Evaluation of Deep Subsurface Resistivity Imaging for Hydrofracture Monitoring

Project Number: DE-FE0013902

Quarterly Progress Report
Project Period: Oct. 1, 2013 – Sept. 30, 2015
Period Covered: Oct. 1, 2013 – Dec. 31, 2013

for
U. S. Department of Energy
National Energy Technology Laboratory

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Jan. 30, 2014

Signed:_______________
Gayle Guy, Corporate Communications Manager
For Dr. Andrew Hibbs

1 Disclaimer

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3 Executive Summary

Hydraulic fracturing (fracking) has enabled commercial production from unconventional formations. However, fracking is more expensive than the conventional methods used to produce gas and oil, and fracked 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, triggering 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 is to quantify how well an in-situ measurement of bulk electrical resistivity using the new method of Depth to Surface Electromagnetic (DSEM) imaging can be related to the changes in rock properties and fluid propagation that occur as a result of hydraulic fracturing. Electromagnetic data will be 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.

This report covers the first quarter of the 24-month project. During this reporting period, we developed an approach to project fracture surface area from Tomographic Fracture Imaging (TFI) data, completed a preliminary calculation of the signal produced by a hydrofracture using an adaptation of a prior published model, and conducted an initial test of our new data collection hardware.

4 Accomplishments

4.1 Milestone Log

	Planned	Actual
Project Management Plan ***Status:*** Complete	**10/2013**	**10/2013**
M1. Completion of Code ***Status:*** To be completed January 31, 2014.	**01/31/2014**	
M2. Assembly of Sensor & Receiver Hardware ***Status:*** To be completed March 30, 2014.	**03/30/2014**	
M3. Completion of DSEM and Seismic Survey ***Status:*** To be completed August 15, 2014.	**8/15/2014**	
M4. Identify Change in the DSEM Data Due to Fracking ***Status:*** To be completed August 31, 2014.	**8/31/2014**	
M5. Invert Data to Produce a 3D Subsurface Image ***Status:*** To be completed September 30, 2014.	**9/30/2014**	
M6. Quantify Resistivity Change Due to Fracking ***Status:*** To be completed March 31, 2015.	**3/31/2014**	
M7. Define Clear Case for EM to Improve Hydrofracking ***Status:*** To be completed September 30, 2015.	**9/30/2015**	

4.2 Project Description

The specific problem addressed in this project is to quantify whether a measurement of resistivity can provide improved monitoring of SRV during fracking. DSEM provides the first capability to image resistivity in deep hydrocarbon reservoirs with horizontal completion. This comes down to two subsidiary problems: A) whether a sufficient EM signal exists when acquired via DSEM, and B) whether the EM data can be effectively combined with seismic data to significantly improve imaging and quantification of SRV. This project will experimentally address problem A. For problem B we will investigate three basic avenues to combine EM and TFI information using the data collected to address problem A.

The following work was completed in this reporting period.

4.3 Work Completed

4.3.1 Task 2 - Model DSEM Signal of a Fracture Network

The goal of this task is to estimate the range of surface electric fields for a typical fracture network. There are two basic steps: a) project the change in rock resistivity as a result of hydrofractures. We assume that the fracturing fluid is more conductive than the host rock and forms a connected conducting anomaly. The calculation will be 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.

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

The tomographic fracture images produced by our collaborator Global Microseismic Services (GMS) typically comprise a connected series of voxels where seismic energy was released. The critical unknown for projecting the resistivity change due to fracking is to estimate the width of the fracture. In this period we developed an approach to project the fracture surface area from the TFI data, and then calculate the average fracture width from the volume of fluid pumped. This is a new approach that has not yet been tested. In the first quarter, we assembled a complete set of TFI files, well logs and pumping information from a commercial frac job monitored by GMS.

GMS already determines the statistical distribution of fracture length. In this task we need to process the data to quantify the fracture area. This will be done in the following reporting period.

4.3.1.2 Task 2.1 Results

TFI data files are in the TSurf format. To open them in order to determine their surface area we are investigating either purchasing a commercial software package for seismic data or finding a freeware program produced by an academic geophysics group.

