SECTION 5 – TESTING AND MONITORING PLAN

The operating plans for the proposed Hackberry Carbon Sequestration Well No. 001 will include a robust testing and monitoring program, which are designed to satisfy the requirements of SWO 29-N-6 ***§625.A*** [40 CFR ***§146.90***]. This section discusses the key details of this program.

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Reporting Requirements

As per the requirement of 29-N-6 ***§629A*** [***40 CFR §146.91***], HCS will provide semi-annual reports to the UIC Director containing the following:

- Any changes to the physical, chemical and other relevant characteristics of the CO2 stream from what has been described in the proposed operating data.
- Monthly average, maximum and minimum values of injection pressure, flow rate and volume, and annular pressure;
- Description of any event that exceeds operating parameters for annulus pressure or injection pressure as specified in the permit
- Description of any event which triggers a shut-off device and the response taken
- Monthly volume and/or mass of the CO2 stream injected over the reporting period and the volume injected cumulatively over the life of the project
- Monthly annulus fluid volume added
- Results of any monitoring as described in this Section

In addition, reports will be submitted within thirty (30) days after the following events:

- Any well workover
- Any test of the injection well conducted if required by the Director

Reports will be submitted to the Director, within 24 hours of the following:

- Any evidence that the injected VO2 stream or associated pressure front may cause an endangerment to a USDW
- Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs
- Any triggering of a shut-off system, either down-hole or at the surface
- Any failure to maintain mechanical integrity

Notification must be made to the UIC, in writing, 30 days of advance of:

- Any planned workover
- Any planned stimulation activities
- Any other planned test of the injection well

All reports, submittals and notifications will be submitted to both the EPA and the LADNR. All records will be retained by HCS throughout the life of the project and for ten (10) years following site closure. Data on the nature and composition of all injected fluids collected will be retained as well for ten (10) years after site closure. The records will be delivered to the Director after the retention period if required by the director. Monitoring data as described in Section 5 will be retained for 10 years after it is collected. Well plugging reports, post-injection site care data and the site closure report itself will be retained for ten (10) years following site closure.

Testing Plan Review and Updates

This testing and monitoring plan will be reviewed and updated to incorporate monitoring data collected as described at least every five (5) years. An amended testing and monitoring plan will also be submitted within one year of an area of review reevaluation, following any significant changes to the facility such as the addition of monitoring wells or newly permitted injection wells within the area of review; or as required by the Director.

Testing Strategies

Initial Step Rate Injectivity Test

In order to determine the fracture gradient of the Hackberry Carbon Sequestration Well No. 001, per SWO 29-N-6 ***§617.B.4.a*** [***40 CFR §146.87(d)(1)***] and SWO 29-N-6 ***§617.5.c*** [*40 CFR* ***§146.87(e)(3)***], a step-rate injectivity test will be performed before CO_2 injection begins. A bottom hole pressure gauge and temperature gauge will be run to the bottom of the wellbore. A surface gauge with continuous readout will also be installed. All gauges will be calibrated prior to the test. Initial bottom hole pressure and temperature readings must be taken prior to beginning injection.

[redacted]

Testing Method

HCS will collect samples of the CO_2 injection stream and perform analysis to meet the requirements of SWO 29-N-6 ***§625.A.1*** [40 CFR ***§146.90(a)***]. Samples of the CO_2 stream will be collected quarterly for the chemical analysis parameters provided below and continuously for pressure and temperature. The purpose of analyzing the carbon dioxide stream is to evaluate potential interactions of carbon dioxide and other components of the injectate.

Parameters Measured

Parameter/Analyte	Frequency
Pressure	Continuous
Temperature	Continuous
pH	Quarterly
CO_2 (%)	Quarterly
Water (lb/mmscf)	Quarterly
Oxygen (%)	Quarterly
Sulfur (ppm)	Quarterly
Methane (%)	Quarterly
Ethane (%)	Quarterly
Other Hydrocarbons (%)	Quarterly
Hydrogen Sulfide (ppm)	Quarterly
Benzene (%)	Quarterly

Table 5- 1: Injectivity Test Parameters Measured and Measurement Frequency

Sampling Methods

Samples of the carbon dioxide stream will be collected from the CO_2 pipeline at a location which represents the injection conditions, with a sampling station connected to the pipeline via a sampling manifold. Sample cylinders will be purged with injectate gas to remove any laboratory-added gas and ensure a quality sample collection.

Mechanical Integrity Testing – Annulus Pressure Test

HCS will perform internal mechanical integrity tests (MIT) prior to initial injection and after any subsequent workovers to meet the requirements of SWO 29-N-6 ***§627.A.2*** [*40 CFR* ***§146.89(b)***].

[redacted]

The results of the Annulus Pressure Test will be reported to the UIC Division on Form UIC-5 within 30 days of the test.

External Mechanical Integrity Testing – Temperature Log

HCS will perform external mechanical integrity tests (MIT) annually to meet the requirements of SWO 29-N-6 ***§627.A.3*** [40 CFR ***§146.89(c)***] by running a temperature log, through tubing. Temperature logs will be run prior to beginning injection operations and will establish the baseline to compare against future logs. Prior to running the temperature logs, the well will be shut in long enough to stabilize temperatures, approximately 36 hours. Correlation between the baseline and subsequent logs will demonstrate mechanical integrity. Temperature logs will be reported to the UIC Division within 30 days of the log run.

Pressure Fall-Off Testing

To meet the operational testing requirements in SWO 29-N-6 ***§625.A.6*** [40 CFR ***§146.90(f)***], HCS will conduct a pressure fall-off test every five years. These fall-off tests will be used to measure formation properties near the injection well and to monitor for any changes in the near-well bore environment that may impact injectivity and increase pressures.

Testing Method

Prior to beginning the pressure fall-off test, injection rate and pressure will be maintained as constant as possible, while continuously recorded. Upon shutting in the well, pressure measurements will be taken continuously through the use of two bottomhole pressure gauges, with one serving as a backup and for verification in cases of questionable data quality. The fall-off period will continue until radial flow conditions are observed, as indicated by a straight line of pressure decay on a semi-log plot.

