This relation allows us to discretize the leakage current into fundamental electrical sources (poles) or EM sources dipoles. This was implemented in codes 3DDC and 3DEM for this project and has proved invaluable in utilizing steel well casings as source antennas.

To confirm the accuracy of the solution, it was necessary to model a casing problem for which there are published solutions. One such configuration of significant practical interest is the split casing configuration shown in Figure 8A used to send electrical signals from the bottom of a well to the surface. Figure 8B shows a comparison of the researchers' approach to calculating the current distribution for a split casing with a published solution by DeGauque (DeGauque & Grudzinski, June 1987). The two results are very similar, but near to the top of the casing, the current calculated by the new approach is smaller. Figure 9 shows a second comparison, this

time with a more recent solution for the same problem by Trofimenkoff (Trofimenkoff, Segal, Klassen, & Haslett, November 2000). The agreement is very good.

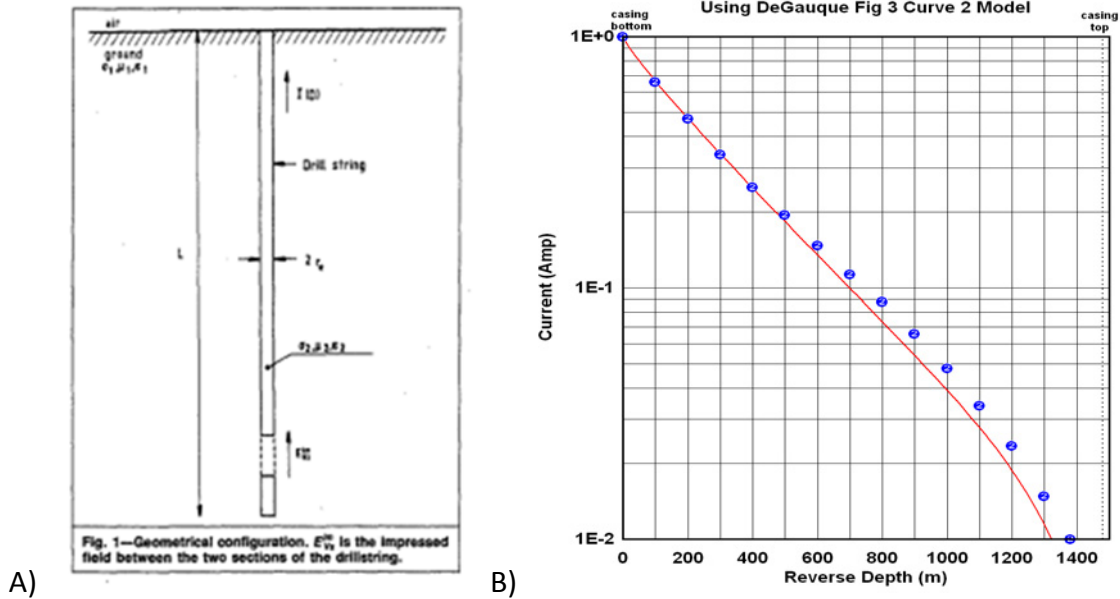


Figure 8. Comparison for solutions for a casing driven as a split dipole. A) Split casing source geometry. B) Calculated current along the casing. Red line: Modeled. Blue symbols DeGauque solution

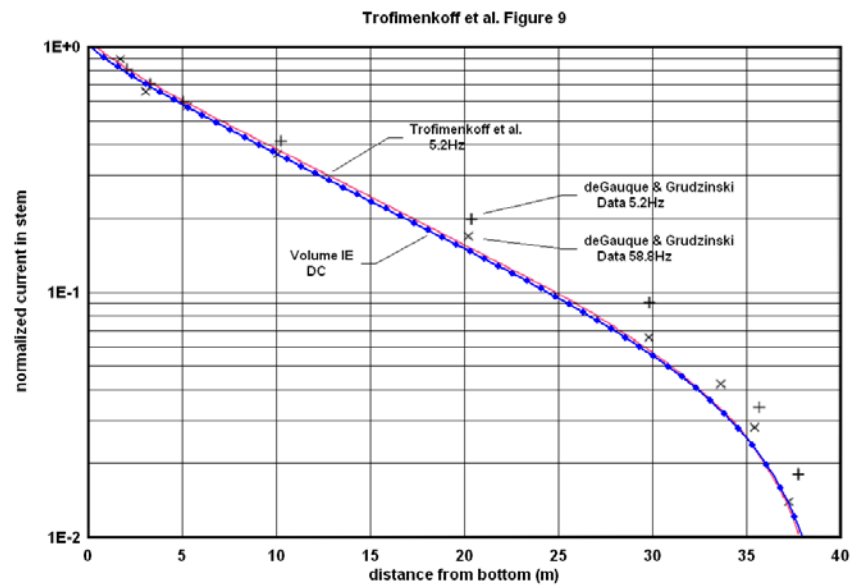


Figure 9. Second comparison of solutions for a casing driven as a split dipole

For the second step, the casing current solution is used as an input to a complete 3D electromagnetic (i.e., AC) code.

As previously discussed, it is very challenging to model an object with one or more very small dimensions within a space discretized into small volume elements. A hydrofracture is an extreme case. A now standard analytic method (Weidelt, 1981) is to model a fracture zone using a rectangular sheet, where the sheet is characterized by its conductivity-thickness product, σt .

The goal was to produce a 3-dimensional code that could project the surface EM field produced by a hydrofracture of arbitrary orientation and position with an earth model containing multiple resistive layers. Given the absence of experimental data, the only way to test this code was against other calculations of the fields resulting from a fracture.

Probably the most widely accepted method is the EM modeling code developed by Weidelt (Weidelt, 1981) and modified by Zhou (Zhou, 1989, Zhou, Becker & Morrison, 1993; Zhou, Lee, Goldstein, Morrison & Becker, 1986). This code solves for the currents induced in a rectangular sheet by an arbitrary electric or magnetic source. The resulting SHEET code computes the secondary magnetic and electric fields at any point in the surrounding half space as a function of frequency that is accurate to low frequency or DC. The SHEET code has been improved, modified, and verified over the years.

We first adapted the SHEET code to DSR to allow a line of current dipoles to be used as the source current distribution. The code can only accommodate an earth model comprising a single half space of uniform resistivity. For the purpose of comparison with our general 3D fracture modeling code, this limitation was accommodated.

The two fracture configurations run with the SHEET code are shown in Figure 10. The fracture code requires a small spacing between the fracture and current source, and this was set to 1 m. The half space resistivity was set to 25 Ω -m, which is an approximately weighted average between the 47 - 49 Ω -m resistivity of the Niobrara, Ft Hayes and Cordell shales and the 4 Ω -m to 21 Ω -m of the intervening and surrounding layers.

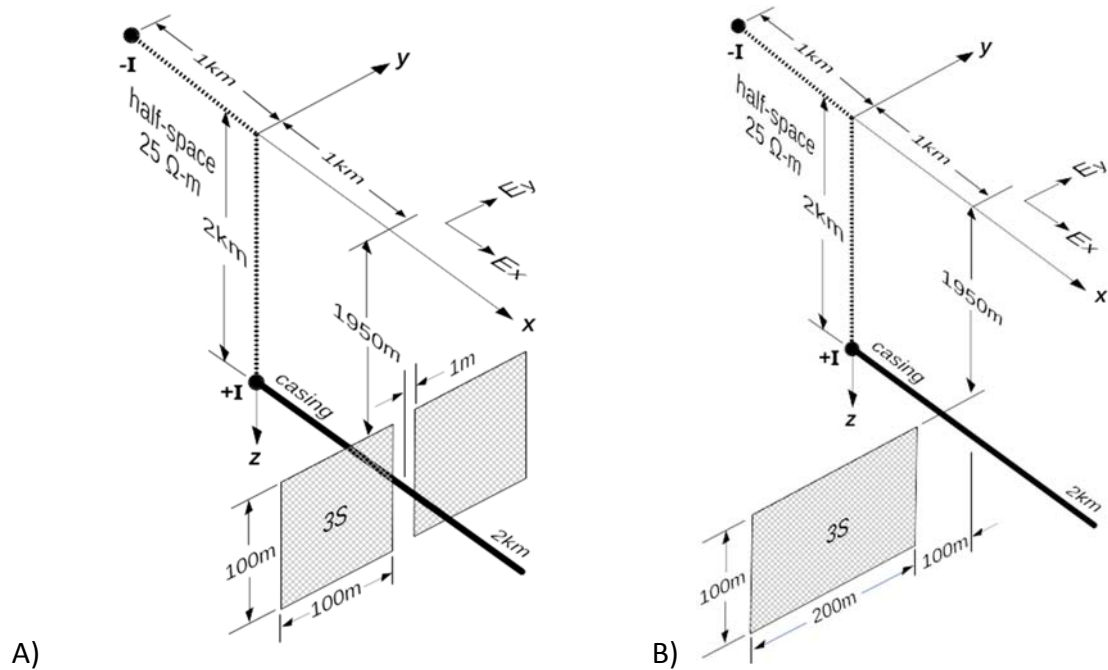


Figure 10. Fracture orientation and dimensions used for the SHEET code. A) Symmetric fracture in an orthogonal plane to the lateral section of the casing, B) Offset fracture in the same plane

The modified 3DEM code was completed. The 3DEM code allowed us to calculate the signature of a hydrofracture produced by current flow along a true 3D casing, comprised of a horizontal section connected to a vertical section and located in a layered earth. A comparison with the SHEET code is shown in Figure 11.

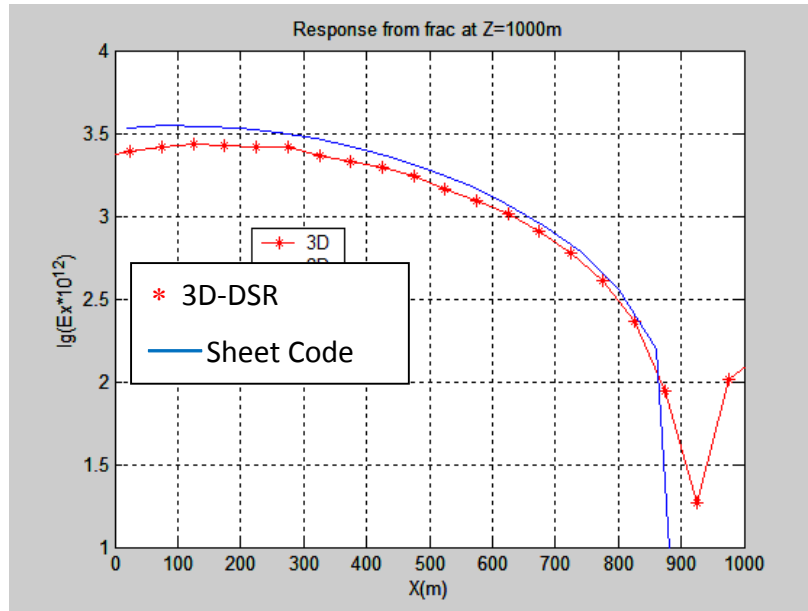


Figure 11. Comparison of the surface radial E-field for a sheet fracture adjacent to a vertical casing (E_x). Red symbols: results of the 3DEM code using a fracture represented by single voxel, 10 m wide. Blue Line: Weidelt Sheet fracture solution of conductivity-thickness product of 3.

Initial results using the 3DEM code for symmetric orthogonal fractures (Figure 10A) gave an unexpectedly small signal for both the surface E-field along the axis of the casing lateral, E_x , and the surface E-field perpendicular to the casing lateral, E_y . To study the result further, a more proven sheet code was run for the same model. The result for the sheet code is shown in Figure 12. The maximum value of the surface E_x field due to the fracture is 20 pV/m. In comparison, the minimum detectable field for one-hour data stacking is 10 pV/m (per unit current).

