Midwest Geological Sequestration Consortium

Enhanced Oil Recovery I: Loudon
Single-Well Huff ‘n’ Puff

Final Report

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EXECUTIVE SUMMARY

A carbon dioxide (CO$_2$) huff ’n’ puff (HNP) was selected as the Midwest Geological Sequestration Consortium’s (MGSC) first Phase II enhanced oil recovery (EOR) pilot project because of its simplicity of design and execution. A HNP is the injection of CO$_2$ in the tubing-casing annulus of an oil-producing well.

In the Illinois Basin, a CO$_2$ EOR industry could provide the necessary capital investment for the development of a CO$_2$ sequestration infrastructure consisting of capture/separation at industrial sites and power plants, pipelines to major sinks, and wells. Because no major or large independent oil companies operate in the Basin at present, field demonstrations of CO$_2$ EOR are an important part of the MGSC Phase II pilot program.

A major initial challenge was the selection of a suitable site. Primary issues were negotiations with operators, surface access to the site, sensitive surface attributes at the site, the projected pilot CO$_2$ requirement, and each well’s history. Operator issues included multiple operators reconsidering their interest in pursuing a CO$_2$ injection pilot, permitting requirements for CO$_2$ injection, and budgets. Surface access to sites and wells by CO$_2$ transport trucks, well workover units, drilling rigs, and MGSC staff posed a significant challenge. Sensitive sites, such as those in proximity to farm houses, ponds, and streams were excluded. The history of wells within selected patterns was excluded based on type of well completion (e.g., open hole) and re-completion (e.g., reduced diameter internal liner), problem wells (e.g., frequency of well work-overs such as rods parting or pump failure), and current well status. A well in the southThe reservoir at the Loudon Field HNP site is in the Cypress Sandstone and is 1,500 feet (457 m) deep. The formation is characterized by very fine- to fine-grained sandstone in 6–10-foot (1.8–3.0-m) packages, interbedded with shales. These sands are typically elongated bodies that may coalesce to form larger flow units. The average permeability within the reservoir is 31 mD, and the average porosity is 16%.

In order to create a realistic model of reservoir architecture, a geostatistical approach was utilized. Well log data were first normalized and then transformed into permeability and porosity values using core data. These results were used to produce multiple realizations of the framework of reservoir properties. The average of these realizations was considered as the most likely scenario and was used for reservoir simulation.

In the summer of 2007, 43 tons (39.1 tonnes) of CO$_2$ were injected into the annulus of the oil-producing well at the Loudon Field HNP site. CO$_2$ gas was injected over a period of about one week at a rate of 5–10 tons (4.5–9.1 tonnes) per day. After injection, the well was shut-in for one week, and then liquid was produced via the rod pump. Prior to CO$_2$ injection, the well produced 0.5–1.0 barrels (0.079–0.16 m$^3$) of oil per day (bopd). During the first week of production after the shut-in period, the well had a maximum daily rate of 8 bopd (1.3 m$^3$), but declined over the next couple of weeks to 3–5 bopd (0.48–0.79 m$^3$).
Over two months, the well was estimated to produce about 100 barrels (16 m³) of oil above the pre-injection forecast for oil production.

To determine if CO₂ remained in the Cypress reservoir, the Monitoring, Verification, and Accounting program consisted of (1) monitoring ambient air quality at the site to ensure worker safety; (2) monitoring CO₂ injection composition, volumes, and rates; (3) monitoring shallow groundwater quality; (4) measuring produced oil, gas, and water; and (5) monitoring surface and subsurface injection pressure and temperature. The HNP pilot had aerial photography that included three color bands and near infrared. Electrical resistivity and electromagnetic surveys were also used. All results were negative with regard to indications of CO₂ outside the injection zone.
Introduction

A carbon dioxide (CO₂) huff 'n' puff (HNP) was selected as the Midwest Geological Sequestration Consortium (MGSC) enhanced oil recovery (EOR) Phase I pilot project because of its simplicity in design and execution. A HNP is the injection of CO₂ in the tubing-casing annulus of an oil-producing well. Although the purpose of a HNP is to increase oil production, it is not traditionally considered EOR, but rather a single-well stimulation.

In the Illinois Basin, a CO₂ EOR industry could provide the necessary capital investment for the development of a CO₂ sequestration infrastructure consisting of capture/separation at industrial sites and power plants, pipelines to major sinks, and wells. Because no major or large independent oil companies operate in the Basin at present, field demonstrations of CO₂ EOR are an important part of the MGSC Phase II pilot program. The success of a U.S. Department of Energy (U.S. DOE) Phase II EOR pilot may be adequate evidence for small operators to pursue a larger-scale multiple-well pattern flood prior to full-field implementation of a CO₂ flood.

The primary objectives of the HNP pilot were to estimate the incremental oil recovery due to CO₂ injection and the volume of CO₂ required. Secondary objectives were field testing of the injection equipment and the implementation plan.

Background

HNP Process

A HNP has three components: the injection period (huff), the soak (shut-in) period, and the production period (puff). For a HNP test, CO₂ is injected into an oil-producing well, not a dedicated injection well. At the surface, the CO₂ is injected through a casing valve into the annular area between the casing and tubing to the bottom of the wellbore into the geologic formations that the well produces (Figure 1). The oil producing geologic intervals cannot be isolated from the annulus; therefore, the production tubing cannot be set in a downhole packer. Generally, HNP injections are relatively small volumes.

Figure 1  Wellbore diagram of C. Owens #1.
and are intended to increase production of only the HNP oil-producing well and not surrounding wells. (Pattern floods with dedicated injectors, such as West Texas type floods, are designed to increase oil production at surrounding wells.)

Oil recovery from a HNP EOR is improved by dissolution of injected CO$_2$ into the oil and through expansion of CO$_2$ from the reservoir to the near wellbore area of the HNP well. Ideally, during production, injected CO$_2$ will completely bypass the oil around the well during injection and mix completely with all oil within the injection radius of the CO$_2$ during the soak period. For a given geologic formation at constant temperature, relatively higher pressure and greater contact time (soak time) between CO$_2$ and oil increases the volume of CO$_2$ dissolved with the oil. However, pressure that is too high can cause CO$_2$ to displace some of the oil from around the HNP well. A soak period that is too long may allow CO$_2$ to move too far from the HNP well and closer to surrounding wells. Additionally, a long soak period will have lower pressure, which leads to less CO$_2$ dissolved in the oil and less driving energy during the production period.

**Loudon Oil Field**

The Loudon oil field in Fayette County, Illinois (Figure 2) was discovered in 1937 by Carter Oil. Primary production continued via solution gas drive until the 1950s when Humble Oil began water flooding. In the 1980s, Exxon Corporation had two polymer pilot floods in the southern part of the field that were discontinued in the 1990s. In the mid-1990s, Petco, the current operator, took ownership and continued water flood operations (Figure 3).

Most of the Mississippian formations in the Loudon oil field have produced oil. Originally the Devonian formations were oil-producing but presently are used by Kinder-Morgan for natural gas storage.

The original oil-in-place for Loudon is estimated at 800 million standard barrels (MMstb). The oil produced to date is about 400 MMstb. A decline curve projection of remaining oil production for the entire field under current operations is 7 to 10 MMstb (Figure 3). In the MGSC U.S. DOE Phase I project, the CO$_2$-EOR potential of Loudon was 35 to 47 MMstb.

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**Figure 2** Location map of the Loudon field, Fayette County, Illinois.
**HNP Screening Process**

The geologic zone selected for the HNP pilot needed to represent a relatively large proportion of the Illinois Basin’s oil production, which limited selection to the Cypress, Aux Vases, and St. Genevieve formations (or their equivalent). Additionally, the API gravity of the crude oil needed to be representative of the Basin’s oil. An API gravity value of 37° is very common in the Basin, so a range of 35 to 40 was considered.

In some commercial applications of an HNP test, a CO₂ tank truck can drive to the well site; CO₂ can be injected directly from the tank truck into the tubing-casing annulus as the surface casing pressure is observed and regulated. However, for this present research project, a production well surrounded by existing wells was desired so that the surrounding wells could be used to monitor the CO₂ distribution. Consequently, a single isolated well was considered an inferior candidate.

A single geologic zone completion was desired so that there would be less doubt about the vertical distribution of the CO₂ within the zone. For the CO₂ volume budgeted for this test (150 U.S. tons [136 metric tonnes]), the pressure of the formation could not be depleted, nor could it be very high. For the HNP, the pressure had to be sufficient to ensure enough energy to dissolve the CO₂ into the oil but not displace too much oil from around the well. Pressure between 300 and 700 psia was considered optimal.

A field implementation criterion was to have access roads for CO₂ tanker truck delivery to the well site. Township roads had winter load limits that had to be coordinated daily with the township road...
commissioner. For oil field lease roads, the CO₂ delivery company had to give approval to allow its trucks to drive to the location.

**HNP Lease: Owens #1**

Based on this screening criterion, C. Owens #1 within the Loudon oil field, Fayette County, Illinois, was selected. The Owens lease originally had four wells producing only in the Cypress Sandstone; presently the Owens lease has two producing wells, the Owens #1 and #4, which are the westernmost wells within the 40-acre lease (Figure 4). Owens #4 is south of Owens #1. The Coddington lease is to the west of the

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**Figure 4** Location of the Owens #1 and surrounding wells. Electric log cross sections A-A’ and B-B’ are shown. The Owens lease, outlined, in dashed red is located in the southern part of Loudon field. The black solid boundaries in this figure correspond to the geostatistical model boundaries.
Owens lease; Coddington #2, a water injector, is west of Owens #1, and Coddington #4, an oil producer, is southwest of Owens #1. The Hawkins lease is north of the Owens lease. Hawkins #1, a water injector, is immediately north of the Owens #1. No wells presently bound the Owens #1 to the northeast, east, or southeast; however, geologic models suggest limited geologic communication between Owens #1 and the remainder of the Owens lease, including Owens #4.

Due to current water injection in the area (Coddington #2 to the west and Hawkins #1 to the north), bottom-hole shut-in pressure at Owens #1 was about 450 psia. Temperature was about 80°F (about 26.7°C). The API gravity was 37°. Via a very crude method called a bucket test, the operator reported the oil rate at 2 barrels per day (bopd), and the water rate as 46 barrels per day (bwpd). Hydrocarbon gas production is vented at the wellhead via the casing-tubing annulus, and the rate is not recorded. In general, Illinois Basin crude oils have very low gas content.

Figure 1 is a wellbore diagram of the Owens #1. The well is completed open-hole in the Cypress Sandstone with casing set to 1,516 ft (462 m). Total depth was 1,546 ft (471 m). The production history of the well documented several tubing- and rod-related workovers.

Geologic and Reservoir Modeling

In order to reduce the outer boundary effects on the geologic and reservoir models, an area that included at least two wells beyond Owens #1 was chosen as the outer boundary of the geologic model, shown in Figure 4.