Analytical Methods

Standard diagnostic log-log and semi-log plots will be generated with observed pressure changes and/or pressure derivative plots. The purpose of these tests is to determine specific near-well bore conditions, such as well skin, the prevailing flow-regimes and hydraulic property and boundary conditions. Comparison of pressure fall-off tests prior to beginning injection operations with those performed subsequently can indicate whether significant changes in the well or reservoir conditions have occurred. Analysis will consider the effects of two-phase flow effects, and parameters determined from the fall-off test will be compared to those used in the site computational modeling and AOR determination. Any significant changes in reservoir properties may result in a reevaluation of the AOR. Results of the pressure fall of test will be reported to the UIC Division within 30 days of the test.

Quality Assurance/Control

All field equipment will be inspected and tested prior to use. Pressure gauges used in the fall-off test much be calibrated in accordance with manufacturers' recommendations and calibration certificates will be provided with the test results. The use of the second bottomhole pressure gauge will further provide validation of the test results.

Cement Evaluation and Casing Inspection Logs

Casing inspection logs will be run annually, through tubing on wireline and whenever tubing is removed for workover operations. The following tools will be run at that time:

- Multiple-armed calipers to measure the inner diameter of the casing as the tool is raised or lowered into the well
- Ultrasonic tools to measure wall thickness and provide information about the outer surface of the casing or tubing as well as cement bonding
- Electromagnetic tools that measure magnetic flux of the tubular and can provided mapped circumferential images to indicate potential pitting.

Monitoring Programs

Continuous Injection Stream Monitoring

HCS will continuously monitor the injection pressure, rate and volume, plus the annulus pressure to meet the requirements of SWO 29-N-6 ***§625.A.2*** [40 CFR ***§146.90(b)***]. To facilitate the collection, monitoring and reporting of operational data, a Supervisory Control and Data Acquisition system (SCADA) will be installed on the site of the injection well.

The pressure and temperature of the injected carbon dioxide stream will be continuously monitored by the use of digital pressure gauges installed in the carbon dioxide pipeline near the pipeline interface with the wellhead and will be connected to the SCADA system on site. A Coriolis mass flow transmitter will be installed on the injection well to measure the mass flow rate of carbon dioxide injected. The flow transmitter will be connected to the CO_2 storage site's SCADA system to

continuously monitor and control the rate of CO_2 injection.

Reservoir temperatures and pressures will be measured through a fiber-optic, sDAS (Seismic Distributed Acoustic Sensing), embedded in the cemented annulus behind the long string casing. The gauges are described in detail in the Vertical Seismic Profile technology discussion in the plume monitoring section of this plan.

Analytical Methods

Continuously monitored parameters will be reviewed and interpretated regularly, to ensure the parameters are within permitted limits. The data will also be reviewed for trends to help identify need for equipment maintenance or calibration. Monitoring results will be included in the semi-annual reports.

Corrosion Coupon Monitoring

HCS will conduct corrosion monitoring of the tubing and casing materials of the well to meet the requirements of SWO 29-N-6 ***§625.A.3*** [40 CFR ***§146.90(c)***]. HCS will implement a corrosion coupon monitoring system, to be evaluated quarterly, as well as casing inspection logs performed every 5 years at the time of permit renewal. If plume surveys indicate it is time to recomplete uphole to a shallower sub-section, then the tubing and packer will be removed and inspected, and a casing inspection logging suite will be run. If abandonment of a sub-section is not warranted at the time of permit renewal, then a thru-tubing inspection will be performed.

Sampling Methods

Corrosion coupons, made of the same material as the production casing and the injection tubing, will be placed in the CO_2 injection pipeline. The coupons will be removed quarterly and assessed for corrosion using American Society for Testing and Materials (ATSM) standards for evaluating corrosion tests. When the coupons are removed, they will be inspected visually for any signs of corrosion, including pitting. The weight and size of the coupons will be measured each time they are removed. The rate of corrosion will be calculated using a weight loss method where the rate equals the weight loss during the exposure period divided by the duration of the period.

Ground Water Quality Monitoring

Hackberry Carbon Sequestration, LLC will conduct ground-water quality and geochemical monitoring above the confining zone to meet the requirements of SWO 29-N-6 ***§625.A.3*** [*40 CFR* ***§146.90(c)***]. The purpose of the ground water monitoring is to detect potential changes that may result from fluid leakage out of the injection zone. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Parameters Measured

Parameter/Analyte	Frequency
Aqueous and pure phase carbon dioxide	Every five years
Total dissolved solids	Every five years
pH	Every five years
Specific conductivity (SC)	Every five years
Temperature	Every five years
Density	Every five years
Other parameters including major anions and cations, trace metals, hydrocarbons, and volatile organic compounds)	Every five years

Table 5- 3: Ground Water Quality Parameters Measured and Measurement Frequency

Sampling Methods

Fluid samples in the groundwater monitoring well will be collected at the monitored formation temps and maintained at the formation pressures within a pressurized sample container to prevent any losses of dissolved gases. Prior to sampling, the well will be purged of any fluid stored in the well bore. Static fluid level and temperature will be measured prior to purging the well. A U-tube sampling system will be lowered to the monitored zone via wireline or slickline and the rate of sample collection should not exceed the rate at which the well was purged.

Analytical Methods

Water samples will be tested, and results maintained for the parameters listed above. If any impurities exist in the injectate, they should also be tested for in the groundwater samples to detect any concentrations beyond the baseline. Results from the samples will be maintained in an electronic database.

Trends that may indicate fluid leakage include:

- Change in Total Dissolved solids
- Changing signature of major cations and anions
- Increasing carbon dioxide concentration
- Decreasing pH
- Increasing concentration of injectate impurities
- Increase concentration of leached constituents
- Increased reservoir pressure and/or static water levels

Laboratory to be Used/Chain of Custody Procedures

Water samples will be sent to an EPA approved laboratory. Standard chain-of-custody procedures will be followed, and records maintained to allow a full reconstruction of how the samples were collected, stored and transported, including any problems encountered.

Quality Assurance and Surveillance Measures

Duplicate samples and trip blanks for QA/QC purposed will be collected and used to validate test results and ensure samples are free of contamination.

[redacted]

Injectate Plume and Pressure Front Tracking

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1D and 2D Models

To determine the magnitude of changes in the CO_2 plume, 1D and 2D models are generated to measure the effect on different scenarios. In this section we will explain the methodology behind each one of these models.

Seismic surveys create a seismic wave that travels through the earth and are subsequently reflected back to geophones that listen for these waves. The seismic waves can be created by a "shot" which is a term that refers to explosives or other mechanical sources. A vibrator is the most common mechanical source and is a device that uses a steel plate to pound into the earth and generate seismic waves. Geophones are recorders that listen for the sound waves that are reflected back to surface as seen in Figure 5-7. Specifically, they allow engineers to determine the time it takes for seismic waves to bounce off each transition zone between formations. The differences in time between each reflection allow for the calculation of a velocity in each formation. The variation in sonic velocities allow for geologists to understand the lithology of the subsurface. Seismographs are then used to store the data sent by the geophones.