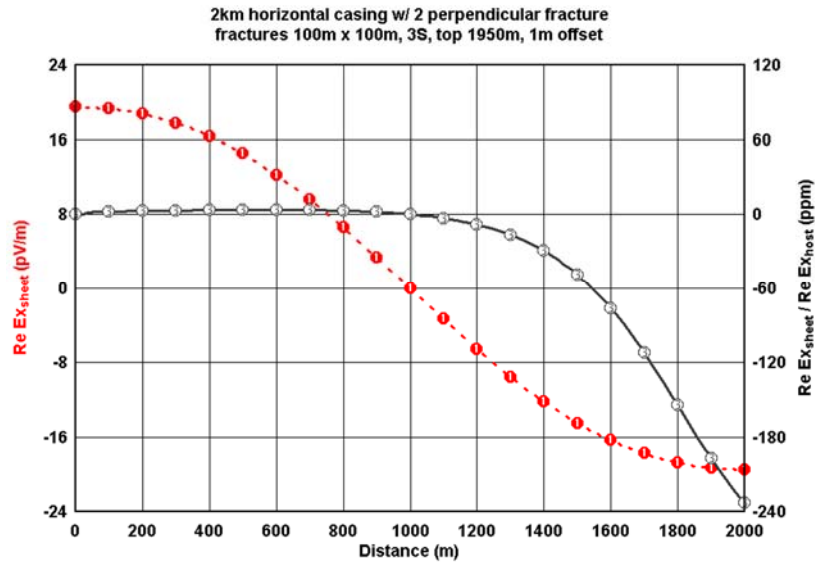


Figure 12. Surface E-field (E_x) along the axis of the lateral casing as a function of distance (along the lateral casing) for fracture in a plane orthogonal to the lateral section of the casing. The fracture plane is at 1000 m. Values are for a 1 A transmit current

Another configuration of practical relevance is the offset fracture shown in Figure 10B, with results shown in Figure 13. This geometry could correspond to a fracture produced at an adjacent casing. Because the fracture is further from the casing, the E_x signal is reduced to an unmeasurable level. However, the E_y field is significant and detectable by present sensor technology.

This latter result suggests that the optimum means to detect and isolate the signal from a fracture is to energize the direction perpendicular to the fracture, so the perpendicular fracture signal would not be coupled to the main fields.

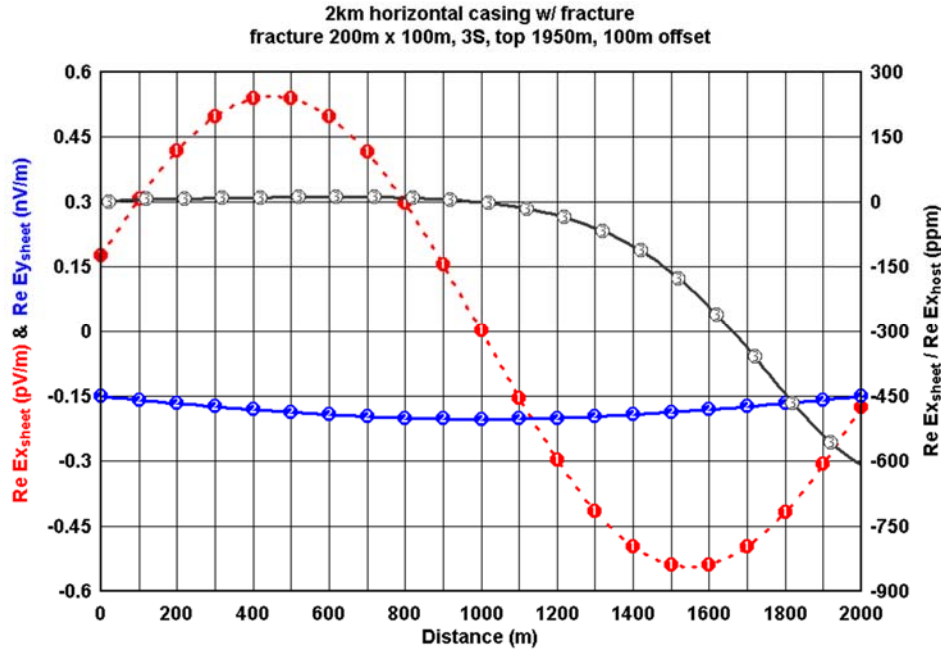


Figure 13. Surface E-fields (E_x , E_y) above the axis of the lateral casing as a function of distance (along the lateral casing). The offset fracture lies in a plane orthogonal to the lateral casing at a distance of 1000 m. Values are for a 1 A transmit current.

5.3.3 Task 3 – Expand Survey Capability for Simultaneous Monitoring

As part of this project 15 new data acquisition systems and 60 new sensors were built to improve the simultaneous monitoring capabilities. Quality control codes were also developed so we could collect the best quality data possible. Figure 14 shows a sensor and DAS with battery and Wi-Fi antenna. All equipment was verified via laboratory calibration of sensor and receiver channels to confirm operation against documented specifications. Additionally, equipment was field tested in conjunction with other projects in California and Texas before completing the hydrofracture monitoring survey.



Figure 14. Sensing equipment. Left: Most recent sensor. Right: Data acquisition unit

The primary metric for the preliminary equipment test was the sensor noise level as deployed in the field. This noise level represents the minimum detectable change in surface signal. Our target number was 300 nV/rtHz at a frequency of 1 Hz and above, and 3 μ V/rtHz at 0.1 Hz. This target is shown as the red dashed line in Figure 15. Also shown is a typical noise spectrum for a pair of sensors. These were deployed as part of a field test in the Anza Borrego Desert. At 1 Hz and above the noise is about 80 nV/rtHz.

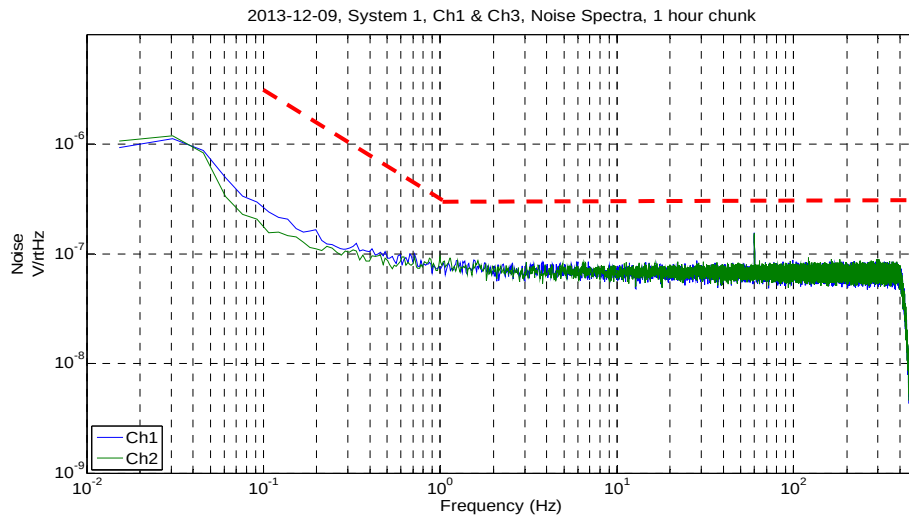


Figure 15. Noise Spectrum for Two E-field Sensors (Blue, Green) Compared to the Target Noise Level (Red Dash). At 0.5 Hz the Field Performance is 5 times better than the Target.

The real-time quality control software allows one person, the observer, to monitor all deployed systems to confirm they have been deployed correctly, monitor source transmit cycles, and ensure the systems have not been disturbed from a central location in near real time. This helps speed up the deployments and results in better quality data.

5.3.4 Task 4 - Acquire DSR and Microseismic Data during Hydrofracturing

The goal of this task was to collect DSR and seismic data during a commercial hydrofracturing operation. The data were collected at a well pad in Weld County Colorado operated by Encana Oil & Gas. This pad has 14 wells drilled to the Niobrara formation with lateral lengths of 7000 - 8000 feet. The wells were completed in > 35 stages each, and we acquired EM data over five adjacent fracture stages. To support this program Encana agreed to use brine with 70,000 ppm NaCl content (2 x the salinity of seawater) for three stages. Data were collected for one day of fracturing with fresh water, approximately 17 hours of brine fracturing, and over the subsequent day of fresh water fracturing. The EM sensor array was centered over the high salinity stages of the hydrofracture. A commercial seismic survey was also commissioned involving 2196 data channels, utilizing over 24000 geophones plus layers of downhole seismic channels.

5.3.4.1 Subtask 4.1 Survey design and field scout

A 4-person group of GroundMetrics staff visited the proposed test site in June 2014 to conduct reconnaissance and collect noise data during a frac'ing procedure. Portable equipment was installed at field locations adjacent to the treatment well up to ~100 m away. In Figure 16 we show panels from the 6 dipoles for 3 hours of noise data (30 minutes per plot) from 1830 to 2130 GMT. Spurious noise transients can be seen in all plots, which is expected in areas with cultural noise. In the third panel, an abrupt change in the character of the ambient noise can be seen, which corresponds with the initiation of the fracturing process.

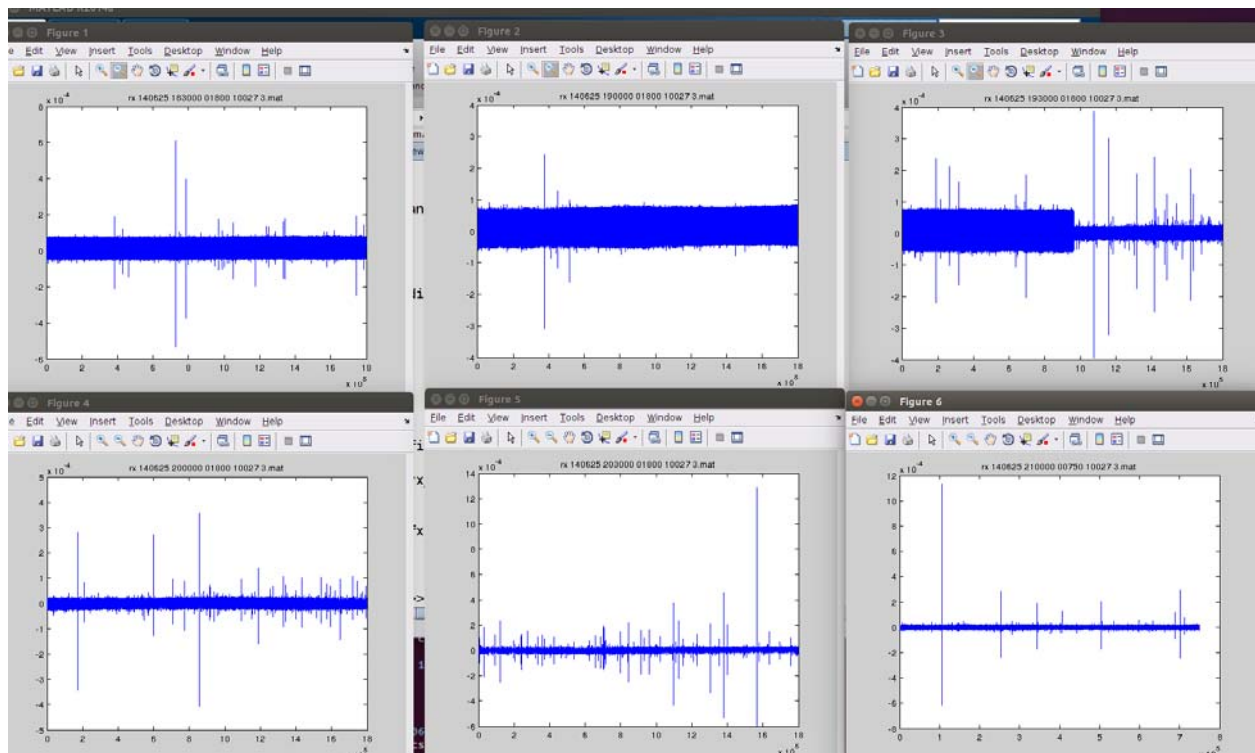


Figure 16. Noise measured at various locations on the frac'ing site

The high levels of background noise and site restrictions meant that the placement of sensors and the attention to detail were critical in collecting a useful set of data. Placement near the pumps and generators would be too noisy even for a 32-bit recording system. Fortunately, with this operation the fracturing occurs in horizontal wells almost 1 km from the wellheads, where the noise is somewhat more manageable.

The survey plan took the modeling, scout trip and site restrictions into account and is shown in Figure 17. The symbols marked with stars and the “TX” indicate transmitter positions. TXDHS is the position of the downhole source; the other Tx positions are surface transmitter electrodes used for a surface-only array to characterize the near surface geology. Locations marked as circles are receivers. These constitute a DAS and four electric-field sensors, deployed as two orthogonal dipoles oriented N-S and E-W.