Geologic Modeling

In the absence of modern log suites, and especially where gamma-ray logs are lacking, the use of normalized spontaneous potential (SP) curves can aid in construction of a geologically reasonable model of the distribution of sandstone and shale. The normalization step reduces the SP variation from well to well that results from fluid chemistry (electrical activity) and other borehole conditions, creating a calculated SP curve that is more representative of lithology than a raw SP log signature.

The normalized SP curves were crossplotted against 17 core analyses to obtain regression curves relating SP to core permeability and relating core permeability to core porosity. Core-based values at cored wells were replaced by analytical values during modeling. The permeability and porosity models were upscaled prior to reservoir simulation.

An essential design consideration for any oil field operation, from basic field development to EOR, is the creation of a digital reservoir model that reflects the geology and simulates the behavior of subsurface fluids. Successful creation of the reservoir model requires estimation of the porosity and permeability
throughout the reservoir body. In modern oil fields, the data on which this estimation is based are derived from wireline logs and measurements made on subsurface cores.

In the process of preparing a geologic model, data availability proved to be problematic. The Loudon oil field was discovered and developed well before wireline porosity tools existed. Although core data are available, those from development wells tend to emphasize the “best” portions of producing formations. This tendency proved true in the area of the Carter Oil C. Owens #1 well. Log signatures suggest that the Cypress Sandstone section in the Owens #1 consist of thin, 6 to 10 feet (about 2 to 3 m) thick sandstones separated by thin shale beds or interbedded shaly sandstones but nearby cores from the Heckert lease south of the Owens lease were taken from Cypress sandstones that change facies to a thick bedded, massive sandstone body that is informally referred to as the Heckert facies sandstone (Figure 5). Cypress reservoirs outside of the Heckert facies are typically small, lenticular pods that coalesce to about 200 acres (about 81 ha) in area and are individually up to 10 feet (3 m) thick. These reservoir pods commonly stack vertically to more than 20 feet thick and the thin interbedded shales and shaly sandstones compartmentalize the reservoirs into multiple, unconnected flow units. Photos of the core from Heckert facies and the Owens facies are shown in Figure 6. According to geologic mapping, the Owens #1 well penetrates several of these pods, two that are likely reservoir quality. These pods are shown in Figure 7 (a, b and c) as the A8 and A9 intervals.

Early attempts to create geologic models near the target well using core-derived porosity and permeability data resulted in an overly optimistic model dominated by the numerous nearby cores taken in the Heckert facies sandstone. The available core data suggest that permeability and porosity are reduced by increased clay content along both lateral and vertical margins of thinner sand bodies. As the conceptual geological model locates the Owens #1 outside of the Heckert facies, the overly optimistic porosity and permeability predicted by the first geologic model made it unsuitable for reservoir simulation.

The ideal geologic model would be based on data that are both representative of the target zone and widely distributed throughout the study area. Given the scarcity of core data in the Owens facies, compared with the wide availability of electric logs, the use of log data as an estimator of rock properties was applied.

**Methodology**

For the 138 wells in the model area, 62 logs and 17 cores were available. These logs were scanned and digitized (Figure 8). No porosity logs existed, and four gamma-ray logs were available. The logs of cored wells were inspected to differentiate those cores taken in the Owens facies from those of the Heckert facies, and the latter were excluded from the study. Eleven core were available from the Owens facies for modeling.
Figure 5  Stratigraphic cross section showing changes in reservoir facies from thick-bedded Heckert facies in the southwest to thin-bedded sandstone and shale Owens facies in the northeast.
Figure 6  Two core photos from the Heckert #902 well approximately ½ mile to the south of the Owens #1. The photos show the thinly bedded Owen facies with interbedded shales (top) and the thick-bedded Heckert facies (below).
**Figure 7a**  Geological model of the Owens area. Figure 7a is a cross section showing the time-stratigraphic correlative intervals within the Cypress Formation. The sandstone intervals are up to 10 feet thick and separated by thin shale beds or interbedded shaly sandstones. The line of section is shown in Figures 7b and 7c.
Figure 7b, 7c  Figure 7b is an Isopach map of the net sandstone thickness of the A8 interval. These sandstones typically form lenticular “pods” that coalesce into larger bodies up to 200 acres in extent and trend northeast-southwest. The Owens #1 within this interval is located in marginal reservoir at the edge of this sandstone body. Figure 7c is an Isopach map of the net sandstone thickness of the A9 interval. This is the primary reservoir within the Owens #1 well and has similar depositional characteristics as the A8 interval.
The following three sections describe the derivation of the rock properties from well logs.

**Normalize SP curves**

To generate a useful model, it was necessary to convert the SP log—the log curve most nearly independent of hydrocarbon content—to a sand/shale curve through normalization. The following steps were used:

*Figure 8*  Spontaneous potential log curves showing the variation in log character for the modeled area. Owens #1 is located by star. The logs show the area of thick, massive Heckert facies sandstone to the south of the Owens #1 and the thinner, interbedded sandstones and shales of the Owens facies throughout much of the rest of the model area.
1. Visually pick the highest and lowest observed SP values within approximately 150 ft [about 46 m] of the Barlow lime, which reduces the effects of shale baseline drift. The cleanest sandstones in the interval were generally in the Tar Springs Sandstone (~100 ft [about 31 m] above the Barlow), and the shaliest intervals were usually in the Fraileys Shale immediately above the Barlow.

2. Normalize the curve between 0 (pure shale) and -100 (clean sand) using the formula:

\[
\text{Normalized SP} = \frac{\text{Raw SP} - \text{Limit}}{\text{Limit}} 
\]

The negative SP values were chosen for the purpose of graphically plotting the normalized SP curve with the raw SP curve.

This normalization technique produces a curve that is an indicator of the percent of sand in the logged interval (Figure 9). The set of 62 normalized SP curves were imported into Isatis geostatistical software for creation of a preliminary geostatistical model estimating the distribution of lithotypes within the reservoir interval. This estimate was built using a pluri-Gaussian technique (Figure 10).

**Figure 9** The Owens #1 well showing the raw SP curve and the normalized SP curve. The maximum normalized SP values of approximately -75 for the Cypress reservoir in the Owens #1 is typical for the Owens facies reservoir rock compared to values of up to -100 for the Heckert facies reservoir rock. In general, sandstones with normalized SP values under -50 are non-productive. The lower normalized SP values in the Owens facies are related to the increased clay content in this facies. This clay content is visible, in part, as wispy shale laminations in the core photo in Figure 6.
Create SP-Permeability and Permeability-Porosity transforms

To determine the parameters that provide the best correlation, the following steps were used:

1. Depth-shift cores to minimize driller and log depth difference errors.

2. Crossplot the values from the cores of permeability (both raw and log10), porosity, and the SPnorm values from the log. This step used a data window containing only the data points for which SPnorm was greater than 50% sand and used a reduced major axis fit for regression. Multiple regression equations were applied to each crossplot.

Figure 10  A three-dimensional matrix showing the distribution of SP-defined lithotypes within the modeled area. The curves in each square represent the vertical changes in the proportions of the lithotype within the area covered by the square. The figure covers the same area as that represented in Figure 8 and is about 7,000 by 7,000 feet in extent. The green star marks the square containing the Owens #1 well.
3. Visually and mathematically evaluate regression curve fits to determine optimum regression curves (Figure 11).

Evaluation of the “goodness of fit” found that the relationship between permeability and normalized SP in the data set was stronger than the relationship between porosity and normalized SP.

**Apply transformations**

To estimate porosity and permeability, the following two steps were used:

1. Convert the SPnorm curves to calculated permeability curves using the formula in Figure 11a, substituting observed permeability values for calculated values where core analyses are available.

2. Convert calculated permeability curves to calculated porosity curves using the formula in Figure 11b, substituting observed porosity values for calculated values where core analyses are available.

This gave porosity and permeability at individual wells. The maximum permeability calculated by the transform was 264 md while the maximum porosity was 22%. Within the Owens #1, the transform calculated maximum permeability was 41 md and the maximum porosity was 19%. The next section describes how cells in the geostatistical model were populated.

**Three-dimensional geostatistical modeling**

Final modeling of internal reservoir stratigraphy followed a two-step process beginning with creation of a numerical model using a pluri-Gaussian technique, followed by a turning band simulation.
Pluri-Gaussian framework

In the Pluri-Gaussian framework, data values were assigned to four lithotypes that were used to model the proportions of the facies within a three-dimensional space. Normalized SP values for all wells were assigned a lithotype as follows:

- Shale, 0 to −30
- Shaly sandstone, −31 to −50
- Sandstone, −51 to −80
- High-permeable sandstone, −81 to −100

Trends in facies distribution were examined by creating a vertical proportion matrix for the study area (Figure 10). The curves in each square in the figure represent the vertical changes in the proportions of SP-defined lithotype within the area represented by each square. The results of the vertical proportion matrix correspond with the conceptual model of thick wedges of high-permeability (Heckert facies) sandstones in the southwest corner of the model and interbedded sandstones and shales in the rest of the model. The next step was to define the lithotype rule and the Gaussian random functions (variograms). Only the first Gaussian function was necessary because of the nature of the transitions between facies. The function was modeled using a spherical structure with a sill of 1.2 and a range of 200 ft (61 m) along the Y-axis direction, 80 ft (24 m) along the X-axis, and 12 ft (about 4 m) along the Z-axis with a rotation of N40° E in the horizontal plane. Fifty pluri-Gaussian simulations were created using the defined variograms and lithotype rule. The resulting simulations were used to guide subsequent simulation of the distribution of permeability and porosity with the turning band method.

Turning band framework

A traditional geostatistical approach was used to populate the model with permeability and porosity values. As a first step, variogram maps were created of the normalized SP data, shown in Figure 12a, to determine the horizontal anisotropy. The variogram maps indicated a strongest trend in the N30E. A final direction of N40E was chosen based on the variogram maps and the pluri-Gaussian modeling results. Before any geostatistical modeling could be done, it was first necessary to apply a Gaussian anamorphosis transformation to the permeability and porosity data. Semi-variograms of the resulting transformed data were computed. The final semi-variogram model, shown in Figure 12b, was based on an exponential structure with a range of 300 ft (91 m) in the x-direction, 1,200 ft (366 m) in the y-direction, 20 ft (6 m) in the z-direction with a horizontal rotation of N40° E. This model had a nugget of 0.05 and a sill of 1.0 After performing successful cross-validation, 50 simulations were created using 1,000 turning bands on a stratigraphic grid. The simulations were then averaged to generate the most likely scenario.
Figure 12a  Variogram map of the normalized SP data showing a trend in the N30E direction. This was used in combination with the results of the plurigaussian simulations to determine a N40E direction of anisotropy.

Figure 12b  The final semivariogram model overlaying the semivariogram of the Gaussian anamorphosis transformed permeability data. The red model and semivariogram is calculated in the N40E direction, the direction of maximum anisotropy, while the green model and semivariogram is calculated in the N130E direction, the direction of minimum anisotropy. The histogram at the bottom shows the changes in the number of pairs calculated for the semivariograms for each direction.
The grid consisted of 76 nodes in the x-direction and 81 nodes in the y-direction with mesh spacing of 40 ft (12 m), and 100 nodes in the z-direction with a mesh spacing of 1 ft (0.3 m). This was upscaled to final version consisting of 39 nodes in the x-direction and 41 nodes in the y-direction with mesh spacing of 80 ft (24 m), and 50 nodes in the z-direction with a mesh spacing of 2 ft (0.6 m).

