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CO_2-Enhanced Gas Recovery in Shale: Lessons Learned in the Devonian Ohio Shale of Eastern Kentucky

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The Kentucky Geological Survey is a state-supported research center and public resource within the University of Kentucky. Our mission is to support sustainable prosperity of the commonwealth, the vitality of its flagship university, and the welfare of its people. We do this by conducting research and providing unbiased information about geologic resources, environmental issues, and natural hazards affecting Kentucky.

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Technical Level

General — Intermediate — Technical

Statement of Benefit to Kentucky

Natural gas produced from shale is the most abundant petroleum resource underlying the commonwealth. This investigation of the potential to store carbon dioxide and use it for enhanced recovery of natural gas supports industry and long-term economic development in the state.

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Contents

Figures

Figures
(continued)

Tables

CO_2-Enhanced Gas Recovery in Shale: Lessons Learned in the Devonian Ohio Shale of Eastern Kentucky

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Abstract

The Kentucky Geological Survey tested CO_2-enhanced gas recovery in the Devonian shale in Johnson County, in response to a directive from the Kentucky General Assembly in 2007; the study site included a fracture-stimulated shale-gas well. To supplement a standard suite of open-hole logs acquired when the well was drilled, a well-logging program was designed to identify open perforations, construct a flow profile, and acquire pre-injection baseline data to characterize the Devonian Ohio Shale for a pressure falloff test. Tubing and packer were installed, with gel and brine filling the annulus between the tubing and packer to block flow-through perforations identified above the packer. From Sept. 6–10, 2012, 87 tons of CO_2 was injected in three phases, with at least 12 hr between phases to allow for pressure decline. On the last day of injection, the pressure of the annulus between the casing and injection tubing approached the injection pressure, indicating CO_2 had leaked out of the test zone. Therefore, the test was terminated before a planned injection of 300 tons of CO_2 was completed. Following injection, the well was closed for 2 weeks to allow a "soak." A meter run was constructed to monitor flowback, and during the flowback a second flow profile and post-injection production log were acquired. Analysis indicates the leak was likely the result of communication through induced fractures (from the original completion) from the Ohio Shale to the overlying Berea Sandstone. The Ohio Shale likely retained some of the CO_2, thus confirming the potential to displace additional natural gas, but the small volume of CO_2 and escape of an unknown amount of CO_2 from the zone of interest severely constrained anything but a qualitative assessment.

Introduction

The Intergovernmental Panel on Climate Change (2014) and others have identified an increase in manmade emissions of greenhouse gases, particularly CO_2 emitted from industrial sources such as electric utilities, as contributing to climate change. The concerns identified by the Panel have driven research to develop carbon-management strategies, including storing CO_2 in deep geologic structures and formations. Geologic storage of carbon has been identified as an essential strategy for mitigating manmade carbon and reducing the effects of greenhouse-gas emissions (Pacala and Socolow, 2004; Metz and others, 2005; National Energy Technology Laboratory–Office of Fossil Energy, 2015; Koperna and others, 2016), and often the beneficial reuse of that stored CO_2 is cited as being a valuable offset for the cost of capture and storage. Since the 1970s, CO_2 has been injected for enhanced oil recovery in deep reservoirs in Texas, Louisiana, and Mississippi, among other states. CO_2-enhanced gas recovery and sequestration have been tested in coal; the advantage in coal is that CO_2 becomes immobile by adsorbing onto organic matter in the coal (Reznik and others, 1984; Gunter and others, 1997, 2005; Reeves, 2002). With the emergence of the "shale revolution," organic-rich shales across the United States are being recognized as self-sourced hydrocarbon liquids and natural-gas reservoirs. These shales are world-class resources that have reframed the U.S. petroleum industry. Nuttall and others (2006, 2009) investigated the potential for the organic-rich Devonian shales of eastern Kentucky to store CO_2 and found that CO_2 is preferentially adsorbed, and there is associated potential to displace natural gas. Although CO_2 storage in organic-rich shale is feasible, the low permeability of shale could limit injectivity, and enhanced gas recovery in shale has not been demonstrated. The purpose of this project was to investigate that injectivity and storage potential of CO_2, and measure potential displacement of natural gas in shale.

General Geology

Shales of Early Mississippian and Late Devonian age occur in the subsurface of nearly two-thirds of Kentucky. These thinly bedded, fissile, gray and black (carbonaceous) shales thicken and deepen in the eastern Kentucky portion of the Appalachian Basin and the western Kentucky portion of the Illinois Basin (Fig. 1). The shales are absent in the Bluegrass Region of central Kentucky and in the Mississippi Embayment of the Jackson Purchase Region of extreme western Kentucky. South of the Cumberland Saddle, along the axis of the Cincinnati Arch in central Kentucky, the thickness of the shale is usually 15 m or less. The shale thickens eastward from a minimum of 0 m in some locations along the crest of the Cincinnati Arch to more than 518 m in Pike County. The shale is exposed in outcrop around the margin of the Jessamine Dome (along the perimeter of the Inner and Outer Bluegrass Regions of central Kentucky) and along the drainage of the Cumberland River in south-central Kentucky. Exploratory drilling for oil and gas has identified a subcrop of the shale beneath the Cretaceous sediments of the Mississippi Embayment of western Kentucky.

Because data are available and access to wellbores is likely, the Upper Devonian Ohio Shale in eastern Kentucky was the focus of this study. Nomenclature of these Upper Devonian shales varies across eastern Kentucky. The American Association of Petroleum Geologists' Committee on Stratigraphic Codes proposed a three-digit and up to five-character mnemonic code for stratigraphic information (Cohee, 1967). Codes used in this report are listed in Table 1. For a full list of codes, see www.uky.edu/KGS/emsweb/kyogfaq/stracode_list.pdf (accessed 05/29/2019). The relatively thin Chattanooga Shale (generally correlative to the Ohio Shale) occurs at shallow depths in south-

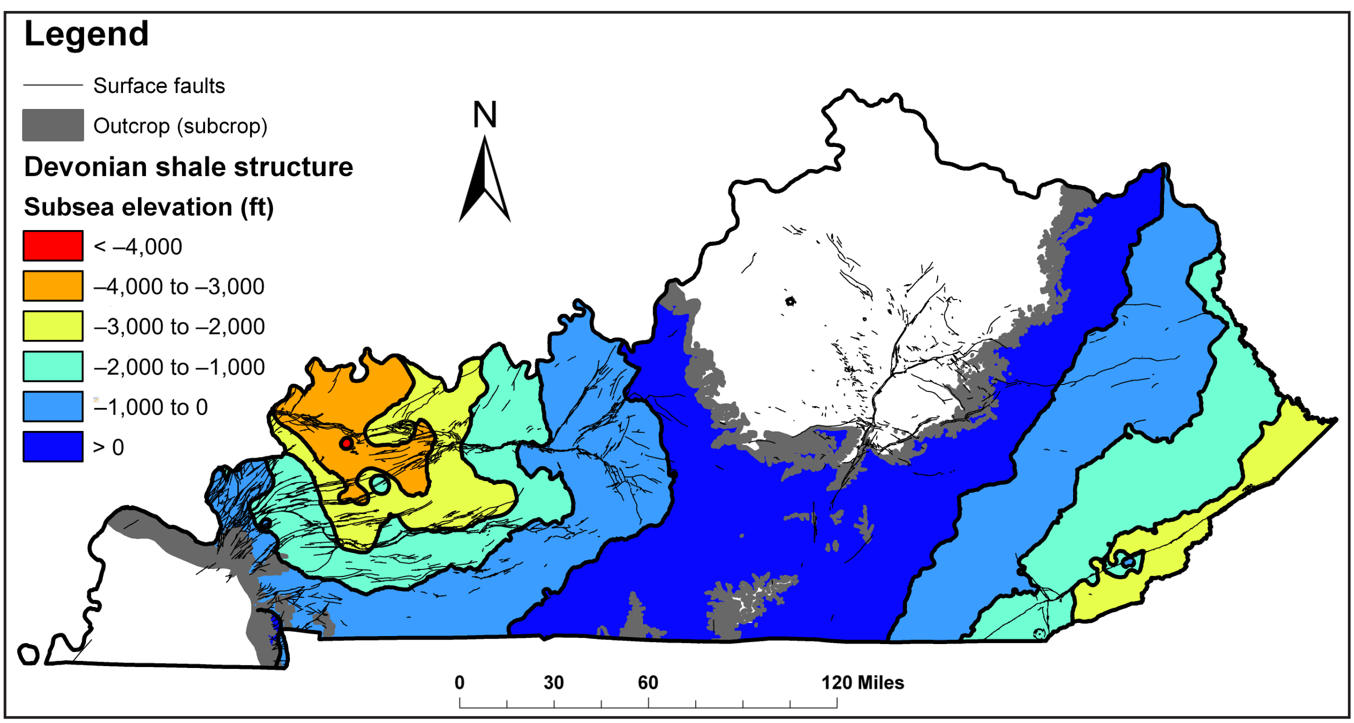


Figure 1. Generalized structure of the top of the Devonian shale sequence in Kentucky.

eastern Kentucky north of the Tennessee state line and in the Cincinnati Arch area of central Kentucky. Ohio Shale–related nomenclature is used throughout most of the Appalachian Basin of eastern Kentucky, where the shale is deeper, thicker, and a prolific natural-gas producer. These shales unconformably overlie Middle Devonian to Silurian dolomites and sandstones known collectively and informally as the "Corniferous" and are overlain by the Upper Devonian Berea Sandstone or Bedford Shale. The Devonian shale sequence of eastern Kentucky is typically subdivided into seven recognizable units (Fig. 2): The Ohio Shale includes the Cleveland Shale, Three Lick Bed, and Upper, Middle, and Lower Huron Shale Members and is underlain by the Olentangy and Rhinestreet Shales. In the subsurface, these units are differentiated based on gamma-ray and density differences noted on open-hole wireline logs that are related to variations of the organic-matter content in the shale. The uppermost black, carbonaceous shales (Cleveland and Upper Huron Members of the Ohio Shale) pinch out eastward into a gray, more clastic-dominated sequence correlative to the intervening Three Lick Bed. Where the Cleveland and Upper Huron are indistinguishable or missing, the shale above the Lower Huron is designated in this report to be the Chagrin Shale. The Olentangy gray shale and Rhinestreet black shale are correlative with the Java Formation of West Virginia (see, for example, de Witt and others, 1993). These units thin and pinch out toward the Cincinnati Arch and the western margin of the Appalachian Basin. Some authors (Ettensohn and others, 1979) have asserted that the Olentangy and Rhinestreet are members of the Devonian Ohio Shale, a convention that is not used in this study.

House Bill 1: Incentives for Energy Independence Act (2007)

In 2007, the Incentives for Energy Independence Act (House Bill 1, or HB1) was passed during a special session of the Kentucky General Assembly (www.lrc.ky.gov/record/07s2/HB1.htm; last visited 08/31/2016). This act directed the Kentucky Geological Survey to drill deep wells in both coal fields (Bowersox, 2013; Bowersox and Williams, 2014; Bowersox and others, 2016), test enhanced oil and gas recovery (Frailey and others, 2012), and test the Devonian shale for enhanced gas recovery and sequestration potential. To facilitate these tasks, the General Assembly appropriated $5 million from the General Fund and encouraged the Survey to use this seed money to identify and match any available federal and private funding "to the extent possible." The major portion of the $5 million appropriation was allocated for the projects to drill deep test wells in the Appalachian and Illinois Basins. There was enough funding to support the Devonian shale test project if an existing well was used.

Project Overview and Goals

The goal of this project was to conduct a transient pressure test in an eastern Kentucky Devonian shale well, using 100 to 300 tons of CO_2, in order to investigate storage of CO_2 in the shale and measure possible enhanced production of natural gas. The plan was to conduct the test in a producing gas well surrounded by multiple wells that could serve as monitoring wells. Data to characterize the organic content, gas content, porosity, and permeability of the shale would be compiled and used in reservoir-simulation software to investigate injection scenarios and

Table 1. Formation codes used in this report.

339BRDN	Mississippian Borden Formation
339SNBR	Mississippian Sunbury Shale
341BREA	Devonian Berea Sandstone
341OHIO	Devonian Ohio Shale
341CLVD	Cleveland Member, Ohio Shale
341TLBD	Three Lick Bed, Ohio Shale
341HURNU	Upper Huron Member, Ohio Shale
341HURNM	Middle Huron Member, Ohio Shale
341HURNL	Lower Huron Member, Ohio Shale
341OLNG	Devonian Olentangy Shale
341RNST	Devonian Rhinestreet Shale
344CORN	Corniferous (Devonian and Silurian carbonates and shales, undifferentiated)

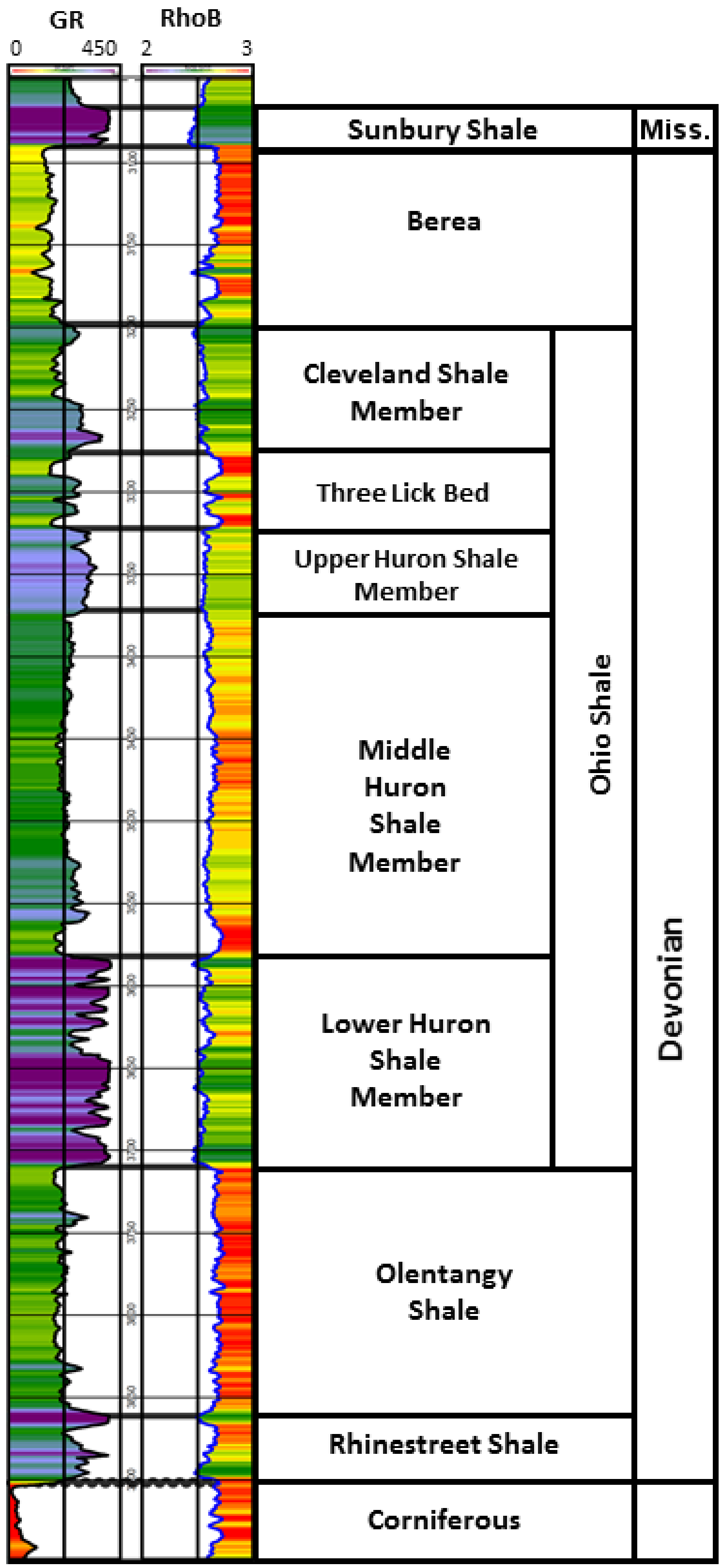


Figure 2. Typical stratigraphy and gamma-ray log of the Devonian Ohio Shale sequence in eastern Kentucky: the Weaver Bentley No. 1 well, Letcher County (API no. 1613300144, KGS record no. 31683).

predict possible outcomes. Pre- and post-injection wireline logging would provide data to identify zones with possible CO_2 uptake. CO_2 storage would be investigated by using a mass-balance approach to assess CO_2 injected compared to CO_2 recovered during flowback. Enhanced natural-gas recovery would be indicated by an increase in production in the test well after injection or by displacement of natural gas to nearby monitoring wells, as indicated by pressure increases in the monitoring wells. Specific indicators of success were expected to be increased production volumes after CO_2 injection, demonstrated by a mass-balance comparison of CO_2 injected versus CO_2 recovered on flowback.