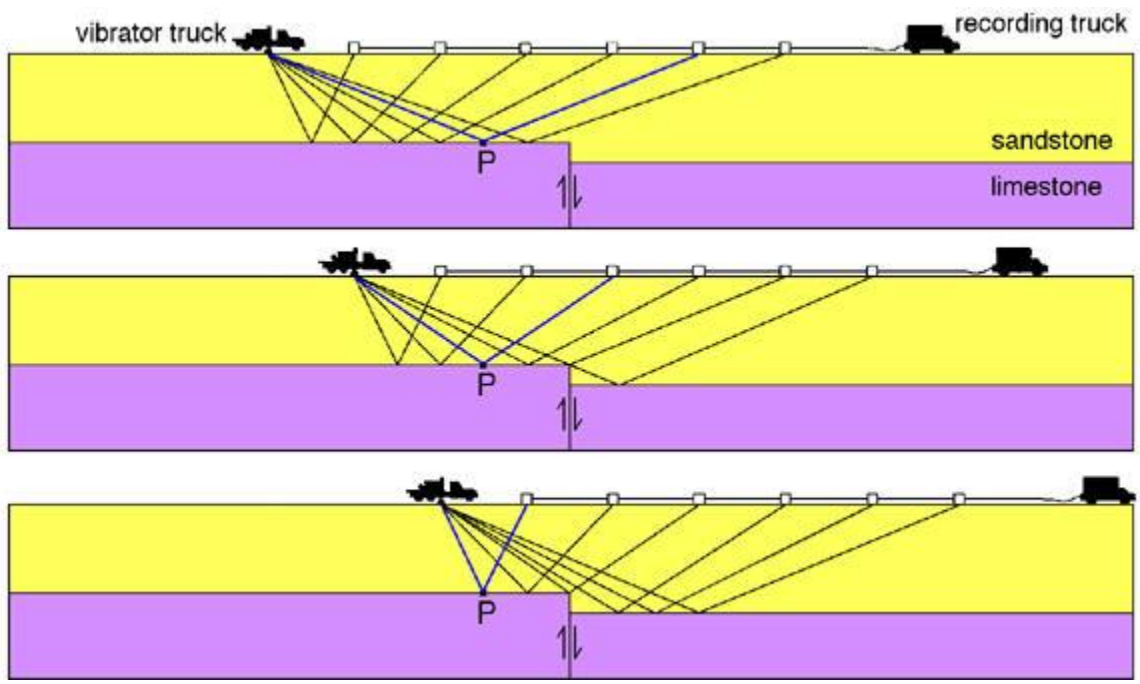

Figure 5- 7: Illustration of Seismic Surveys (example is on land – the truck would be replaced by shallow-bottom boat)

1D Model

One-dimensional (1D) seismic surveys operate on the same principles as previously discussed. Figure 5-8 shows an example of a checkshot survey which is a common method of obtaining 1D seismic data. However, the geophones are placed vertically, along the wellbore. As the shots are fired from surface, the geophones are able to record the seismic waves at various depths. They provide the most accurate measures of sonic velocities of the geologic layers effected by the construction of the wellbore. These are generally used to create more accurate two-dimensional (2D), three-dimensional (3D), and four-dimensional (4D) surveys. 1D surveys make the assumption

that each formation is horizontally homogeneous so they can only provide average sonic velocities. The data from 1D surveys can also be used to correct sonic logs and generate synthetic seismograms. Synthetic seismograms are used to predict the seismic responses of the subsurface. Acoustic logs are a special variation of 1D seismic surveys. They use wireline sonic tools to generate acoustic data along the wellbore. These are used for different purposes than seismic surveys, but they can lead to a 1D understanding of the variation in velocities.

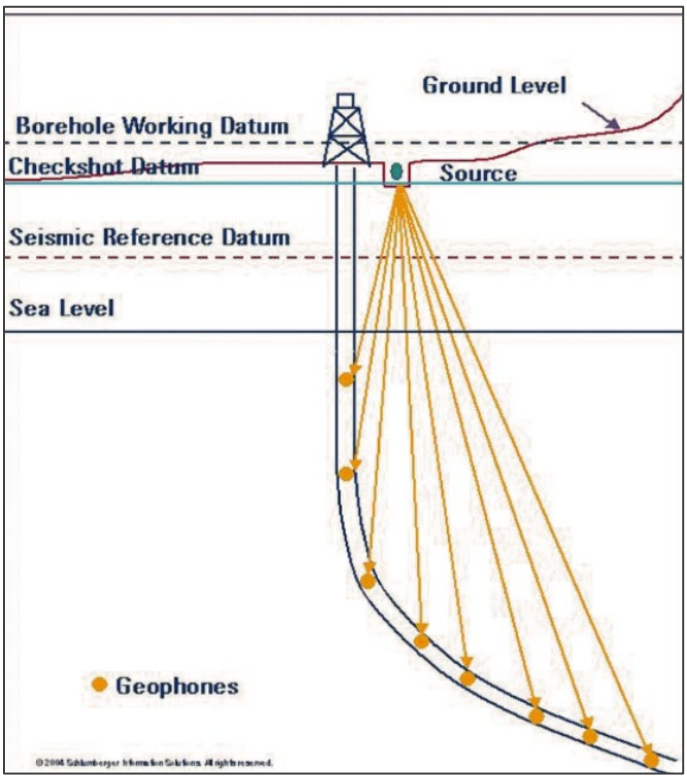

Figure 5- 8: Illustration of a Checkshot Survey

[redacted]

[redacted]

2D Model

Following the results of the interpretation of a 1D model, a subsequent geological model is built to reflect the two saturation cases, connate formation fluids as one case and CO_2 replaced fluid as the second case.

2D seismic surveys work off the same principles as previously discussed, but they provide a picture of a thin slice of the Earth's crust. The geophones are instead placed in a line along the surface and record the seismic waves as they reflect off each formation. 2D surveys require multiple lines to be set in order to achieve the best results. They ideally set each line to be orthogonal to the strike of a geologic structure and parallel to the dip of said structure. They provide information of various formations, faults, and other subsurface characteristics. The intersection of multiple 2D surveys allows for the geologist to interpret contour lines and generate geologic maps. These surveys are cheaper and have less environmental impact than 3D surveys. 2D surveys are commonly used for initial exploration of unexplored areas to give geologists an understanding of what formations lie beneath the surface.