The plan orients the transmitter field between TXDHS and Tx1 to generate a N-S primary electrical field, roughly in line with the horizontal well trajectories. Hydraulic fracturing is expected to be roughly perpendicular to this trend, or in the E-W direction. In this configuration

the measured field will more clearly reflect the secondary field due to the enhanced conductivity of the fracture. In the modeling, we see a 10x reduction on the E-W although the fracture field is roughly the same for both components. This thereby enhances the detectability of the fracture field in the E-W component.

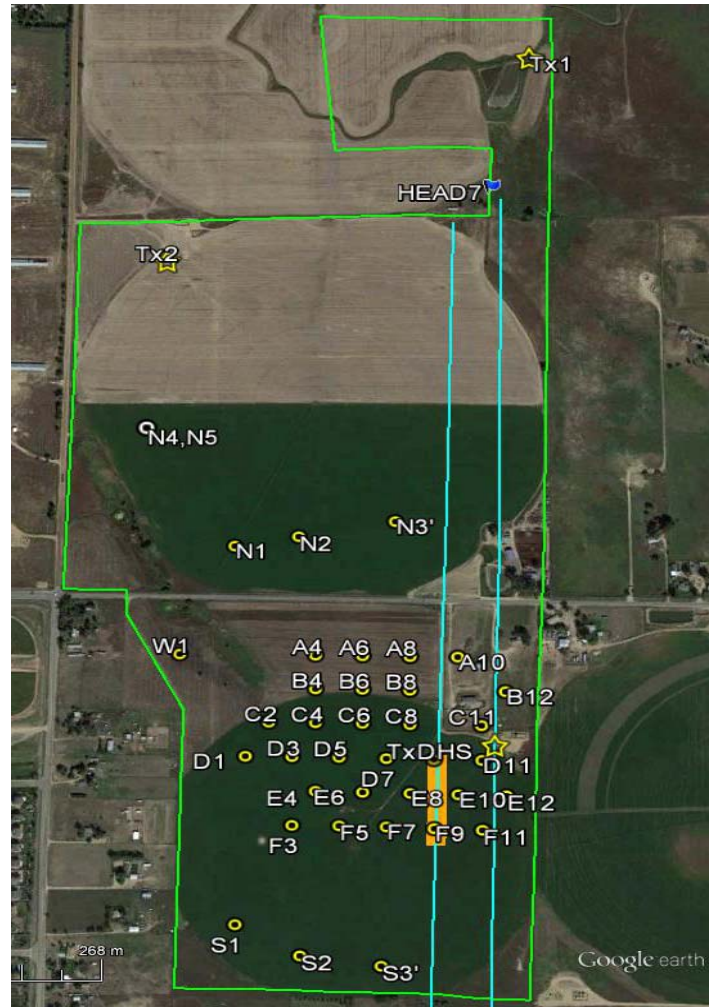


Figure 17. Sensor array and well containing the downhole source (right aqua line) and the well where frac'ing occurred during the test (yellow rectangle)

5.3.4.2 Subtask 4.2. EM data collection

The field crew arrived in Colorado on July 7, 2014 and began deploying equipment. Laser equipment was used to set locations and maintain planned configurations (see Figure 18).



Figure 18. Using 4-way laser to line up orthogonal dipoles

The field crew installed a suite of two pairs of orthogonal magnetic field sensors and one orthogonal electric field sensor, 60 km to the northeast of the test site. These sensors were intended to measure the atmospheric electromagnetic field at a remote location where there is no measurable signal from the DSR source. The magnetic component of this field is coherent over 100s of kilometers and is used as a reference to mitigate the natural electromagnetic field at the fracturing site.

A commercial transmitter was used to provide the source current. The transmitted current was measured by the proprietary current monitor system described in 5.2.1. The transmitter, current monitoring system, and rented electrical generator as deployed at the test site are shown in Figure 19. The transmitter output was a 100% duty cycle square wave of fundamental frequency 0.6 Hz and amplitude 15 A. As discussed below for one of the frac stages we also applied a 50% duty time-domain waveform.



Figure 19. The DSR source transmitter (front left), two channel current monitoring unit (front right) and electrical generator (rear) as deployed at the site during the fracturing experiment

We arranged for a wireline truck to lower a custom-designed electrode down a well adjacent to the frac well. By this time, 24-hour frac'ing operations had commenced and the installation took place at night as shown in Figure 20. The current electrode was connected to the wireline conductors to carry up to 20 amps of low frequency current. This 1 ⁷/₈" device, which is small enough to move through tubing, contacts the well casing with a bow spring centralizer. The downhole electrode was installed and moved down the well by wellhead pumping, with the position measured with the wireline cable.



Figure 20. Downhole electrode installation into the well

For this survey three of the fracturing stages applied high salinity brine instead of low salinity water as the fracture fluid. The brine, with a conductivity of roughly 50 Siemens, enhanced the response from the induced fractures. Tracers were also pumped into the brine stages, and the brine pump cycle was 3000 bbl, 4000 bbl, 0 bbl, 3000 bbl. An overview of the entire frac'ing site showing the red brine trucks is shown in Figure 21.



Figure 21. Aerial view of the site

The survey was carried out as planned in July, 2014. During the data acquisition, we compared the measured surface field to the output of our forward 3DEM model of the well and local geology. The results are shown in Figure 22. The level of agreement is very encouraging and an indication our EM model of the vertical + lateral casing is accurate.

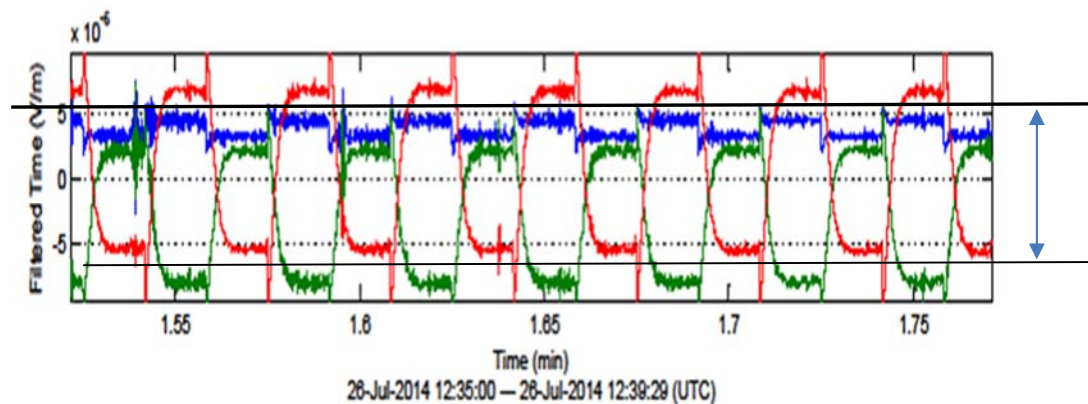


Figure 22. Comparison of the predicted surface E-field from the 3D model ($0.44 \mu\text{V} \times 14.92\text{A} \times 2 = 13.13 \mu\text{Vpp}$) and the measured field of $13.085 \mu\text{V}$

5.3.5 Task 5 - Quantify the Resistivity Change Produced by Hydrofracturing

The goal of Task 5 was to process the data collected in Task 4 to identify an EM signal

unequivocally related to hydrofracturing in the expected region. The continuous data recording, including background segments, allowed us to search for a “frac” signal within the background data. That is, we will be able to subtract a background response and thereby better isolate the frac signal.

Data processing consisted of a multi-step process. As the first step, the coherence of the measured electric field at each sensor location with the applied current waveform was calculated over a period of two minutes. The component of the measured electric field that was coherent with the transmitted current was then divided by the transmitted current to obtain a transfer function (TF) measured in V/m per $A = V/Am$ for each sensor axis and each sensor location. In addition, we did painstaking removal of background noise spikes and other man-made noise events. We also applied remote station data to remove background trends due to natural field noise in the data (see below).

5.3.5.1 Subtask 5.1 Process DSR data to extract the EM signal change due to frac'ing

Focusing our attention on sensors far from the fracturing zone, which are termed the *reference sensors*, we established the smallest detectable signal change during the fracture test. The variations in TF for channel 1 (east – west) and channel 3 (north-south) of the reference sensors are shown in Figure 23. The purple shaded areas correlate with fracturing activity in the treatment well.

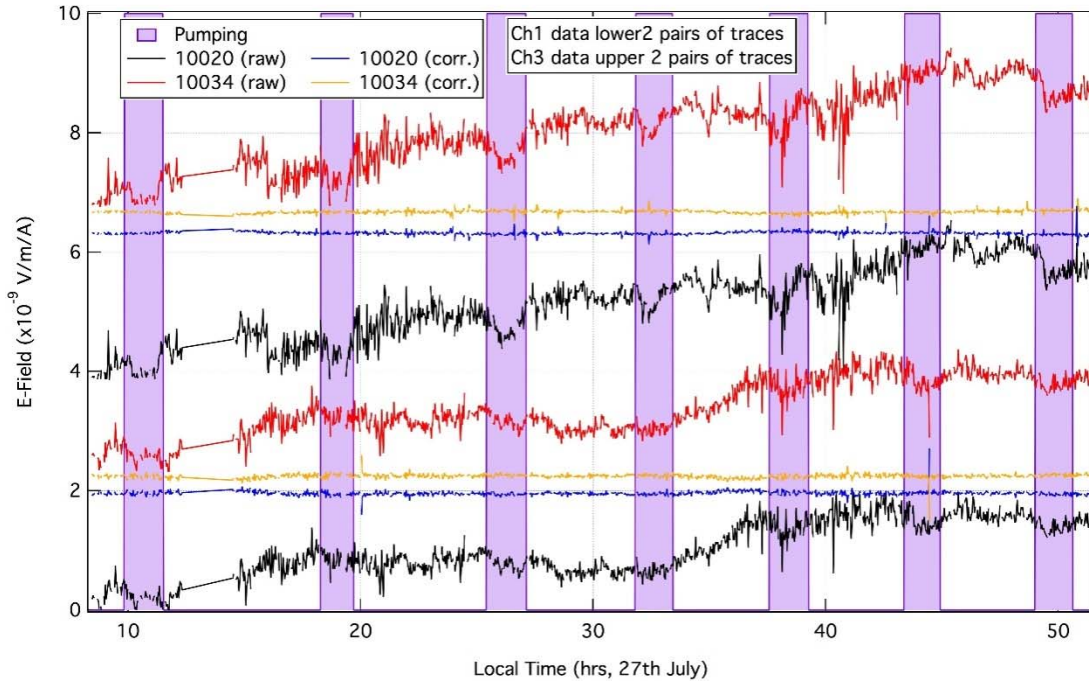


Figure 23. Variation in TF for channel 1 (east – west) and channel 3 (north-south) of reference sensors over two minute intervals. The corrected curves (yellow and blue) are data after subtraction of the interference common to both channels.

It is clear from Figure 23 that there is external interference of approximately 0.5 nV/m that is being recorded in all four sensor channels. To reduce the presence of this common noise in the data, a regression fit was performed between the E-W channels (ch1) of the reference sensors, and the resulting equation was then used to subtract the common signals. This procedure was repeated for the N-S channels (ch3). The result of this cancellation is plotted with yellow and blue lines in Figure 23. The apparent upwards drift in the data was completely removed. The standard deviation of the cancelled data varies from 0.030 nV/Am to 0.040 nV/Am for the four interference-mitigated plots in Figure 23 over the entire 48 hours of the test. After processing these data, the standard deviation is reduced to 0.01 nV/Am. This value essentially corresponds to the internal noise level of the electric-field sensors under shielded laboratory conditions and is an exceptional result for field operations.

Figure 23 gives a level of confidence that the deployed sensors accurately recorded the ambient electric field. To quantify the accuracy further, an internal calibration circuit within each DAS

was activated approximately every 30 minutes to quantify the stability of the acquired data. The DAS outputs a nominal 1 V signal that is passed to the input of each sensor in turn. Diurnal deviations of order 10^{-4} V are apparent in each channel, with a standard deviation over the entire recording interval of approximately 20 ppm. The accuracy of the measurement is the combination of the 5 ppm to 30 ppm measurement error of the transmitter output current and the 10 ppm to 35 ppm error of the surface electric field.

We applied a similar data processing scheme to all surface sensors. Data were corrected for the transmitter current, and averaged in intervals continuously during the multistage frac operation. We then subtracted the background field from the corrected voltages to isolate the signal from the ongoing frac operations. We plot these data in Figure 24.