**Final Geostatistical Model**

After creating the model, the estimated SP values were then back transformed to permeability and porosity values. Images of the final model are represented in Figure 13. The mean permeability of the transformed data from the core data was 31.07 md while the mean of porosity was 16%. The model had a mean permeability of 31.65 md and a mean porosity of 16%. After visually inspecting the model to ensure that it matches the expectations of the conceptual model, the model was used for reservoir simulations, which is described in the following section.

**Reservoir Modeling**

The primary goal of the reservoir modeling was to ensure a measurable oil response in the field was possible. The geostatistically generated geologic model (porosity, permeability, thickness, and depth) was used as input to the reservoir model. The fluid properties were generated using a four-component, Peng-Robinson equation of state (EOS). The composition (mole fraction) was adjusted until the EOS-derived fluid properties matched the general observations of density, viscosity, and solution gas-oil ratio within the Basin (Table 1). General values were 37° API, 3 to 7 cp, and 50 to 100 scf/stb were used. Pederson's correlation was used for oil viscosity.

<table>
<thead>
<tr>
<th>Table 1</th>
<th>Initial fluid composition used in four-component equation of state to match general observations of fluid properties within the Illinois Basin.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pseudo-component and mole fraction</td>
<td>CO₂</td>
</tr>
<tr>
<td></td>
<td>0.01</td>
</tr>
</tbody>
</table>

A general relative permeability set was used. The relative permeability data from oil, water, and gas water are given in Figure 14. The irreducible water saturation was 35%, the critical gas saturation was 10%, and the residual oil saturation was 25%. No hysteresis effect was included. Capillary pressure was not used.

Due to lack of individual well production history, a rigorous history match was not attempted. To prepare the “initial” conditions to CO₂ injection, the simulation model started with 25 years of primary production, followed by 40 years of water flooding. The simulated Owens #1 HNP followed this pattern.

The bottom-hole injection pressure was set at 850 psi. The model projected 26 tons (24 tonnes) of CO₂ over 1 week of continuous injection. Shut-in (soak) periods of 1 and 2 weeks were used but resulted in
Figure 13  Renditions of final geostatistical permeability and porosity models showing the reservoir architecture. Vertical lines represent offsetting wells within the models. Owens #1 well located in the middle of the models and is marked with red plus marks on the vertical wellbore line.
little difference in oil production. The peak oil production from the reservoir model was about four times the pre-injection oil rate (0.8 bopd to 3.5 bopd).

**MVA Design and Plan**

The monitoring, validation, and accounting (MVA) program design and plan was based on the pilot duration and injection volume. The short duration of the pilot and the small CO₂ injection volume (43 tons [39 tonnes] of CO₂) limited the resources that were allocated to the MVA program. The goal of the MVA program was to test the deployment and monitoring strategies of a few MVA techniques and to be able to detect significant CO₂ leakage events should they occur. The MVA program consisted of (1) atmospheric monitoring, (2) shallow geophysical surveys, (3) gas sampling, (4) shallow groundwater monitoring, (5) groundwater and geochemical modeling, (6) cased hole well logging, and (7) reservoir brine monitoring.

**Atmospheric Monitoring**

Atmospheric monitors were installed at the pump skid site and the well site and activated during CO₂ injection operations only. The monitors are primarily for health and safety purposes to alert operators of any CO₂ leaks that are not otherwise heard or seen. The monitors are custom-made with a Telaire 7000 CO₂ detector and siren/beacon alarm system that is programmed to send an alarm if the ambient CO₂ concentration exceeds 2,000 ppm. The monitors are set up with visual and audible alarms. A button must be physically reset once the alarm is tripped. The devices do not have any data-recording capabilities.
In the immediate area of the pump skid, one monitor was located near the rear of the storage tank. This choice was based on CO\textsubscript{2} volume and was upwind from operators. Two monitors were placed at the well site between the office trailer and the HNP well.

**Shallow Geophysical Surveys**

Two geophysical methods were used to monitor possible seepage of CO\textsubscript{2} from the injection formation (Cypress Sandstone) into the overlying shallow (<100 ft [30 m]) geologic materials. Electromagnetic induction (EM) and electrical earth resistivity (EER) were selected for monitoring because both techniques are sensitive to changes in moisture content and to the contrasting conductivity signatures of leaking gas relative to saturated soil. It was anticipated that seepage and accumulation of CO\textsubscript{2} outside the injection formation might result in smaller conductivity and larger resistivity signatures. However, it was realized that natural changes in soil moisture could have significant effects on these techniques and would need to be controlled or included.

The EM equipment has the advantage of being very mobile, resulting in the potential to monitor large areas. Data can be collected from two or three possible depths of investigation by using fixed dipole (antennae) separations when conducting the EM survey, making it a relatively simple method for basic screening of potential CO\textsubscript{2} seepage.

EER provides much better spatial resolution than EM, but is limited to a smaller monitoring area because of the lack of mobility of the equipment and survey setup time. Both methods are sensitive to buried conductors, such as metal pipes. However, EM is also sensitive to metal surface objects, such as vehicles and metal buildings, as well as to overhead power lines. Neither technique has been used for this specific application, and the EM and EER signatures caused by CO\textsubscript{2} seepage have not been previously reported in the literature.

**Gas Sampling**

Gas samples collected from the annulus space of the CO\textsubscript{2} HNP well and oil production wells were used to determine the behavior and migration of CO\textsubscript{2} in the injection reservoir. Soil gas samples were collected to determine whether CO\textsubscript{2} was seeping from the injection reservoir into the biosphere. This effort used a variety of gas sampling and analytical techniques.

**Shallow groundwater monitoring and modeling**

The objectives of the groundwater modeling were (1) to design a groundwater monitoring system to monitor for CO\textsubscript{2} leakage to shallow groundwater, (2) to determine the flow and transport of any CO\textsubscript{2} leakage from the injection well, and (3) to determine the risks to the environment and human health from CO\textsubscript{2} leakage.
Analytical element modeling (AEM) was used for this project because shallow groundwater and surface water flow can be modeled simultaneously using a relatively simple data set. A disadvantage of the AEM method is that transient flow and three-dimensional flow can be only partially represented in the model, and gradual variation in aquifer properties cannot be represented at all. However, these issues were not significant at this site.

Three groundwater monitoring wells (Owens #1, #2, and #3 shallow [S]) were drilled to a depth between 21 and 24 ft (6 and 7 m) and were screened in a glacial sandy gravel, the main aquifer for residential wells in the area. A fourth well (Owens #1 deep [D]) was drilled to a depth of 135 ft (41 m) and screened in the shale and limestone bedrock. Water-level data were collected from the groundwater monitoring wells installed at the site for the period March through September 2007. The water levels in the three shallow wells (Owens #1S, Owens #2S, and Owens #3S) exhibited a similar trend: some variation through mid-May and then an exponential decline through September 2007. This decline was most likely a reflection of seasonal patterns in precipitation and evapotranspiration. The water level in the bedrock well (Owens #1D) exhibited a much smaller seasonal decline. The major trend in this well was the slow recovery of the water level after sampling. The well took about 5 days to recover fully after the groundwater sampling event. Collectively, the groundwater-level data showed that the vertical gradient was seasonal. During the wetter portion of the year (late fall through early spring), the vertical gradient was downward but reversed to an upward gradient during drier periods of the year.

Model results indicated that groundwater flow was primarily to the east and west due to the presence of a groundwater divide near the site. Groundwater monitoring wells were installed north of the CO₂ injection well to capture the CO₂ plume in case of leakage to shallow groundwater and also to the south of the CO₂ injection well to capture upgradient water.

The particle tracking module of the model was used to determine the transport of CO₂, assuming there was leakage from the injection well into the surficial aquifer. To simulate the worst case and maximum risk to human health and the environment, CO₂ was assumed not to react during transport. Head measurements at the point of leakage were varied from 601 ft (183 m) (approximately 10 ft [3 m] above background heads), 661 ft (201 m), and 861 ft (262 m), and model predictions of the spacial distribution of the CO₂ plume were obtained. The model results for the smallest leak (low head conditions) indicated that the plume would not travel more than 750 ft (229 m) in 10 years and would not appear to pose a significant risk.

Cased Hole Well Logging

The Schlumberger reservoir saturation tool (RST) logs, the ultrasonic image tool (USIT) logs, and the cement bond logs (CBL) were planned pre- and post-injection to observe the injection zone and intervals above the injection zone for CO₂. The RST uses pulsed neutron technology to measure sigma of the
reservoir, which is influenced by the reservoir fluid in the pore space. Repeat passes can be used to determine whether there is fluid movement behind the casing or whether the fluid type is changing (CO₂ displacing water). The CBL uses acoustic impedance to measure cement bonding behind the casing. The CBL gives a relative indication of cement to pipe and cement to formation bonding. A disadvantage of the CBL method is that it averages the values all around the casing, so it is not very effective in determining channels. The USIT uses an ultrasonic signal to build a radial profile of the cement behind the pipe. Additionally, USIT is used as a pipe integrity tool in that it gives inside diameter and wall thickness of the casing.

Reservoir Brine Monitoring

The produced brines from the three oil-producing wells in the pilot area (Owens #1, Owens #4, and Coddington #4) were sampled at the wellhead directly from the production tubing. After decades of water injection in this field from multiple sources, the water is of unknown origin, but is highly saline.

Outreach

Outreach was carried out primarily by the on-site researchers from the Illinois State Geological Survey (ISGS). Scientists contacted local officials, landowners, and residents to inform them of the field test. Site personnel fielded drop-in visitors, were often asked questions about the field test, and interacted with community members on site and off site. Water wells of abutting landowners were sampled, and each landowner was contacted by the deputy project director personally to discuss the project. Permission to lay pipeline across the site owner’s property was obtained through one such conversation. A final report summarizing groundwater information was provided to abutting landowners. To support the field test, a field brochure and a general brochure were developed and distributed throughout the project. Posters describing the field test site were produced and kept on site in preparation for visitors.

Equipment

Injection Equipment

The CO₂ injection equipment for this test consisted of a 60-ton (54-tonne) portable storage tank, a pump skid, and an in-line heater (Figure 15). This equipment was selected based on project requirements for numerous field tests over a wide range of injection and pressure conditions. The plans required testing at six different locations, so it was determined to be more cost effective to procure equipment dedicated for the test program rather than to incur large costs for mobilization/demobilization, equipment rate, and operator charges to bring in third-party injection equipment for every test. Also, the Phase II field testing called for the ability to control the delivery of CO₂ over a wide range of flow and pressure conditions, including in some cases the delivery of gas CO₂ to the wellhead. To accommodate the full
range of required conditions, a custom pump skid was designed based on the use of three small positive-displacement pumps. An in-line heater allowed adjustment of the temperature of the CO$_2$ for delivery to the injection well in order to simulate anticipated pipeline pressure and temperature.