4.3.1.3 Task 2.2 Calculate surface EM signal

As part of another project that was completed in this reporting period, collaborator Berkeley Geophysics Associates (BGA) completed a preliminary calculation of the signal produced by a hydrofracture using an adaptation of a prior published model.[1] The calculation is for a single long fracture sheet extending 200 m away from the well and 100 m parallel to the well, at various lateral distances from the well, as illustrated in Figure 1. Rather than specify its thickness, the third dimension of the fracture was represented by a conductivity-thickness product, σt, determined by the average thickness of the fracture multiplied by the conductivity of the fluid in the fracture. For this initial calculation we used σt = 10, which is an upper bound value, corresponding to a highly conductive proppant material with very high conductivity (2000 to 5000 S/m) and a fracture opening width of 2 mm to 5 mm.

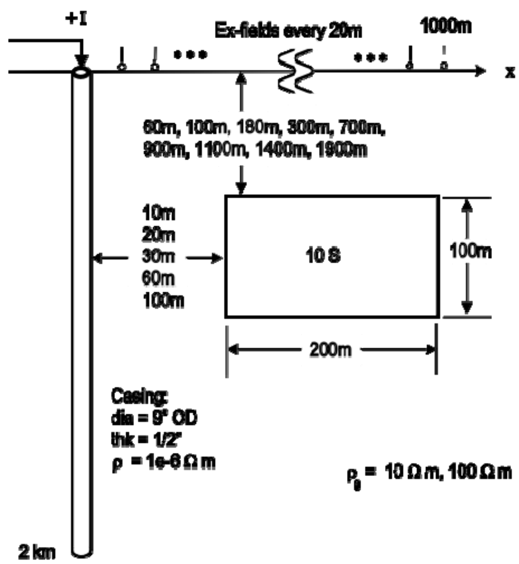

Figure 1. Schematic of the Geometry Used to Calculate the Field Produced by a Sheet Fracture for the Top and Bottom Source Configurations. Note Model is 2D.

The model was calculated for fractures at different depths down to the well depth of 2000 m. The results of this calculation are that for the measurement sensitivity we demonstrated for the new eQubes and Eos recorders, a sheet fracture at the full modeled depth is detectable out to the maximum modeled receiver offset distance of 1 km.

For this present program we need to model a signal produced by a 3D fracture in the vicinity of a horizontal casing. Our original approach was to marry the casing solution with the full 3D DC code developed by Dey & Morrison.[1] However, we later became aware of a subsequent code, based on Dey & Morrison, that was developed by 16 years later by Morrison and J. T. Smith,[2,3] another of Dr. Morrison's graduate students. This newer code utilizes a staggered non-uniform grid to remove the need for field transformations from boundary edges to voxel centers. Furthermore Dr. Smith is currently available to work with BGA in order to make the modifications needed to marry the two codes.

To calculate the surface signal we also need to know the variation of the Earth's resistivity with depth down to the basement layer below the formation to be fracked. Typically the resistivity structure of the formation is given in scientific publications, (see Figure 2),[4] and can be determined from standard well logs that are recorded from the bottom of the surface casing (~500 m) to the bottom of the well. However, for an accurate EM solution we need a resistivity profile that extends from the surface to at least a few hundred meters below the formation. To assemble this extended dataset we contacted the North Dakota Department of Oil and Gas, who were able to match a shallow drilled water well record to a nearby standard oil/gas well drilled to through the Three Forks formation that is 200 ft below the Bakken depth (~10,000 ft). They were also able to find logs for wells in the area that extended to 13,070 ft and 15,228 ft. Using this composite information we are constructing a 15-layer resistivity model of the Bakken.

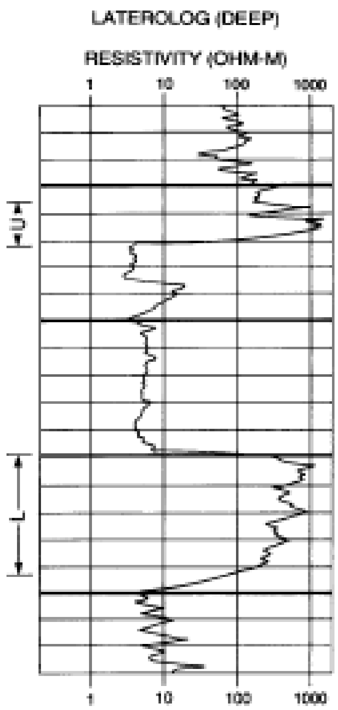

Figure 2. Standard resistivity log of the Upper (U), Middle, and Lower (L) Layers for the Bakken Formation.