Figure 24 shows difference fields in the N-S and E-W directions during 7 stages of hydraulic fracturing with the high salinity stages marked with the orange boxes. The plots show a highly variable field in the E-W direction and a roughly constant field in the N-S direction. The maximum signal size is roughly 4% of the total E-W field.

We note that the size and direction of the frac signal is in line with predictions made above, where by design we expected to see the field only in the E-W component. The oscillatory nature of the field anomaly is also expected as frac fluid in each stage is injected and dissipates into the formation. The complexity of the fields during non-saline stages is not fully understood at this time but clearly the effect of hydraulic fracturing and the interaction with the formation is not a simple event.

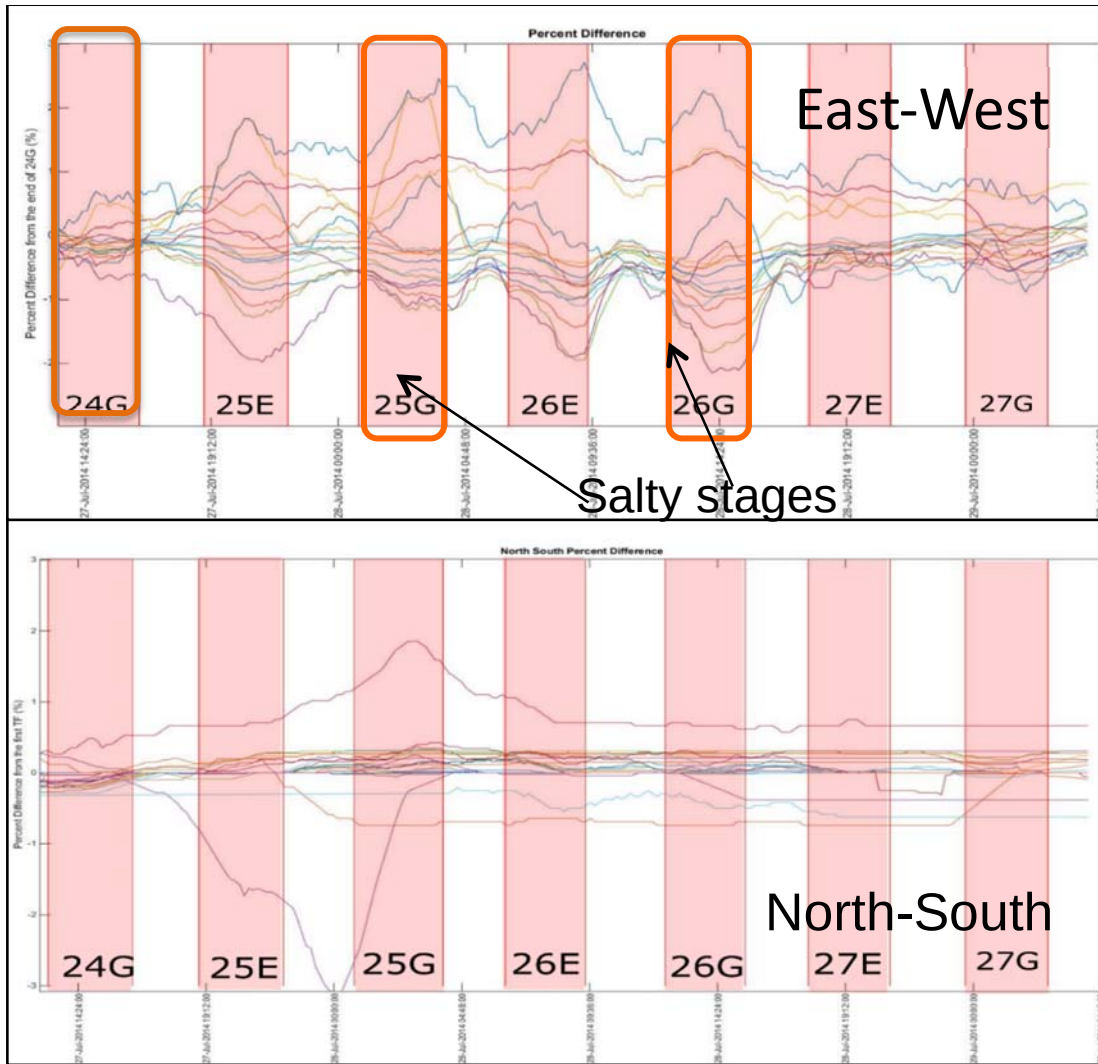


Figure 24. Electrical field change over 6 frac stages

5.3.5.1.1 Time domain processing

As noted above we also collected some 50% duty cycle, time domain data over one of the salty frac stages. In Figure 25 we plot stacked waveforms over the frac stages using N-S and E-W sensors from a single station. The pre- and post-stack differences clearly show frac signal in the E-W sensors but not the N-S ones.

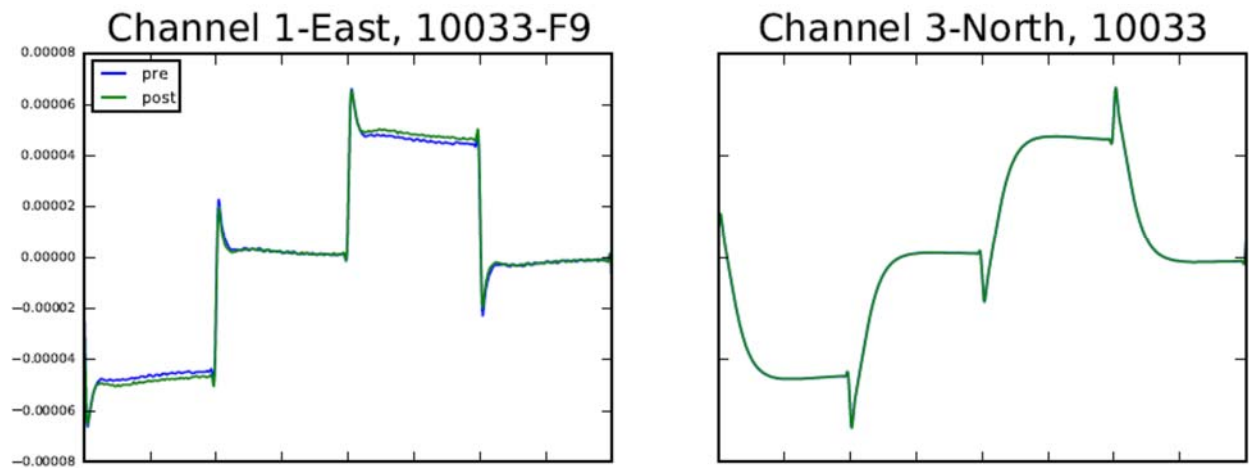


Figure 25. Time-Domain waveform data

5.3.5.2 Subtask 5.2 Develop 3D inversion

This subtask is discussed in Section 6.1.

5.3.5.3 Subtask 5.3 Quantify DSR signal of hydrofracturing

In this task, we determine a suitable resistance change characteristic of a frac'ing induced fracture and convert the DSR subsurface resistivity image to a hydrofracture image. We planned to correlate the subsurface features with the known and projected geology. We then planned to compare the DSR-derived image in a side-by-side manner with the conventional microseismic image.

Figures 26 and 27 show the data anomaly produced for the time domain processed during frac stage 26G. The colors indicate the degree of change in the pre-frac/post-frac data comparison – the legend appears on the right of the figure. As predicted, the E-W sensors showed a much larger change than the N-S ones. The dashed and solid lines indicated the expected extent of induced fractures; dashed lines are high salinity stages.

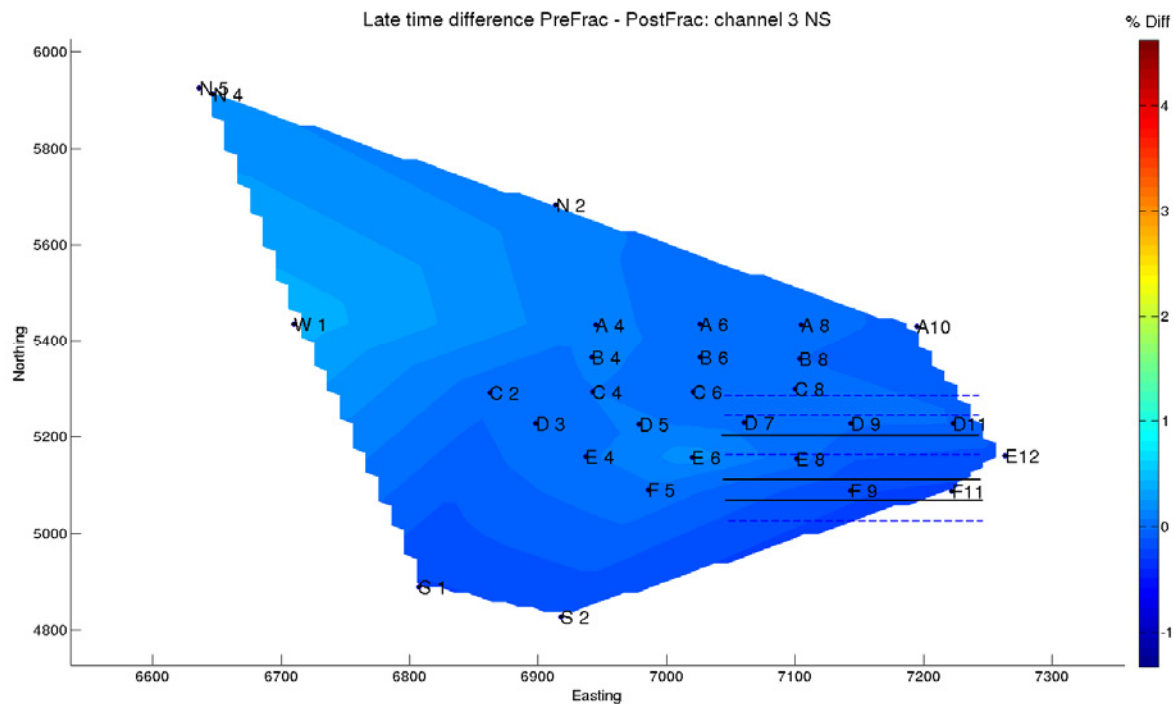


Figure 26. Degree of change pre/post frac; N-S sensors

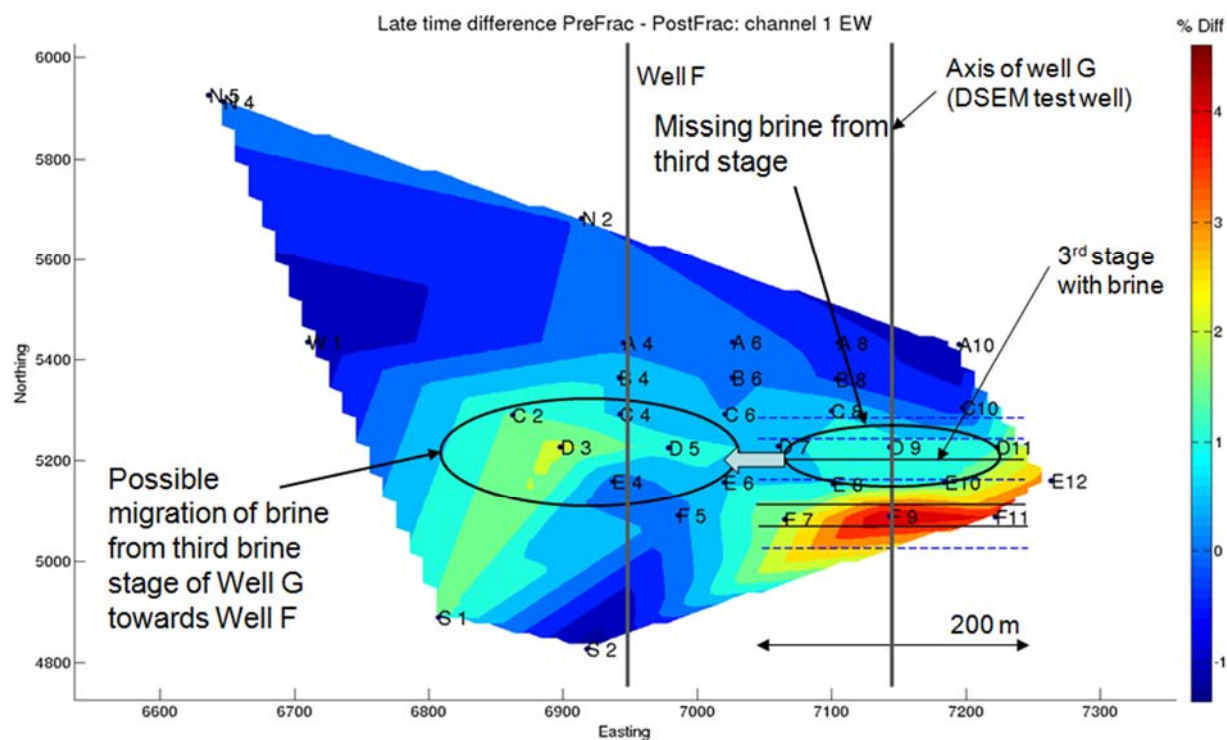


Figure 27. Degree of change pre/post frac; E-W sensors

The largest change in electric field is located above the two consecutive brine fracture stages. Even more interesting is an anomalous response around 200 m to the west, which indicates a conductivity change above noise level at station D3. We considered the possibility of poor data on the sensor located there and reprocessed that site with a robust, outlier-rejection method, but the anomaly remained in the data. We have since interpreted this to indicate that frac fluid from at least one of the stages migrated several hundred meters to the west. This interpretation was later confirmed by presence of the tracers injected with the brine stages.

