



Fact Sheet

Practical, Environmentally Sound CO₂ Sequestration

CO₂ “Huff ‘n’ Puff” Validation Test

In 2009, the Plains CO₂ Reduction (PCOR) Partnership conducted a small-volume, short-term carbon dioxide (CO₂) huff ‘n’ puff (HnP) test in an oil well producing from a deep limestone (carbonate) layer in the Williston Basin. The HnP was one of four CO₂ storage validation field projects performed during Phase II (2005–2009) of the ongoing PCOR Partnership Program.

Goals and Key Results

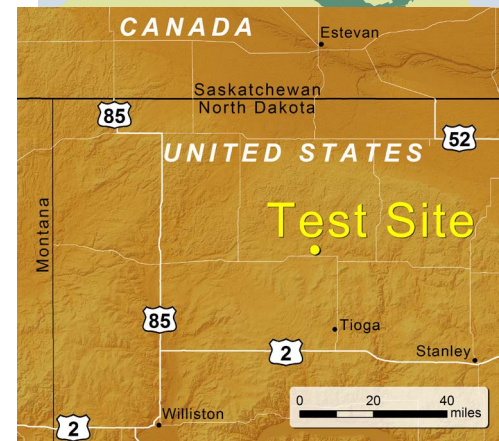
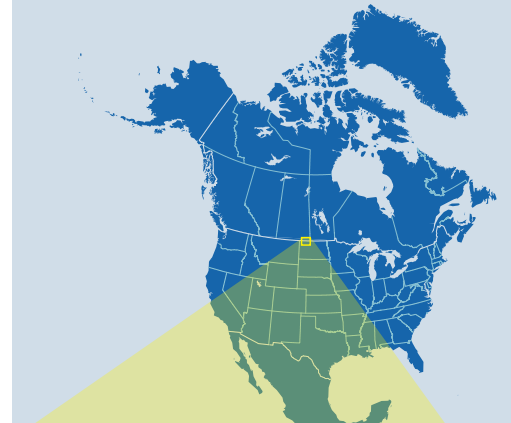
The project was designed to 1) evaluate the technical and economic viability of CO₂ injection and storage in limestone oil reservoirs at depths greater than 8000 feet, 2) determine the effectiveness of the CO₂ HnP approach to stimulate oil recovery from individual mature wells in the Williston Basin, and 3) test the ability of two specialized Schlumberger monitoring products—the wireline reservoir saturation tool (RST) and vertical seismic profile (VSP) technology—to detect and monitor a small-volume CO₂ plume in the reservoir. Results included:

- Injection of 440 tons of supercritical CO₂ into fractured oil-bearing limestone at a depth greater than 8000 feet, the deepest HnP at the time.
- More than double the preinjection oil production rate over the 4 months the well was monitored by the project following the HnP treatment.
- Successful use of RST for monitoring the movement of CO₂ along the wellbore (baseline and repeat logging) and predicting CO₂ presence away from the wellbore (when coupled with reservoir simulation).
- Good results were obtained from VSP for geologic characterization, but given a fractured reservoir and a low volume of CO₂, VSP results for CO₂ plume detection were poor.
- Development and demonstration of a dual-porosity/dual-permeability model coupled with RST data that was able to match field observations for the fracture-dominated reservoir flow environment.



CO₂ pumping unit arriving on-site.

Fast Facts



Location: Williams County, North Dakota
Injection Zone: Mission Canyon Limestone
Zone Depth: 8050 feet
CO₂ Injected: 440 tons
Injection Duration: 36 hours
Postinjection Monitoring: 4 months
Partners: Eagle Operating, Praxair, Schlumberger Carbon Services, U.S. Department of Energy, and PCOR Partnership

CO₂ HnP is an effective EOR technique in a deep limestone reservoir, and RST coupled with reservoir simulation is useful for monitoring CO₂ in that environment.

Site Selection and Permitting

Using criteria described in scientific literature, the PCOR Partnership project team looked for candidate wells for the CO₂ HnP test. Partner Eagle Operating offered its E. Goetz No. 1 oil well in the Northwest McGregor oil field, a mature well producing oil from limestone at a depth of 8050 feet. The model of Patton and others¹ was used to estimate potential incremental oil production, assess production variables, and determine the volume of CO₂ for injection. Table 1 describes the characteristics of the well.