4.3.1.4 Task 2.2 Results

GMI did not receive approval to incur costs until 11/15/2014 and thus we only activated BGA to begin work on December 1. At that point we initiated BGA to resurrect a 3D model developed by Dr. Torquil Smith and modify it to accept electric field inputs characteristic of an electrically driven casing. This code was completed on Dec 31 and was being tested and finetuned at the time of writing this report.

4.3.2 Task 3 – Expand Survey Capability for Simultaneous Monitoring

A hydrofracking 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 fracking process. At the time the project began, GMI had the capability to deploy up to 10 data recorders. To deploy a substantially larger number it is necessary to be able to monitor each sensor channel from central locations. To do this we are taking advantage of data recording and monitoring equipment used by the seismic survey industry.

There were three main areas of work on Task 3 in this reporting period.

1. **Complete and test a new data acquisition system.** Our present data recorder has a first stage input board that takes the analog difference of two pairs of eQube sensors, filters and amplifies the signal, and passes the output to an analog-to-digital converter. When selecting International Seismic's *iSeis* data recorder we performed a design study to modify these boards for the new hardware. In Task 3 we completed the integration, and named the resulting new system the Eos. International Seismic built a first run of 10 Eos units. However the GPS receivers (which were not modified in the new design) failed to work correctly on 3 units, and so they could not be shipped. We were able to configure our engineering prototype for field use as well, and a total of eight first version Eos units were tested in the field Dec. 3 – 18, 2013.
2. **Interfacing GMI's eQube sensors.** In order to improve reliability and reproducibility, we transitioned fabrication of our electric field sensors to an outside manufacturer. A number of minor design modifications were made to make the sensors easier to assemble to reduce component costs. A first batch of 28 sensors was purchased by GMI under internal funds. Two units were damaged beyond repair during assembly, but the remaining 26 were connected to recorders and worked well. These were our first sensors built by an outside supplier rather than in house, a crucial step towards large-scale survey viability.
3. **Initial Testing.** In May 2013 GMI received an Energy Innovations Small Grant from the San Diego State University Research Foundation to conduct a proof-of-concept DSEM survey at a geothermal well. The original plan was to use GMI's existing four prototype recorders and 16 E-field sensors. Instead we delayed the test until the end of the year in order to use the new equipment being developed for this program. By taking advantage of this other project we were able to test the new equipment much more extensively, and under much more realistic conditions than originally planned.

The field test took place in the Anza Borrego Desert 3 hours east of GMI's office in San Diego, CA. A diagram showing the layout of the survey is shown in Figure 3. The sensor line extended to 4 km (38 locations, 4 eQubes per location), with extended transmit (4 hrs) and sensitivity (72 hrs) runs. Despite the very challenging electrical environment of the arid desert in late fall, the equipment functioned very well with no breakages or loss of analog data. We did experience intermittent GPS failures on three of the units, but the other five worked without issues.

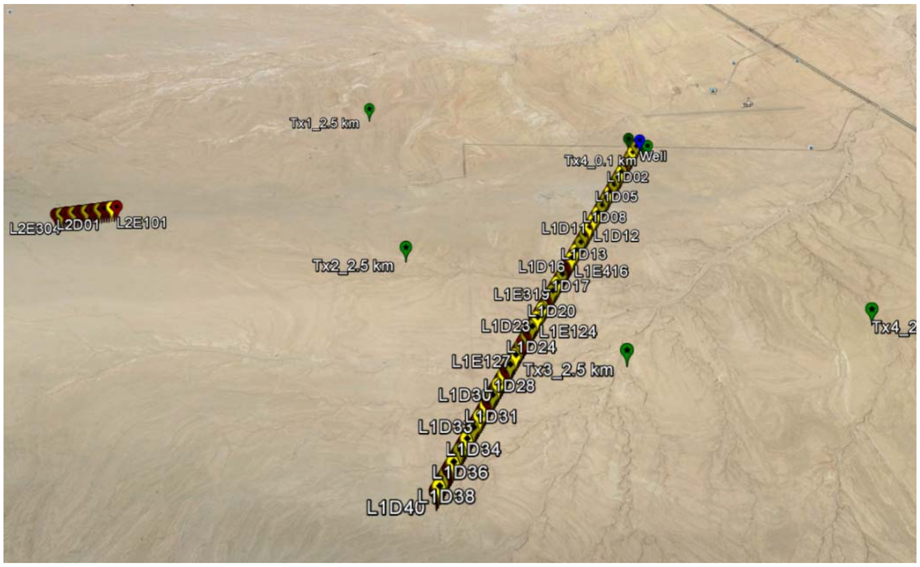

Figure 3. Survey Configuration in the Anza Borrego Desert. The Main Line Extends 3.4 km Southwest of the Well, the Longest DSEM Survey to Date.