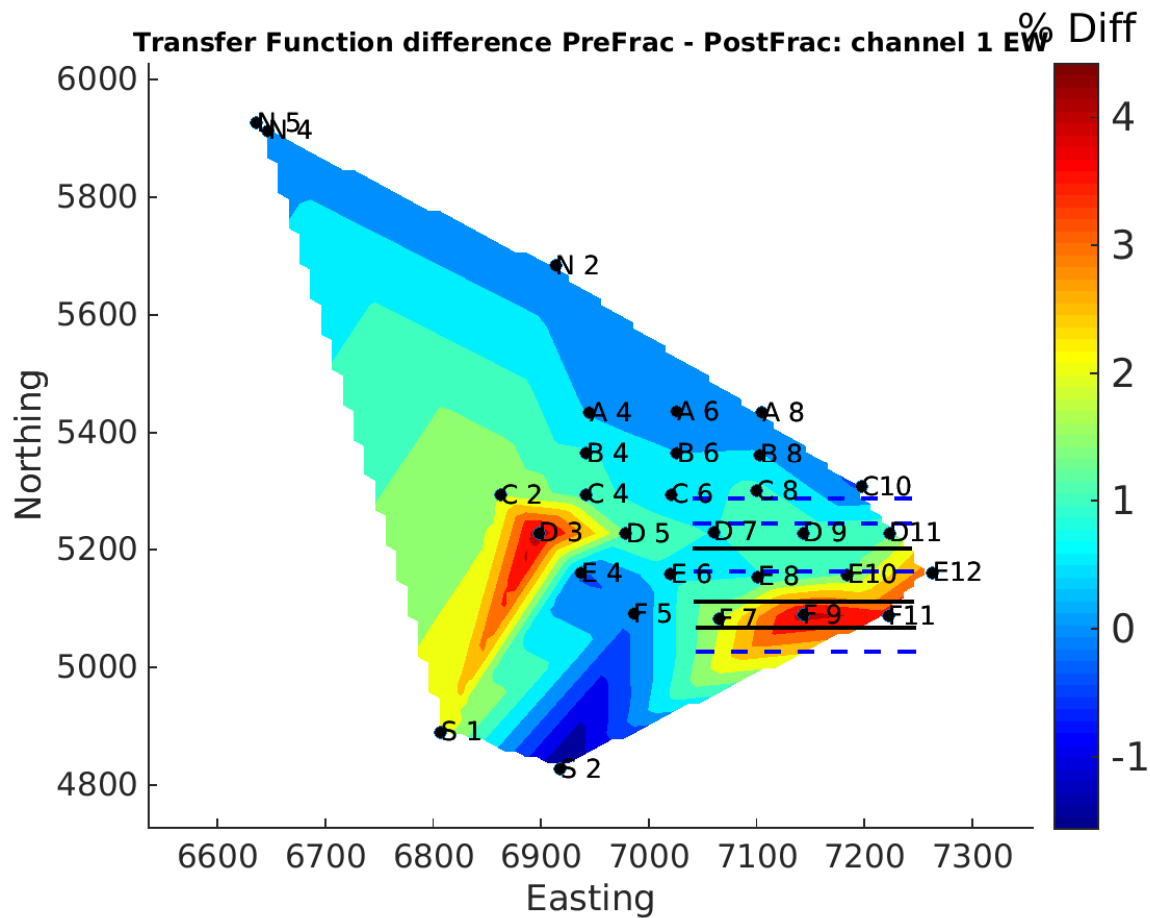


Figure 28. Equivalent processing of all frequency data from all stages

Data were processed in the frequency domain (Figure 28) are mutually consistent, indicating the signal is robust and does not depend on a specific set of processing steps applied to the data.

The above anomaly maps show a clear indication of the surface electric field anomaly due to

hydraulic fracturing events. The data show a larger field in the high salinity stages and no anomaly in the N-S stages. This anomaly roughly correlates with the expected position and lateral extent of the fractures and it is tempting to suggest that this data treatment is sufficient to mark the fractures. We explore this further below.

Figure 29 combines the percent-change in electric field data together with the microseismic results. The stars represent locations of several relevant fracture stages monitored by both the microseismic sensors and our DSR system. Red circles indicate the locations associated with microseismic events occurring as a result of brine injection (and the blue circles with freshwater frac'ing).

The dark reds (more significant conductivity changes) spatially correlate well with the high density microseismic events. Similarly, the lighter red tones (fewer significant conductivity changes) correlate with regions of lower density microseismicity. Both datasets agree and reinforce each other, lending increased confidence that the brine did move almost 1000' to the West. The electric field data however indicate much more clearly the region being affected by the injection to the West.

A surface map of the microseismic events record during the fracturing was forwarded to us by Encana. These data mark all of the record events during the fracturing that could be picked and located. We show this map together with the EM anomaly in Figure 29.

We do see that the events are more numerous in the zones of higher EM anomaly, to the east of the treatment well. This suggests that there is more fracturing and fluid injection in this direction. We also note that the microseismic events do not cluster together to form linear fractures, as expected for this operation. This may be the result of noisy data, a poor background velocity model or a more complex induced fracture system.

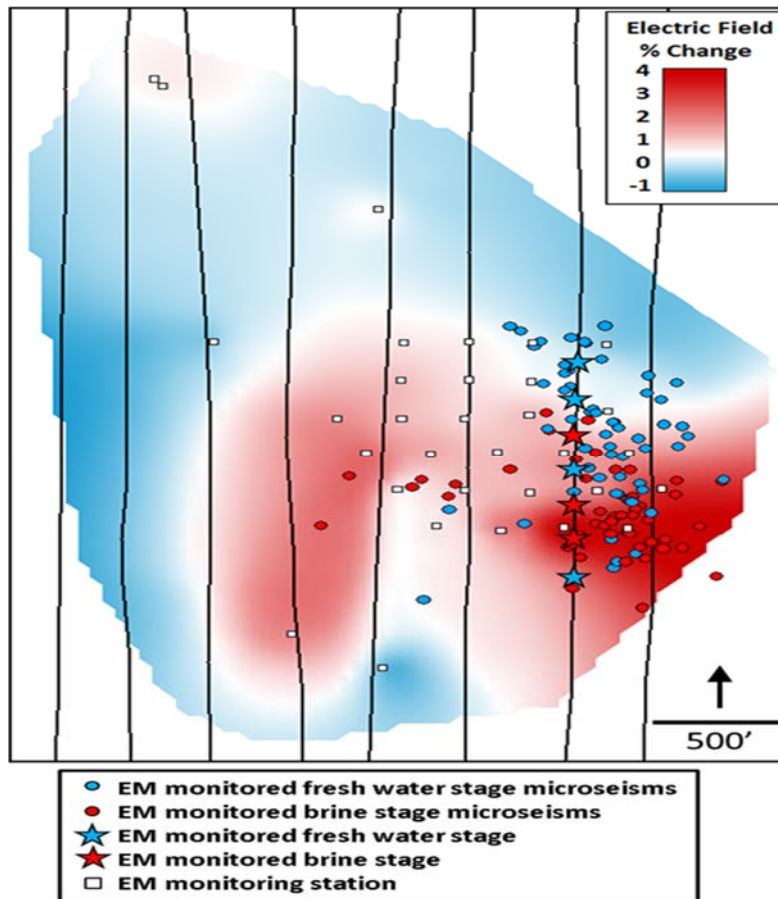


Figure 29. Microseismic/EM comparison

5.3.6 Task 6 - Project DSR Benefit for Hydrofracture Applications

The ultimate goal of this program is to quantify how well an in-situ measurement of bulk electrical resistivity can be related to the changes in rock properties that occur as a result of hydrofracturing. This comprises more than simply proving fracturing causes a measurable resistivity change (Task 5), and in Task 6 we will interpret collected data using forward and inverse geophysical codes.

5.3.6.1 Subtask 6.1 Use DSR alone to image fluid penetration and SRV

Our plan was to incorporate the combined 3D code developed in Subtask 2.2 into an iterative inversion architecture. This 3D code was adapted to include a horizontal casing under Task 2.2 and then used to generate subsurface resistivity images from the data prepared in Task 5.1.

To accomplish data inversion, we began a collaboration with the University of British Columbia

to modify 3D code to model and invert electrical data from a distributed (casing grounded) source. The process involved considerable development and testing but ultimately it has provided a very useful tool in processing DSR data. Figure 30 shows a comparison of the surface field calculated by the modified code and our 2D code used to calculate the field from a line of current sources in a well.

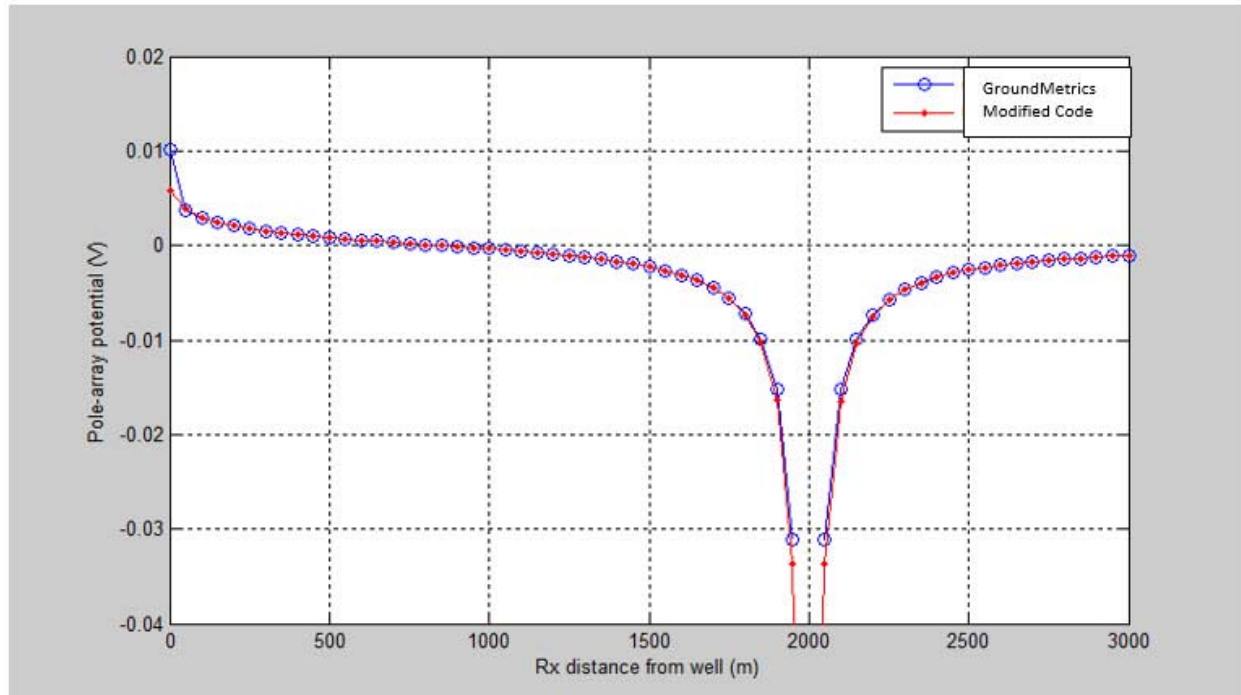


Figure 30. Comparison of the modified code with the present GroundMetrics 2D code for a uniform Earth model

Although initial results are promising, the full test comes from fitting the collected field data to a numerical model that includes a fractured rock volume. This sort of inversion had never been successfully performed. It involves fitting tensor electric field data to a 3D distribution of resistivity, including a series of induced fractures, using well casing grounded electric current sources.