**Storage tank**

A 60-ton (54-tonne) insulated, portable CO$_2$ storage tank was leased for the duration of the project. The tank is filled periodically from CO$_2$ tank truck deliveries of about 20 tons (18 tonnes) each and stores CO$_2$ as liquid at its vapor pressure, of approximately 350 psig and at a temperature of about 10°F (about –12°C). CO$_2$ from the tank is fed through a line under the bottom of the tank to the suction side of the injection pump skid. The storage tank has a pop-off relief valve set for about 350 psig and a secondary relief valve at 380 psig.
**Pump skid**

The CO₂ pump skid is designed to inject CO₂ at surface pressures up to 1,200 psig and flow rates up to 21 gallons (79.5 L) per minute (gpm) or 5.4 tons (4.9 tonnes)/hr. The pump skid consists of three single-cylinder piston pumps in parallel, a 2-inch (5-cm) supply line, a 1-inch (2.5-cm) discharge line, and a 1-inch (2.5-cm) return line. The skid is equipped with instrumentation to measure the injection flow rate and send a proportional 4 to 20 mA signal to a data recorder. Temperature and pressure indicators are available for monitoring suction and discharge temperatures and pressures. Temperature and pressure switches are provided to automatically shut off the pumps in the event of abnormal operating conditions.

Each pump has a capacity of 4 or 7 gpm using the sets of sheaves provided for each pump and motor combination. The system is designed to operate with one, two, or three pumps on-line at any time.

There is a hand-operated bypass valve downstream of each pump. When the hand-operated lever is in the up position, CO₂ flows through the valve and into the return line to the CO₂ storage tank. When the lever is in the down position, the valve regulates the pressure of the CO₂ between the pump discharge and the valve. There is an adjustable spring on each of the hand-operated valves that can be manually adjusted to automatically divert flow to the return line if a specified discharge/injection pressure is exceeded. If the discharge/injection set pressure is not exceeded, all of the CO₂ flows into the discharge line and into the in-line heater. If the discharge pressure is exceeded, some or all of the CO₂ is diverted back to the storage tank as needed to maintain the pressure at the discharge pressure setting. The valve also operates as a check valve, preventing backflow of fluids from the return line back into the pump discharge line should a condition develop where the pressure is lower on the pump discharge than it is on the return line.

A globe valve on the return line can be manually adjusted to send some or all of the pump discharge back to the CO₂ storage tank without actuating the hand-operated valve or exceeding its specified pressure. This configuration gives the operator the option of injecting just enough CO₂ to maintain a discharge pressure at or below the set pressure (by using the set pressure in the hand operated valves) or to inject at a constant rate less than the total discharge of all operating pumps (by using the globe valve on the return line).

**In-line heater**

The pump skid receives CO₂ from the portable storage tank. The pump skid delivers CO₂ to a propane-fired, in-line heater. The CO₂ exits the heater and goes to the wellhead. Temperature and pressure gauges are also provided between the line heater and the wellhead so that the temperature and pressure of the CO₂ injected into the wellhead can be recorded. High-pressure (1,500 psia) relief valves are part of these lines. The in-line heater uses glycol to provide heat transfer between the burner tube and the CO₂ line.
Production Equipment

Portable multiphase well tester

The portable well tester separates liquid from gas using a centrifugal-type separator. The separated gas is measured with a Vortex meter calibrated from the manufacturer. The separated liquid rate is measured using a Coriolis mass liquid meter. After the liquid is separated from the gas, an infrared absorption technique is used for water cut measurement. The infrared meter was calibrated based on actual Owens #1 well oil and produced water samples sent to the manufacturer.

The unit was designed to test a wide variety of wells from 15 to 40 API gravity, liquid flow rate range of 200 to 1,500 barrels per day, gas flow rate range of 0 to 75 million cubic feet (2.1 million m³) per day (mcfpd), and 0 to 100% water cut. However, for this site, lower liquid rates and higher gas rates were anticipated; so the tester was modified to handle these different rates using turbine-type meters calibrated from the manufacturer.
**Pumping unit, separator, and stock tank**

The pumping unit is an Oilwell model (Figure 16), which has a stroke length of 24 inches (61 cm) and a speed of 13.5 strokes per minute. The pump barrel was an inset pump on rods. The pump diameter is 1.75 inches (4.45 cm). The rods are 0.75 inch (1.9 cm) in diameter. The production tubing was 2.87 inches (7.29 cm); no packer was set at the bottom of the tubing string.

The Owens lease separator and stock tank were located about 900 ft (274 m) to the northeast of Owens #1. Owens #1 and Owens #4 produce into the same separator and stock tank. The separator was designed to separate oil and water using gravity through an internal baffling system. The separator capacity is 100 bbl with about 20% oil based on the setting of the system at the time of this test. The separated oil enters the stock tank, which has a capacity of 140 bbl. The stock tank is emptied periodically by tanker truck. The separated water is piped directly to a central water flood facility for re-injection as part of the field's active waterflood.

**Power and Fuel**

A 60-kW diesel generator provided power to the pump skid, a light tower, and one of the ambient CO₂ monitors. The portable generator diesel tank capacity was 75 gallons (284 L).

The pumping unit, portable test separator, two ambient CO₂ monitors at the injection site, and office trailer required 220-volt alternating current.

The in-line heater required propane to heat the glycol within the unit. The propane tank was 500 gallons (1,893 L).

**Data Acquisition Equipment**

**Downhole pressure and temperature sensors**

The EZ-Gauge™ system uses a small-diameter capillary tubing line connected to a downhole pressure chamber. The pressure chamber is placed downhole, below the pump, like a joint of production tubing. A pressure transducer is attached to the capillary tubing at the surface. The system is purged with a low-density, inert gas, usually helium. Once the system is installed, the pressure at the surface is corrected for the additional hydrostatic pressure of the helium gas column in the capillary tube.

The EZ-Gauge™ SG pressure transducers are used in applications that require rugged repeatability and resolution over a wide pressure range. The strain pressure transducers provide laboratory accuracy in a small, low-power design. The EZ-Gauge™ system requires no downhole electric equipment.

An EZ-Gauge™ data analyzer unit is used in remote data-gathering areas. Information is gathered at selected time intervals and is stored in memory. Unit parameters (e.g., survey intervals) and data retrieval
are performed using any type of portable personal computer (PC) through a RS232 interface. Information from the PC is then uploaded to a central computer to generate print and plot reports. Data can be gathered and stored from both downhole and surface sensing devices. These data loggers are set up to record and view up to four input devices consisting of either pressure, temperature, flow rate, or 4- to 20-mA devices.

Specifications of the EZ-Gauge™ setup are given here:

- Accuracy, ±0.08% FS (standard)
- Combined effects of nonlinearity, hysteresis, and repeatability:
  - Resolution, ±0.0001% FS
  - Drift, <0.1% FS per year
  - Operating temperature range, –5°F to 175°F (about –20.5°C to 79.4°C)

**Surface pressure and temperature sensors**

Casing and tubing pressures of the injection well and production wells were measured using Siemens Sitrans P DSIII Transm (7MF4033-1AE10-1AC1-Z) pressure transducers/transmitters programmed for a range of 9 to 900 psig. Based on the manufacturer’s specifications, the resolution and accuracy of the pressure transducers were at least 0.027 psig and ± 5.6 psig, respectively. Maximum drift included in the preceding accuracy error was reported to be ± 2.25 psig over a 5-year period.

The temperatures of the casing and tubing of the injection well and production wells were measured using Pyromation resistance temperature detectors (R1T185L483-041/2SC-8HN22) and Siemens Sitrans TKH300 temperature processors. The processors were programmed for a range of –30 to 50ºC (-22 to 122ºF). The accuracy of the temperature resistance temperature detectors was reported to be limited to ± 0.68ºC (33.33°F) in the temperature range applied and processor drift less than 0.024ºC (32.04°F) (0.03% of the maximum span) after 1 year.

The sensor errors are for the sensors only and do not reflect total system error or account for field-related problems, such as paraffin deposition on the temperature probes.

**Data acquisition system**

Each of the oil wells in the pilot are outfitted with two surface pressure sensors and two surface temperature sensors. One pressure and temperature sensor pair is mounted on the production or injection tubing and the second pair on the casing. Each sensor is connected by a 20-mA current loop wire to a remote data converter that converts the sensors’, electrical current to digital, calibrated values of pressure.
and temperature. The data converter at each well is connected to a radio transmitter that sends the data for pressure and temperature to a common receiver located within the field office trailer located at Owens #1. Each of the well data converters has provisions for additional channels that are used to send data from the downhole pressure and temperature sensors, installed by Halliburton (now Well Dynamics), to the same common receiver. The common receiver point collects the data several times each minute from each well and stores that data on a PC programmed to collect all data from each well.

In addition to well pressure and temperature, this system also collects liquid and gas flow rate data from the portable test separator. The liquid flow rate data are sent by the data converter and transmitter located at the injection well. The CO$_2$ injection rate data are collected and transmitted by a separate transmitting unit located within close range of the CO$_2$ pump skid. As with the pressure and temperature data, the flow rate data are collected.

Each transmitting unit located at each wellhead has an independent power supply (battery) system that is continually recharged by a solar panel. This feature allows for total independence from local power sources, which may not always be present. (No power was available at the water injection wells.)

The common receiver and data collection computers are housed in the field trailer located within 1,000 ft (304.8 m) of each well. The data collection computer collects incoming data from the outlying wells and assembles and stores it into a readable time-stamped form. The field trailer is outfitted with an independent battery driven power supply that is invoked whenever the main power is off, which prevents data loss. (The trailer is outfitted with a secondary backup computer that can be placed online quickly if the main collection computer fails.)

Data from the data collection computer are transmitted to the University of Illinois at Urbana-Champaign daily by use of a remote satellite transceiver contained within the field trailer. The satellite transceiver allows the system independence from local Internet connections, which may not always be present.

**Injection flow rate meter**

The CO$_2$ injection rate was monitored using a turbine flowmeter. The turbine flowmeter measures the volumetric flow rate of the liquid CO$_2$ by counting the rotations of a small vaned rotor within the flowmeter housing. The liquid CO$_2$ engages the vaned rotor, causing it to rotate at an angular velocity proportional to the fluid flow rate. The angular velocity of the rotor results in the generation of an electrical signal. The counter sums the electrical pulses, and the pulse frequency is then related directly to the flow rate. The output signal of 4 to 20 mA is sent to the data acquisition system. A local indicator displays the instantaneous flow rate in gallons per minute and the totalized flow in gallons.
Field Office Trailer

The office trailer was located at the Owens #1 site (Figure 17). The trailer is 28 ft (8.5 m) long and 8 ft (2.4 m) wide. The data acquisition equipment and satellite equipment are located in the trailer.