Photographs of the equipment at the site are shown below in Figure 4. The eQube sensors and Eos units were placed on the ground without excavation, or other ground disturbance, which is an important practical advantage over prior electric field sensor technology. For this first test a variety of seismic data acquisition software was used to set up the Eos units and read back their data from a nearby laptop computer, because GMI's own EM software has not been developed.

Figure 4. GMI sensing equipment. Left: Most recent GMI eQube sensor. Right: GMI data acquisition units.

4.3.2.1 Task 3 Results

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 is 300 nV/mHz$^{0.5}$ at a frequency of 1 Hz and above, and 3 µV/mHz$^{0.5}$ at 0.1 Hz. This target is shown as the red dashed line in Figure 5. Also shown in Figure 5 is a typical noise spectrum for a pair of eQube sensors. At 1 Hz and above the noise is about 80 nV. Not all the data have been processed from all 114 data files as of the time of this report, but so far no sensor has failed the noise target.

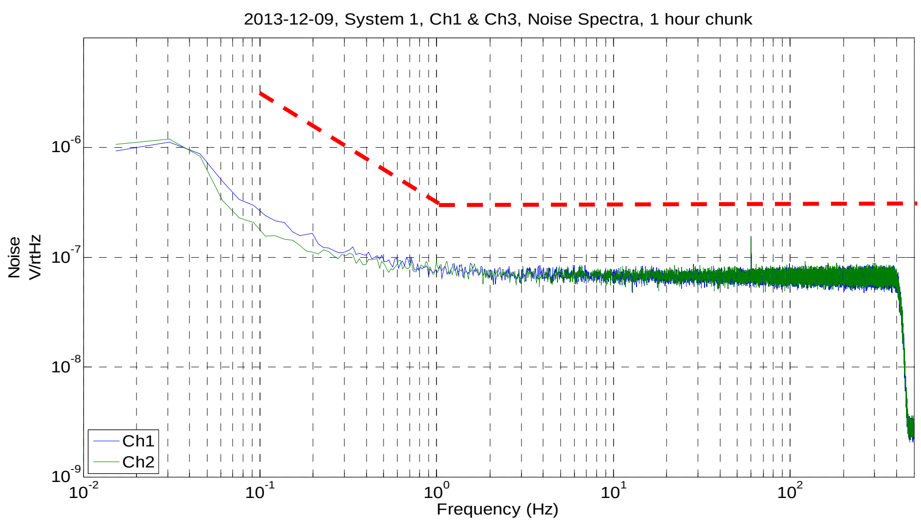

Figure 5. Noise Spectrum for Two E-field Sensors (Blue, Green) Compared to the Target Noise Level (Red Dash). At 0.5 Hz the Field Performance is > 5 x Better than the Target.

Figure 6 shows the effect of averaging the data from eight sensors (six measured E-fields) for a signal transmitted with fundamental frequency of 0.5 Hz with current of approximately 17 A (the majority of the survey was conducted with ~10 A). The vertical axis is the standard deviation of the transfer function (the TF), the part of the measured data that is coherent with the transmitted current, divided by the amplitude for the current. The TF has units of V/mA and its standard deviation is an accurate measure of the variation in the measured field, and thereby an accurate approximation of the minimum detectable signal. For a transmitter current of 10 A, a TF value of 10^{-10} V/mA in Figure 6 corresponds to a minimum detectable field change of 1 nV/m. After 128 averages the TF falls for all six measurement channels tested to approximately 10^{-11} V/mA (=0.1 nV/m for 10 A current). An individual data file is 16 seconds long, so 128 averages corresponds to 2048 s (34.1 minutes). In the field during a "plug and perf" well completion it is likely we could average for 2 - 4 hours, enabling further averaging and noise reduction.

