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Connectivity of a CO_2 Injection Reservoir Verified by Integration of Continuous Fluid-Pressure Monitoring and 3D Seismic Survey

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The Southeast Regional Carbon Sequestration Partnership (SECARB) Phase 2 field project at Cranfield Field, Mississippi operated by Denbury Onshore LLC is conducted by the Gulf Coast Carbon Center at the Texas Bureau of Economic Geology with support from the National Energy Technology Laboratory (NETL) and the U.S. Department of Energy (DOE) and managed by the Southern States Energy Board (SSEB). This location provides a unique opportunity to monitor large-scale (10^5-10^6 tones) CO2 injection in an anticline structure at 3 km depth. Prior to the injection, the Cretaceous-age Tuscaloosa sandstone reservoir was reinterpreted/recharacterized with well data and a poststack 3D seismic data set collected in 2007. Carbon dioxide has been injected continuously in supercritical phase since July 2008 to support enhanced oil recovery. Pressure monitoring began two weeks prior to injection initiation and has been essentially continuous throughout the ongoing injection.

A total of 11 injection wells and one dedicated permanent observation well have been involved in the experiment. Daily injection has increased to over 6,000 mmcfd and 500,000 metric tons of CO2 were injected around February 15, 2009 (Figure 1A). The injection zone gauge in the observation well showed pressure in the injection zone had increased continuously for 6 months, raising the ambient reservoir pressure approximately 8 MPa (1200 psi) above initial conditions (Figure 1B). The derivative of the pressure time series (rate of pressure change; Figure 1C) reveals fine details of pressure response to various injection events, and is particularly useful for verifying reservoir connectivity between injection wells and observation well. Examples of the following are present in the data (Figure 1D & E): 1) Good correlation between injection rate changes at an injection well and the rate of pressure change at an observation well indicative of pressure connection within the reservoir, suggesting flow continuity; 2) Poor correlation between an injector and the observation well that is indicative of flow barrier(s); 3)Inconclusive interpretation for two injection wells, most likely due to low injection rates, perhaps constraining the low end of pressure sensitivity.

Core description, wireline-log correlation, and seismic interpretation indicate that the Tuscaloosa sandstone reservoir unit is amalgamated, multiple fluvial channel fills (IVF) deposited in a lowstand incised valley. Integration of 3D seismic data improves reservoir interpretation by providing necessary controls between and beyond wells for details needed for explaining and predicting flow barriers. In addition to poststack data, some reprocessing items were added to aid interpretation, including 90° phasing, frequency-decomposition, and stratal slicing. An amplitude stratal slice generated at reservoir level from a 90°-phase, high-frequency-enhanced, 50-Hz dominant frequency volume (Figure 2) has optimal correlation with the pressure monitoring results. The three wells with good connectivity to the monitoring well are all located in a sandstone-prone area with strong, negative amplitudes. Amplitude patterns related to poorly connected wells suggest three types of flow-barriers in the reservoir unit:

1. Faults and eroded incised-valley base. In the eastern testing area a N-S fault is interpreted to have coincided with the eastern boundary of the IVF; the western boundary of the IVF does not co-exist with faults. All injection wells outside of the boundaries (26-1, 27-1, 29-4, 28-1, and 24-2) have shown no sign of pressure connection to the monitoring well that is located in west of the boundary.
2. Abandoned channel fills. Shale-prone, low-sand areas indicted by low amplitudes are inferred to have caused poor connection between the monitoring well and injector 25-2 in the north. This may also have contributed to the poor connections with injectors 24-2, 27-1, and 26-1.
3. Shale laminates between sandy shute bars or point bars within a fluvial sand-belt. This may have caused low injection rates in some injectors (e.g., 29-2, 48-1).

Initial conclusions from the interpretation indicate that fluid-pressure monitoring and seismic mapping can be integrated to provide information sufficient for verifying and predicting geologic connectivity within a CO_2 injection reservoir.