In the following example, Figure 5-10, a 2D geologic model is built to reflect the two (2) saturation cases and VSP geometry is used as indicated. This shows how VSP technology monitors the CO_2 front. In-situ log results, or open hole sonic or density logs, are inserted in the left and formation log on the right. A weighted distance linear interpolation is used to generate the 2D P-wave model.

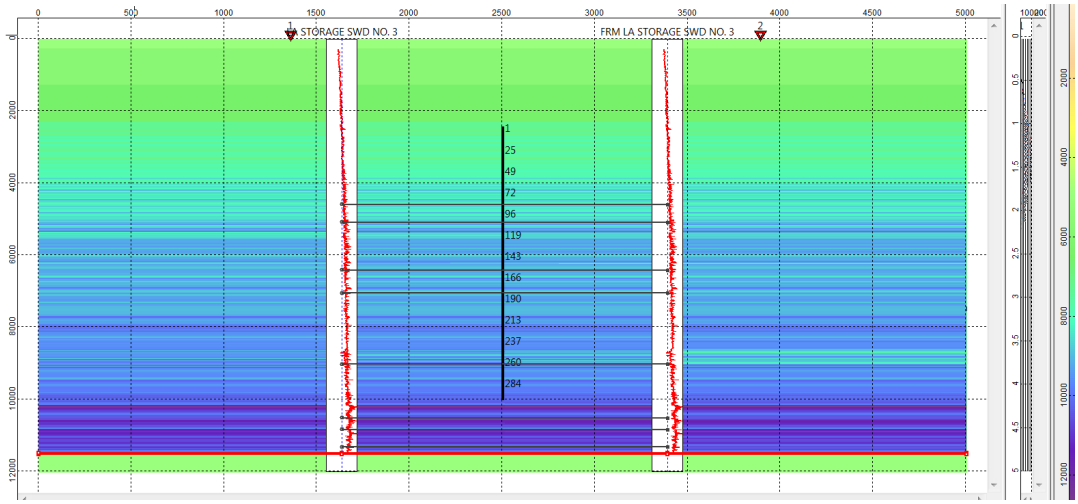

Figure 5- 10: Geological Model Used for 2D Modeling for a VSP survey

An expected response using 100% water and a modeled response using CO_2 indicates a change of amplitude and is interpreted that it is feasible to use VSP to monitor fluid changes with the rock for this project as seen in Figure 5-11.

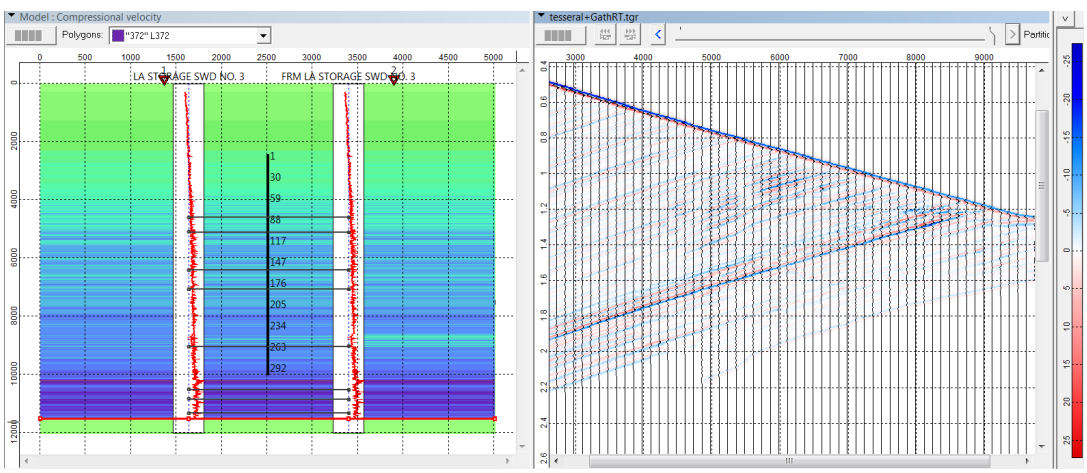

Figure 5- 11: One Shot Geometry for VSP Geometry (Top: on the Water Zone, Bottom: on the CO_2 Zone)

<u>Processing Workflow and 4D Seismic Volume Determinations</u>

The final interpretation from consecutive surveys will be made by observing gas volume build-ups over time. When 1D, 2D, and 3D seismic surveys are combined with a time component, i.e. surveys conducted at various time periods from one another (year 1, year 5, year 10, etc.), a 4D model is produced. The 4D interpretation of a seismic survey will identify changing volumes of gas build-up which are represented by log shifts on 1D and 2D responses or heat blooms on 3D models.

A basic example of the workflow is illustrated in Figure 5-12.

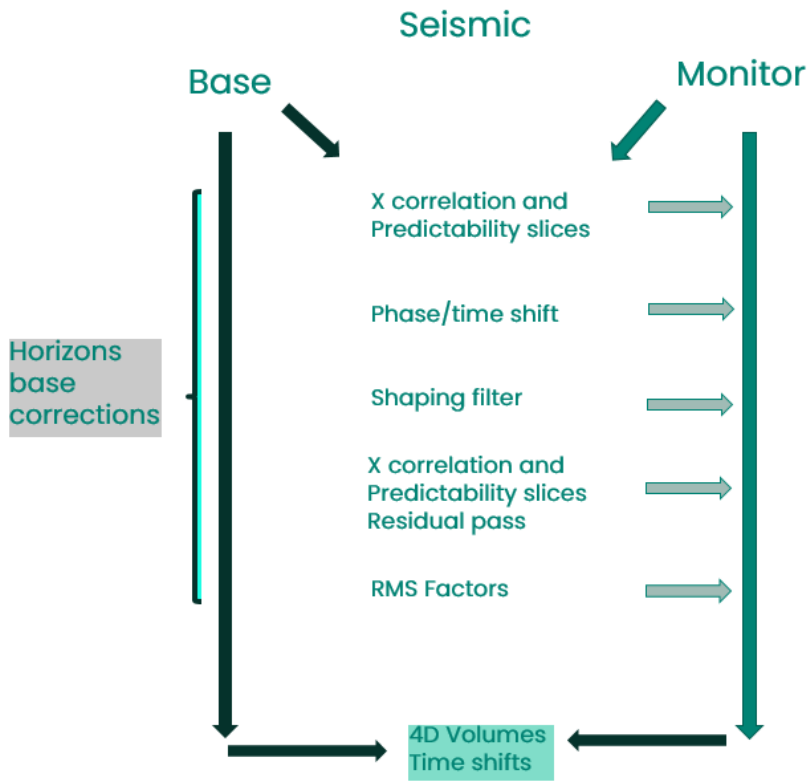

Figure 5- 12: 4D Processing Workflow Diagram

The 3D model of the horizon is generated from the base survey and every subsequent survey conducted generates a reflection differential which is mapped on the 3D model to determine plume geometry. This process is repeated to show time-lapsed growth or development of the injectate plume.