Selection Criteria

Budget constraints dictated that the project could not be conducted in a newly drilled and constructed well. We tried to identify industry partners willing to contribute access to a well, which would also fulfill the cost-matching requirements of HB1. The selected well should meet as many of the following criteria as possible:

- Uncased through the Devonian shale section to facilitate advanced logging and sample acquisition.
- Uncompleted or completed using the prevailing nitrogen foam or slickwater fracturing (that could include a sand proppant)—an industry-standard shale completion.
- Have a standard suite of open-hole nuclear logs, with digital well-log data in LAS format (Canadian Well Logging Society, 2018) preferred, to serve as baseline information.
- Be available for re-entry for sidewall coring and acquiring advanced well logs.
- Available detailed record of historic gas production.
- Accessible for gas sampling.
- Be on a well site big enough to support on-site CO_2 storage tanks, pumping units, analytical and monitoring

equipment, and other support vehicles and equipment as needed.

- Be accessible for CO_2 delivery (route, road surface, and grade must meet conditions requested by commercial CO_2 suppliers, with no low underpasses, weight-limited bridges, low-water fords, and other related limitations).
- Owned and operated by a company willing to put the future production of the selected well at risk.
- Legal control and access available for all wells within an "area of review," as established by the U.S. Environmental Protection Agency for monitoring and Class II or Class V permitting.

Key Reference Wells

Modern detailed information on petrographic and mechanical properties of shale in Kentucky is sparse. Lithologic data, adsorption isotherms, and other information have been gathered for several eastern Kentucky wells (Fig. 3, Appendix 1). CO_2 and methane adsorption isotherms (yellow dots in Figure 3) indicate preferential adsorption of CO_2 and suggest that enhanced natural-gas production is likely (Nuttall and others, 2006, 2009). The Columbia Natural Resources Elk Horn 24752 well (API no. 16119017910000, KGS record no. 94539), Knott County, was drilled to a total depth of 3,004 ft in 2003. Sidewall cores were acquired and laboratory data were used to process an elemental capture spectroscopy log and compile a shale-properties analysis. The Interstate Natural Gas J. Jude Heirs No. 3 well (API no. 16159014850000, KGS record no. 96877), Martin County, was drilled to a depth of 3,272 ft in 2005. Because there were no conventional or sidewall cores for this well, log analysts processed the ECS (elemental capture spectroscopy) log using regional data and their knowledge to compile a shale-properties analysis.

The Ashland Exploration Kelly-Skaggs Unit 3RS well (API no. 16115001200000, KGS record no. 33985), Johnson County, was drilled to a total depth of 1,510 ft in 1978. The well was completed in the Cleveland (1,010–1,120 ft) and Lower Huron (1,294–1,382 ft) Members of the Ohio Shale. The well was cored from a depth of 967 ft to total depth. This well was studied extensively as part of the U.S. Department of Energy's Eastern Gas Shales Project and is identified in project literature as the "KY-4 well." Information on this well is available in Kalyoncu and Snyder (1979), Zielinski and Nance (1980), Hosterman and Whitlow (1981), and Leventhal and others (1981). We used these data from the Eastern Gas Shales Project to refine reservoir simulations and to help with planning the injection test.

Proposed Test Site

Burk Branch, Pike County

With the cooperation of Pike County Judge-Executive Wayne T. Rutherford, a project site in southwestern Pike County, eastern Kentucky, was chosen. Located along Burk Branch, the site is adjacent to an access road across valley-fill material associated with an active coal surface mine. The site included a proposed test well, the Interstate Panther Land Corp. No. 3, and multiple surrounding wells that penetrated shale that could serve as monitoring wells.

Pike-Letcher (Interstate) Panther Land Corp. No. 3 Well, Pike County. The proposed injection test well, the Pike-Letcher Panther Land No. 3 (API no. 16195017180000, KGS record no. 80823), is located along Burk Branch in southwestern Pike County (Fig. 4). Originally drilled as a gas producer from Pennsylvanian sands in 1951, the well was drilled deeper by Interstate Natural Gas, then logged, cased, and completed as a Devonian shale gas well in 1991. Sometime prior to 1997, the well was shut-in because of its proximity to ongoing surface coal-mining operations, and no production records are available. The casing was perforated at depths between 3,334 and 3,494 ft in the Lower Huron Member of the Ohio Shale. The well was drilled along the initial course of Burk Branch, and as a result of its proximity to the surface mine, the wellhead was periodically raised by adding sections of casing at the surface as the depth of the valley fill increased, leaving the well on the slope face of a future mine-reclamation site. Additional data required for modeling and simulation (sidewall core samples for determination of porosity, permeability, and other parameters) cannot be readily acquired in cased holes. Three nearby wells drilled and operated by Quality Natural Gas were selected as monitoring wells. These are older wells that were completed by explosive detonation in the wellbore with no

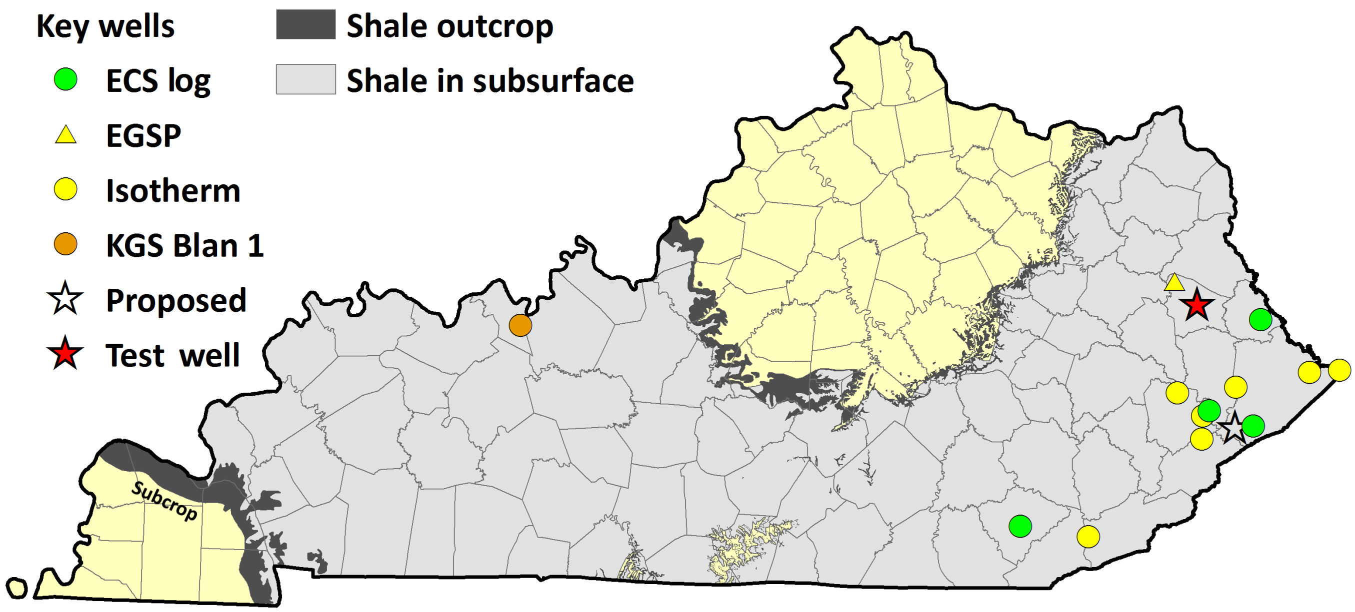


Figure 3. Study and reference wells used in planning and design of the CO_2-enhanced gas recovery project. Open star = initially proposed well. Red star = final test well. EGSP = Eastern Gas Shales Project.

expectation that additional downhole data could be acquired from them. Available well-log data for the Panther 3 well are summarized in Figure 5. See Nuttall (2010) and Appendix 2 for a compilation of digital data for this well.

Rosewood Resources Ted Bargo No. 02 Well, Knox County. A partial solution to the lack of shale reservoir data in the Panther 3 well was to use an extensive set of analytical data from the Rosewood Resources Ted Bargo No. 02 well (API no. 16121014490000, KGS record no. 99456), Knox County (Fig. 3). This well was drilled in 2006 to a total depth of 2,238 ft in the Silurian Lockport Dolomite. A total of 110 ft of material was recovered in five separate coring runs from the Cleveland Member of the Ohio Shale from 1,990 ft to the base of the Lower Huron Member of the Ohio Shale at 2,110 ft. After reaching total depth, a supplemental set of rotary sidewall cores was obtained at key depths as indicated by downhole geophysical logs. Rosewood Resources contributed core analyses, petrology, methane adsorption isotherms, Rock-Eval pyrolysis, and shale rock-properties data for this well. Figure 6 summarizes the gamma-ray density log through the Devonian shale interval, showing the cored intervals. Measured porosity from core analysis ranged from 0.6 to 4 percent, with a mean of 1.6 percent. The available mineralogy, petrology, Rock-Eval, and porosity data were used by Rosewood Resources to calibrate the shale properties of an elemental spectroscopy log run by Schlumberger in the well for shale modeling. LAS versions of these log data were acquired from Rosewood Resources, and copies of the analytical data and digital logs for this well are in Appendix 3.

Blue Flame Batten and Baird No. K-2605 Well, Pike County. Because we were unable to acquire data for modeling and simulation from the Panther 3 well and because the nearest available data set was from a well more than 70 mi away (the Bargo 02 well), we looked for opportunities to acquire additional detailed shale reservoir-characterization data. The Blue Flame Batten and Baird No. K-2605 well (K-2605, API no. 16195058900000, KGS record no. 102566), Pike County, approximately 5.6 mi east of the Panther 3 well (Fig. 3), provided such a piggyback opportunity. Battelle Memorial Institute and the Midwest Regional Carbon Sequestration Partnership, along with HB1, provided funding to acquire these data. Schlumberger Carbon Services provided an in-kind services discount and acquired a standard open-hole nuclear logging suite and ECS log. Nineteen rotary sidewall cores were acquired in closely spaced pairs at the depths of selected high and low gamma-ray intervals that the open-hole logs had indicated should be represen-

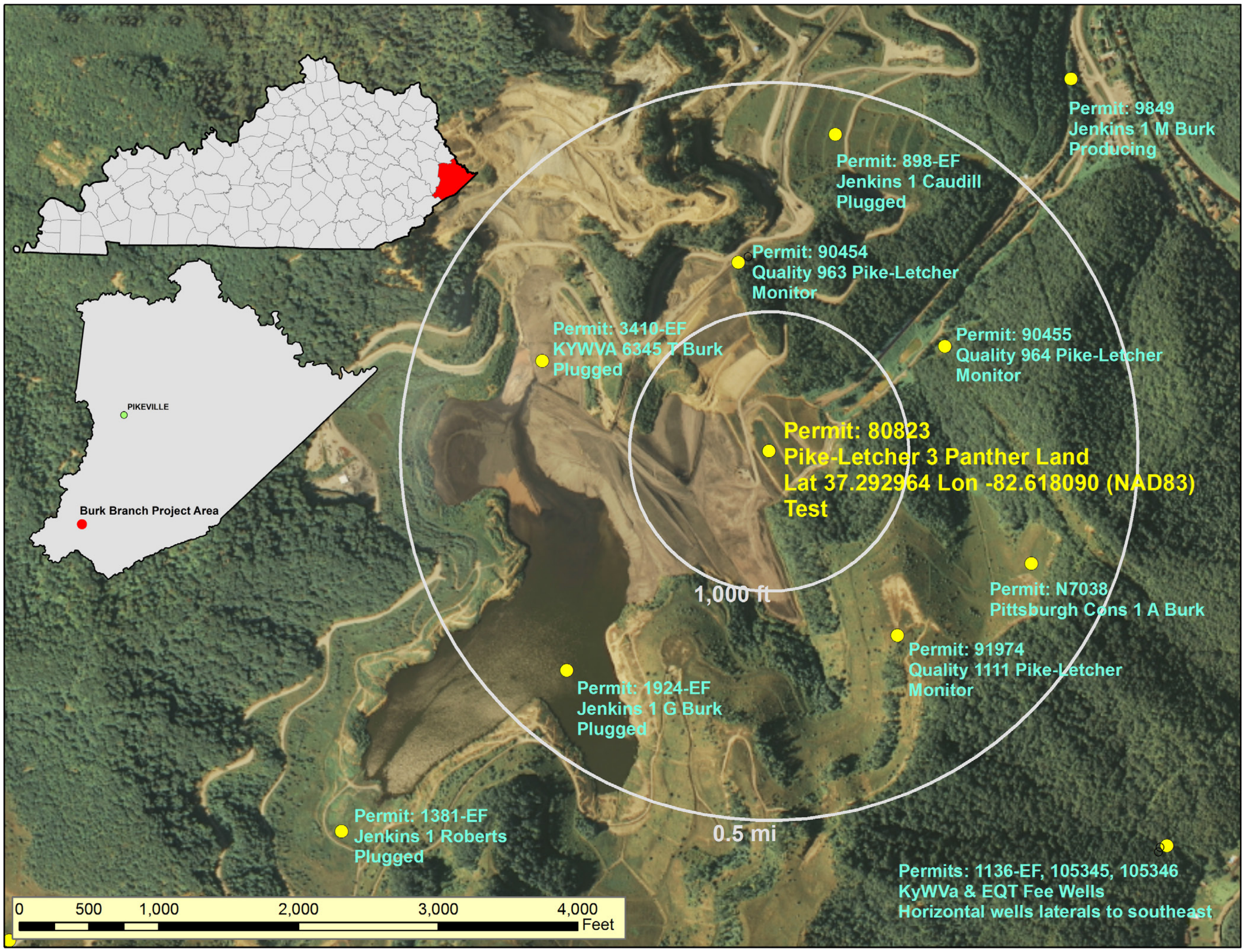


Figure 4. Location of the Panther Land 3 well and surrounding wells, the initially proposed test site, showing the 1,000-ft- and 0.5-mi-radius areas of review. Aerial photograph base map from KGS (kgs.uky.edu/kgsmap/kgsgeoserver/viewer.asp).

tative of high and low total organic carbon values, respectively. Acquiring rotary sidewall plugs in pairs was intended to ensure adequate sample volumes for both destructive and nondestructive tests and analysis since there would not be conventional whole-core sampling (Fig. 7). Chesapeake Appalachia contributed tight rock, shale analytical laboratory, and petrographic work for the sidewall cores and drill cuttings. The well logs and analytical data were processed under contract by Schlumberger to produce a shale-specific model (calibrated Shale Montage Analysis) to characterize lithology, mineralogy, gas content, total organic carbon, and other parameters over the shale interval in the Blue Flame well.