The North Dakota Department of Mineral Resources (NDDMR) ruled that the relatively small scale of the proposed Northwest McGregor HnP activities was within the range of everyday oilfield operations. Accordingly, no additional permits were required, and no special informational meetings were held.

Table 1. Reservoir Characteristics of the E. Goetz No. 1 Well²

Location	Northwestern North Dakota
Oil-Producing Formation	Mission Canyon Formation
Lithology	Primarily limestone
Average Oil Zone (pay) Thickness	14 feet
Average Porosity	15%
Primary (rock matrix) Oil Zone Permeability	0.35 mD
Secondary (fracture) Oil Zone Permeability	Yes
Depth from Surface to Oil Zone	8050 feet
Average Oil Zone Temperature	216°F
Oil Zone Discovery Pressure	3127 psig
Oil Zone Pressure at Time of HnP Injection	2700 psig
Oil Gravity (API)	41.7° (specific gravity 0.8)
Cumulative Oil Production	2.2 million barrels (one barrel = 42 gallons)

Preinjection Phase

Several actions were taken in the weeks leading up to injection. First, an injection and monitoring plan was developed based on reservoir and production data obtained from NDDMR. This included initial development of a computerized geologic model for the reservoir.

Next, baseline wellbore integrity and geochemical conditions were established using several techniques: 1) ultrasonic logging indicated that the well casing and cement were intact, 2) downhole RST and VSP technologies were run to provide a baseline analysis to compare pre- and postinjection fluid saturation in the candidate injection zone, and 3) fluid samples from the proposed injection zone and from shallow groundwater wells in the vicinity of the well were analyzed for CO₂, ions, and metals.

Finally, the interior of the injection well tubing was cleaned and swabbed, the tubing and pump rods inside the well were removed and inspected, and the integrity of the steel well casing was confirmed through pressure testing.



Worker assembling the downhole VSP probe.

Injection Phase

The 36-hour injection occurred June 25–26, 2009. The food-grade (>99% pure) CO₂ was purchased from Praxair and shipped by rail from its Wyoming gas plant to Stanley, North Dakota. The CO₂ was then transported by tanker truck to the injection site. The pumping unit and technical support to conduct the injection were also provided by Praxair. As indicated in Table 2, a total of 440 tons of CO₂ was injected into the oil reservoir. A perfluorocarbon tracer (PFT) was mixed into the CO₂ at the wellhead to provide an additional method for monitoring the presence and movement of the CO₂.

Soak Phase

At the end of injection, the well was sealed to maintain pressure and allow the injected CO₂ to “soak” into the oil reservoir (move outward through the injection zone). Although the HnP soak period can last many weeks, the E. Goetz No. 1 well responded quickly, producing oil after the minimum soak period of 2 weeks.

Because maintaining pressure is critical to CO₂ disbursement, monitoring during the soak phase was limited to actions



Pumping unit and pipe and valve system used to inject CO₂ into a thin, permeable oil-bearing zone at a depth of 8050 feet.

Table 2. Operational Parameters for the Injection of CO₂ into the E. Goetz No. 1 Well²

Total Mass of CO ₂ Injected	440 tons
Maximum Allowable Injection Pressure (bottomhole)	5375 psig
Average Injection Rate	12.2 tons/hour
Average Injection Pressure (surface)	2200 psig
Average Injection Pressure (bottomhole)	5000 psig
Average Injection Temperature (bottomhole)	180°F
Wellhead Pressure at End of Injection	2800 psig
Length of Injection Period	36 hours

that could be conducted with a sealed injection well. The downhole sensors provided temperature and pressure data at the depth of the injection zone, and a single RST run was adequate to show the position of the small-volume CO₂ plume. The results were incorporated into the model to improve its accuracy. The downhole VSP could not be deployed because it would have required opening the well, resulting in the loss of reservoir pressure.