5.3.6.1.1 Unconstrained 3D inversion

In our first test we applied our full data set to a 3D inversion using the newly modified code.

This code uses iterative linearized inversion to fit collected data to model generated data. The

code utilizes a starting model, normally made from existing logs and other data, and adjusts the model parameters in various ways to minimize the data-model misfit. We applied a starting model based on interpolated wells logs in the field, resampled into 10 m blocks (Figure 31). The code then used a variety of inversion constraints to arrive at data misfits within a few percent. We used both N-S data and E-W field from surface and downhole transmitter positions in all inversions.

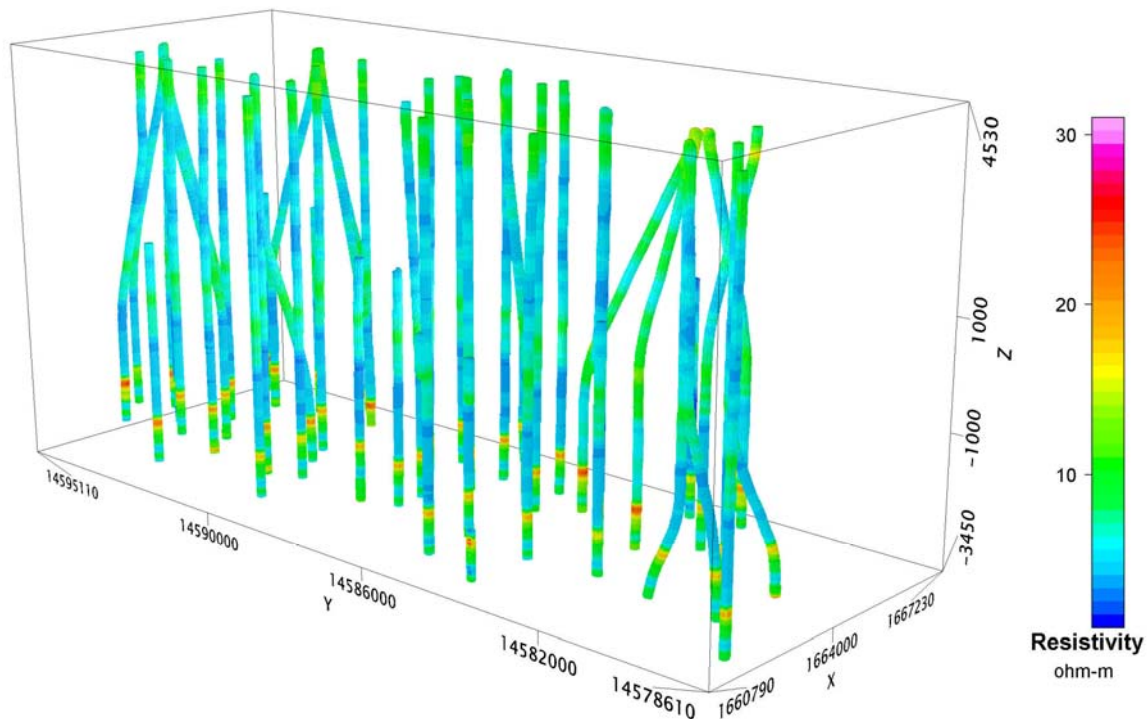


Figure 31. Resistivity logs in the survey area. Reservoir depths are 3450 ft in depth.

The workflow consisted of fitting data collected before fracturing began to a resistivity model and then using this model as a starting point to fit data collected after the fracture events. The difference in resistivity would therefore represent the formation changes due to fracturing.

Several things became clear from this workflow

1. The data fit to 2 percent of the total or so was not sufficient when the anomaly is roughly 0.4 percent of the total field. Although both field components are required to fit the background data the inversion should instead concentrate on the E-W component to do fracture inversion.

2. The collected data from a single downhole source were insufficient to image the induced fracture without many constraints.
3. The inversion code needed to be tightly constrained to fit data using changes in particular volumes only.
4. We needed to develop this workflow first using synthetic data so that we understood suitable model and data treatment.

5.3.6.1.2 Inversion of simulated data

The next step in the data interpretation is to tune existing inversion codes to invert a DSR data set for an induced fracture. Here we try to re-create the existing scenario but using “perfect” simulated data from a known model.

Although the data are perfect and the model is known the inversion of these data is a challenging procedure. In this case only one downhole transmitter site is available, and no downhole receiver sites. Secondly, the fractured volume (10m x 150m x 60m) is a very small percentage of the volume illuminated by the DSR survey. That is, the DSR arrays sample several km³ of formation surrounding the fractured volume. Finally, even with a target volume with a high resistivity contrast the expected field change is likely a few percent at most. All of these conditions suggest that the inversion needs to be focused and constrained to achieve a reasonable image of the target volume.

Of course a number of constraints can reasonably be applied. The imaged data will be a time-lapse difference. Secondly, since the background will not change we only need to image parts of the volume affected by the induced fracturing. This reduces the volume to be imaged considerably and improves the precision of the inversion.

Figure 32 illustrates the simulated data for this test. Here we consider a uniform volume with a single fracture at a depth of 2 km. We use a single downhole point source and a return electrode located northward. The fracture propagates E-W at the position shown. The “fracture” is a 120m x 60m x 60m volume of 3S/m conductivity. This is intentionally 5 times larger than the expected anomaly for the true fracture, to provide the inversion a better chance at imaging the target.

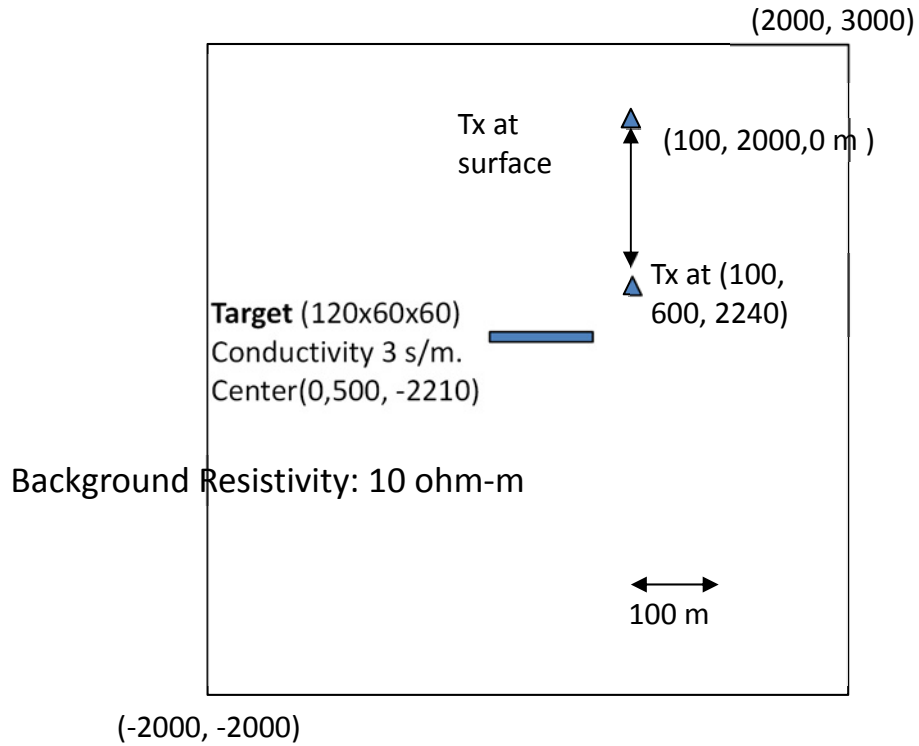


Figure 32. Model for the simulated Inversion

Using a single downhole source and an array of surface electrical field receivers we calculated the DSR field with and without the fracture and we display the absolute and percentage data differences in Figure 33.

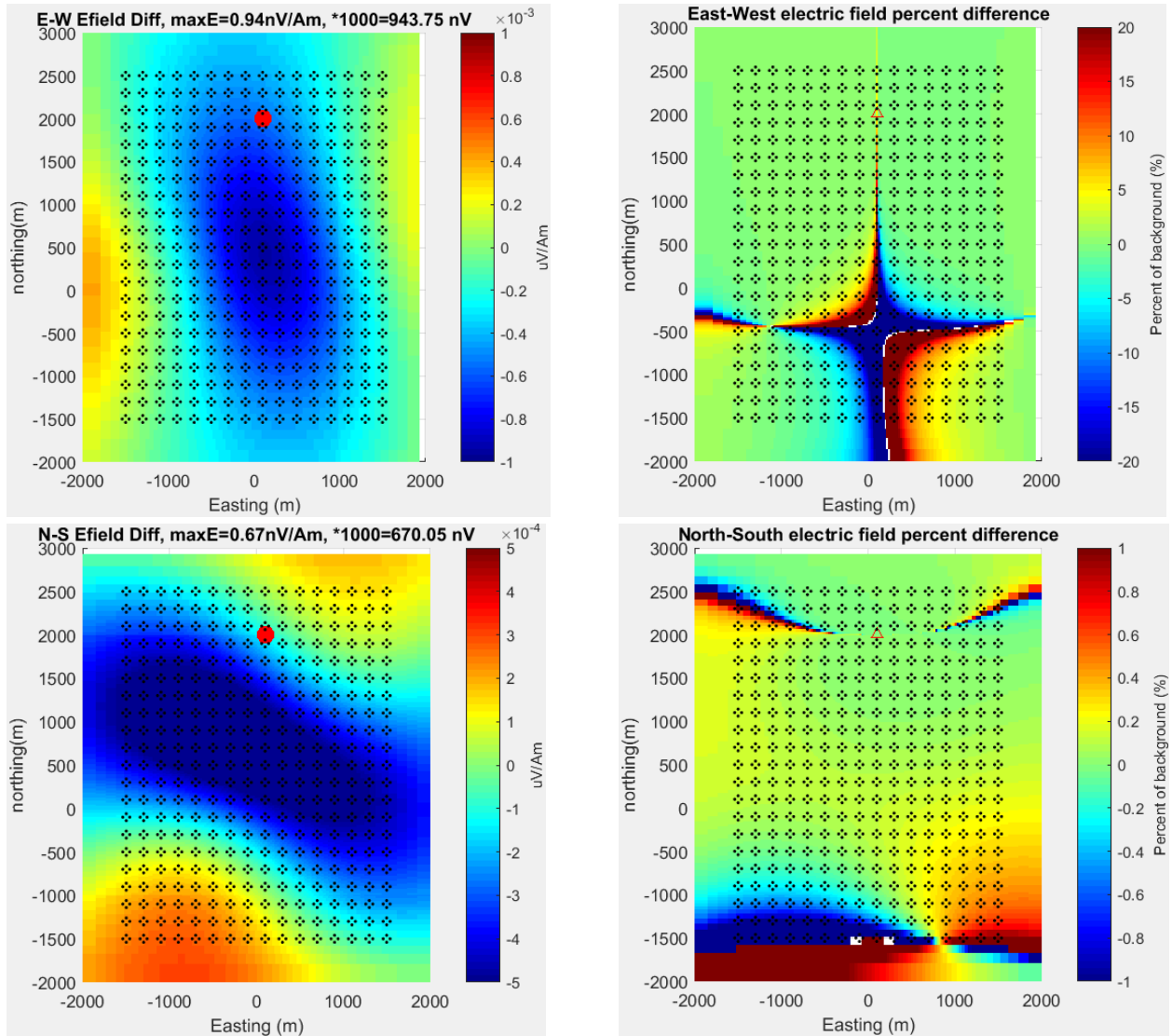


Figure 33. DSR Data differences with and without the fracture

The figure shows several interesting features. First we notice that the anomaly is a broad feature on the absolute difference map, about the same size on both the N-S direction and E-W direction. The map shows that the full anomaly covers a region of several Km on the surface.

We note however that due to the placement of the return electrode the primary field direction is N-S in the vicinity of the fracture, and the E-W field is quite small. The anomaly is therefore much more visible in the E-W data, showing a difference of over 10 percent, where it is less than 0.5 percent on the N-S data.