A bulk-density gamma-ray cross plot (Fig. 8) reveals the relationship between the higher gamma-ray/lower density shale units that have higher total organic carbon and the lower gamma-ray/higher density gray shale units that occur with less organic-rich shale. In the K-2605 well, the Cleveland Shale Member of the Ohio Shale is distinctly off this trend, however. Bulk-density photoelectric factor cross plots of each unit (Fig. 9) indicated the Cleveland exhibits a somewhat lower photoelectric factor than observed in other units of the Ohio Shale, possibly indicating a higher quartz content and a slight predominance of montmorillonite or smectite mixed-layer clays that are difficult to differentiate with standard X-ray analysis. X-ray diffraction mineralogic analysis of the bulk and clay fractions was performed on composited air-rotary cuttings collected through the shale interval at 10-ft intervals. Total organic carbon and X-ray compo-

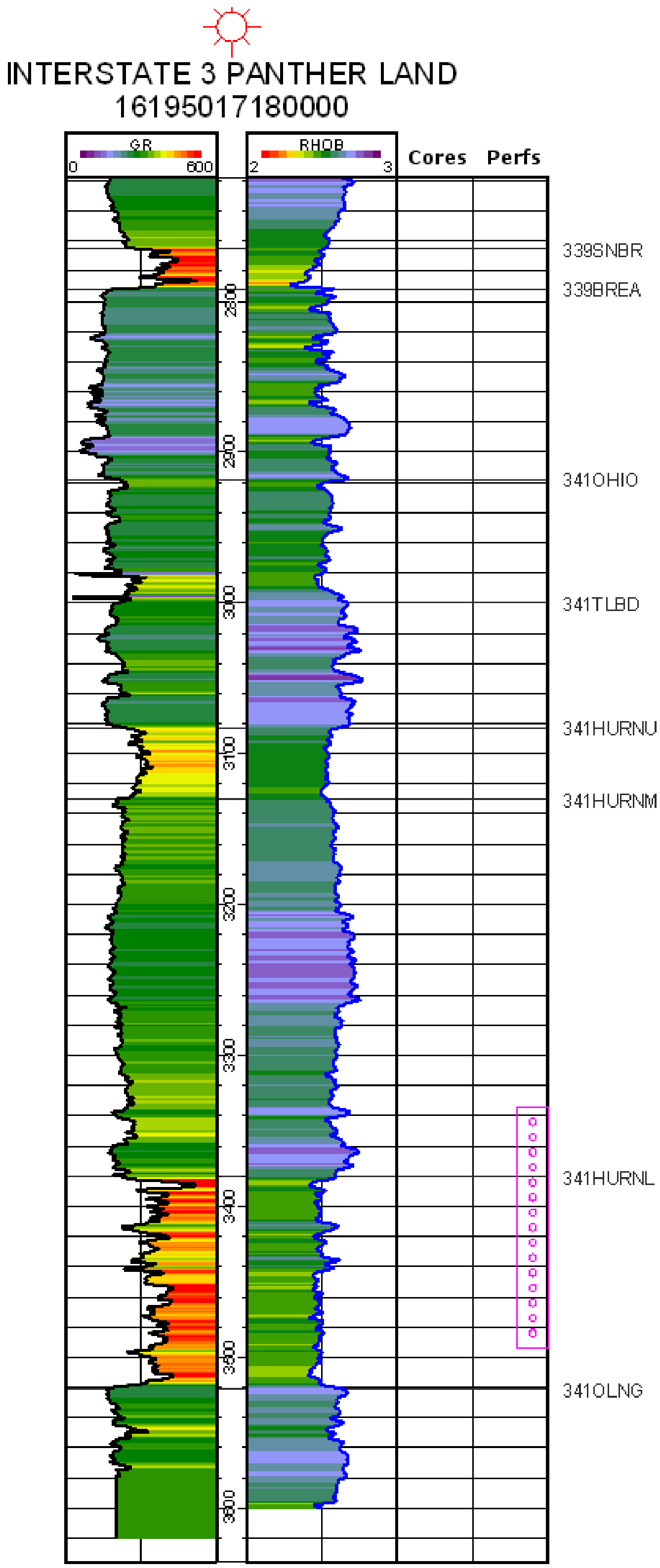


Figure 5. Gamma-ray and density log of the Devonian shale interval in the Pike-Letcher (Interstate) Panther Land 3 well, Burk Branch, Pike County, Ky., showing the perforated interval in the Lower Huron Shale (purple box).

sitional data for the K-2605 well are presented in Figure 10. Figure 11 summarizes the X-ray diffraction data, comparing the Bargo 02 and K-2605 wells. Bulk (Fig. 11a) and clay (Fig. 11b) mineralogy differ between the wells, but are within the typical compositional range of the Devonian shales in the Appalachian Basin (Hosterman and Whitlow, 1983). Different laboratories often use different criteria to identify clay types, particularly mixed-layer clays, however; this may account for the differences in clay mineralogy shown in Figure 11b.

Organic matter occurs in the largely marine shale primarily as algal material: *Tasmanites* (Fig. 12a) and undifferentiated bituminite (Fig. 12b). Rock-Eval pyrolysis and total organic carbon analysis indicate a lean (Fig. 13) source-rock potential with a calculated bitumen reflectance between 0.94 and 1.77 percent R_o, within the oil to wet gas and condensate maturity window. Total organic carbon and X-ray diffraction data from sidewall plugs and drill cuttings (Fig. 14) were used to calibrate the elemental capture spectroscopy log model. Two models are commonly used by Schlumberger to estimate total organic carbon: The TerraTek model is part of the tight-rock analysis services offered by Schlumberger, and the Schmoker model calculates total organic carbon using the bulk density of a shale formation (Schmoker, 1979, 1993). These models are then used in the shale properties analysis to obtain continuous estimates of the adsorbed and free-gas volumes in the shale (Fig. 15). The shale analysis, or montage, is a presentation of the iterative elemental analysis to best fit the ECS data to specific mineral species within the context of lithologic data from standard nuclear log suites and the laboratory analysis of core and cuttings. Table 2 summarizes the porosity and permeability findings for the 10 closely spaced depth pairs of rotary sidewall cores acquired in the well. Gas-filled porosity averages 2 percent and permeability averages 0.0000728 mD.

Reservoir Simulation. Stratigraphic data for three key wells were used to build a reservoir model for simulating injection and testing various scenarios (Schepers and others, 2009). Be-

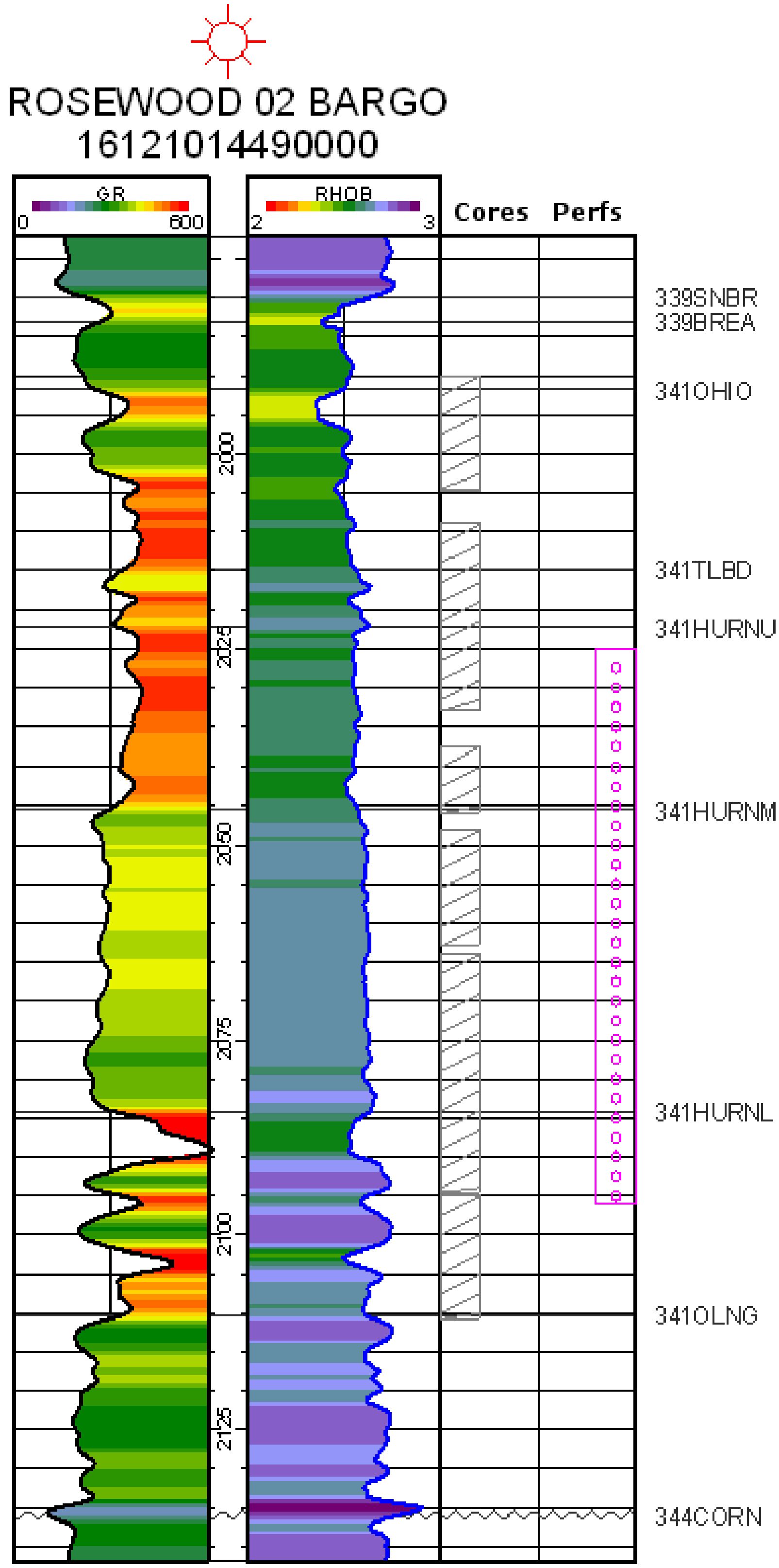


Figure 6. Gamma-ray and density log of the Devonian shale interval in the Rosewood Resources Bargo 02 well, Knox County, Ky., showing the perforated interval in the Ohio Shale (purple box).

cause no production data were available for the Panther 3 well, production data sets from seven nearby wells (Fig. 16, Appendix 4) were selected for geostatistical modeling and history matching. History-matched gas-production data served as proxies for characterizing the fracture permeability using geostatistical methods. These data were provided to Advanced Resources International, who simulated CO_2 injection into a shale reservoir using COMET3 software. COMET3 is a multiphase, dual-porosity, dual-permeability model used extensively to simulate enhanced gas recovery in coals. Modeling and simulation results (Schepers and others, 2009) indicated that for injection of 100 to 300 tons of CO_2, a cyclic "huff and puff" injection strategy for the test well would be the scenario that would most likely yield successful (that is, measurable) results.

Kentucky Geological Survey Marvin Blan No.1 Well. Because shale samples could not be recovered from the target shale zone in the Panther 3 well, we looked for additional data to better characterize the petrographic and mechanical properties of organic-rich oil and gas shale. The Kentucky Geological Survey Marvin Blan No. 1 deep saline test well in western Kentucky (API no. 16091013960000, KGS record no. 104925), another project funded by HB1 (Bowersox, 2013; Bowersox and Williams, 2014; Bowersox and others, 2016), was cored, and data from the New Albany Shale were acquired for characterization of the shale. These data and findings were detailed by Nuttall (2013). Comparison with other key reference wells indicated that using the Blan well data would be beneficial for planning and design of the east-

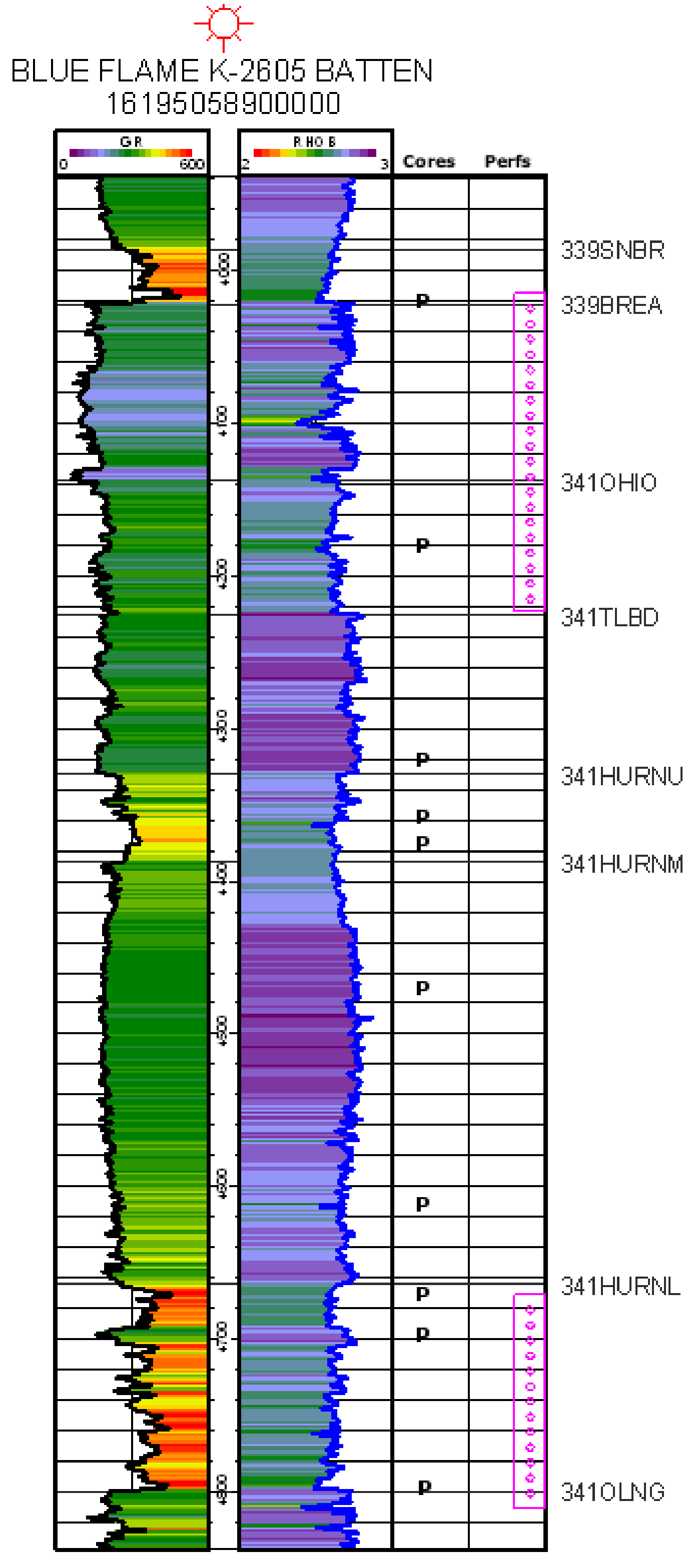


Figure 7. Gamma-ray and density log of the Devonian shale interval in the Blue Flame Batten and Baird K-2605 well, Pike County, Ky., showing perforated intervals in the Ohio Shale (purple box) and depths for rotary sidewall core plugs (P) recovered for analysis.

ern Kentucky CO_2 injection and enhanced gas recovery test.

Burk Branch Summary

Data acquired in assessing the proposed Burk Branch test site provided insights into the properties of Upper Devonian organic-rich shales and will provide baseline information for continued development of the resource. Most important, the data were used to constrain reservoir simulations to model multiple injection and test scenarios and led to identifying the most effective injection-test strategy within the budgetary limitation of 100 to 300 tons of CO_2 and a relatively short duration available for the test.

Sulphur Spring Project, Johnson County

The agreement to test CO_2 injection in the Panther 3 well was abandoned during negotiations for a contract to grant well access and perform any required site construction. CO_2 injection was determined to be inconsistent with the well and site owner's future resource-development plans. A second solicitation for a candidate test well resulted in the selection of a new site at Sulphur Spring in Johnson County.