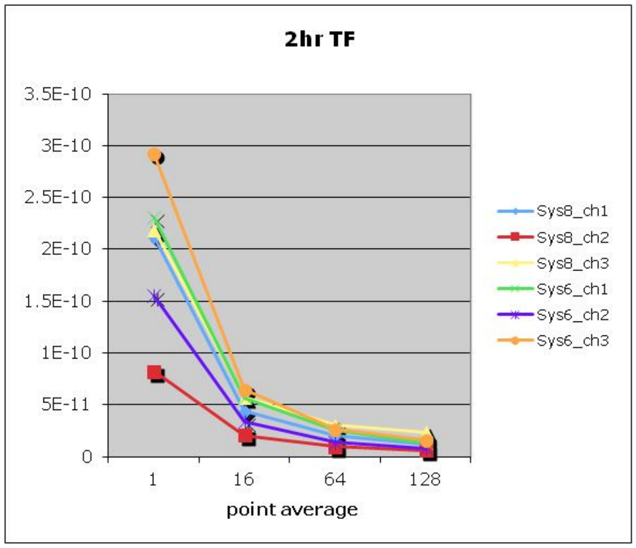

Figure 6. Reduction in the Standard Deviation of the Transfer Function vs. the Number of Averages.

4.3.3 Other Considerations

As this report covers only the first quarter of the project, the work has not yet reached a point for dissemination of information. Once we have processed project data of interest to the scientific community, we will submit papers to appropriate conferences.

4.3.4 Next Reporting Period

Goals for the next reporting period are on schedule. The first goal is completion of the code, which was not achieved (nor due to be achieved) at the end of the period this report covers but will be by the time the report is submitted. The second goal is assembly of sensor and receiver hardware. Prototype devices are already assembled, as detailed in this report and shown in Figure 4, and manufacturing efforts are continuing.

5 Products

There are no completed products for this project after only one quarter of performance. Working with collaborator Berkeley Geophysics Associates, we have completed a preliminary calculation of the signal produced by a hydrofracture using an adaptation of a prior published model.[5] Once this model has been fine tuned and validated, it will be considered a product of this project. The fine tuning is projected to be completed by Jan. 31, 2014, but considerable validation will be needed before the model and its outputs will be deemed ready for publication.

6 Participants & Other Collaborating Organizations

6.1 GroundMetrics, Inc.

GroundMetrics is leading the project as well as developing the project hardware for the EM measurements. Our staff is led by Dr. Andrew Hibbs, project PI. We have a number of engineers in our 2 and 3 labor categories, and only two of them worked more than a man-month on this project this reporting period as the work was spread across the staff.

Name:	**Dr. Andrew Hibbs**
Project Role:	PI
Nearest Person Month Worked	1
Contribution to Project:	Dr. Hibbs is overseeing the technical work, particularly the development of the computer code.
Funding Support	N/A
Individual in Foreign Country	N/A
Travelled to Foreign Countries	N/A

Name:	**Mr. Todor Petrov**
Project Role:	Chief Engineer
Nearest Person Month Worked	1
Contribution to Project:	Mr. Petrov oversaw the development of our hardware and supervised verification.
Funding Support	N/A
Individual in Foreign Country	N/A
Travelled to Foreign Countries	N/A

Name:	**Mr. Joseph Pendleton**
Project Role:	Engineer Level 3
Nearest Person Month Worked	1
Contribution to Project:	Mr. Pendleton worked under Mr. Petrov on building and testing equipment.
Funding Support	N/A
Individual in Foreign Country	N/A
Travelled to Foreign Countries	N/A

6.2 Berkeley Geophysics Associates

Our subcontractor Berkeley Geophysics Associates is currently working with us on the calculation of a signal produced by a hydrofracture. BGA is headquartered in Berkeley, CA and led by Prof. Frank Morrison of the University of California, Berkeley.

6.3 Global Microseismic Services

Our subcontractor GMS is providing seismic services to the project. GMS's main contribution will come when we do our large data collection, but in this reporting period they provided us with TFI information to incorporate into our modeling and calculations.

7 Impact

As the project has only completed one quarter of work, there is not yet any impact to describe from that quarter. However, the potential impact of the overall project could be substantial.

Fracking is more expensive than conventional methods used to produce gas and oil, and fracked 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, and earthquakes caused by hydrofracturing or water disposal. This program may offer a methodology that can achieve complex mapping of subsurface fluids to monitor the fracking process.

Knowledge of fracture networks can be used to define frac stage locations and the duration of pumping at each stage. Tomographic Fracture Imaging™ is a proprietary technology of project team member Global Microseismic Services' (GMS) parent company Global Geophysical Services, Inc. (GGS) that produces a 3D image of the natural fracture network in the Earth. Seismic emissions of much smaller magnitude than are detectable by hypocenter methods are extracted from the trace data. However, while TFI produces images of entire fracture networks, the underlying data represent the fracture of the host rock, not the passage of fluid into the new pore spaces and the resulting increase in porosity.