Field Work

The original plan was to locate all of the injection and production equipment around the Owens #1 well. However, the Air Liquide CO$_2$ transport trucks were not rated for the lease road that led to the Owens #1 site. Consequently, the injection equipment was located near the Owens lease tank battery, which was very close to a township road. A 1.5-inch (3.8-cm) pipe with couplings and unions was run about 330 ft (101 m) to the north lease boundary and 950 ft (290 m) east to the tank battery. The site around the injection equipment is referred to as the “pump site,” and the area around the Owens #1 is referred to as the “well site.” Gravel was added to both sites and the road leading to the well site.

Huff ‘n Puff Operations

Pre-injection

Well and site preparation

The liquid CO$_2$ pumping equipment (storage tank, pump skid, and in-line heater) was installed and pressure tested the week before injection (Figure 17).

A gravel pad was placed around Owens #1 for the portable test separator, office trailer, and parking. Gravel also was placed in the area of the pump site for the CO$_2$ tanker delivery (Figure 18).

Baker-Hughes designed the chemical corrosion treatment plan. The recommended chemical was Baker-Hughes CRO 195, which is commonly used in West Texas CO$_2$ EOR floods. Additionally, Petco was using this chemical as part of the water flood chemical treatment to the highly saline injection water. Based on anticipated flow rates in the tubing and flow line, a batch treatment of one gallon (3.8 L) per week was selected. Corrosion coupons were placed in the three producing wells and monitored weekly for changes in corrosion pit rate. Immediately before CO$_2$ injection, a batch treatment was applied to each producing well.

The portable test separator was piped in parallel to the flow line at Owens #1. A backpressure regulator was initially placed upstream of the portable test separator. After various attempts to produce through the separator at higher pressure, the backpressure regulator was moved and kept upstream of the separator and through the remainder of the metered flow period.
Baseline Flow Rate

Pre-injection oil rates at Owens #1 were available from the production foreman, the lease battery, and the portable test separator. The production values from these three sources were inconsistent. The Owens #1 was reported by the production foreman to make 2 bopd and 48 bwpd from the Cypress based on a bucket test, a very short-term test of diverting production from the wellhead to a calibrated container that yields a water and oil volume over a specific time.
Presently (2/11/07) No CO2 Delivery Trucks are expected to drive to Owens #1. Trucks will unload at the Tank battery and CO2 will piped across the field to Owens #1.

Figure 18  Sketch of the equipment layout at the Owens #1 well site.
Since February 28, 1973, the Owens lease battery has had only two producing wells: Owens #1 and Owens #4. Their production is commingled at the tank battery. Immediately before the CO\textsubscript{2} pilot setup, both wells produced into the lease battery during 57 of 66 days. The average rate was 3.95 bopd. There were 9 days when only Owens #4 produced; its average rate was 2.88 bopd over this 9-day period. Using the lease battery records, the estimate for Owens #1 is 1.07 bopd. Removing one well from the separator disrupts daily rates for 1-3 days. The 9-day period was considered adequate to minimize this effect.

For about 4 days before the CO\textsubscript{2} injection period, the portable test separator values ranged from 0.2 and 0.5 bopd and 35 and 36 bwpd. The gas rate was insignificant. Although the separator should have provided accurate pre-injection oil production rates, water cut based on the red-eye meter and liquid density were overestimated during the pre-injection period. The separator software most likely assumed a brine density lower than actual and set water cut or density values exceeding a theoretical maxima. Because the data were truncated, recalibration was not possible.

Based on this information, the pre-injection oil rate was estimated at 1 to 2 bopd and the oil rate at 36 to 48 bwpd. The average reservoir pressure (shut-in) for Owens #1 was 450 psig. Composition of the oil and gas revealed less than 2\% CO\textsubscript{2}.

**Injection**

Liquid CO\textsubscript{2} was pumped from the storage tank using one of three liquid CO\textsubscript{2} pumps. The CO\textsubscript{2} passed through the in-line heater before moving to the 1,280-ft (390-m) pipeline to the wellhead.

Various pump-related problems occurred during the pumping process. Most of these were diagnosed as reduced pump rates assumed to be from CO\textsubscript{2} vaporization upstream of the pumps. To improve and maintain pump rates, CO\textsubscript{2} was bled upstream at different times during the injection operations. Causes of reduced pump rates were suspected to be CO\textsubscript{2} phase changes due to heat loss, which was reduced by adding insulation, and regular cleaning of a in-line filter screen, which was found to have accumulated leaves and other foreign matter, likely from an animal’s nest. It was not determined whether the foreign material was from the pump skid or the storage tank. Other problems were that the flowmeter stopped working, and v-belts flew off the pulleys. (A booster pump upstream fo the pump skid would likely sovle many of these problems.)

Injection was constrained by the injectivity of the Cypress at Owens #1. Because CO\textsubscript{2} gas was desired, very little hydrostatic head was available in the casing-tubing annulus to increase the subsurface injection pressure. To address this issue, a portion of the pumped CO\textsubscript{2} was recirculated to the storage tank downstream of the pump skid but upstream of the in-line heater. To increase the CO\textsubscript{2} injection rate, the injection pressure and volume regulator were controlled. However, these adjustments frequently did
not work. As the rate was lowered, the residence time of the CO₂ in the pipe line and CO₂ temperature both increased, causing CO₂ expansion, which added additional back-pressure to the pumps (because of the low Cypress injectivity). When this situation occurred, injection would cease for several hours. Consequently, the in-line heater temperature became a more important factor for maintaining higher injection rates for this injection project. To improve injection rate during daylight hours, the in-line heater temperature was lowered and at times was shut off completely.

Over 5 days, 43.0 tons (39 tonnes) of CO₂ were injected (Figure 19). The active injection time was 4.4 days. During this time, approximately 150 gallons (568 L) of propane and 94.4 gallons (357.3 L) of diesel fuel were used.

**Post-Injection**

**Pumping unit operations**

The post-injection shut-in or soak was 8 days. During the flowback period, three consultants, the field superintendent, and production foreman were on location with ISGS personnel. Consultant expertise was in HNP operations, data acquisition, and portable test separator.

Consultants and field personnel agreed that the casing pressure needed to be lowered to produce liquid from the insert pump in order to minimize the gas entering the downhole pump and to keep gas dissolved in the liquid phases.

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*Figure 19  Cumulative hourly totals for injected CO₂.*
Prior to attempting liquid production with the pumping unit, casing gas (10 MMscf or 0.59 ton [0.54 tonnes]) was produced (primarily CO₂) to a pressure of 318 to 543 psig. Then the pumping unit was turned on. It was very difficult to initiate liquid production.

Various combinations of casing pressure and tubing pressure were used to initiate production of liquid from the pump (Figure 20). Initially, while the pump was on, tubing pressure was reduced to 100 psig in 25 psi increments. (Bleeding off to atmospheric pressure never resulted in liquid production.) Following this period, liquid production occurred for 15 to 45 minutes, followed by a gas production period of 30 minutes to 2 hours. Afterward, the well was shut-in for 2 to 4 hours so that wellbore pressure could equilibrate and another production attempt could be made. The time intervals allowed two to three attempts daily.

Various combinations of casing and tubing pressure were attempted unsuccessfully. Toward the middle of the week, the casing was bled to atmospheric pressure, and various tubing pressures were applied. None of these combinations worked either. After nearly 4 days of these types of attempts, it was decided to pump the well continuously through the period of gas only. After almost 4 hours, the well started to produce liquid continuously.

It is hypothesized that gas separated from liquid in the casing-tubing annulus, resulting in liquid and some gas entering the downhole pump. As liquid was pumped to the surface, the pressure was reduced, and gas came out of solution in the upper part of the tubing. The lower viscosity, lower density gas moved faster upward in the tubing than the liquid while the well continued to pump liquid (at the pump). Only

**Figure 20** Owens #1 pressure during the first week of production. SCP-surface casing pressure; STP-surface tubing pressure; BHP-bottomhole pressure
gas was produced at the surface. Eventually, the liquid level rose in the tubing to the surface, and the well began to pump liquid at the surface.

The well produced liquid continuously for several hours to several days before liquid flow rates returned to zero, and the startup procedure was repeated. Eventually the tubing backpressure regulator was opened completely.

Corrosion treatment was applied continuously at the rate of 0.5 gallon (1.9 L) per day; additionally, a weekly one-gallon (3.8-L) batch treatment was used. No evidence of corrosion that was attributable to CO₂ was detected. Corrosion due to O₂ was detected twice, once when the casing was open and air was allowed to enter, and a second time when the source of O₂ was uncertain (Figure 21).

**Out-of-Zone MVA**

The out-of-zone MVA is for all zones at lesser depths than the injection zone; most were near the surface (<100 ft [30 m] below the surface).

**Atmospheric monitoring**

The atmospheric monitoring alarms rarely were activated. The monitor closest to the rear of the storage tank was activated primarily when the tank pressure exceeded the low pressure pop-off relief valve. Because of the noise caused by the pop-off relief valve, this type of discharge provided an audible alarm.
The atmospheric monitors were redundant in this respect. With respect to MVA, no CO$_2$ discharging from the subsurface to the atmosphere near the HNP well was detected.

**Shallow geophysical surveys**

The EM survey showed variations in soil conductivity and detected buried pipes and abandoned infrastructure around the site. The global positioning system (GPS) and integrated location system were very helpful in collecting and processing the data. It would be almost impossible to use this method without these aids. However, the instruments were very sensitive to metal in the survey area, whether buried or above ground. To be effective for monitoring, the measurements must be repeated regularly. For this pilot, three surveys were made. For a more definitive monitoring program, much more frequent measurements would be required, but the labor required for frequent measurements with the EM34 system is prohibitive. Consequently, this system is not recommended for future work within existing oil fields.

The resistivity survey showed variations in the resistivity and chargability of the soil and had relatively good spatial resolution within the surveyed area. Three-dimensional models of the resistivity and chargability were calculated. Resistivity showed good promise for monitoring the shallow subsurface around an injection well because it is very sensitive to changes in the gas and liquid phases within the soil pores. Further research may determine whether the chargability variations also provide information about hydrocarbon content or CO$_2$ content of the soil. The major limitation of the method is the limited spatial coverage of the grid, because it is dependent on the location of the resistivity cables. It is recommended that future monitoring efforts concentrate on resistivity/induced polarization surveys using dedicated grids of electrodes. These grids would be centered around the injection well, and a dedicated resistivity meter would be programmed to acquire a full set of measurements on a regular basis (e.g., daily). Adjustments could then be applied for changes in soil moisture due to precipitation events.

Data collected from all of the geophysical methods deployed at the site exhibited similar patterns with respect to location and the magnitude of values. These patterns were likely due to the geology of the site. Based on the limited data collected, there were no definitive results that would suggest CO$_2$ leakage from the injection reservoir into the shallow geologic environment surrounding the injection well. Further follow-up investigations would be required, using other monitoring techniques, to determine the cause of the small differences that were observed in pre- and post-CO$_2$ injection data.

**Gas sampling**

Soil gas concentrations in the vadose zone were monitored to determine whether CO$_2$ was leaking from the injection zone into the biosphere. This technique was limited because the high water table at the site impeded the collection of soil gas. Carbon dioxide concentrations from samplers at various depths
(1.5, 4, and 8 ft [about 0.5, 1, and 2 m]) and locations (nests 1, 2, and 3) varied from instrument detection limit to 7%. The limited data collected from the vadose zone did not indicate that changes in either CO$_2$ concentrations or variability were sufficient to suggest leakage from the injection formation.