Interstate Fee SS-#1 Well

The Interstate Natural Gas Co. Fee SS-#1 well (API no. 16115014350000, KGS record no. 93687) is near Paintsville, along Sulphur Spring Branch of Rush Fork in Johnson County, eastern Kentucky (Fig. 17).[1] In 2002, the well was drilled to a total depth of 1,910 ft in the Devonian Olentangy Shale. An open-hole wireline nuclear-log suite for air-filled boreholes was obtained that included gamma-ray, density, neutron-porosity, caliper, temperature, medium and deep array induction, and photoelectric-effect logs. The gamma-ray, density, and temperature curves were digitized and saved in LAS format for subsequent analysis. A

[1]The SS-#1 and SS-#1A wells were drilled approximately 200 ft north of their permitted locations. The locations used for this report were determined with differentially corrected—using the Wide Area Augmentation System—handheld GPS devices with position averaging.

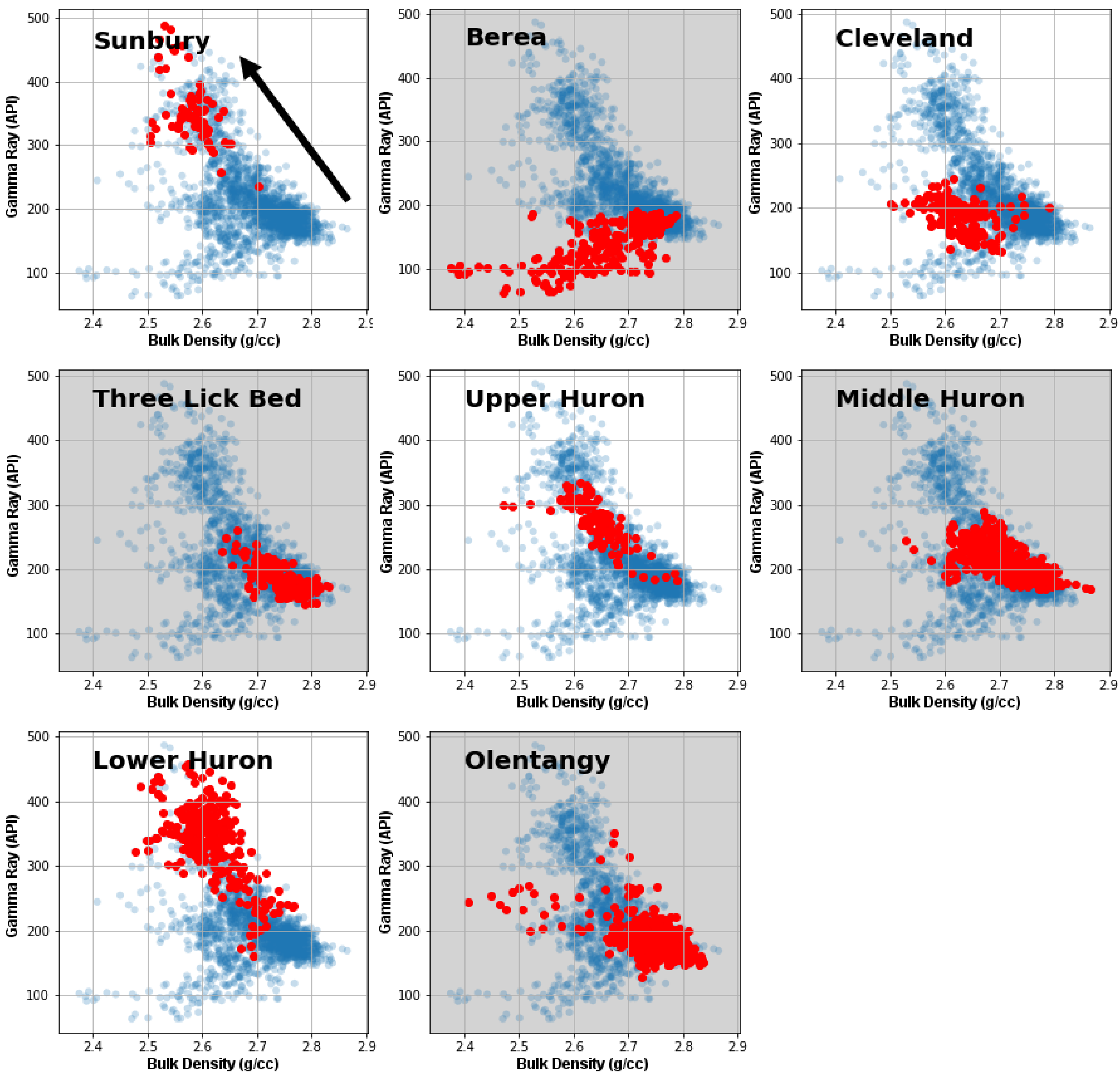


Figure 8. Bulk-density versus gamma-ray cross-plots for the K-2605 well by formation, showing variations in lithology between high gamma-ray, low-density, organic-rich intervals and more clastic, low gamma-ray, higher-density intervals (gray background); background (blue) is all available data from the Sunbury Shale to the Olentangy Shale. The first gamma-ray reading was at 4,990 ft in the Olentangy Shale; no cross plot is available for the Rhinestreet Shale.

total of 1,808 ft of 4.5-in. casing was cemented and perforated in the Mississippian Sunbury and Devonian Berea from 1,126–1,204 ft and in the Ohio Shale from 1,274–1,672 ft. The well was fracture-stimulated using 2.5 million standard cubic feet of nitrogen and completed as a natural-gas producer but was never commercially produced. Figure 18 illustrates the well-construction and experimental setup. The well was shut-in June 3, 2002, and no gas production-history data are available. In the period between drilling and the CO_2 test, Interstate Natural Gas Co. changed the name they used to operate wells to Crossrock Drilling. The surface property, mineral rights, and all wells on the tract are now owned and operated by Crossrock Drilling, an advantage for completing the project. See

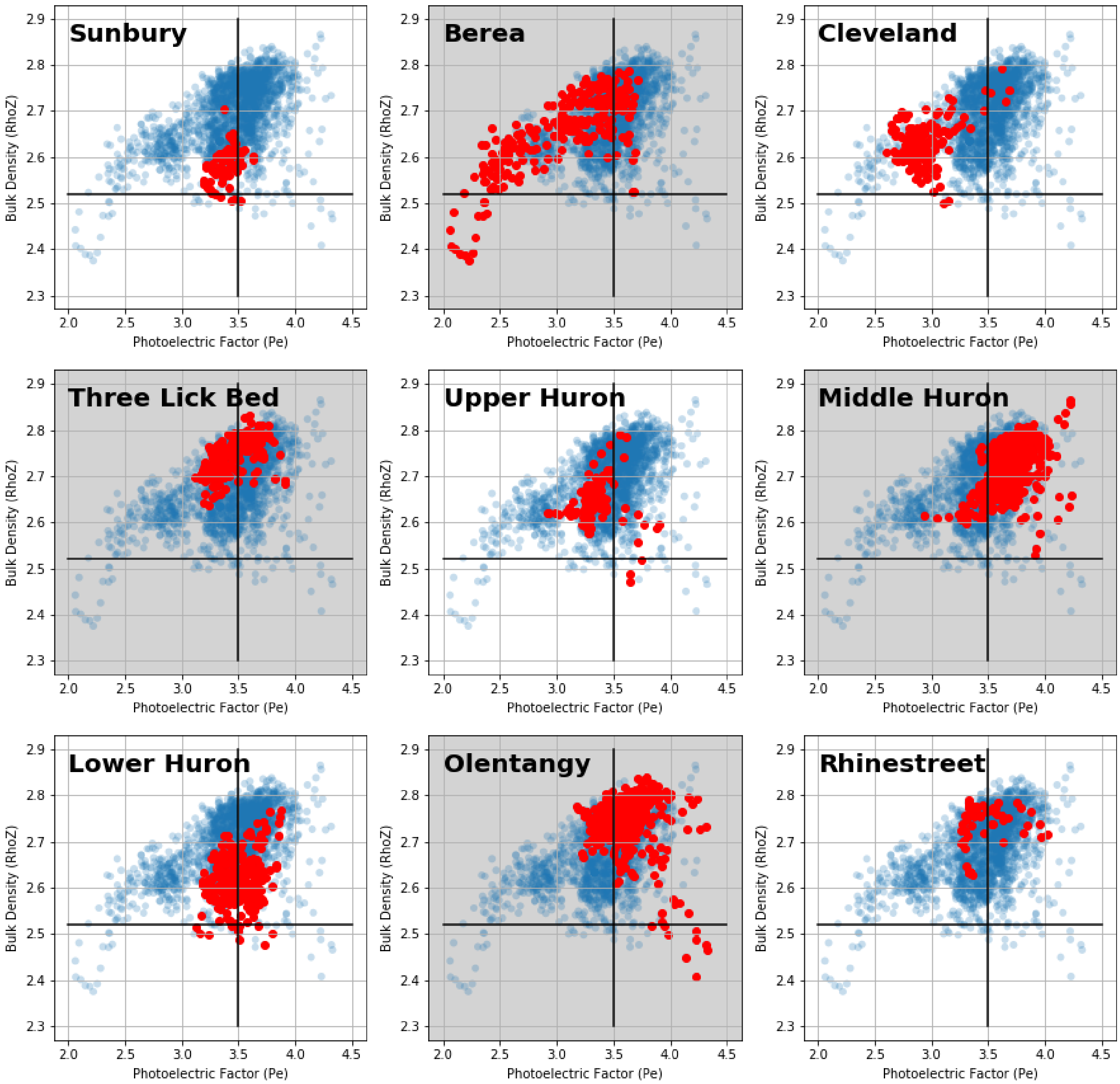


Figure 9. Photoelectric factor versus bulk density cross-plots for the K-2605 well by formation, with illite reference lines (Pe = 3.5 and RhoZ = 2.52), showing variations in clay mineralogy between organic-rich and more clastic intervals (gray background); background (blue) is all available data from the Sunbury Shale to the Rhinestreet Shale.

Appendix 5 for data from the original drilling and subsequent well test.

Three additional wells on the same lease were chosen to serve as monitoring sites for the project and were instrumented with data loggers to record continuous surface pressure and temperature information. The SS-#1A well (API no. 16115014390000, KGS record no. 93799) is a close-offset, or twin, well with a surface location 10 ft from the SS-#1 well that was drilled to a total depth of 825 ft in the Mississippian Borden Formation. The SS-#1A well was treated with gelled water, acid, and sand in the Mississippian Big Lime through perforations at depths between 712 and 724 ft, based on a porosity zone and show of gas identified in the SS-#1 well. The SS-#2 well (API no. 16115014340000, KGS record no. 93686) was drilled to a total depth of 1,866 ft in the Devonian Olentangy Shale and was

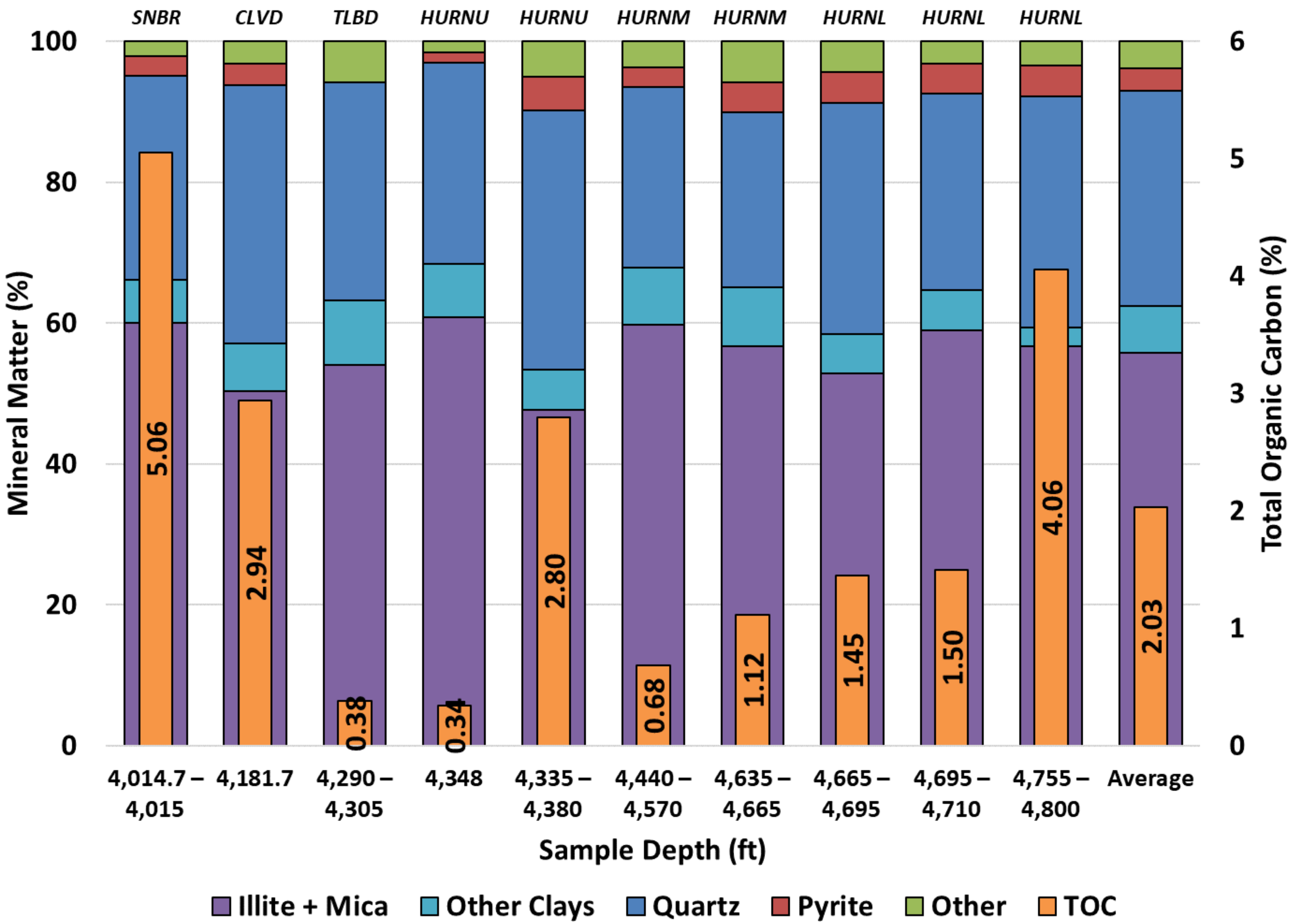


Figure 10. Summary of X-ray diffraction and total organic carbon analyses of the Devonian Ohio Shale samples from the K-2605 well, Pike County, by formation. SNBR=Sunbury Shale Member. CLVD=Cleveland Shale Member. TLBD=Three Lick Bed. HURNU=Upper Huron Shale. HURNM=Middle Huron Shale. HURNL=Lower Huron Shale.