Production Phase

The HnP production phase is defined as the period during which the well produces incremental oil at a higher rate than before the HnP treatment. Eagle Operating, which managed well production, reported improved oil recovery for the 4-month postinjection study period (presented in Table 3) and beyond. Thirty percent of the CO₂ was recovered during the test. Additional monitoring beyond the test period would be required to determine the amount of CO₂ ultimately stored in the reservoir.



Collecting gas samples during the production phase.

Wrap-Up Monitoring

Because the validation test ended in November 2009, gas and fluid monitoring occurred for only the first 3 months of the HnP production phase. Monitoring included analysis of fluids from the E. Goetz No. 1 well, from the adjacent E.L. Gudsvangen No. 1 well, and from shallow groundwater wells in the vicinity of the HnP injection well. The fluids in the non-HnP wells exhibited neither statistically relevant changes in chemical composition nor the



Collecting a fluid sample from the injection well at the beginning of the production phase.

presence of the PFT. These results indicated that the CO₂ remained within the injection zone during the validation test period. Field activities ended with a final round of the ultrasonic, caliper, and RST logging technologies and acquisition of a repeat VSP.

Modeling and Simulation

Based on the RST and VSP data incorporated into the site-modeling and CO₂ migration simulation, CO₂ flow within the reservoir was beyond original simulation predictions. Data from core sample fracture analysis indicated an extensive natural fracture network capable of providing alternative permeability pathways. Development of a dual-porosity/dual-permeability model greatly improved the ability to simulate CO₂ migration.

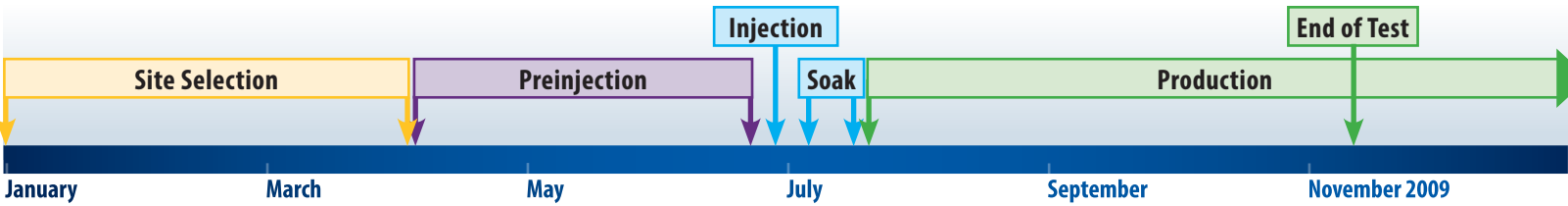
Table 3. E. Goetz Production Statistics

	Baseline	HnP ^a	Improved Recovery ^a
Oil Production Rate (not including downtime)	1.5 BOPD ^b	3.3 BOPD	2.2×
Oil Cut	2.8%	6%	2.1×
% of Injected CO ₂ Produced Back	NA	30%	NA

^aAveraged for the period July 6 through November 10, 2009.
^bBarrels of oil produced per day.

Summary

The increase in both production rate and oil cut during the study period clearly demonstrates the technical efficacy of the CO₂ HnP for wells completed in the deep, thin limestone of the Northwest McGregor Field. Incorporating the data from core sample fracture analysis greatly improved the ability to model the reservoir permeability and subsequently simulate CO₂ migration. RST and VSP worked well for baseline reservoir and seal characterization. RST is also a very good tool for monitoring the vertical movement of CO₂ in the near-wellbore environment. The VSP was not able to track the CO₂ plume, possibly because the volume of injected CO₂ was low and the CO₂ in the reservoir was concentrated in the fracture spaces. As VSP was unable to see the small volumes of CO₂ that were injected, its usefulness as a monitoring tool in smaller-scale injection and storage projects, such as the HnP approach to enhanced oil recovery (EOR), is limited. Later work using VSP in the larger-scale Bell Creek EOR project has demonstrated that VSP can be an effective monitoring tool for larger-volume injection/storage projects.



Common Terms Explained

What Is HnP?