**Groundwater Quality**

The background groundwater pH, alkalinity, and total CO$_2$ of the shallow groundwater near the CO$_2$ injection well did not vary significantly over the monitoring period. Water samples collected up to 6 months after injection generally had pH values similar to or greater than background values. Alkalinity and total CO$_2$ concentrations in the groundwater samples also exhibited the same variation as pH values and likely could be accounted for by seasonal variation.

The isotopic composition of the groundwater suggests no evidence of migration or leakage of the injected CO$_2$ to the shallow groundwater. The $\delta^{13}$C values of the dissolved inorganic carbon (DIC) in the groundwater samples collected up to 5 months after CO$_2$ injection from the monitoring and local residential wells did not vary significantly. The $\delta^{13}$C values did not exhibit the systematic decrease that would be expected if the injected CO$_2$ were to have migrated to the shallow aquifers. The isotopic composition of the groundwater confirms that the observed changes in the groundwater pH and alkalinity were not due to the injected CO$_2$. The variations in pH and alkalinity concentrations during the summer months were likely due to natural seasonal changes in groundwater recharge. The $\delta^{18}$O and $\delta$D as well as the $^3$H also suggest that there was no migration of the brines into the shallower groundwater during this study.

During the post-injection monitoring period, a nearby landowner informed us of an unusual odor coming from his water well. Because of the pre-injection groundwater data and subsequent tests, it was demonstrated that the odor was biological in nature and not related to CO$_2$. Additionally, the relationship that project staff had developed with the landowners in the area was an important part of resolving this landowner’s concerns.

**Logging**

The logs were the RST and the cement mapping tool (CMT). The RST log is sensitive to the various types of fluids in the reservoir, the annulus behind the casing, and in the borehole. The CMT log is sensitive to cement compressive strength behind the casing.

The USIT tool requires a very clean casing surface. The Owens wells had too much scale and chemical buildup to get a response, so the tool was unsuccessful. Consequently, the CBL was run. Because of concerns about losing the logging tools below the end of the casing, the cased hole sondes were not lowered adjacent to the injection zone. Both Owens #1 and #4 showed no signs of CO$_2$ in the intervals logged above the injection zone.
Schlumberger ran cased hole logs pre- and post-injection to identify any effects the CO₂ may have had on the reservoir, fluids, or cement. Additional information from ISGS logs run before and after injection and the original open-hole log data were combined to make the final evaluation.

Because of the CO₂ response at Owens #1 and #4, only these wells were logged post CO₂ injection. Neither well showed any sign of the CO₂ moving up and out of the injection zone behind the casing. Also, neither well showed a problem with the cement quality behind the casing, whether pre- or post-injection of the CO₂.

**Injection Zone MVA**

The injection zone MVA includes the measurements from the Cypress Sandstone for the Owens #1: logging, gas composition of surface gas samples, brine quality of surface gas samples, bottom-hole pressure, bottom-hole temperature and fluid production.

**Owens #1 HNP response**

After nearly 5 days of various attempts to produce from Owens #1, the oil production rate peaked after 6 days at 8 bopd (1.27 m³/day). The oil rate steadily decreased over 3 weeks to about 3 bopd (0.477 m³/day), which is 50 to 200% above the 1 to 2 bopd (0.159 to 0.318 m³/day) pre-injection. After 2 months
production, it was estimated that 93 barrels were produced above the pre-injection oil rate of the Owens #1 well (Figure 22).

The portable test separator developed operational problems, and reliable data from it was unavailable. The water production rate was reduced to below 30 bwpd (4.77 m$^3$/day) from the 36 to 48 bwpd (5.72 to 7.63 m$^3$/day) pre-injection water rate estimate. The reduced rate continued for nearly 30 days. Toward the last week of reliable portable test separator data, the water rate was nearly 30 bwpd. (Figure 23).

The casing gas production was relative high and measurable for two weeks; however, during some periods, the gas rate was at nearly atmospheric pressure, and the gas meters recorded no measurable casing gas flow rate. Casing gas was measured separately from the portable test separator using turbine flowmeters. During this time, the casing CO$_2$ concentration was sampled and exceeded 70% concentration. After 2 years, the low pressure casing gas had in excess of 60% CO$_2$ concentration; however, during March 2009, concentrations were as low as 30%. We estimated that 31.1 tons (28.3 tonnes) of CO$_2$ were produced during 13 weeks of measurable gas production.

For the 2 years following the injection, the well continued to produce at higher oil and water rates than before CO$_2$ injection. The additional response is likely due to the CO$_2$ reducing near-wellbore flow restrictions, such as scale deposition. Total fluid production increased, and a larger downhole pump was installed.
Gas sampling

Gas concentrations in the annulus of the injection well (Owens #1) were monitored. Prior to CO$_2$ injection, methane concentrations were greater than 85% with correspondingly small (<2%) CO$_2$ concentrations. After injection, CO$_2$ concentrations increased to greater than 80% and remained near that concentration for approximately 5 months. Seven months after injection, CO$_2$ concentrations have remained greater than 60%, and methane concentrations have increased to approximately 40%. Oxygen concentrations have varied from below instrument detection limits to about 15% throughout the pilot period. Nearly 2 years later, the low pressure casing gas CO$_2$ concentration is 40% (Figure 24).

Gas concentrations in the annulus of the two oil-production wells (Owens #4 and Coddington #4) closest to the injection well were monitored. Methane and oxygen concentrations were less variable in Owens #4 than in Coddington #4. In general, CO$_2$ concentrations were below detection limits in Coddington #4. Methane concentrations in Owens #4 were generally at 95% throughout the pilot period. CO$_2$ concentrations were generally less than detection limits until 190 days after injection, when detected concentrations were about 3.5%; concentrations remained relatively constant until the end of the monitoring period (206 days). On September 19, 2007 (178 days after injection), the Owens #4 well failed to produce liquid but was producing gas. Measurement of the tubing string gas indicated CO$_2$ concentrations at 95%. The well was immediately shut-in and underwent maintenance procedures due to the lack of production. The elevated and relatively constant CO$_2$ concentrations in the annulus of Owens

![Figure 24](https://example.com/figure24.png)
#4 during that time in conjunction with the lack of production and large \( \text{CO}_2 \) concentrations in the tubing string suggest that \( \text{CO}_2 \) breakthrough occurred at Owens #4 about 170 days after injection started.

When Owens #4 returned to production in about 2 weeks, no excessive gas production was present. Furthermore, the post-injection cased hole logs showed no change in saturation around this well. The excessive gas production at Owens #4 occurred following a lengthy shut-in at Owens #1. It is hypothesized that the water injection from the north and northwest displaced some of the \( \text{CO}_2 \) gas remaining in the reservoir to the south at Owens #4.

**Brine and geochemical modeling**

The injection of \( \text{CO}_2 \) into the Cypress Sandstone decreased the pH of the formation brine and dissolved calcite in the unit. The brine became supersaturated with respect to calcium carbonate. There has been no clear evidence to date that the injected \( \text{CO}_2 \) has migrated from the Cypress Sandstone. Long-term geochemical modeling suggested that the formation matrix system may continue to change for centuries. The relatively small reduction in mineral volume resulting from the dissolution of the original mineral assemblage may be compensated by the precipitation of secondary minerals. The primary mineral phase in the Cypress Sandstone is quartz, which remains inert; its dissolution and precipitation are unaffected by pH changes. Most of the other original silicate minerals remained stable in simulations because of their typically slow reaction kinetics.

As expected, the \( \delta^{13}\text{C} \) of the DIC from the injection well showed a dramatic, negative shift in composition after the injection of the isotopically negative \( \text{CO}_2 \) in this well. The \( \delta^{13}\text{C} \) results easily identified the large quantity of \( \text{CO}_2 \) sampled at the Owens #4 production well 7 months into the experiment as the injected \( \text{CO}_2 \).

**Logging**

The Owens #1 injection well showed a few differences between pre- and post-injection log runs. After considering the character of the responses and likely scenarios, there does not appear to be residual \( \text{CO}_2 \) in this well. The Owens #4 monitor well showed a distinctive response of residual \( \text{CO}_2 \) saturation of about 5\% in a 4-ft (1.2-m) interval at the top of the sand.

**Summary**

The objectives of the EOR I: HNP pilot were met: \( \text{CO}_2 \) injection, incremental oil, and \( \text{CO}_2 \) production were quantified. The injection equipment and implementation plan were tested and revised. MVA techniques were revised and changed for subsequent \( \text{CO}_2 \) injection pilots. Important and relevant results are as follows.
Prior to CO₂ injection, methane concentrations were greater than 85% with correspondingly small (<2%) CO₂ concentrations. After injection, CO₂ concentrations increased to more than 80% and remained near that concentration for approximately 5 months. (After 2 years post-injection, CO₂ concentrations remained greater than 50%, and methane concentrations increased to approximately 50%.) Oxygen concentrations varied from below instrument detection limits to about 15% throughout the pilot period.

Methane and oxygen concentrations were less variable in Owens #4 than in Coddington #4. In general, CO₂ concentrations were below detection limits in Coddington #4. Methane concentrations in Owens #4 were generally at 95% throughout the pilot period. CO₂ concentrations were generally less than detection limits until 190 days after injection when concentrations were detected at about 3.5% and remained relatively constant until the end of the monitoring period. On September 19, 2007 (178 days after injection), the Owens #4 well failed to produce liquid but was producing gas. Measurement of the tubing string gas indicated CO₂ concentrations at 95%. The well was immediately shut in and underwent maintenance procedures due to the lack of production. The elevated and relatively constant CO₂ concentrations in the annulus zone of Owens #4 during that time, in conjunction with the lack of production and large CO₂ concentrations in the tubing string, suggest that CO₂ breakthrough had occurred at Owens #4 about 170 days after injection started.

There were approximately 2 incremental barrels of oil produced per ton (0.91 tonne) of injected CO₂. Water rate was decreased, and overall well behavior was improved long-term. A major concern of Illinois Basin oil field operators, prevention of CO₂ corrosion, was demonstrated. Effective control was achieved with chemical batch and continuous treatments. Use of temperature to control rate at the in-line heater increased injection during the daytime hours.

Producing the well via rod pump with excessive dissolved CO₂ in the tubing likely would have happened earlier if the well had been allowed to pump continuously until liquid was brought to surface. It is probably unnecessary to reduce the casing pressure early in the flow period.

In the geologic modeling procedures, the use of normalized SP was integral to developing the sandstone-shale distribution and permeability estimate. The limited availability of core analyses was overcome by means of general well log-transform with a subset of porosity data available.