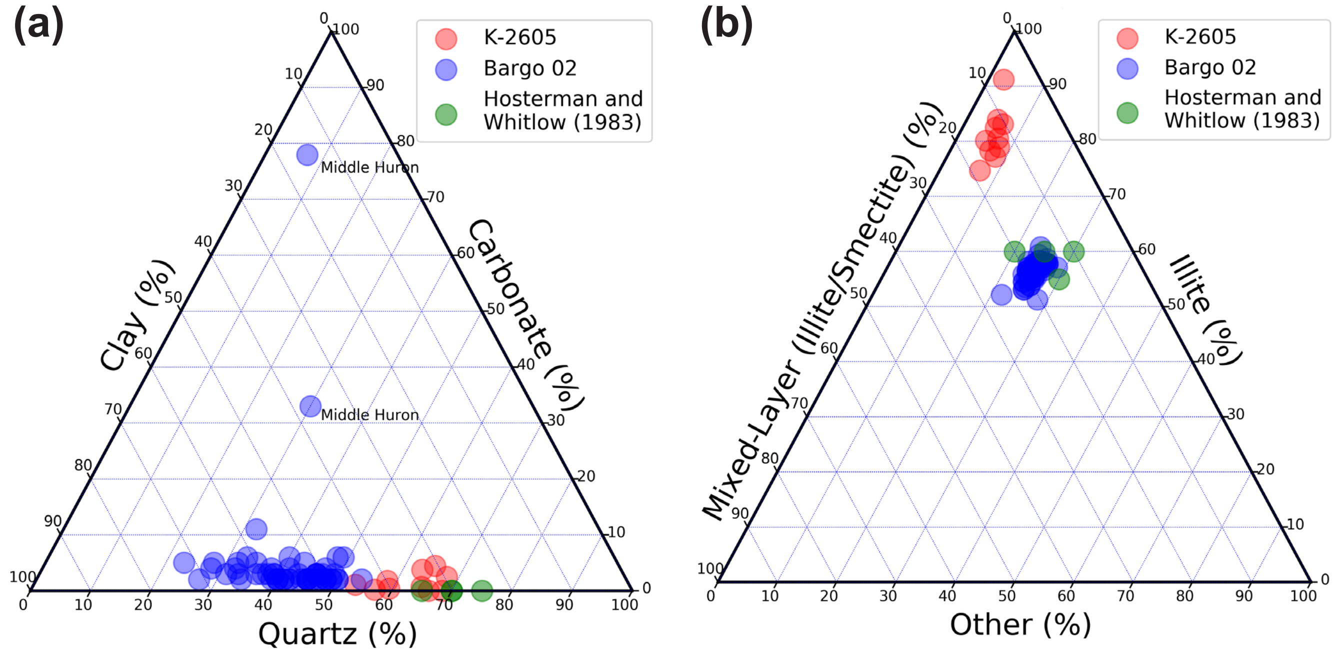


Figure 11. Ternary diagrams of the major components (a) and clay types (b) from X-ray diffraction analysis of the Bargo 02 and K-2605 wells compared to average shale composition for members of the Devonian Ohio Shale reported in Hosterman and Whitlow (1983, p. 11).

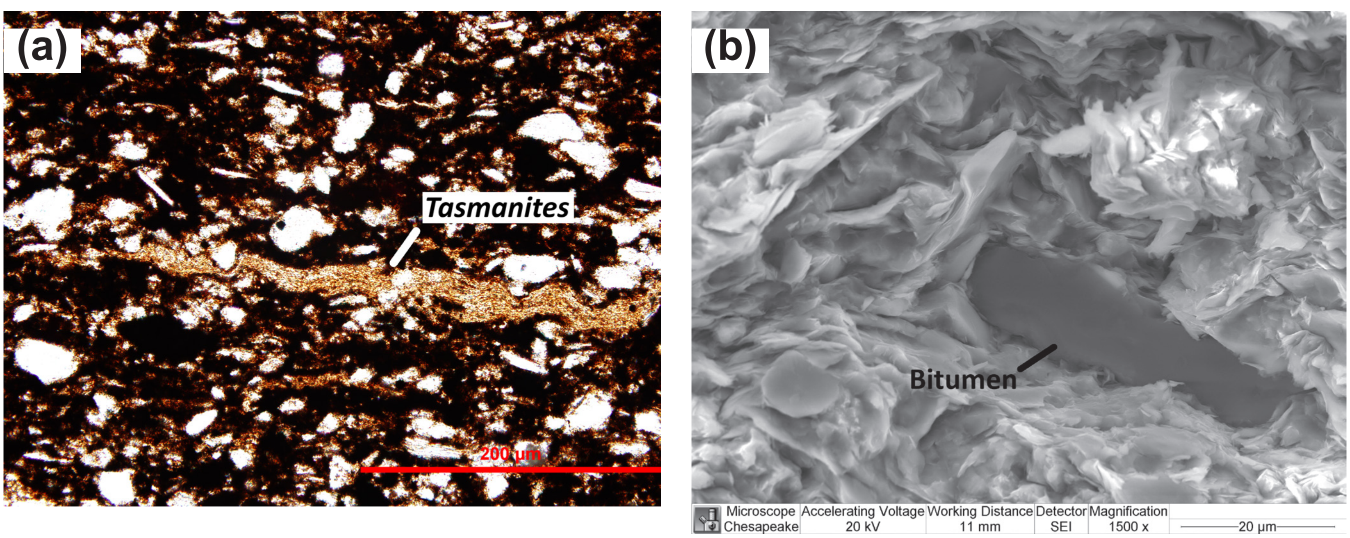


Figure 12. Common occurrences of organic matter in the K-2605 well: (a) A compacted *Tasmanites* in the Lower Huron at a depth of 4,672 ft, magnification 40x, plane polarized light. (b) Undifferentiated bitumen in the Three Lick Bed at a depth of 4,319.7 ft, magnification 1,500x, secondary electron image.

completed using a nitrogen fracture stimulation of two intervals: the Devonian Berea, from 1,250–1,288 ft, and the Devonian Ohio Shale, from 1,426–1,760 ft. The SS-#4 well (API no. 16115018550000, KGS record no. 99227) was drilled to a total depth of 2,058 ft in the Lower Huron Member of the Devonian Ohio Shale. The SS-#4 was completed in the Devonian Berea from 1,380–1,390 ft, and the Ohio Shale was left unstimulated in the open hole below 4.5-in. casing set to a depth of 1,685 ft. Drilling records and well logs from the fourth well on the lease, the SS-#3 (API no. 16115014420000, KGS record no. 93904), were used for correlation, but the SS-#3 was not instrumented.

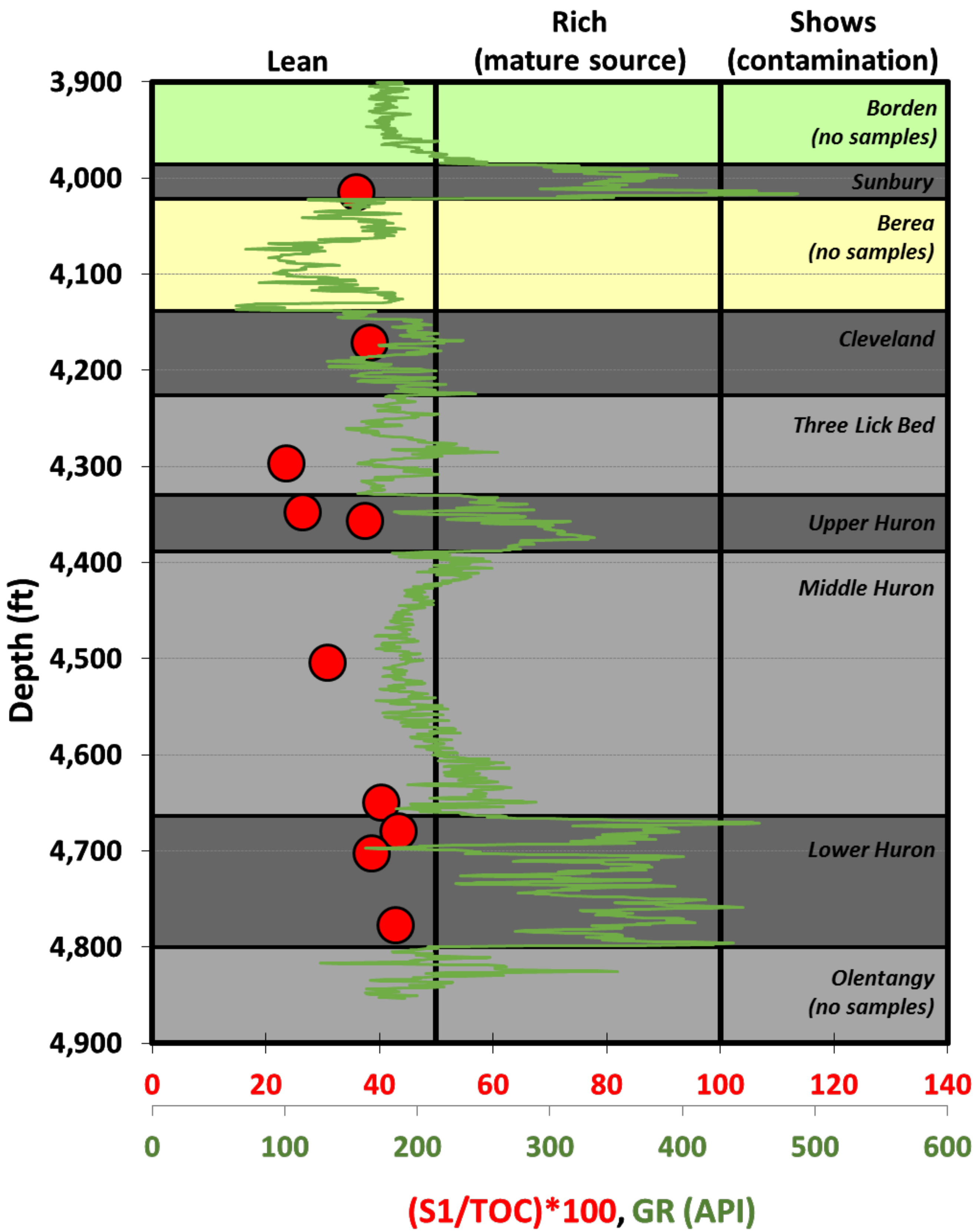


Figure 13. Source-rock maturity from Rock-Eval analysis for the K-2605 well, showing higher gamma-ray units (dark gray), indicating higher organic richness.

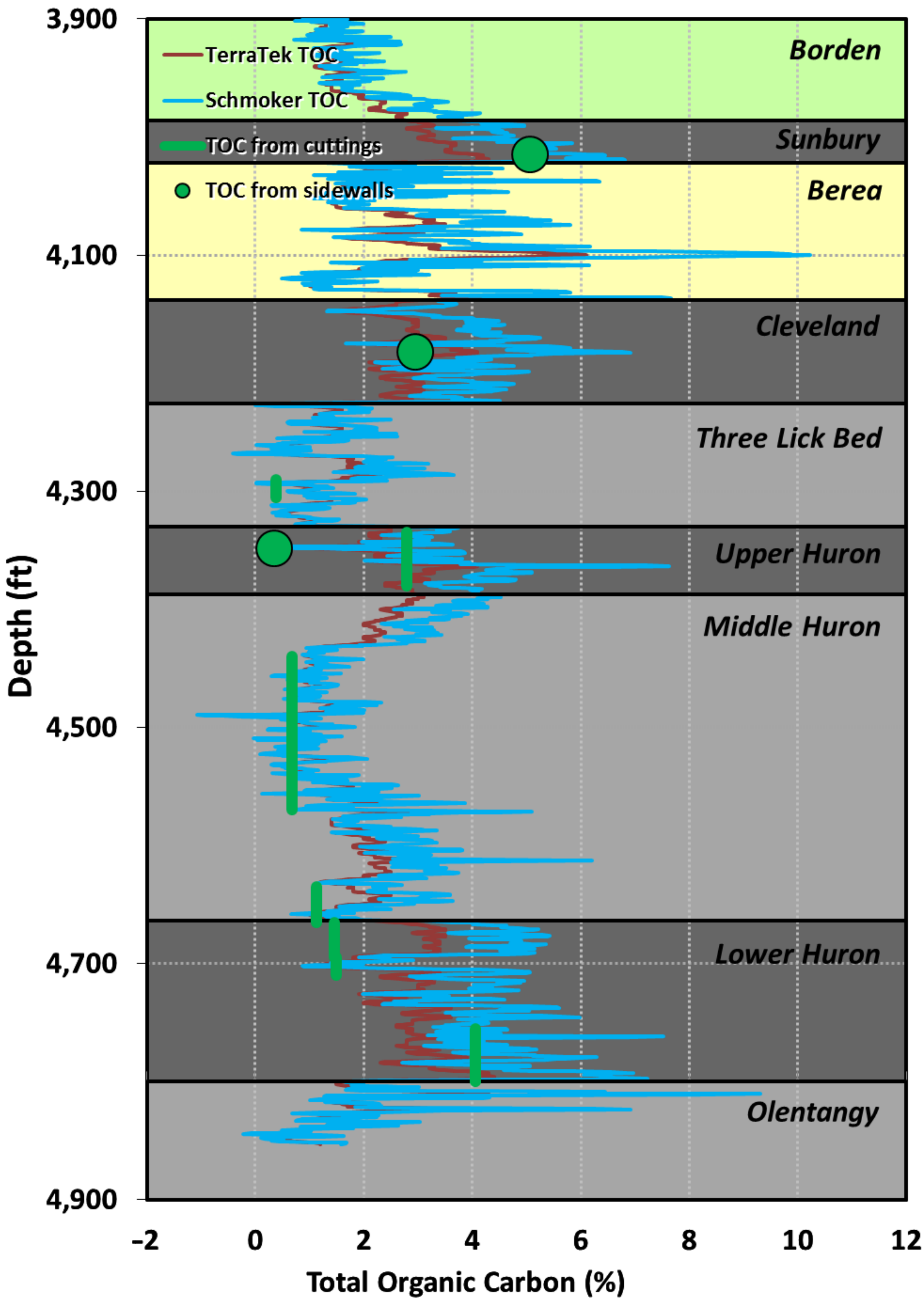


Figure 14. Total organic carbon estimates from well logs, showing analysis of sidewall cores and composited cuttings samples for the K-2605 well, Pike County, Ky.

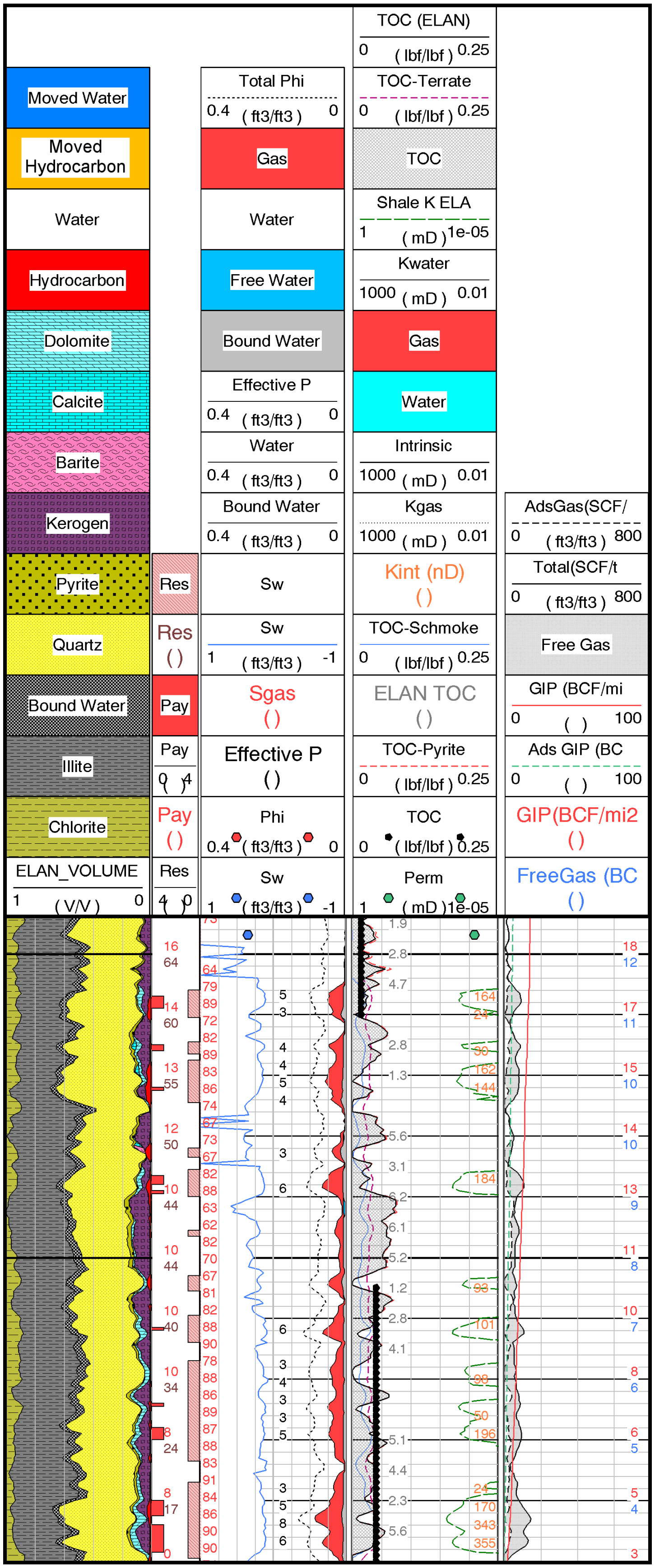


Figure 15. Part of the processed Schlumberger ECS well montage for shale analysis in the Lower Huron in the K-2605 well, Pike County, showing lithology, estimated adsorbed and free gas, and the gas-in-place calculations.