For the data inversion we tried several tactics. First we inverted all of the data and provided no constraints on the downhole model. The resulting inversion placed resistivity anomalies within a few meters of the surface receivers and close to the downhole source, and not near the actual target. Further trials with an unconstrained model produced similar unsatisfactory results. Data sensitivity is a challenge but can be mitigated by using justifiable constraints on the inversion model.

Next we constrained the inversion to change the model only at the depths consistent with the fracturing. In this case the inversion generated a model with anomaly near the downhole source, and not near the actual fracture (Figure 34).

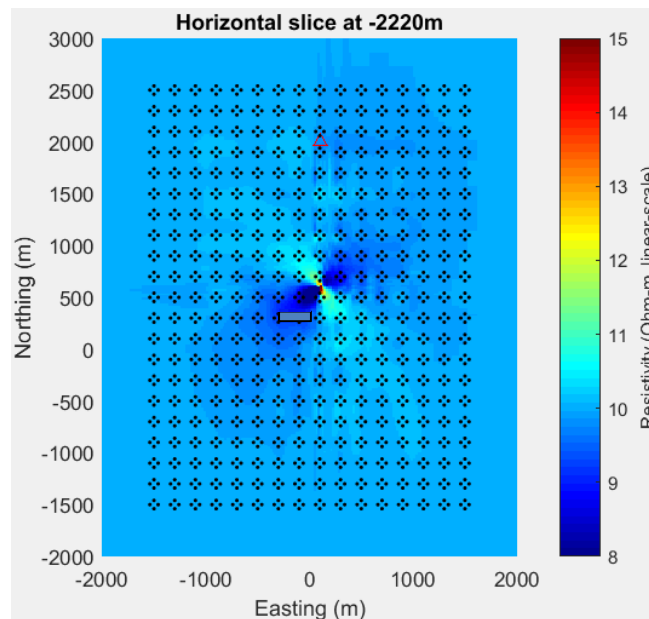


Figure 34. Reservoir constrained synthetic model

Finally, we constrained the inversion to a) only decrease the resistivity to fit the data, b) image a selected volume around the frac stage, and c) fit only the E-W component data. In this case the results were far better.

Figure 35 first shows the frac anomaly in true perspective, then an expanded view of the recovered anomaly compared to the true target body. Here we see that the inversion has placed the target fairly close to the true position.

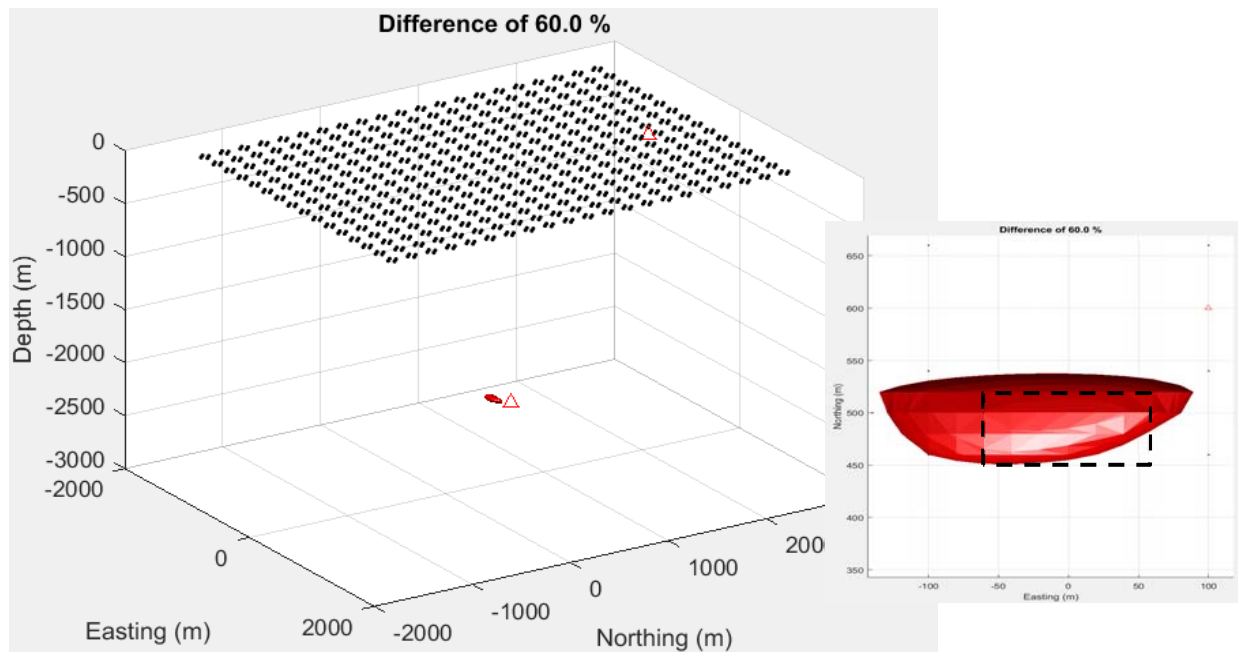


Figure 35. Inversion model for synthetic constrained data inversion

This exercise showed the difficulty in fitting a limited set of DSR data to even a well-known fracture volume. The problem is, in general, non-unique, under-determined (not enough independent data) and ill posed (not linear). We therefore need significant constraints to achieve a reasonable result.

For real data the added complexity is the heterogeneous and unknown background and the limited and imperfect data collected. We explore this below with the true data set. Here the process is multi-step. We first construct a background model, and calculate the true source currents in the steel-cased well. For this analysis we have limited our calculation to a single unconstrained inversion and a series of constrained forward models.

5.3.6.1.3 Step 3: Constrained 3D modeling

In this final data interpretation step we begin with a starting model as described above and use the modified 3D code to calculate forward models for specific fracture distribution and compare these numerical data to collected data. The goal is to produce an anomaly distribution based on a reasonable fracture distribution that fits the observed data within reasonable limits.

The modeling is all based on using a well casing source current with the true position of the return electrode and a volume and conductivity match for fluids and proppants injected during the operation. The fluid conductivity was determined using tables of electrical conductivity for fluids with varying salinity and temperature and was anticipated to be 50 S for the fracturing fluid used. The fracturing process was anticipated to produce 5% additional porosity in the fractured volumes which changes the resistivity from 20 ohm-m to roughly 0.5 ohm-m.

In Figure 36 we show the final model used to for the collected data. The model consists of 3 fracture stages each with 3 fracture distributions. The fractures are 5 m wide distributions of 0.5 ohm-m formation. The fracture stage corresponds to the salty stages used for the treatment. We note that three distinct fractures per stage were required to fit the data. Combining the fracture into one stage fits the E-W component data but not the N-S data.

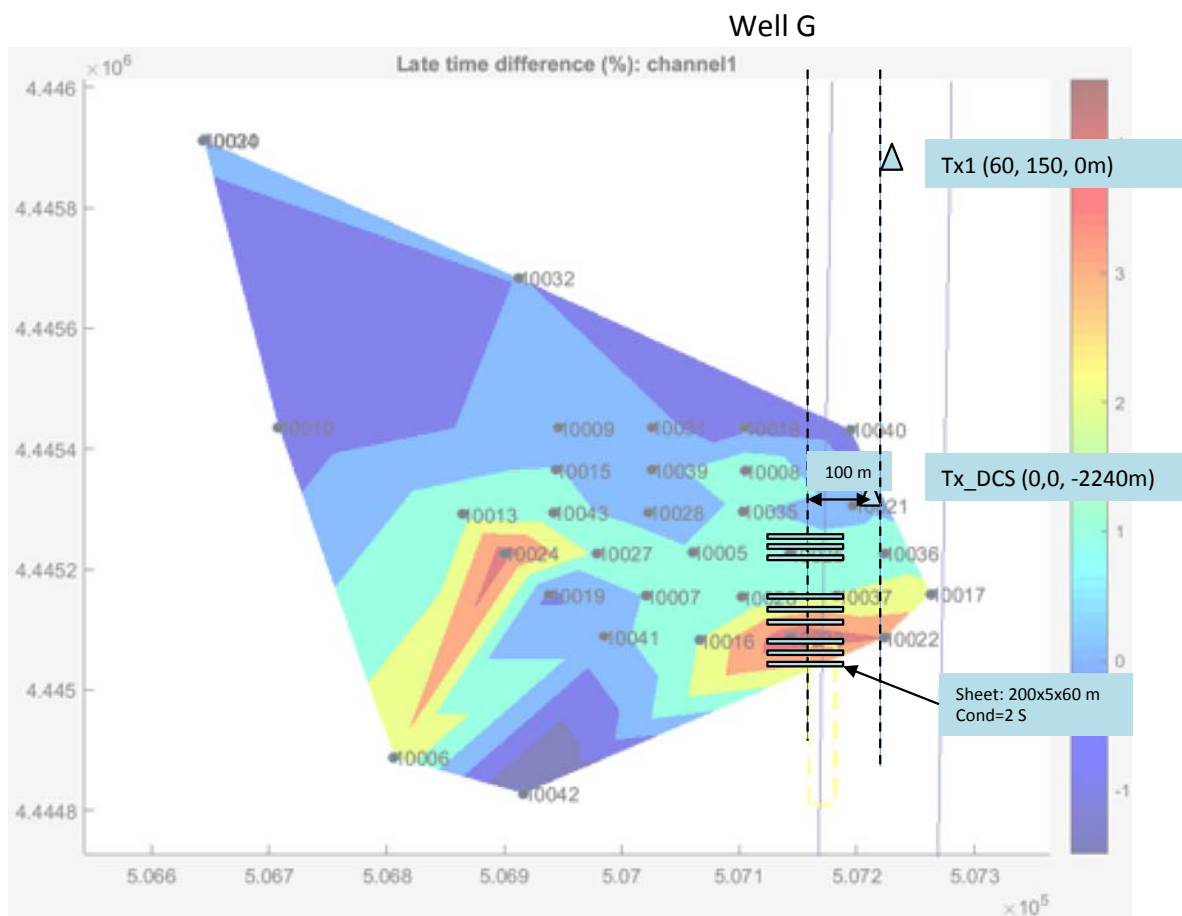


Figure 36. Forward model of the individual fractures superimposed on the collected data

In Figure 37 we show the forward model calculation using this model for the E-W component compared to the collected data. Here we note that the anomaly size predicted by the model is much broader than the observed anomaly from the EM data. This is mainly due to the incomplete sampling for the true data. If we reduce the array over which data are calculated, we find a good match between observed and calculated data (Figure 38).