Vadose zone MVA in the Illinois Basin may not be feasible due to saturated soil conditions near the surface. Use of shallow geophysical survey techniques in oil fields may be less applicable due to buried pipelines between wells and above-ground electrical lines. Gas sampling of the casing gas was important and necessary to quantify the CO₂ production and corrosion potential. Importantly, residential groundwater monitoring alleviated concerns of a landowner when excessive odor in a water well was suspected of being CO₂ related.
Appendix

ISGS Geophysical Logging at Loudon

A request was made on October 26, 2006, to log Owens #1 with a caliper probe in order to help determine the condition and rugosity within the uncased portion of the well (Weiler Sandstone), the condition at the bottom of the casing just above the open portion of the well, and, to some degree, the inside condition of the casing itself. Original 1939 well records and schematics indicated that fracturing was performed within the open portion of the well using explosives. The total depth (TD) of the well was also a major consideration for performing this initial investigative logging using the Illinois State Geological Survey (ISGS) caliper probe. Precise information from existing records in reference to casing condition, casing interval(s), and casing size(s) was limited; due to the age and history of Owens #1, it was hoped that caliper logging could provide additional insight.

Due to the results of the caliper logging, decisions were made to have the ISGS record natural gamma, 8-inch (20.3-cm), 16-inch (40.6-cm), 32-inch (81.3-cm), and 64-inch (162.6-cm) normal resistivity, self-potential (SP), and single-point resistance (SPR) within all five wells. The gamma could be used to log the entire formation and correlate with logs being recorded by Schlumberger (both pre- and post-injection) as well existing 1939 Schlumberger electric logs (e-logs). The resistivity logs were specifically recorded to help with qualitative analyses within the open portion of the well, since the formation was expected to be non-uniform and very rugose.

Methodology

Log Data Acquisition System & Software

The ISGS logging system is a 2000 model MGXII digital logging acquisition system manufactured by Mt. Sopris, Inc. of Golden, Colorado. The cable is a 3/16-inch (0.48-cm) (outside diameter) single-conductor coaxial cable and is spooled on a Mt. Sopris 4WNA-1000 winch, capable of carrying up to 6,000 ft (1,828.8 m) of 3/16-inch (0.48-cm) diameter cable. Data are recorded on a rack-mounted, customized PC capable of recording large amounts of data rapidly and displaying high-resolution, detailed images on a rack-mounted LCD screen monitor. The operating software, MSLog, produces a proprietary log file in addition to an LAS file. The ISGS uses WellCAD v4.2 software, developed by Advance Logic Technology (ALT), Luxembourg, specifically for post-processing Mt. Sopris proprietary RD files. WellCAD also has a module for importing from and exporting to Schlumberger LIS and DLIS file formats.
**Caliper Logging**

The caliper sonde or probe is a 1984 Mineral Logging System (MLS) three-arm mechanical probe, which can measure diameters from 2 inches (5.08 cm) to 30 inches (76.2 cm). The caliper probe is 74 inches (187.96 cm) long and 1.25 inches (3.18 cm) in diameter. The probe is operated by the MGXII acquisition system and MSLog Software, which converts and records the data digitally while logging.

The probe is operated by lowering it to the bottom of the hole prior to opening the arms. At the bottom of the hole, the arms are slowly opened to full tension and to the extent of the borehole wall. As the probe is raised from the bottom of the hole, the tips of the arms slide along the borehole wall, causing the arms to move interdependently in and out as the borehole wall and diameter increases and decreases. The probe may show boundaries associated with lithologic change, the presence of fractures and cavities, and the narrowing or widening of the borehole. The trace is depicted in real time as a single line plotted in inches with depth in feet on the PC monitor. The caliper log can also show casing intervals and joints, borehole rugosity, variations in casing size, transitions from an open to a cased borehole, and unusual obstructions or damage on the inside of casing. The advisability of running logs that require nuclear sources can be determined with the caliper log. Caliper logs are generally considered essential in the interpretation of other geophysical logs since many logs are affected by changes in borehole diameter.

The shorter 6-inch (15.2 cm) set of caliper arms were used in Owens #1 in order to help prevent the arms from closing under the weight of the cable in case the hole was not completely vertical and/or the probe became slightly tilted toward one side. The spring tension of the mechanism that opens and maintains tension on the caliper arms may have weakened over the past 24 years due to the age and continual use of the probe. Observations of the caliper data over the past 4 to 5 years suggest that this or other possible malfunction within the probe may be the reason for occasional anomalous data when recorded within casing known to be in good or excellent condition. With this in mind, it is important to note that the data collected are relative and therefore should be taken into account if used for qualitative analyses and interpretation.

**Gamma Logging**

Gamma logging is performed using a Mt. Sopris 2PGA-1000 Polygamma combination probe, which also includes SP and SPR measurements. The 2PGA-1000 is 31.3 inches (79.5 cm) long and 1.63 inches (4.14 cm) in diameter; it weighs approximately 7 pounds. The user is able to attach to a number of different probes in order collect additional data such as the multi-electrode 8-inch (20.3-cm), 16-inch (40.6 cm), 32-inch (81.3 cm), and 64-inch (162.6 cm) normal resistivity probe (2PEA-1000), electromagnetic induction probe (2PIA-1000), fluid temperature and resistivity probe, and the spinner-flowmeter probe.
A natural gamma log is a graph of the gross gamma radiation (high energy electromagnetic radiation) emitted by the earth materials surrounding the sonde. Most natural earth radiation is generated from isotopes of potassium-40, thorium-232 and uranium-238. Gamma logs can be recorded within fluid-filled, air-filled PVC or steel cased boreholes. The radius of detection range with the PGA-1000 is generally about 1 (2.5 cm) to 6 inches (15.2 cm) but may exceed this distance depending on gamma intensity. ISGS natural gamma logs are graduated in counts per second and/or API values. API values can be related to oil field borehole logs.

The chief use of the gamma log is for stratigraphic correlation and identification of lithology. Detrital sediments with fine-grained textures such as shale and unconsolidated clay generally have the highest gamma intensity.

**Pre-injection Results**

*Owens #1*

On October 27, the ISGS logged the entire length of the well using the caliper probe. The original 1939 open-hole e-logs by Schlumberger indicate that the well was initially drilled to a TD of 1,546 ft (471.2 m) below ground surface (bgs), with a 6-inch (15.2 cm) casing installed to 1,516 ft (462.1 m) bgs and left open from 1,516 ft (462.1 m) to 1,546 ft (471.2 m) bgs. The interval from 1,526 ft (465.1 m) to 1,546 ft (471.2 m) bgs was subsequently shot with 60 quarts of nitroglycerin within the uncased sandstone. The caliper depth indicated that the TD was about 1,523 ft (464.2 m) bgs, about 7 ft (2.1 m) below the bottom of the casing as indicated in the original well diagram. It also suggests that approximately 23 ft (7 m) of open hole from 1,523 ft (464.2 m) to 1,546 ft (471.2 m) had collapsed or was backfilled with material since the hole was constructed in 1939. At approximately 1,518 ft (462.7 m) to 1,520 ft (463.3 m) bgs, the caliper measurement is roughly 17 inches. Above this and up to a depth of approximately 1,510 ft (460.3 m), the caliper measurement averages out to approximately 10 inches (25.4 cm). From 1,510 ft (460.3 m) to 1,498 ft (456.6 m), the average caliper measurement is about 6.1 inches (15.5 cm), and from 1,498 ft (456.6 m) to 1,485 ft (452.6 m) the measurement appears to increase to about 6.8 inches (17.3 cm). For some unknown reason, the measurement decreases significantly to about 4.5 inches (11.4 cm) from 1,485 ft (452.6 m) to 1,469 ft (447.8 m). This occurs several additional times throughout the remainder of the hole above these intervals. As mentioned previously, it’s unclear whether these changes are due to actual conditions or mechanical/electrical issues associated with the probe. The overall appearance of the caliper trace also indicates that the casing wall is bumpy, not smooth, which could be an indication of the presence of some type of precipitate or sludge, or it could indicate the physical deterioration of the steel casing itself over the years, or a combination of both. Whatever the reason, it corroborates with Schlumberger’s assessment in reference to the condition of the casing inner wall and why their Ultrasonic Imager Tool (USIT) was unable to operate effectively during the pre-injection logging.
Recognizing that only the top 6 to 7 inches (15.3 to 17.8 cm) of formation was open, Petco cleaned out the well as much as possible in order to make sure that as much of the original formation was open for geophysical logging and injection. Coarse sandstone fragments (1 to 2 inches [2.5 to 5 cm]) appeared to make up a large portion of the material recirculated to the surface. The ISGS logged Owens #1, Owens #4, Coddington #2W, Coddington #4 and Hawkins #1 with gamma, SP, SPR, 8-inch (20.3 cm), 16-inch (40.6 cm), 32-inch (81.28 cm), and 64-inch (162.6 cm) normal resistivity after recirculating the hole was complete in Owens #1. The poly-probe indicated that the hole was now open to approximately 1,533 ft (467.3 m), an increase of 10 ft (3.1 m) in hole depth from the initial caliper run. The fluid level was determined to be somewhere between 242 ft (73.8 m) and 244 ft (74.4 m) bgs from the e-logs. Due to time constraints, we could not rerun the caliper log within the uncased portion of the well below the 1,523-ft (464.2 m) depth. However, as we were to discover later during post-injection logging, debris in Owens #1 once again filled the lower portion of the well back up to the original depth of about 1,523 ft (464.2 m; determined by the first caliper run).

In order to fully appreciate the value of the gamma logging in the cased as well as in the uncased portion of the well, we digitized the original 1939 Schlumberger e-logs and plotted them side-by-side with the ISGS gamma and e-logs. However, since the ISGS logs were recorded in casing, with the exception of the bottom 20 ft (6.1 m), the ISGS e-logs above 1,500 ft (457.2 m) are not useful for correlating with the original 1939 e-logs or the ISGS gamma log. They may, however, provide some limited value as to the condition and integrity of the casing. In addition to the 1939 geophysical logs, original geologic descriptions were included on Owens #1 and Owens #4 geophysical logs for enhanced analyses and to provide complete and thorough records. Owens #1 and Owens #4 were selected to include descriptions due to Owens #1 being the injection and production well, and Owens #4 reported as having CO$_2$ breakthrough. Time was also a consideration. Although there were no quantitative analyses performed between these particular logs, the qualitative assessment indicates good correlation in reference to depth and establishes additional confidence in the original well record.

An anomaly that arose during the gamma logging within Weiler Sandstone at 1,498 ft (456.6 m) to 1,527 ft (465.4 m) revealed gamma count rates in the range of 1,000 to 2,000 counts per second (cps), which were expected to be in a typical Mississippian sandstone range of less than 50 cps. This interval, which included a portion of what is expected to be cased hole, was recorded twice because of the unexpectedly high count rate, as it was initially suspected that the count was because the equipment might be within a shale unit, and/or our depth was off. It was concluded later that the increased gamma radiation is likely attributed to by naturally occurring radioactive materials (NORM). NORM are typically radium isotopes attached to barite that precipitates over time during oil production and water flooding or injection. An accumulation of barite scale can signify an increase in NORM, and vice versa. The radium isotopes associated with this type of precipitation in oil wells are radium-226 and radium-228. These isotopes are
gamma as well as alpha emitters; hence, the increased gamma radiation detected by the gamma probe. Coincidentally, a publication by the USGS entitled “Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment—An Issue for the Energy Industry” reports that NORM were detected at oil field sites in a portion of southern Illinois with greater than five times the median background levels of radiation. It is unclear what effect barite accumulation might have on the overall permeability of the sandstone at the fluid-borehole wall interface and how that might impact production and/or injection.