The addition of a resistivity image, the innovation being pursued under this project, will provide an independent image of the change in fluid distribution in the ground. Such fluid imaging is a basic capability that tracks the core physical property that fracking is designed to change, and may enable new capabilities such as measurement of tensile fractures (instead of only shear). Accurate monitoring of SRV is the key to improving not only the operational efficiency of hydrofracturing but also confidence regarding fluid propagation and fracture trajectory below ground during fracking. Operationally, the potential exists to monitor the change in rock porosity resulting from each frac stage. Accordingly there are a wide range of potential benefits, including:

A. Reduced cost and use of fracture fluid by reducing the number of fracture stages.
B. Improved recovery and reduced environmental impact via improved mapping of fracture propagation.
C. Reduced cost from replacing high cost aspects of a microseismic seismic survey with EM elements. Extension of microseismic methods to formations where they currently are problematic and provide inadequate information.
D. Developing & demonstrating ways to monitor hydrofrac height growth,

For the completion engineer, improved information directly affects the four major decisions about the well: stage spacing (# and distance between fracs), stage volume (fluid and proppant), stage rate, and fluid viscosity. For developmental geologists, the improved knowledge will indicate how far the proppant fluid is being placed. For regulatory agencies, tracking fluid movement and quantity will provide valuable information to make project decisions.

Economic benefits to the public include reduced energy costs, reduced reliance on foreign sources of energy, and increased domestic economic activity. Potential environmental advantages include reducing the amount of water used in fracking, reducing the activity at fracking sites resulting in reduced traffic, noise and associated surface contamination, and providing physical monitoring for projects that cause environmental concerns.

8 Conclusion

We have made a prompt start and applied the full level of effort to the tasks scheduled for the first quarter. By delaying our survey for the EISG program we have been able to conduct a far more extensive test of the new survey equipment than originally planned. The sensor results are the best we have ever recorded and approximately 4 to 5 times more sensitive that our target level. Furthermore we have shown that by averaging the data over just a 34-minute period, we can reduce the measurement noise floor to 0.1 nV/m (for a 10 A transmitted current). The performance is 10 times better than the projections we have used to date in analyzing the sensitivity of DSEM to applications such as CO_2 and hydrofracture imaging.

9 Acknowledgment

This material is based upon work supported by the Department of Energy under Award Number DE-FE0013902.

10 Plans for Next Reporting Period

The program is on schedule and we expect tasks will be addressed and completed as per the program management plan. For convenience, the major tasks for the second quarter are as follows:

1. Confirm the 3D code is running correctly. Project the resistivity change produced by a hydrofracture and calculate the signal for a hydrofracture produced by a horizontal well.

2. Model the signal for the specific geology of the test site and define a preliminary survey plan.

3. Complete the modifications to the Eos. Order 15 new Eos and 60 new eQubes.

4. Submit papers for presentation at 2014 International Conferences for EAGE and SPE.

11 Milestones Not Met

None.

12 Cost Status

	Year I		Year 2			Actual
Budget	Federal	Non Federal	Federal	Non Federal	Total	(as of 12/31/13)
DOE	$ 1,416,443		$ 453,812		$ 1,869,529	
Salaries	$ 298,728		$ 55,274		$ 354,452	$ 58,698
Travel	$ 10,267		$ $867		$ 11,134	
Consultant Services	$ 42,500				$ 42,500	$ 13,661
Materials	$ 191,400				$ 191,400	
Equipment	$ 12,621					
Subcontracts	$ 530,000		$ $310,000		$ 840,000	
ODC	$ 570				$ 570	
Direct Costs	$ 1,068,586		$ $366,141		$ 1,434,727	$ 73,514
Indirect Costs	$ 347,857		$ $87,671		$ 435,528	$232,588*
Cost Share		$ 583,333			$ 583,333	
Total	$ 1,416,443	$ 583,333	$ $453,812		$ 2,453,588	

* These represent estimated indirect costs. We have submitted an indirect cost proposal to the DOE but it has not yet been approved.

References

[1] Dey, A. Morrison, HF. Resistivity Modeling for Arbitrarily Shaped Two-Dimensional Structures. Geophysical Prospecting Volume 27, Issue 1, pages 106–136, March 1979

[2] Smith, J.T., Conservative modeling of 3-D electromagnetic fields, Part I: Properties and error analysis. Geophysics, 61: 5, Sept-Oct 1996.

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