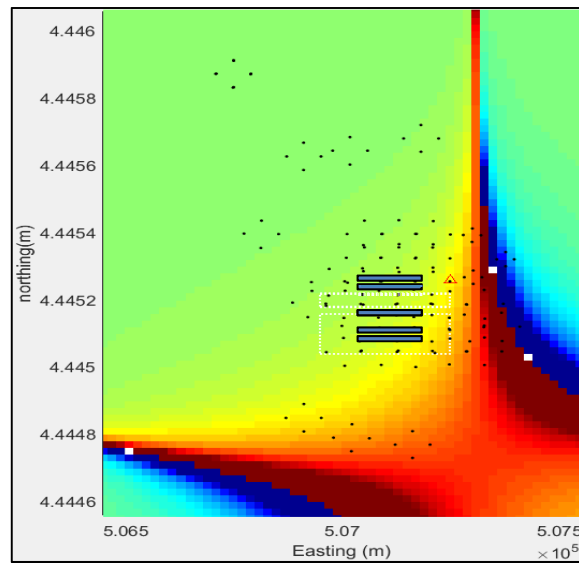


Figure 37. Forward model calculation for E-W component data

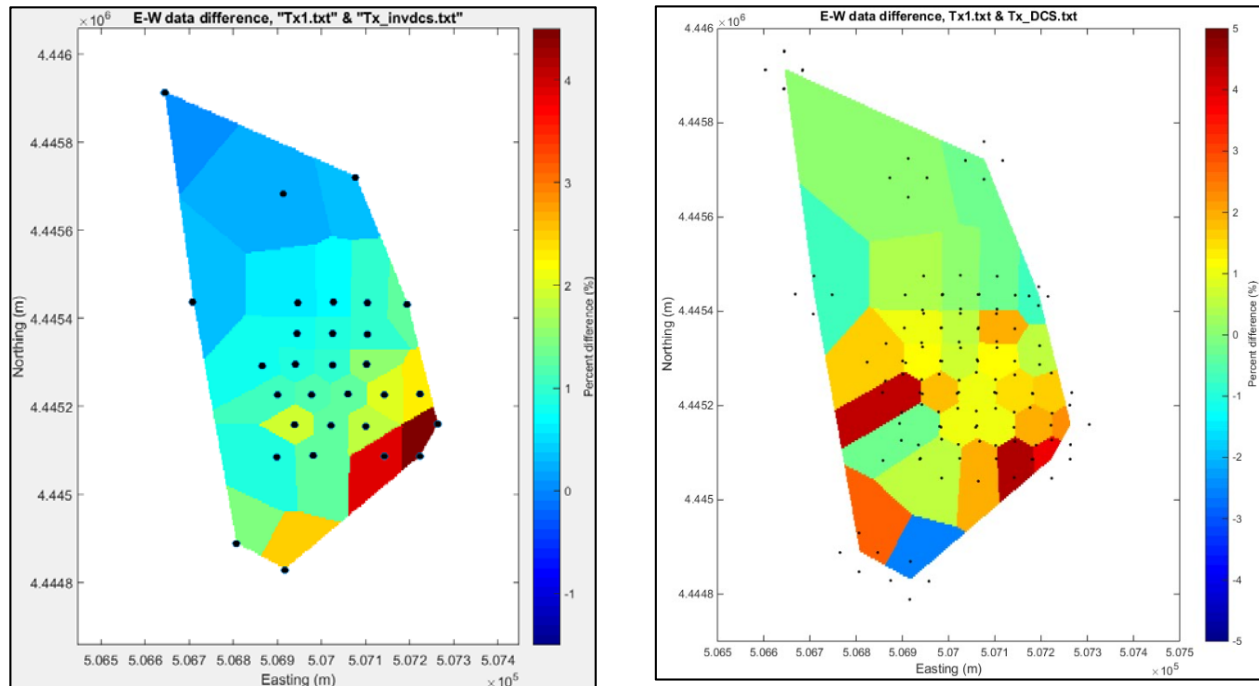
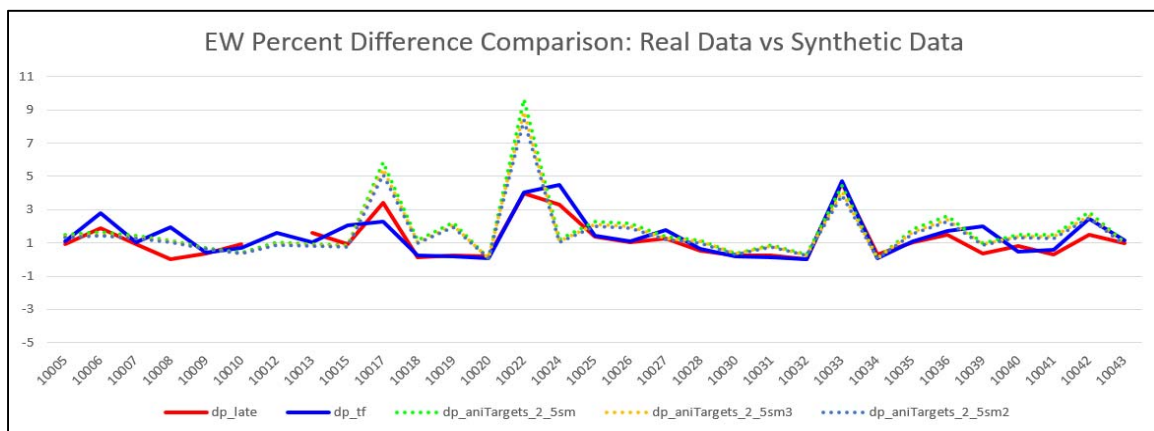


Figure 38. Forward model calculation for E-W component data (right) on a sample grid equivalent to the collected data (left)

Finally, the data fits for the individual station are shown in Figure 39. Here we profile plots of the E-W and N-S data differences compared to model calculations. The E-W and model data in general fit fairly well. The N-S data do not fit well, but note here the scale where the field are 0.3 percent or less of the main N-S. These data are therefore within the noise.



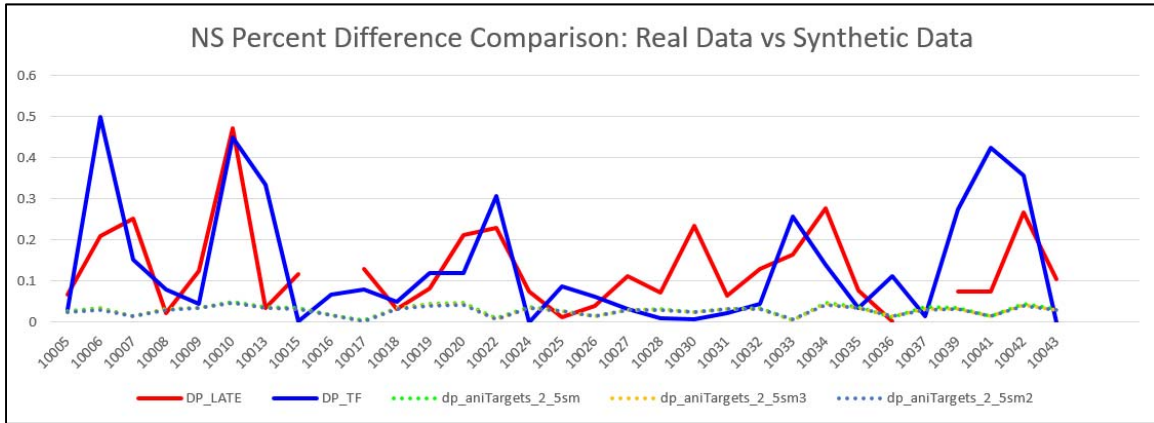


Figure 39. Line plot of the collected and model calculated data for E-W component above and NS component below

This model is to date the best representation of a fracture distribution based primarily on EM data.

5.3.6.2 Subtask 6.2 Use DSR to Augment a Microseismic Image

A surface map of the microseismic events recorded during the fracturing was forwarded to us by Encana. These data mark all of the record events during the fracturing that could be picked and located. We show this map together with the EM anomaly in Figure 29.

We do see that the events are more numerous in the zones of higher EM anomaly, to the east of the treatment well. This suggests that there is more fracturing and fluid injection in this direction. We also note that the microseismic events do not cluster together to form linear fractures, as expected for this operation. This may be the result of noisy data, a poor background velocity model, or a more complex induced fracture system.

5.3.6.3 Subtask 6.3 Jointly invert DSR and conventional microseismic data

The forward model displayed in Figure 37 is an example where the EM modeling was constrained by the microseismic active volume. That is, the data were used together to map the fracture distribution.

5.3.6.4 Subtask 6.4 Identify cases where DSR may replace microseismic methods

We will investigate and identify cases in which microseismic methods are not able to provide

adequate detection of fracture

Microseismic technology has been the main method used to monitor hydrofracture operations. The method relies on elastic deformation of the formation to produce micro-tremors that mark the fractured volume. The method does not necessarily provide a signal from the open or propped portion of the stimulated volume, will not provide any signal from less brittle formations and may map events outside of the target layers, unrelated to the operation. An additional issue is that the event accuracy is a strong function of the number of sensors and their position relative to the fracture. In normal operation the located events constitute a “cloud” surrounding the stimulated volume

The DSR technology instead measures the effects of the injected fluid in the newly created porosity and thereby identifies the stimulated volume.

5.3.7 Task 7 - Project the Cost of DSR Surveys for Hydrofracture Applications

GroundMetrics has done a commercial hydrofracture monitoring survey and thus the costs have been established. The cost for any individual survey is dependent upon its size and scope, which depends on the number of wells and their depth. However, the average price is about \$200k/week. The survey we performed was not integrated with seismic but we know from industry experience that borehole microseismic surveys are generally priced at about \$35k/day + \$50k for mobilization/demobilization. If a customer desires joint interpretation, there is a charge of about \$25k for integration of datasets.

5.3.8 Task 8 – Technology Transfer

We have presented at the European Association of Geoscientists and Engineers’ (EAGE) 76th Annual Conference, the SEG 2014 Development and Production Forum meeting “Reservoir Characterization and Monitoring with Advanced Geophysical Technology,” and GeoConvention 2016. The DOE was acknowledged for the EAGE and GeoConvention submission. The Development & Production Forum was a presentation only. An abstract was also submitted to AGU Fall Meeting 2016, with a presentation that will likely occur in December 2016.

6. Products

The main product of this project is the capability to perform hydrofracture monitoring surveys. GroundMetrics has executed three commercial contracts using the capability established during this project. GroundMetrics has presented its methodology at SEG and GeoConvention, and is due to present further information at AGU's fall meeting in December of 2016.

7. Conclusion

By almost any measure the above described experiment was successful. Applying the Depth to Surface Resistivity (DSR) technology we were able to measure and validate the field anomaly due to salt water injection into an induced fracture at a depth of more than 2 km.

GroundMetrics developed instrumentation with sufficient sensitivity and bandwidth to recover an anomaly that was less than 0.5% of the total field. All this was accomplished during hydrofracturing activities and all of the noise associated with this process. We also showed that the recovered field anomaly was consistent with a water filled fracture of the size and orientation designed by partner Encana Corp. The survey served as a proof of concept that led to three additional commercial surveys including one project for which the results were published in the Journal of Petroleum Technologies, a leading technical journal of the oil and gas industry. This was indeed a proud achievement.

However, imaging these data presents a high level of complexity. The induced fracture constitutes a very small volume compared to the total volume sampled in the measurements, and thereby produces a small field anomaly, even where a downhole source is used. In addition, with only one downhole transmitter position imaging this volume becomes a very non-unique process, even with perfect data. We showed that interpreting these data without heavy constraints is impractical.

We are pleased with the progress during this project. Now that this project has served as a successful proof of concept, there are some possibilities for follow on work to make this tool simpler and more practical. We believe that the following topics need to be addressed to meet this need.

- Conductive proppants

- Although for this test a saline fluid was detected, this does not constitute a propped fracture. We need to be able to image the proppant itself and for this we need an electrically conductive product for testing. We note that several companies are developing such a product.
- Field deployment using multiple transmitter positions
 - We strongly believe that the existing downhole transmitter can be safely and effectively moved within adjacent wells to better image an induced fracture. We would like to test this during a new field trial.
- Using time domain or multi-frequency EM excitation.
 - Recent work has suggested that Electromagnetic Excitation can provide additional image resolution and detail about the proppant and fluid injection. This should be exploited more fully with numerical models and then brought to the field.
- Improved Imaging workflow
 - New models and inversion are required to better image induced fractures. This includes a workflow to better constrain EM images based on fluid flow or mechanical models and it also include better scaling and averaging relations that allow the EM data to image the fractures independently.
- Joint fundamental seismic and EM inversion.
 - Although we showed that the present seismic data set was not suitable for joint inversion, this is not universally true. We fully expect that high quality microseismic data can be used as an effective constraint on EM imaging and thereby improve resolution.

Finally, we must re-state that the need to accurately map the stimulated volume in induced fracture operations remains a key topic in unconventional resource development. That is, we need to have tools that can map the position of injected fluid and proppants and thereby understand the mechanism for petroleum recovery in these complex, low permeability unconventional fields.

We firmly believe that with the future recovery of oil prices the interest in developing improved technology for unconventional oil field management will re-emerge and with it a better capability to manage this uniquely American resource. We strongly feel that EM technology will be part of this future.

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10. List of Acronyms and Abbreviations

σt	Conductivity thickness product
Ω	Ohm(s)
2D	Two dimensional
3D	Three dimensional
A	Amp(s)
AC	Alternating current
ADC	Analog-to-digital converter
bbls	barrels
C	Celsius
cm	centimeter(s)
DAS	Data acquisition system
DC	Direct current
DCS	Deep casing source
DSR	Depth-to-surface resistivity
E	Electric
EM	Electromagnetic
E-W	East-West
ft	feet
GPS	Global positioning system
Hz	Hertz
km	kilometer(s)
l	liter(s)
m	meter(s)
NaCl	Sodium chloride
N-S	North-South
nV	nano Volt(s)
ppm	parts per million
pV	pico Volt(s)
S	Siemens
SIE	Surface integral equation
TF	Transfer function
TFI	Tomographic fracture imaging™
V	Volt(s)
VHF	Very high frequency
VIE	Volume integral equation