All the seismic volumes will be processed with same software and for each of the workflow steps below and will be used for consistency. The following figure, is an example of output from the 4D processing workflow.

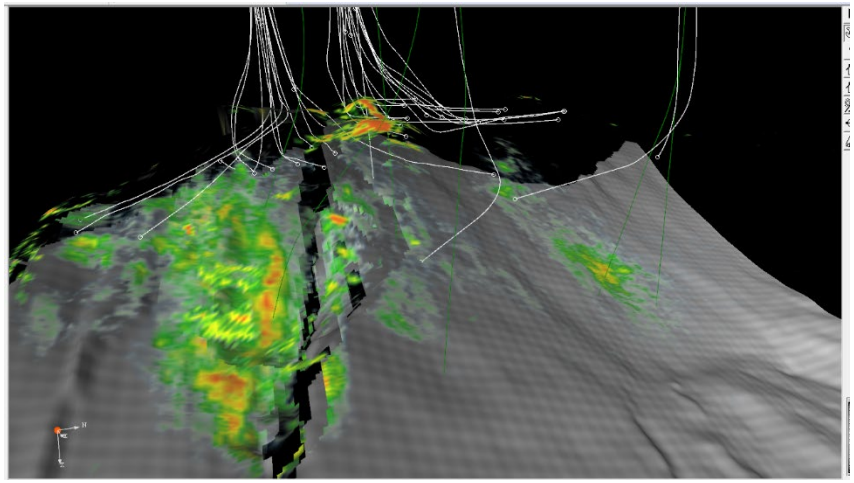

Figure 5- 13: Example of 4D Model (shows time-lapsed gas-replacement of connate fluids)

Inversion Workflow

Baseline surveys will be inverted using post-stack seismic volumes, well log data and a structural model to generate the basic low component model. Subsequent monitor surveys will use the same low component and residual corrections for consistency and the detection of changes over time. These changes over time will be assumed to be due to the injection activities.

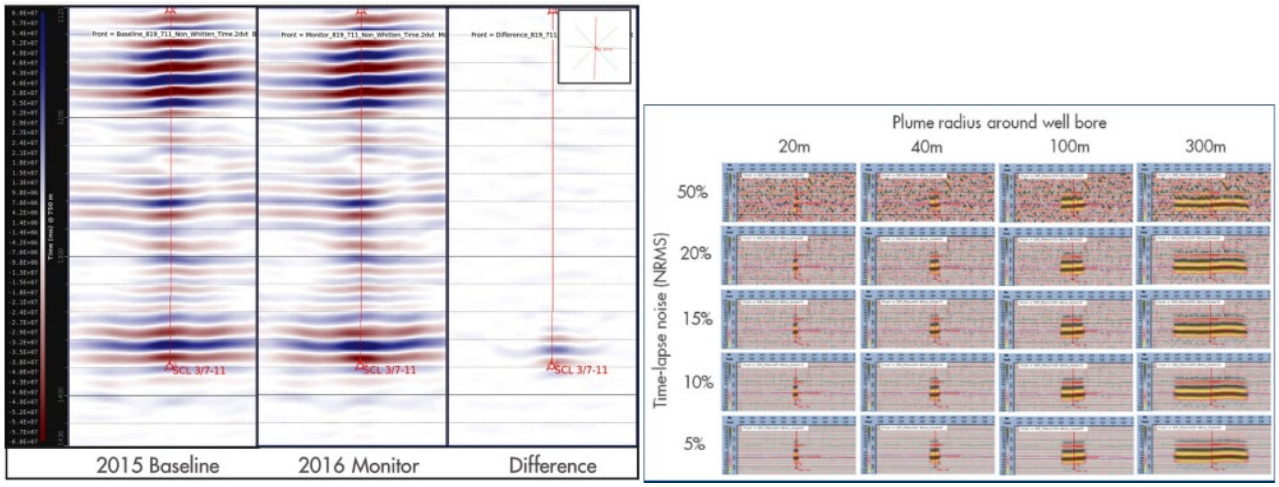

Figure 5- 14: Baseline and subsequent VSP used to determine difference in amplitude attributed to CO_2 injection as measured from the injector well Itself. Estimation of plume growth over time in plot on the right.

Baseline Survey

The importance of a quality baseline survey cannot be stressed. This represents the only opportunity to capture an image of the reservoir before any perturbation of the reservoir occurs due to injection or offset activity (man-made or natural). Without the baseline survey no interpretation of formation changes can be made. Any errors made in the construction of the baseline image will impair sensitivity and interfere with the sensitivity to which formation changes can be made. Further, the size of the baseline survey determines the extent to which plume can be measured. Given uncertainty in our reservoir models, it is important to acquire a baseline survey with sufficient extent to provide utilization in the event the initial reservoir models are not accurately predicting the plume migration.

An example of a 4D time-lapse model is shown below visualized in 3Dimensional space with analysis software. Each horizon can be displayed along with a color code for differences in amplitude over time.