Pre-injection

Gas samples were obtained from the SS-#1, SS-#2, and SS-#4 wells. Several attempts were made to sample the SS-#1A well, to establish a baseline for detecting possible out-of-zone migration of CO_2 into overlying strata. Each attempt resulted in a nearly continuous release of mixed gas and foamed fluids, flowback from the original well stimulation, that precluded obtaining a sample with the available equipment (no water separation or dehydration units were available). For the SS-#1A well, pressure and temperature monitoring were deemed sufficient to detect out-of-zone migration. Crossrock Drilling personnel analyzed the gas with a portable gas chromatograph; results are shown in Table 3. We presumed the initial observed nitrogen in the SS-#4 well is the result of the original nitrogen fracture stimulation. After the well was opened and a gas sample was obtained in 2011, the hydrostatic pressure of the fluid column precluded additional nitrogen entry into the wellbore, but did not preclude equalization in the wellbore head space with dissolved volatile hydrocarbon gases.

A junk basket run into the SS-#1 test well encountered no obstructions and located the top of cement at 1,754 ft, deep enough to run additional cased-hole production logs across the intervals of interest. No fluids were encountered. All subsequent production and pulsed-neutron logging runs were depth-calibrated to the gamma-ray trace of the original open-hole log suite run in 2002. A multi-arm micro-caliper log was run to locate casing collars and verify the depths of existing perforations. Nine perforations were identified that corresponded to depth indications supplied by the well operator on the paper record of the open-hole logging suite.

A baseline production-log suite consisting of a gamma-ray (for depth control) and spinner, pressure, and temperature logs was acquired. The spinner log tool was passed up

Table 2. Porosity and permeability measurements of rotary sidewall core plug groups for the Blue Flame No. K-2605 Batten and Baird well. See Appendix 3 for additional information.

Paired Sidewall Plug Group	*Average Depth (ft)*	*Formation*	*As-Received Bulk Density (g/cm³)*	*Dry Grain Density (g/cm³)*	*Porosity (% of Bulk Volume)*	*Pressure-Decay Permeability (mD)*
Group 2	4,181.9	Cleveland	2.598	2.694	4.32	0.000076
Group 3	4,319.9	Upper Huron	2.732	2.826	4.21	0.000056
Group 5	4,373.9	Upper Huron	2.713	2.808	4.30	0.000063
Group 6	4,473.9	Middle Huron	2.573	2.699	5.56	0.000106
Group 7	4,612.9	Middle Huron	2.672	2.772	4.37	0.000071
Group 9	4,696.9	Lower Huron	2.707	2.795	3.69	0.000065

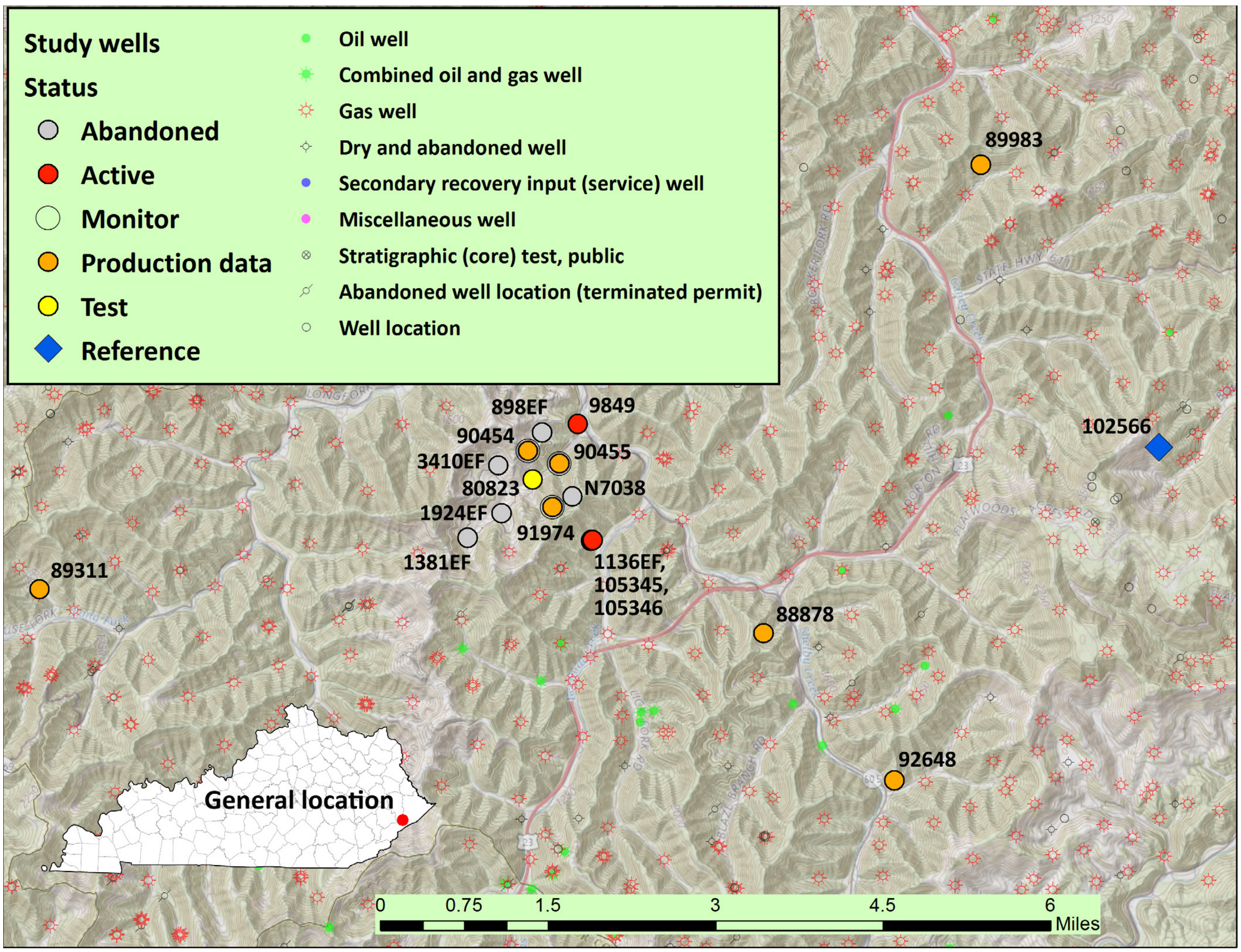


Figure 16. Location of the Panther 3 (KGS record no. 80823) and surrounding wells in the Burk Branch project area approximately 2.5 mi northwest of Dorton, Pike County, Ky.

and down the wellbore multiple times at 30, 60, and 90 ft/min between 1,100 and 1,700 ft in depth. The purpose of the spinner survey was to determine the depths of perforations with active gas flows and their contributions to the total gas flow. Figure 19 is a compilation of the upward passes of

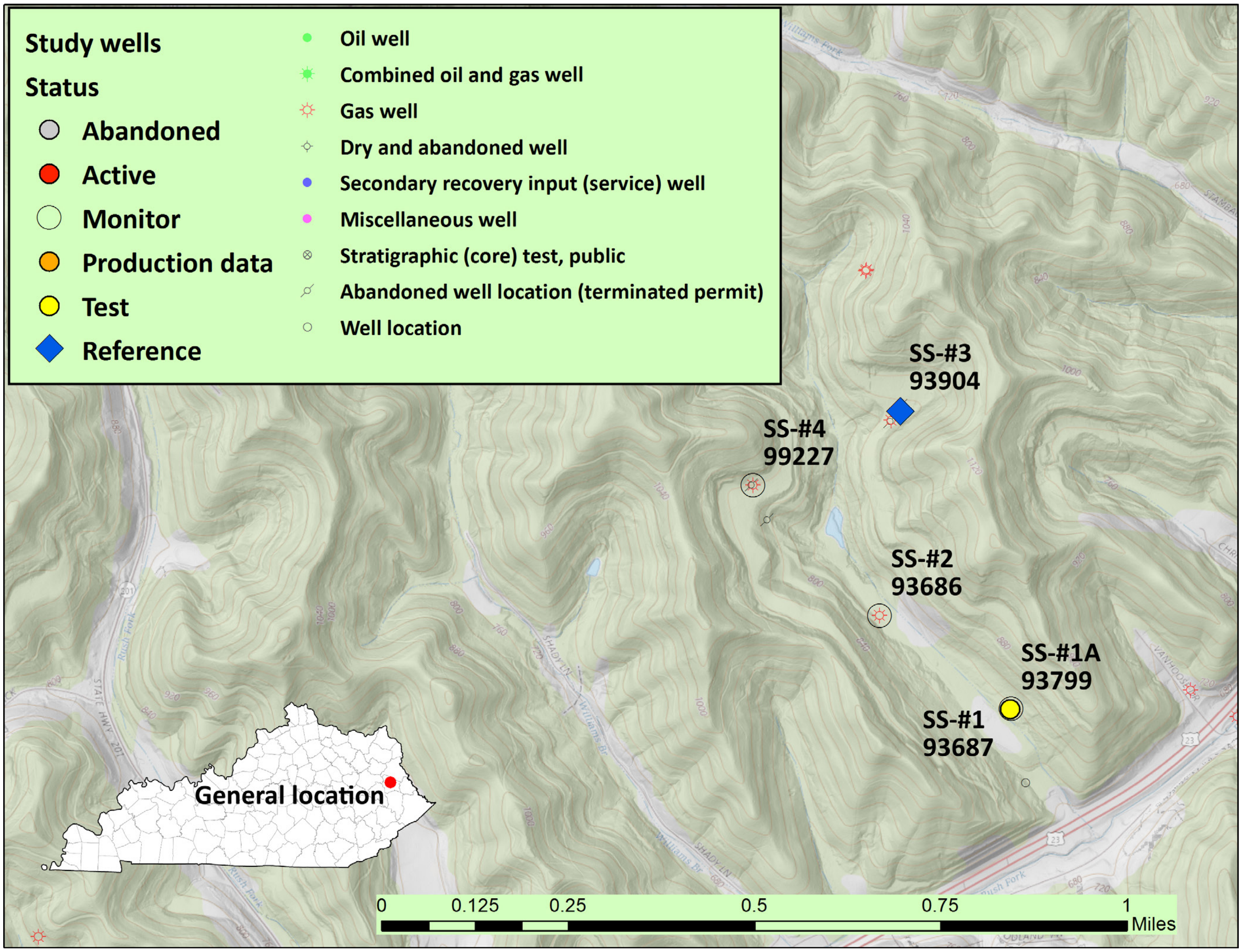


Figure 17. Location of the SS-#1 (KGS record no. 93687) and surrounding wells in the Sulphur Springs project area near Paintsville, Johnson County, Ky.

the spinner survey. No active perforations or gas entry points were detected below the perforation at 1,320 ft. These data were then used to determine the depth for setting the packer to isolate the Berea and Sunbury Shale from CO_2 testing.

A pulsed-neutron log was acquired first in lithology mode, and then a second pass was recorded in sigma capture mode. Sigma mode measures the neutron-capture cross section of a formation and is a relative measure of the ability of the formation and pore fluids to absorb free thermal neutrons. By comparing data acquired before and after injection, CO_2 adsorption into the formation could be indicated by an anomalous drop in the capture cross section.

Two downhole memory readout pressure and temperature gages (primary and backup) were installed in the SS-#1 well using casing hangers set at a depth of 1,724 ft, which was 52 ft below the deepest perforation. The SS-#1, SS-#1A, SS-#2, and SS-#4 wells were equipped with temperature and pressure monitors installed at the surface (Fig. 20). These data loggers display instantaneous pressure and temperature readings and contain memory cards for continuous recording. The units were in continuous operation throughout the test, except for short periods (less than 10 min each) when the data were downloaded and the batteries checked and replaced as needed.

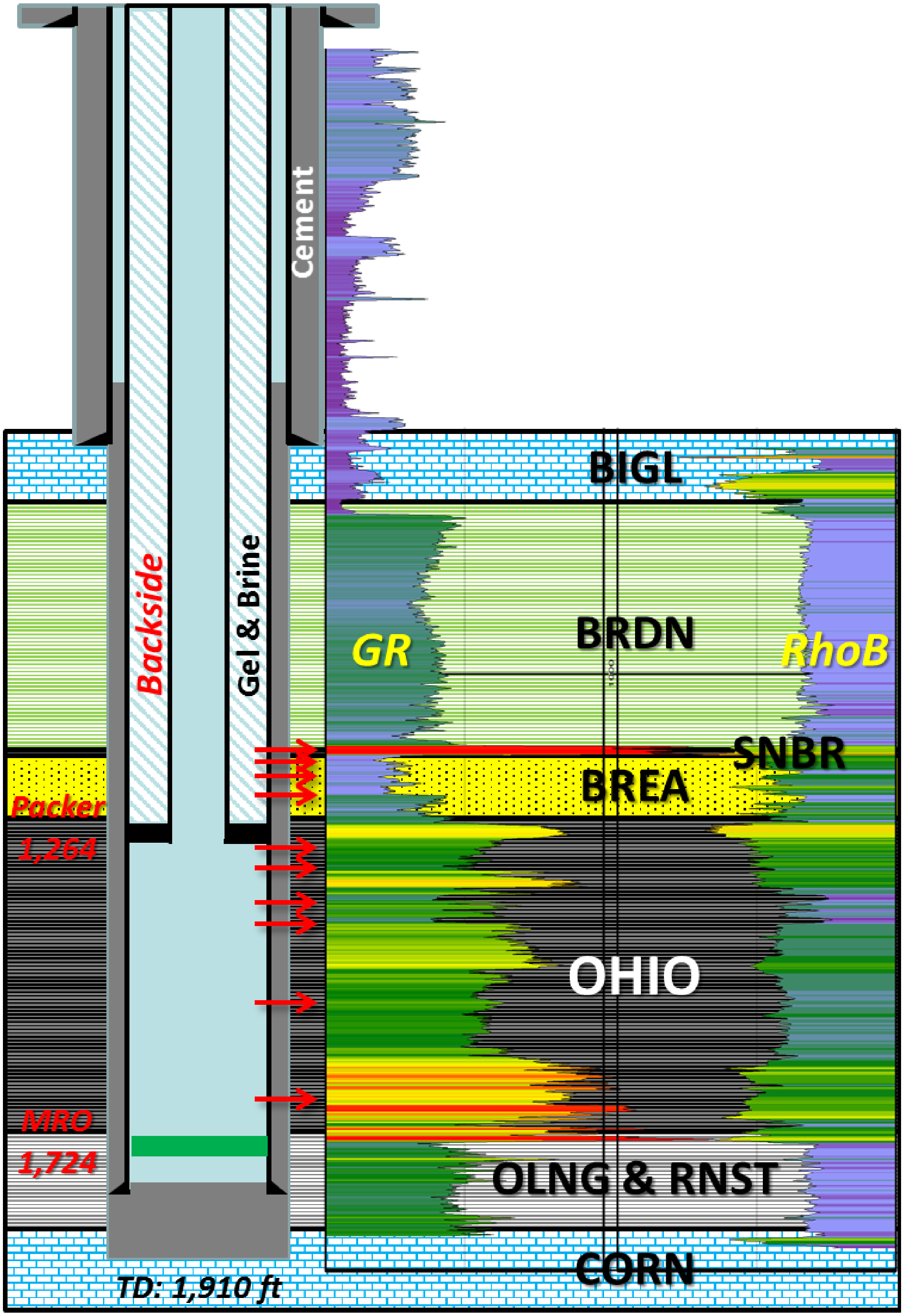


Figure 18. Gamma-ray and density log of the SS-#1 well, showing the casing construction, perforations (red arrows), and experimental setup, including tubing and packer set at 1,264 ft and the downhole memory readout gages (MRO) installed at 1,724 ft. BIGL = Mississippian Big Lime. BRDN = Mississippian Borden. SNBR = Mississippian Sunbury. BREA = Devonian Berea. OLNG = Devonian Olentangy. RNST = Devonian Rhinestreet. CORN = Devonian and Silurian Corniferous. RhoB = bulk density. TD = total depth.