In order to portray the entire gamma log more effectively within a typical range of counts per second, two gamma logs with different depth intervals and count ranges were created from the original gamma log due to the relatively high count rate recorded in the lower 32 ft (9.8 m). This made it easier to graph and display both logs in order to reflect the unique signatures and departures from both depth intervals.

The 8-inch (20.3-cm), 16-inch (40.64-cm), 32-inch (81.3-cm), 64-inch (162.6-cm) normal resistivity logs reflected a range of 2 to 10 ohm-m within the Weiler SS. Not surprisingly, the shorter spaced electrodes reflected lower resistivity, and the longer spaced electrodes reflected higher resistivity, possibly in response to hole diameter changes and fluid quality and content. The 8-inch (20.32-cm) and 16-inch (40.6-cm) curves reflect a consistently lower resistivity with the exception of a slight increase at about 1,522 ft (463.9 m) to 1,524 ft (464.5 m). Coincidentally, this depth is very close to the depth related to the top of the backfill debris within the bottom of the hole (about 1,523 ft). It appears that the ISGS 64-inch (162.6-cm) normal resistivity curve had the best correlation to the 1939 e-log.

The ISGS normal resistivity, SP, and SPR log data remained fully displayed above the uncased portion of the hole for correlation between any of the Schlumberger logs that might reveal any significant information as to the condition of the casing. In general, these e-logs are typically not depicted within the cased portion of the hole. The ISGS normal resistivity logs typically reflect a negative or zero value for ohm-m when inside steel casing. These values can increase and fluctuate depending on fluid level, quality and type, presence of gas, sludge buildup, casing condition, and/or equipment limitations. The normal resistivity logs reflect an increase in ohm-m from about 414 ft (126.2 m) to 792 ft (241.4 m). Without other corroborating logs and data, it is difficult to say what this increase in resistivity is the result of, but could be the result of casing and/or fluid conditions. During post-injection logging, however, the e-logs do not appear repetitive at those same intervals.

**Owens #4**

The interval from 1,509 ft (456.3 m) to 1,514 ft (461.5 m) reveals a minor increase in gamma radiation, which may indicate a slight increase in barite accumulation as well, but to a much lesser degree than was detected in Owens #1 and Coddington #4. As was the case in Owens #1 and Coddington #4, the interval
appears to be within a similar sandstone formation reported in 1939 as having “good permeability, good oil saturation, and low water content.” The fluid level appears to be about 1,143 ft (348.4 m).

**Coddington #4**

Natural gamma, SP, SPR, 8-inch (20.3-cm), 16-inch (40.6-cm), 32-inch (81.3-cm), and 64-inch (162.6-cm) logs were recorded within Coddington #4. A caliper probe was not run. The 1939 Schlumberger e-logs were not digitized for this well due to time constraints. As with Owens #1, Coddington #4 revealed a relatively high gamma count rate within the uncased portion of the hole from 1,497 ft (456.3 m) to 1,514 ft (461.5 m). The count rate peaked at about 1,200 cps at 1,505 ft (458.7 m) to 1,512 ft (460.9 m). Coincidentally, this interval appears to reflect a slightly higher resistivity within the Weiler Sandstone from the original 1939 Schlumberger e-logs. The relatively high gamma count rates within the Weiler Sandstone of Owens #1 and Coddington #4 may possibly be indicative of their production history and production (permeable) zones, or intervals. Water samples taken from Owens #1 reportedly had a mineral concentration of around 60,000 ppm (mg/L) total dissolved solids (TDS). This relatively high saturation of minerals may slowly precipitate onto the borehole wall and casing as fluid discharged from permeable layers, and/or as levels fluctuated from production and flooding operations over decades, the end result being an accumulation of at least barite.

The bottom of the hole was about 1,524 ft (464.5 m) bgs, approximately 22 feet (55.9 cm) higher than the originally reported depth of 1,546 (471.2 m) in 1939. This is very similar to the depth interval and the amount of backfill debris that was encountered at Owens #1, again indicating some similarities between these two wells. The bottom of casing, which can sometimes be difficult to interpret with resistivity logs alone, appears to be close to the depth of 1,495 ft (455.7 m) reported in the 1939 well diagram and schematic. The well schematic for Coddington #4 indicates that the Weiler was shot with 80 qts. of explosives.

**Coddington #2W and Hawkins #1W**

Caliper logging was not conducted in these wells. As in Owens #1 and Owens #4 wells, SP, SPR, 8-inch (20.3-cm), 16-inch (40.6-cm), 32-inch (81.3-cm), and 64-inch (162.6-cm) normal resistivity and natural gamma logs were recorded. The 1939 Schlumberger e-logs were not digitized for these wells. In Coddington #2W, the bottom of casing was originally reported to be at 1,499 ft (456.9 m) bgs. The original TD in 1939 was 1,529 ft (466.04 m) bgs. TD recorded by the ISGS was about 1,516 ft (462.1 m) bgs. Determining where the bottom of the casing was with the ISGS logs was difficult, but it could be anywhere from 1,495 ft (455.7 m) to 1,499 ft (456.9 m). This should be confirmed by Schlumberger logs. The gamma log for Coddington #2W appeared to reflect a typical range for a Mississippian Sandstone with a slightly higher gamma activity overall.
In Hawkins #1W, the TD of the hole was recorded at about 1,510 ft (460.3 m) bgs by the ISGS probe. The original TD reported in 1939 was 1,522 ft (463.9 m) bgs. The bottom of the 6-inch (15.3-cm) internal diameter casing reported at 1,497 ft (456.3 m). The ISGS logs were not useful in helping to determine bottom of the casing. The gamma range for Hawkins #1W reflected a typical gamma range for clean, non-argillaceous Mississippian Sandstone.

**Composite Gamma Log**

A composite of the gamma logs for all five wells was created and plotted with elevation at a scale of 1:240. The order in which the logs were selected is based on the proximity of the wells to each other, beginning with Hawkins #1 and then moving counterclockwise to the other wells.

**Post-injection Results**

Only two wells were logged by the ISGS post-injection: Owens #1 and Owens #4. Owens #1 was logged because it was the injection well and Owens #4 because of CO$_2$ breakthrough and detection.

**Owens #1**

The 1939 e-logs are displayed alongside the pre- and post-injection logs for comparison. Unfortunately, the probe bottomed out at about 1,525 ft (464.8 m) bgs on the post-injection run, approximately 8 ft (2.44 m) above the pre-injection run, which was very close to the depth we bottomed out initially with the caliper probe indicating that the hole collapsed. The fluid level was difficult to determine but the SPR and SP data indicate possibly at about 75 ft (22.9 m) bgs. The post-injection gamma log was included for depth correction with the SP, SPR, and normal resistivity logs.

**Owens #4**

The 8-inch (20.3-cm), 16-inch (40.6-cm), 32-inch (81.3-cm), and 64-inch (162.6-cm) normal resistivity measurements showed a slight increase in resistivity for the 32-inch (81.3-cm) and 64-inch (162.6-cm) spacings and were nearly identical for the 8-inch (20.3-cm) and 16-inch (40.6-cm) spacings compared with pre-injection results. The results appear to be opposite the expectations for the presence of CO$_2$ gas. Coincidentally, one of the largest departures from the pre- and post-injection results matches the interval with the increased gamma radiation at about 1,510 ft (460.2 m) to 1,516 ft (462.1 m). The largest increase in ohm-m on the 64-inch (162.6-cm) trace is about 1.1 ohm-m at a depth of 1,512.3 ft (461 m) bgs. The SPR, however, reflected a decrease in ohms resistance compared with the pre-injection level.

**Disclaimer**

The vast majority of this appendix report was prepared in an effort to provide a general review and summary of the logging efforts by the ISGS for documentation purposes and not as an in-depth analysis on the results.
Owens 1
Pre-injection Logs

1939 Schlumberger Resistivity

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<th>1939 Schlumberger SR</th>
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<td>0</td>
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<td>18</td>
<td>400</td>
<td>SP &amp; RES Log Fill</td>
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<td>50</td>
<td>ISGS Gamma 0 - 1497</td>
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<tr>
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<td>0</td>
<td>Caliper</td>
</tr>
<tr>
<td>20</td>
<td>100</td>
<td>ISGS Gamma 1497-1529 (1 Decade)</td>
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Lithology (Carter Oil 1939)

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<tr>
<th>Depth</th>
<th>R8</th>
<th>R16</th>
<th>R32</th>
<th>R64</th>
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</thead>
<tbody>
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<td>0 mV</td>
<td>0 mV</td>
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<td>0 Ohm-m</td>
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SANDSTONE (WATER)

SHALE

LIMESTONE

SHALE?
SANDSTONE: MODERATE PERMEABILITY, GOOD OIL SATURATION, LOW WATER CONTENT

SHALE

LIMESTONE

SHALE
Owens 4 Pre- and Post-injection Logs

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<thead>
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<td>mV</td>
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<tr>
<td>600</td>
<td>mV</td>
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**Lithology (Carter Oil 1939)**

- **1471.0**: Shale
- **1482.0**: Shaly Sandstone (Water)
- **1488.0**: Shale
- **1492.0**: Shaly Sandstone
- **1497.0**: Sandstone: Good Permeability, Good Oil Saturation, Low Water Content
- **1500.0**: Sandstone: Good Permeability; Good Oil Saturation; Low Water Content
- **1505.0**: Calcareous Sandstone: Fair Permeability, Fair Oil Saturation; Low Water Content
- **1515.0**: Shaly Sandstone (Oil)
- **1520.0**: Sandstone: Fair to Good Permeability; Moderate Oil Saturation; Low Water Content
- **1525.0**: Shaly Sandstone (Oil)
Owens 1 Pre- and Post-injection Logs

**ISGS Gamma Pre-injection (Log. Scale; 1 Decade)**

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<tbody>
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**SP Pre-injection**

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**SPR Pre-injection**

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**Caliper Pre-injection**

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**Gamma Post-injection**

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**SP Post-injection**

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**SPR Post-injection**

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**R8 Pre-injection**

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**R64 Pre-injection**

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**Caliper Post-injection**

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**R8 Post-injection**

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**R16 Post-injection**

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**R32 Post-injection**

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**R64 Post-injection**

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**Lithology (Carter Oil 1939)**

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<tr>
<td>1529</td>
<td>SANDSTONE</td>
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<tr>
<td>1540</td>
<td>SHALE</td>
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### Gamma Composite Log

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<th>Elevation (ft. amsl)</th>
<th>Gamma Hawkins1</th>
<th>Gamma Owens1</th>
<th>Gamma Owens4</th>
<th>Gamma Coddington4</th>
<th>Gamma Coddington2W</th>
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<tbody>
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<td>0  CPS  150</td>
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![Gamma composite log graphs](image-url)