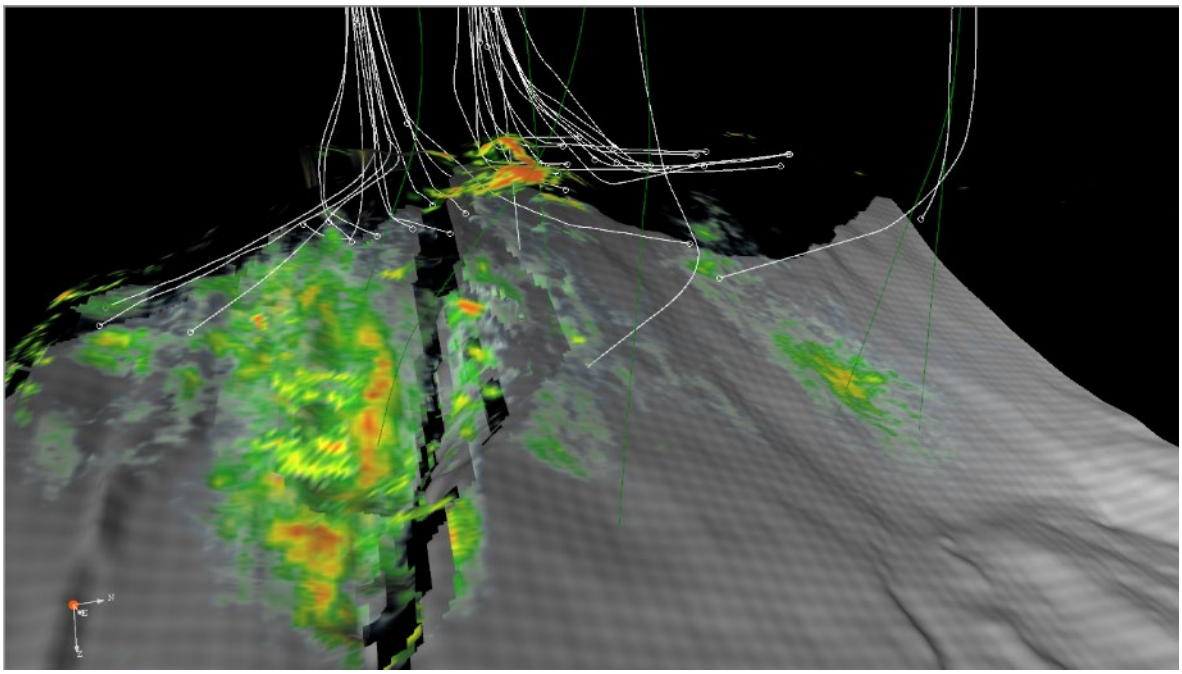

Figure 5- 15: Example of a 4D Output

Equipment Design and Setup

The equipment proposed in this section will be used in the periodic surveys to determine CO_2 plume growth over time. [redacted]

Wellbore Overview

[redacted]

[redacted]

[redacted]

Equipment Overview

[redacted]

[redacted] type seal assembly from the upper sealbore of the packer while leaving the packer down hole.

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Ambient Reservoir Monitoring Technology Overview

Ambient Reservoir Monitoring (ARM) uses a proprietary, patented process based on a signal process known as Streaming Depth Imaging (SDI) to image the intensity and distribution of weak acoustic emissions from reservoir depths. This process starts with a recording of passive seismic data from an array of geophones at the surface or near-surface and uses a modified Kirchhoff migration processing algorithm and a semblance computation to detect the presence of long duration low amplitude seismic emissions coming from depth. This technology was originally developed to monitor the large signals associated with hydraulic fracturing in unconventional oil and gas resource plays but was later shown to be effective at imaging lower amplitude signals from water flood and gas injections, hydrocarbon production, and even signals associated with water intrusions into mines.

In a 2017 article in the SEG Leading Edge magazine, Whiting Oil and Gas, in conjunction with ARM's predecessor company Global Geophysical Services, published a particularly insightful example showing the use of SDI to image the propagation path of fluid and proppant from the horizontal well being treated (Well 2 in Figure 5-25 below) into a second horizontal well (Well 1) while dipping under another over pressured horizontal well positioned between them. Because the proppant contained

a radioactive tracer this provide a rare opportunity to confirm via direct downhole measurement that we had imaged this fluid flow pathway precisely.

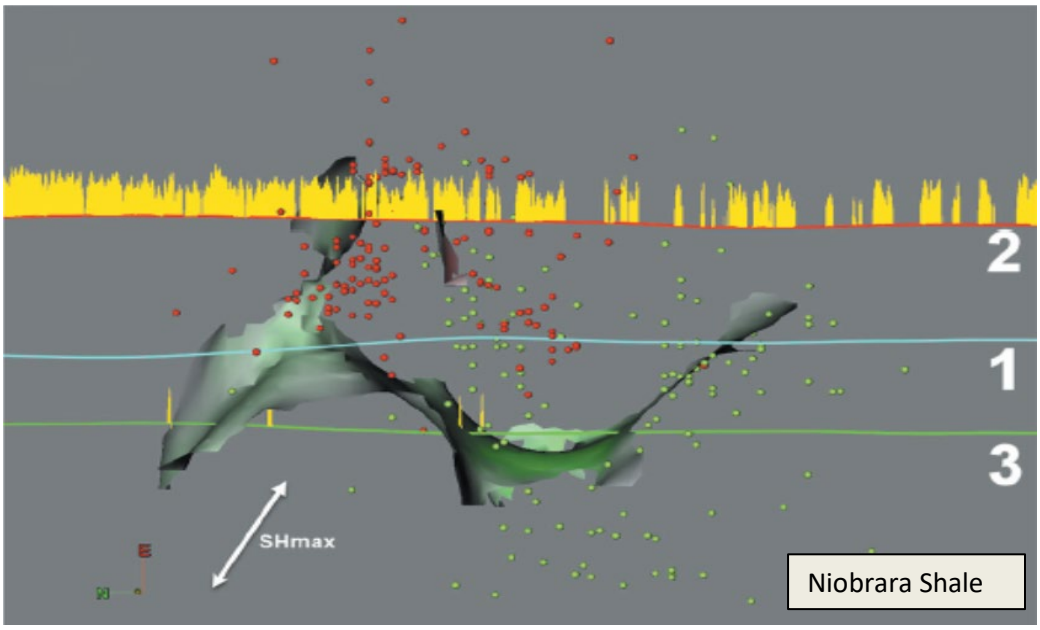

Figure 5- 25: ARM images the acoustic energy caused by fluid flow in fractures (green surfaces). In this example, we monitored the path of the proppant from the Well 2 to 3 going below Well 1. Yellow bars show amount of proppant detected in wellbores using radioactive tracers.

Another important distinction from this example can be made by comparing the microseismic earthquakes (MEQ) from two frac stages recorded using a reservoir level downhole instrument (as shown as green and red on Figure 5-25) versus the SDI results. The MEQ's show some general relationship to the zone being stimulated but do not provide a clear delineation of the permeable pathway.