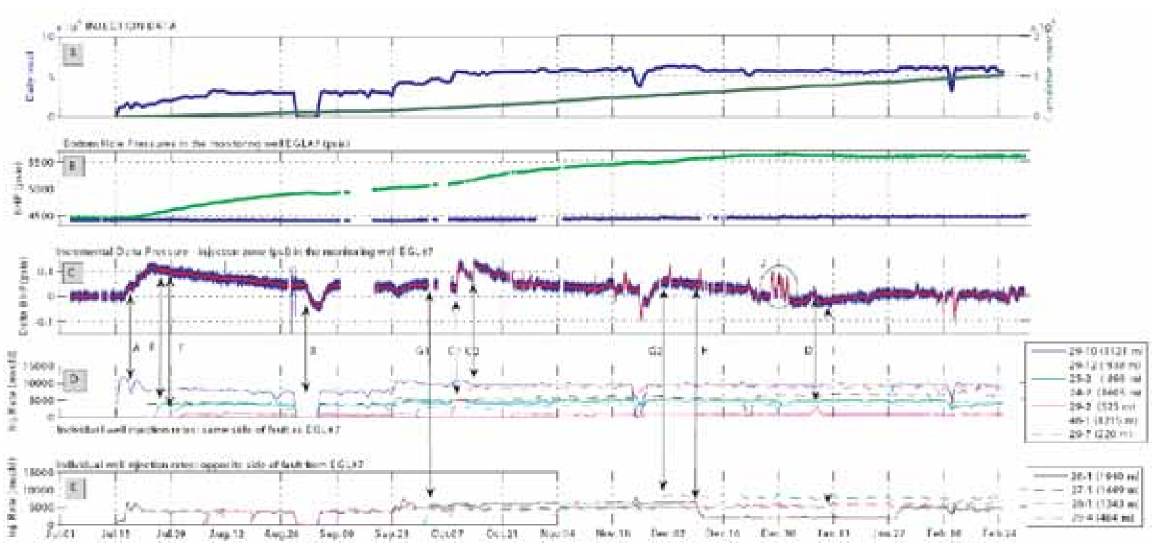

Figure 1. Field-wide injection data and pressure response in the EGL7 monitoring well. (A) Daily and cumulative injection data. (B) Pressure response in injection zone and overlying monitoring zone. (C) Rate of pressure change (temporal derivative) in the injection zone. Blue curve is 10-minute data. Red curve is moving average using an hourly time window. (D) Individual injection rates for injectors on the same side of the fault as the observation well. (E) Individual injection rates for injectors on the opposite side of the fault as the observation well. Injectors are labeled by name with distance from observation well indicated in meters in parenthesis. From Meckel et al. (in review).

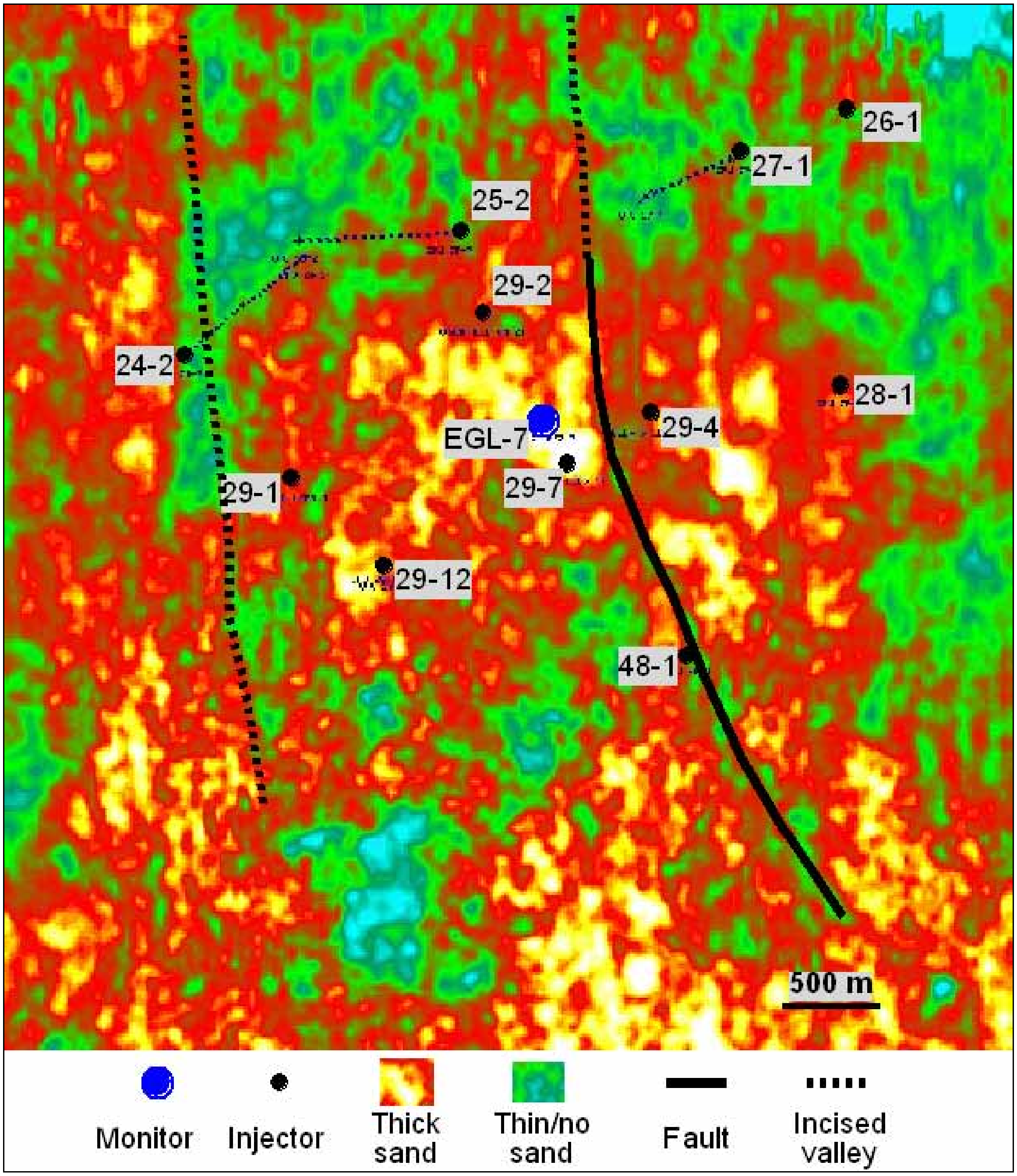

Figure 2. Amplitude stratal slice generated at reservoir level from a 90°-phase, high-frequency-enhanced, 50-Hz dominant frequency volume.