Table 3. Initial gas analysis data for the project test and monitoring wells. nd = not detected.

	Oct. 11, 2011			Jan. 13, 2012	
	SS-#1 (mole %)	SS-#2 (mole %)	SS-#4 (mole %)	SS-#1 (mole %)	SS-#4 (mole %)
Methane	82.184	81.721	79.787	81.866	87.011
Ethane	6.046	5.534	4.736	6.983	5.756
Propane	3.077	2.609	2.013	3.630	3.995
i-Butane	0.194	0.135	0.196	0.246	0.503
n-Butane	0.745	0.544	0.504	0.913	1.429
i-Pentane	0.112	0.071	0.107	0.155	0.338
(C6+)	0.226	0.071	0.261	0.220	0.461
Nitrogen	7.142	9.241	12.085	5.791	nd
CO_2	0.137	nd	0.191	nd	0.124
Specific gravity	0.67	0.66	0.67	0.68	0.68
Btu	1,071	1,025	990	1,110	1,203

Observed shut-in wellhead pressures ranged from about 320 to 370 psig for the SS-#1 well and were somewhat affected by ambient atmospheric pressure and temperature.[2] The flowing pressure for the SS-#1 well was estimated to be about 30 psig or less. The SS-#4 well was partially filled with crude oil, and shut-in pressures were essentially 0 psig (again, varying slightly with ambient temperature and pressure).

Development and Testing of the CO_2 Pumping System for the SS-#1 Project

When wells are stimulated, CO_2 is normally pumped as a chilled and pressurized supercritical fluid or as a liquid in what is known as a cryogenic fracture stimulation. The design for the SS-#1 project was to vaporize the CO_2 and inject it as a gas to avoid restimulating the well.

Ferus LP was selected as the CO_2 supplier for the SS-#1 project (John Roney, Ferus LP, personal communication, 2012). Through its relationship with Pittsburgh Cryogenics, Ferus become aware of a technology undergoing testing that incorporated a cold end[3] to pump liquid CO_2 into a truck-mounted heating unit. Pittsburgh Cryogenics developed the technology for an experiment in Alberta with Rolls Royce to test gas turbines. The parameters of that experiment were almost identical to the project design for the SS-#1 well. In the Canadian test, a cold end was installed on a nitrogen pumping unit. The CO_2 was then pumped from these cold ends to the igniter, where it was pumped as vapor. The only difference was that in the Canadian test, the vapor was pumped to a turbine instead of injecting the vapor into a gas well.

Nabors Well Services, an oilfield services company that provides pressure pumping for nitrogen fracture stimulations in eastern Kentucky shale wells, was contracted to use their truck-deployed high-rate nitrogen pump to inject the CO_2. Because we anticipated that pump rate and pressure would be low for the SS-#1 project, a single truck with a single cold end was deemed sufficient. For the injection-project application, the standard three N_2 cold ends were removed from the truck and replaced with the one CO_2 cold end; the other two openings were simply sealed with plates. A second cold end was leased as a backup and as a contingency should higher pump rates be required. In addition, the plumbing of the nitrogen pumper was modified: Specifically, a return line for liquid CO_2 was installed to enable any excess CO_2 being pumped to the cold end to return to the on-site storage vessel.

[2]Diurnal temperature changes differentially heated exposed wellheads. The temperature change and subsequent pressure change were within the sensitivity range of the measuring equipment and are evident in the records.

[3]A “cold end” is a regulator used in handling high-pressure cryogenic fluids, especially nitrogen and CO_2, in various pumping applications.

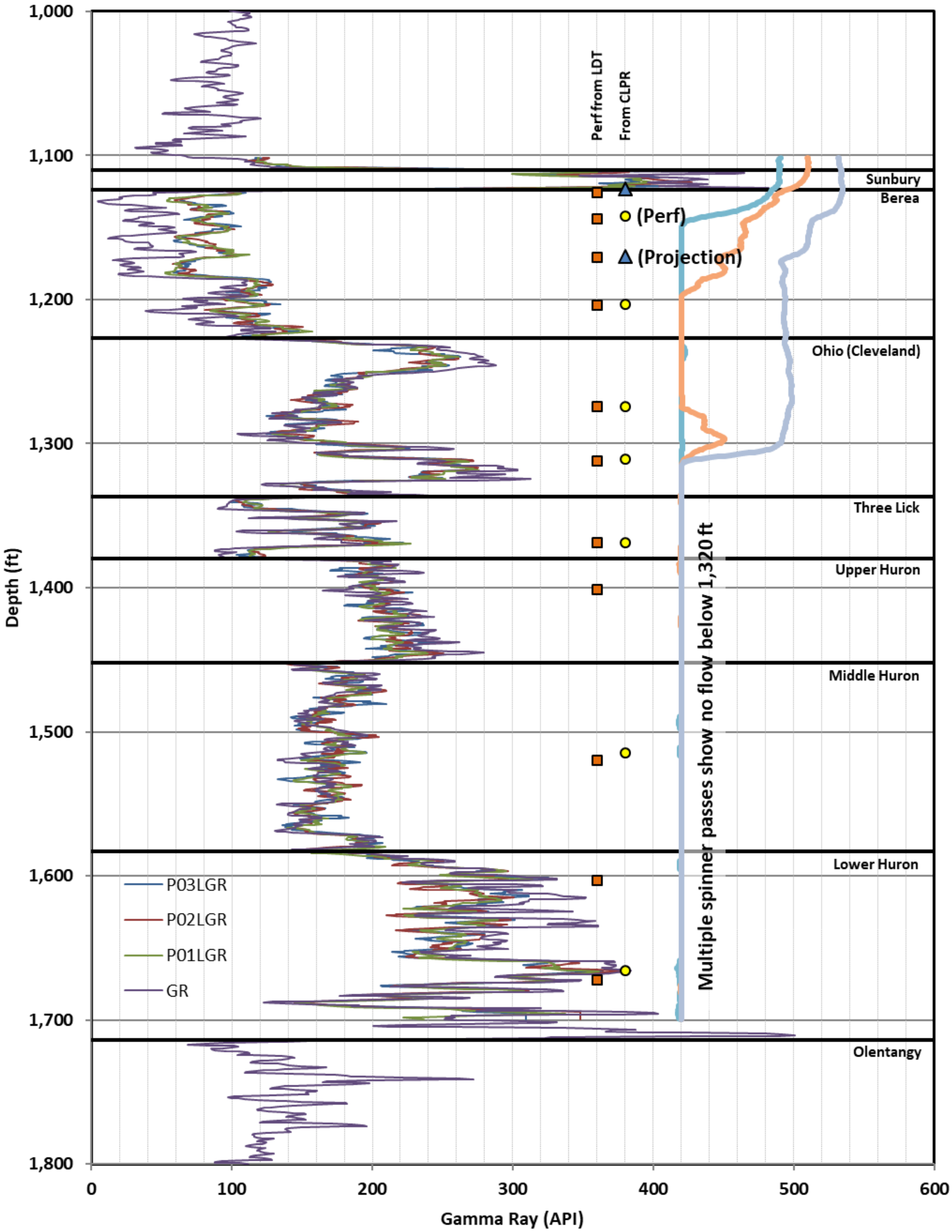


Figure 19. Pre-injection multiple spinner survey (upward passes), showing identified and active perforations with depth-calibrated gamma-ray log curves, for the Interstate SS-#1 Fee well, Johnson County, Ky.

Figure 20. Typical installation of a surface data logger on the wellhead of the SS-#4 well.

A "king" storage vessel[4] was originally selected for on-site storage of up to 100 tons of CO_2. Because of the anticipated low pump rates and the possibility that product would need to be circulated back to the storage vessel, a standard over-the-road CO_2 transport was incorporated between the king storage vessel and the N_2 pumper. The transport allowed greater control for the low pump rate as well as a safe route for the excess product to return to the storage vessel if required.

The equipment setup was tested to simulate the conditions likely to be encountered on location. The test indicated that the cold end could handle the CO_2 pump rate. An in-line choke was installed to provide back pressure, and a flow stack was used as a simulated wellhead. Our primary concern was to develop a cool-down procedure for the cold end. No similar setup had ever been tried before, and there was no timetable for how long would be required for such a cool-down. We found that, using a 1.75-in. supply line, about 15 min was required to cool down the cold end. After this procedure was completed, Nabors started the burner to begin pumping and was able to achieve approximately 550 scf/min at a pressure of 250 psi.

Figure 21 shows the on-site configuration of the CO_2 handling facilities. CO_2 injection was successful at the SS-#1 well. Performance of the equipment and modifications exceeded expectations. During the three days of actual pumping, there were no major issues. On the final day of the test, the setup was tested so that we could gain experience with the potential capabilities of the equipment.

Normally, CO_2 is pumped as a liquid with a fracture stimulation pump that is otherwise known as a "fluid pumper." For pumping a gas, a specialized N_2 pump is required. An N_2 pump is only capable of converting liquid N_2 to gas. This new configuration that adapted a CO_2 cold end proved capable of pumping a gas or a liquid with just a

[4]"King" is a designation used by the industrial gas industry for a large over-the-road CO_2 storage vessel that is delivered empty to a site and later filled.

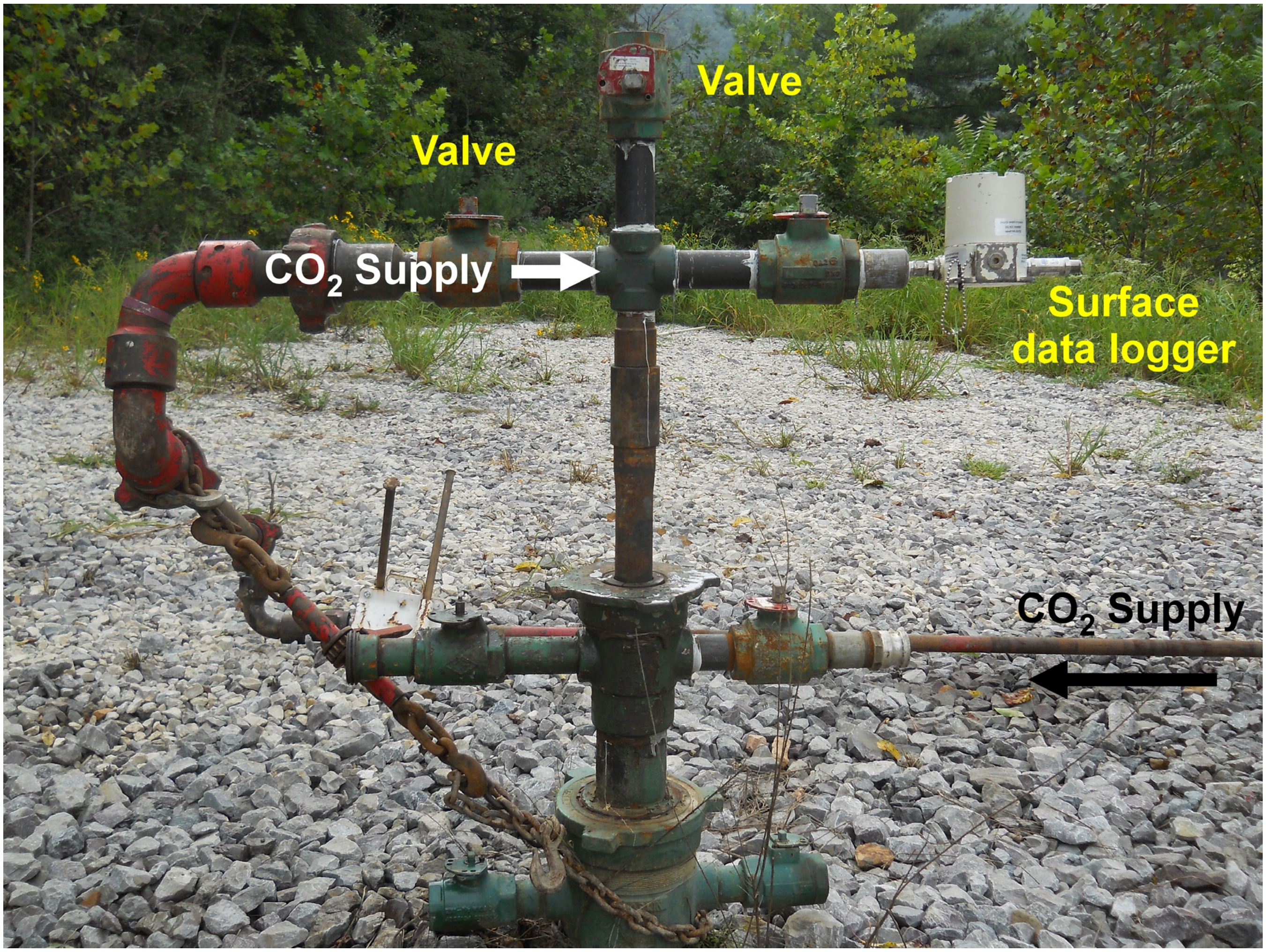


Figure 21. Setup of the SS-#1 wellhead for testing (before installation of the analog pressure gage on the backside annulus). The surface pressure and temperature data logger is on the right and can be isolated with a full-port valve. The top full-port valve enabled access to the well for logging during testing and flowback. The CO_2 supply was delivered from a staging area to the right and entered the well through another full-port valve on the left.

single unit. Changing the N_2 cold end to a CO_2 cold end is relatively easy. The vaporizer (burner) remains unchanged, regardless of fluid. This setup would not replace the high-volume pumps for CO_2, but could provide an alternative for low-rate stimulation treatments that require liquid or gaseous CO_2.

Injection

The injection target in the SS-#1 well was the Ohio Shale. Perforations were indicated on the open-hole log suite in the Devonian Berea Sandstone interval at depths of 1,204 ft (active on spinner survey), 1,171 ft, 1,144 ft (active on spinner survey), and 1,126 ft (Figs. 18–19). To address this situation, tubing and packer were run, with the packer set at 1,264 ft, below the deepest Berea perforation and above the shallowest perforation in the Ohio Shale. The initial setup of the SS-#1 wellhead for testing before the analog pressure gage was installed on the backside annulus is shown in Figure 22. The backside annulus between the 4.5-in. casing and the tubing above the packer was filled with gel and topped to the surface with a potassium chloride brine. The SS-#1 backside pressure was monitored with an analog pressure gage. A 24-hr shut-in tubing pressure of 300–310 psig was observed after the tubing and packer were installed.