Other examples from ARM's archive show that the high pressures associated with hydraulic fracturing are not required to create an acoustic signal that can be mapped from the surface. Figure 5-26 is an example of a water flood in Saskatchewan, Canada. The goal of the project was to illuminate facture networks and permeable pathways in an area of tertiary oil recovery. The method can image weak pressure changes far from a well because even very small fluid pressure changes can induce acoustic activity (Ziv and Rubin, 2000) and the ARM method is highly sensitive. In this study there was a large increase in acoustic emissions observed as the water injecting wells and producing wells were activated as compared to the "quiet" state where neither injection nor production was occurring.

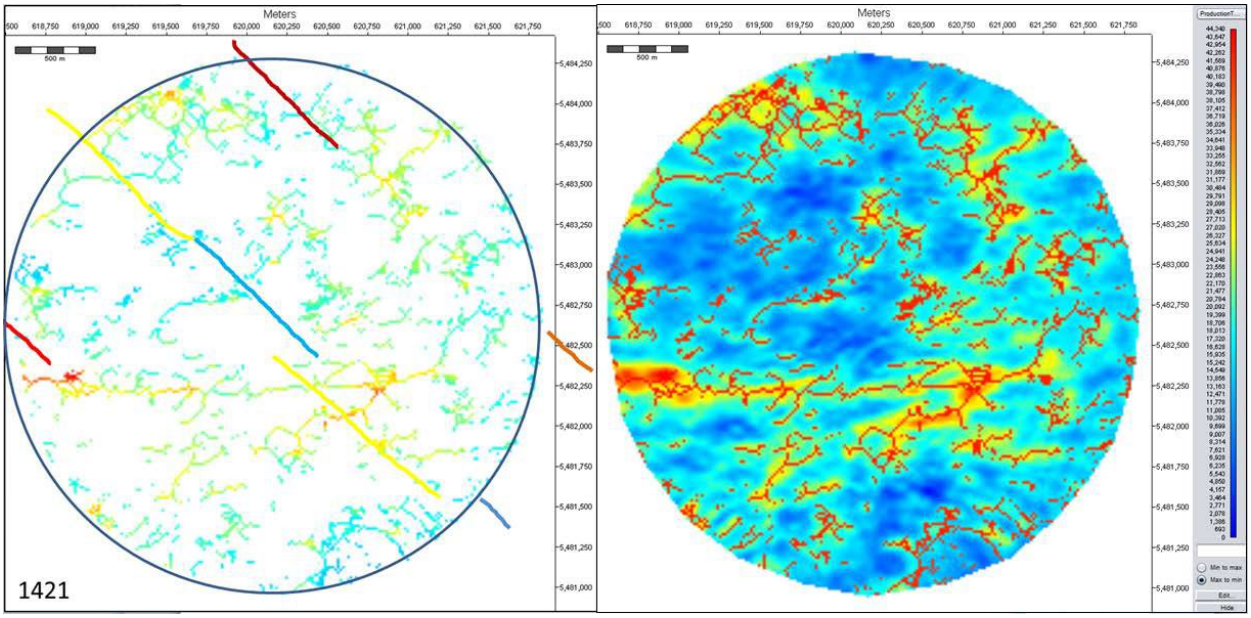

Figure 5- 26: (Left) Depth slice through the ARM images at 1421 meters depth below the processing datum of 650 meters. Colored lines are injector wells. (Right) The same ARM image depth slice superimposed on the stacked 1 hr. of semblance

Monitoring CO_2 sequestration will certainly involve time lapse sequencing where the current image can be compared to previous images recorded in the same location. The example in Figure 5-27 shows the changes in oil and production along the same horizontal well in the Eagle Ford at three different times over a period of 3 years. In this case study the time lapse imaging shows the number of locations and lateral extent of the fluids feeding into the wellbore decreasing over time as the well depletes and/or the induced fractures gradually close or silt up. This example was recorded using a shallow buried grid as we would propose for HCS CO_2 sequestration monitoring.

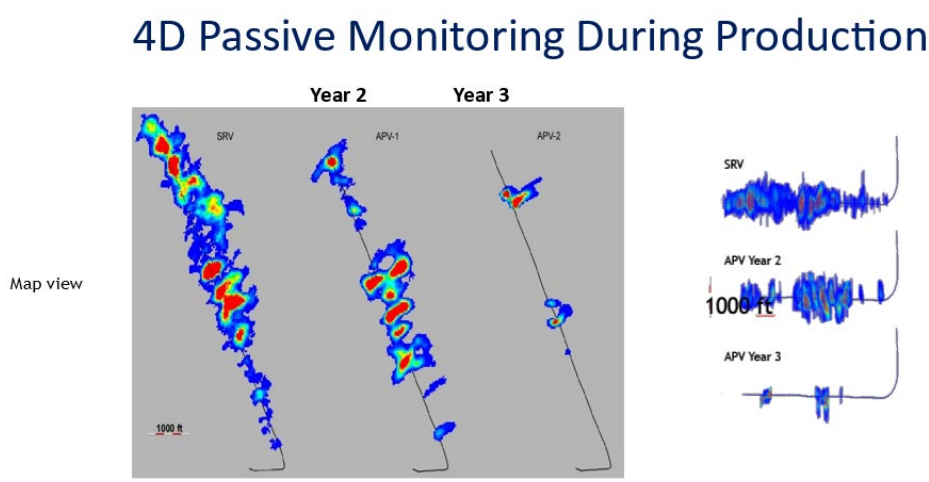

Figure 5- 27: The Stimulated Rock Volume (SRV) and two Active Production Volumes (APV) generated after two and three years of production. (Left) Map-view slices through the volumes at the wellbore depth. (Right) Profile views of the same three volumes sliced along the wellbore. Warm colors show high levels of activity and cool colors show lower activity levels.

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The previous two examples discussed have highlighted the use of SDI to monitor the movement of fluids laterally, i.e., in the X or Y direction in our 3D image volumes. In the next example we specifically show how our images have been used to monitor vertical containment for injected fluids. In a case study conducted in the Appalachian Basin in West Virginia our technology was used to measure the vertical upward extent of the fluids injected during a nitrogen frac into four stacked laterals. In this area the regulators were worried about the potential for the frac fluid to move into shallow aquafers or even to the surface. However, our image illustrates a clear containment of acoustic energy below the Maxton Sandstone cap rock and no "break-throughs" in containment.