Huff'n'puff, or HnP, is oilfield slang for a cyclic process to boost oil production in an underperforming well that is not part of a secondary or tertiary oil recovery operation. The "huff" is the injection of fluid such as CO₂ into the oil reservoir. The well is then sealed for 2 weeks or more, and the fluid is allowed to soak into the production zone. This allows the CO₂ to infiltrate the reservoir and dissolve into the oil, thereby causing it to swell and become less viscous. After soaking, the well is opened, and the "puff" (production) phase of the operation begins—the CO₂-affected oil is produced from the well. Studies have shown CO₂ HnP can increase oil recovery, boost short-term production, and provide important information on the ability to inject CO₂.³ If anthropogenic CO₂ is used, this relatively low cost EOR process will also reduce CO₂ emissions via permanent CO₂ storage in the oil reservoir.

What Is VSP?

A vertical seismic profile, or VSP, technology uses the behavior of compression waves (e.g., sound waves, vibration waves, or waves generated by small explosions) to identify rock layers near the wellbore. It is often used to tie the geology at the well to surface seismic data away from the well. The VSP readings are taken by placing a line of sensors in a well and then activating sources of seismic energy at the surface. By using a variety of source locations, a 3-D image of the geology around the well can be constructed.

What Is RST?

A reservoir saturation tool, or RST, is a set of sensors that can determine the percentage of open space (pore volume) inside a rock and whether the pore spaces contain oil, water, or another fluid. For the Northwest McGregor test, RST was used to determine where pore spaces in the near-wellbore zone of the oil-producing rock contained CO₂. Scientists used this information to understand the vertical distribution of the CO₂ that had been injected into the underground oil-producing zone.

What Is PFT?

A perfluorocarbon tracer, or PFT, is a harmless, nontoxic, chemically inert liquid that can be injected along with the CO₂ to trace its path after injection. Because PFT does not occur in nature and can be detected even at very low concentrations, it is a safe and effective means of tracking CO₂ underground.



Z-Seis VSP truck during VSP downhole data collection.

What Is Geologic Modeling and Simulation?

A geologic model is a 3-D computer-based program that describes the character of a section of underground rock formations. Data describing the geology and fluids of the formations are collected, processed, and interpreted to create a geologic model (also referred to as a static petrophysical model). The accuracy of the model is tested and improved by running oil production simulations on the model and comparing the results to historical oil production data (called history matching). The model and its simulation capabilities can then become a tool for predicting the behavior of CO₂ in the reservoir or storage zone, which is particularly useful in developing CO₂-monitoring and verification programs.

References

- ¹ Patton, J.T., Coats, K.H., and Spence, K., 1982, Carbon dioxide well stimulation—Part 1-A parametric study: *Journal of Petroleum Technology*, v. 34, no. 8, SPE-9228-PA.
- ² Sorensen, J.A., Schmidt, D.D., Smith, S.A., Knudsen, D.J., Steadman, E.N., and Harju, J.A., 2010, Plains CO₂ Reduction (PCOR) Partnership (Phase II) – Williston Basin field demonstration, Northwest McGregor CO₂ huff'n'puff – regional technology implementation plan (RTIP): Deliverable report D55 Task 2 for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, EERC Publication 2010-EERC-04-10, Grand Forks, North Dakota, Energy & Environmental Research Center, December.
- ³ Mohammed-Singh, L.J., Singhal, A.K., and Sim, S.S.-K., 2006, Screening criteria for CO₂ huff'n'puff operations: Paper presented at the SPE-DOE Symposium on Improved Oil Recovery, Tulsa, Oklahoma, April 22–26, SPE 100044-MS.

For more information, please access the Williston Basin Field Demonstration, Northwest McGregor CO₂ Huff'n'Puff Regional Technology Implementation Plan on the PCOR Partnership Web site.

The Plains CO₂ Reduction (PCOR) Partnership is a group of public and private sector stakeholders working together to better understand the technical and economic feasibility of storing CO₂ emissions from stationary sources in the central interior of North America. The PCOR Partnership is led by the Energy & Environmental Research Center (EERC) at the University of North Dakota and is one of seven regional partnerships under the U.S. Department of Energy's National Energy Technology Laboratory Regional Carbon Sequestration Partnership Initiative. To learn more, contact:

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