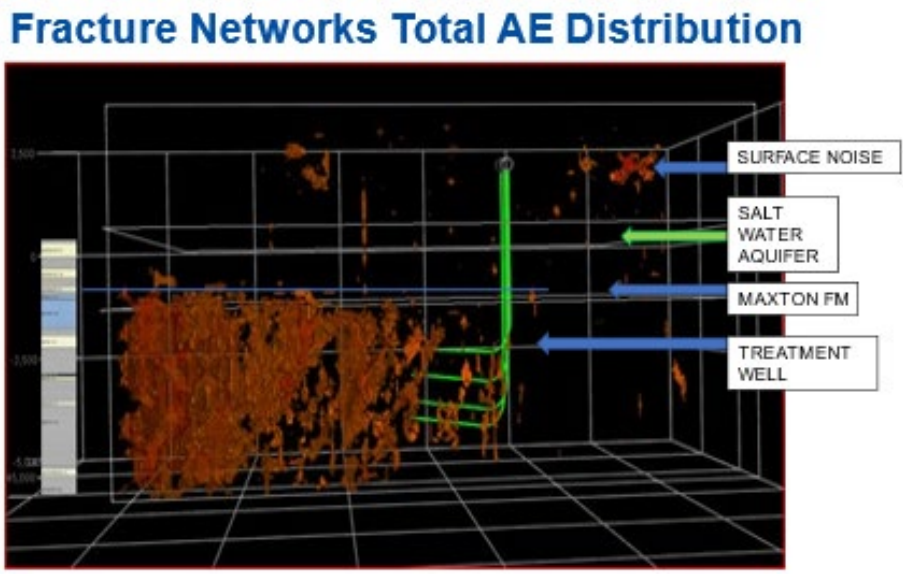

Figure 5- 28: Frac energy was kept below the Maxton formation and thus did not enter the aquifer

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Ambient Reservoir Monitoring Processing Methodology

ARM utilizes patented streaming depth imaging (SDI), based on a modified version of Kirchhoff migration, to image the intensity and distribution of weak seismic signals emitted from reservoir depths. SDI captures low-amplitude signals that are continuous for longer time durations (Sicking et al., 2014, 2015). Imaging these very weak signals requires the use of high-quality trace filtering to suppress noise (Sicking et al., 2016). The objective of the processing is to suppress reflectivity noise and surface-wave noise without modifying the phase of the signal waveforms that are emitted at depth and travel to the receivers at the surface. The most important processing steps include cepstral filtering, median filtering, and low-cut frequency bandpass. The processing is designed to

preserve signal in the 15 to 50 Hz frequency domain, important for transmission of seismic waves in the earth (Woodburn et al., 2012), and this frequency band has the highest signal transmission. The trace-processing workflow preserves this frequency band without phase distortion in the waveforms. Preserving waveform phase is important for SDI performance because the seismic waves generated from the same location at different times will have different waveforms. Summing the images over longtime intervals requires that the signals from the same location stack up to build the signal-to-noise ratio. Knowing the bandwidth of the signals generated at depth is not as important as knowing the bandwidth of the signal that arrives at the receiver grid.

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Traditional seismic methods first identify that a seismic event occurred and then locate and measure that event. SDI assumes that each point in time and space in the model is a potential seismic source. To image the signal, it is streamed through the SDI algorithm using one-way travel times to sequentially move out the trace data as if there were a seismic source at each voxel. For each time step, the coherence (semblance) of the moved-out traces is calculated.

Coherence is a measure of the similarity between traces. The higher the coherence, the more likely that there was seismic activity in that voxel during that time window. A genuine seismic emission will result in the same waveform being received at many receivers, while noise will be less coherent across receivers if surface and reflectivity noise have been removed properly. After filtering, the coherent arrival is visible in both the trace data and in the coherence volume. Further detailed discussion of how the trace processing affects the image is available in Sicking et al. (2016).

The sources at each voxel emit energy multiple times over the time window of recording. These emissions tend to be of a very low amplitude, but the energy accumulates over time, revealing the locations of the active fractures. The images from each of the time steps are summed into a three-dimensional image of the subsurface. This coherence volume is processed further to generate detailed fracture image volumes.

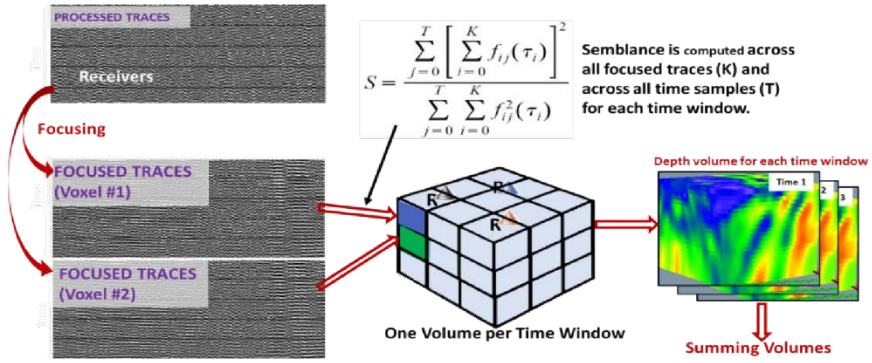

Figure 5- 37: Workflow for one-way travel time depth migration. After trace processing and velocity model building and calibration, the traces are depth migrated for each time window and each depth voxel for the time interval that will be summed; f_{ij} is the trace amplitude.

Fracture networks are extracted from the coherence volume based on a physical model of fracture damage zones. Seismic energy is not evenly distributed in the earth's crust but is preferentially released on fracture/fault surfaces and in damage zones surrounding these surfaces. Fracture mechanics predict that stress concentrations are associated with fractures.

In work related to our ARM seismic method, Tary et al. (2012) [10] compute continuous time-frequency transforms that highlight signals that have time-varying resonance frequencies. They conclude that these signals are the result of resonance in fluid-filled fractures or, alternatively, successions of very small repetitive seismic events along the fractures. They note that there is a direct correspondence between variations in the injection rate and the combined energy emitted. If a fluid-filled fracture is growing, the opening and shearing can initiate the Krauklis waves on the fracture surfaces and they are influenced by the fracture fluid and the surrounding rock. The waves travel along the fracture surfaces, quickly interfering to produce a modal/harmonic resonance of the whole fluid, fracture surface, and surrounding rock system. Recent research on the source of fracture seismic signals has put the fracture seismic method on a solid theoretical and practical base (e.g., Tary et al., 2014 [3]; Liang et al., 2017) [22]. It has now been applied to dozens of field projects.

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