Up to 300 tons of CO_2 was planned to be injected, at low rates and pressures designed to remain below the estimated fracture pressure of the shale at the depths of the open perforations in the

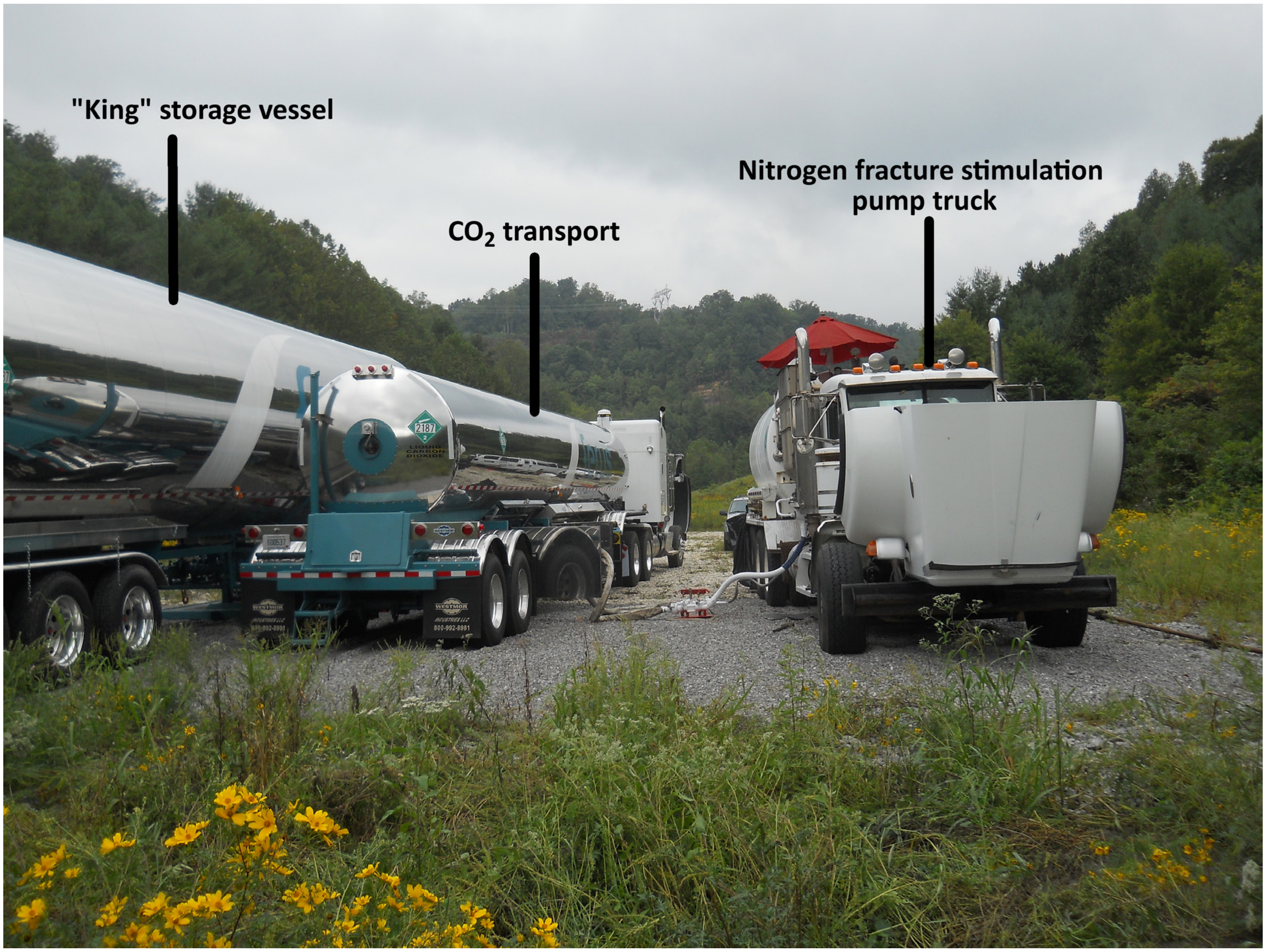


Figure 22. CO_2 was handled on site with a “king” storage vessel (left) and an over-the-road CO_2 transport (middle) connected through a cold end to the vaporizer unit of a nitrogen fracture pump truck (right, with hood raised to increase engine cooling).

SS-#1 well; this test was specifically designed so as not to restimulate the well. To stay within this limit, pressures were not allowed to significantly exceed 1,100 psi, so as to stay below the estimated fracture gradient for the shale at that location.

CO_2 was injected during three 10-hr tests conducted over a week, with 12 to 24 hr or more between tests to allow for pressure falloff. CO_2 was transferred from an on-site storage vessel to an over-the-road CO_2 transport equipped with a transfer pump. The CO_2 was pumped from the transport to a cold end installed on an industry-standard nitrogen-supply and fracture-stimulation service truck, where it was vaporized and heated to 100°F, then injected through tubing and packer into the Ohio Shale.

On Sept. 6, 2012, about 21 tons of CO_2 was pumped at 600–650 scf/min (3 bbl/min) or 2.5 tons/hr, inducing a final shut-in pressure of 840 psi; pressure declined to 580 psi by the next morning when injection was resumed. On Sept. 7, surface pressure initially rose to about 840 psi and then climbed to 890 psi with the injection of about 22 tons of CO_2, again pumping at a rate of 2.5 tons/hr. Injection operations were shut down for the weekend the afternoon of Sept. 7 and resumed on Sept. 10. Initial CO_2 rates of 650–700 scf/min were maintained on Sept. 10 at pressures similar to those in previous injection phases. An injection survey and a step-rate test were conducted to evaluate pressures and higher pumping rates. An estimated 87 tons of CO_2 was injected over the three days.

A second downhole production-log survey was conducted by using a wireline-conveyed spinner tool on Sept. 10, the last day of injection testing. The purpose of the spinner survey was to identify which perforations were accepting the CO_2 during active injection and to determine the relative percentages of CO_2 going into the open perforations. The spinner-survey program consisted of four up and down passes at 30 ft/min, 60 ft/min, 90 ft/min, and 120 ft/min. The spinner tool string included a gamma-ray detector (for depth control), memory readout card for the spinner tool, and temperature and pressure probes. Entry into the well was controlled by assembling the logging tool string, inserting it into a lubricator assembly, and then installing the lubricator on the wellhead. The sealed assembly enabled pressure to be maintained and allowed entry into the wellbore without the wellbore having to be opened to the atmosphere.

During the spinner survey, the CO_2 injection was held steady at a rate of approximately 2.5 tons/hr and a pressure of about 850 psi. When the survey was completed, the logging services company attempted to download the data from the tool's memory card. Although the memory card showed that data were recorded, all attempts to download the data generated an error message, and no data were recovered at the well site. Subsequent efforts to download the data at the logging service's corporate facilities were also unsuccessful. Therefore, a post-injection spinner survey was conducted during flowback operations to help identify the active perforations in the SS-#1 well.

After the logging service rigged down the lubricator and logging tools, we decided to try increasing the pump rates by changing to higher gears on the truck. ("Rigging down" is the process of withdrawing the logging tools from the wellbore into the lubricator, closing the top valve on the wellbore, then removing and disassembling the lubricator and logging tool string.) The stepped flow data as observed from displays in the control van are shown in Table 4.

After 980 psi was reached, the rate and pressure stabilized for about 10 min until the volume of usable CO_2 on site was depleted. The maximum achieved injection rate was about 5.7 tons/hr.

On Sept. 12, a shut-in pressure of 590 psi was noted on the casing annulus (that is, the backside annulus) above the packer in the SS-#1 well. Accordingly, the injection phase of the project was ended, thus terminating the test with no additional CO_2 being pumped. A gas sample acquired from the backside annulus indicated it was 92 percent CO_2. The well was then shut-in for a 13-day soak period to facilitate any potential interaction between the injected CO_2 and the shale reservoir and to prepare for flowback.

Table 4. Progress of step-rate pressure test of CO_2 injection in the SS-#1 well.

Time	*Truck Gear*	*Pressure (psi)*	*Rate (Mcf/min)*
15:20	4th	940	
15:22	5th	950	1.4
15:26	6th	960	1.5
15:29		970	
15:30	7th	980	1.5

Post-injection

On Sept. 25, a meter run was constructed of 2-in. tubing connected to a full-port ball valve on the side of the wellhead of the SS-#1 (Fig. 23). The meter run included a digital flow meter and a gas expansion chamber with fittings for a wellhead gas analyzer. The flow meter recorded flow volumes and temperature across a restrictive choke plate. Initial calculations based on formulas provided by Halliburton Services (1985, p. 60) suggested an estimated 0.25-in.-diameter choke orifice. The chosen setup for the orifice meter was designed by contractors to Crossrock Drilling, and the flow meter was installed in the meter run with a plate including an orifice of 1.375 in. The gas analyzer is a self-contained unit often used in oilfield mud-logging applications to detect methane, ethane, propane, iso-butane, normal-butane, oxygen, carbon dioxide, and hydrogen sulfide to document gas shows and detect potentially unsafe drilling conditions. An expansion chamber was installed to prevent overpressuring the gas supply line to the analyzer at the end of the meter run. A blow-out preventer was installed on the top full-port ball valve to accommodate the lubricator used to rig in the logging tools without opening the well (not shown in Figure 23).

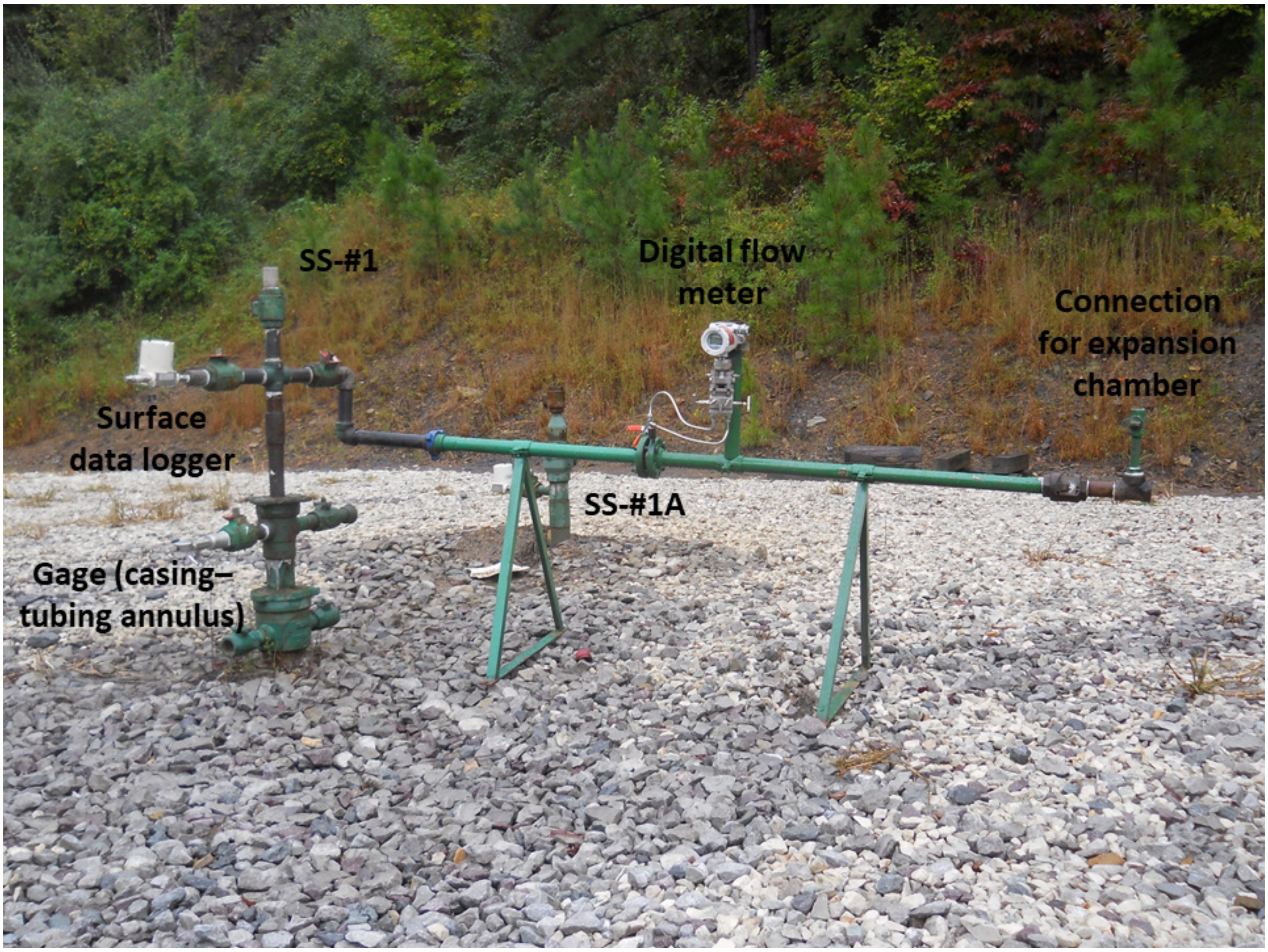


Figure 23. Configuration of meter run for flowback of the SS-#1 well, showing the temperature and pressure data logger on the wellhead at left, digital differential-pressure flow meter in center, and connection for expansion chamber at outlet to right. Note analog pressure gage for monitoring casing/tubing annular pressure on left below surface data logger and wellhead of SS-#1A in background.

Continuous mud-gas readings and gas samples were acquired during flowback from a sampling port on the mud-gas analyzer. Significant atmospheric contamination occurred because the expansion chamber was installed at the open discharge end of the meter run and the flowing pressures rapidly fell to less than 30 psi, which allowed ambient air into the system. Figure 24 shows the changes in flowback gas composition for CO_2, N_2, and CH_4. After an initial period of variability, CO_2 declined, but the increase in N_2, likely the result of atmospheric contamination and a contributor to the variability in CO_2 concentrations, complicates interpretation of the decline. In addition, considerable fluctuation in the flow pressures and rates during that initial flowback period (Fig. 25) is no doubt the result of production-logging operations that contributed to the difficulty of obtaining reliable gas-composition data, including CO_2 concentration values.

Several operations were conducted during the flowback. A suite of production logs including gamma-ray (for depth control) and a spinner, pressure, and temperature survey, was acquired. The spinner survey was conducted during flowback to identify active perforations, on the assumption that perforations taking CO_2 during injection would be most likely to flow the CO_2 back. Multiple up and down passes of the downhole tools affected the metered flow in unanticipated ways.

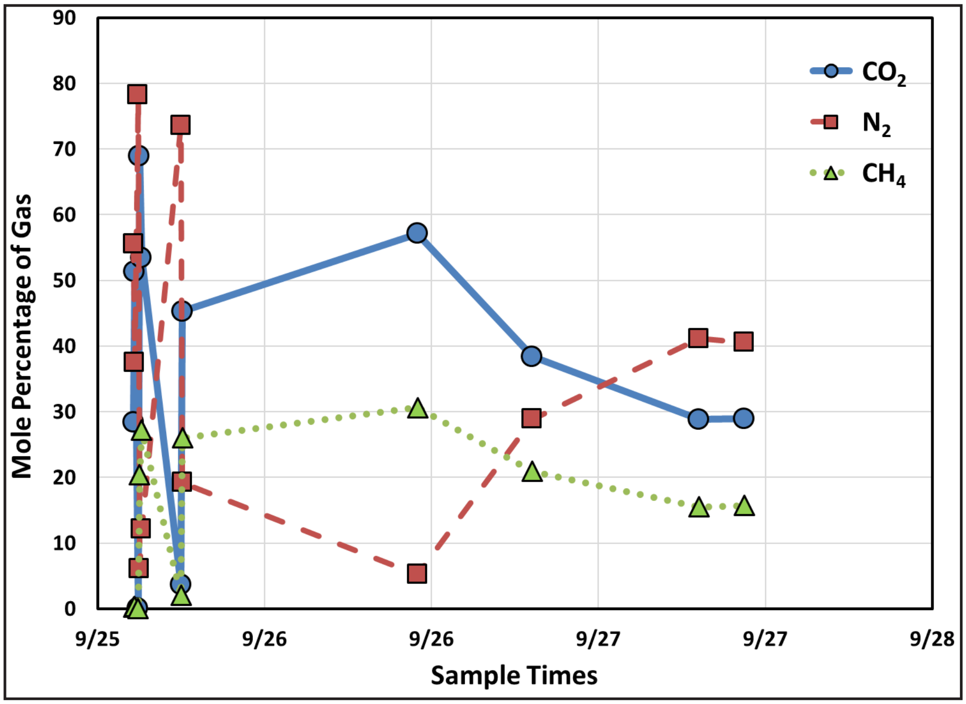


Figure 24. Changes in composition of the produced gas during flowback of the SS-#1 well.

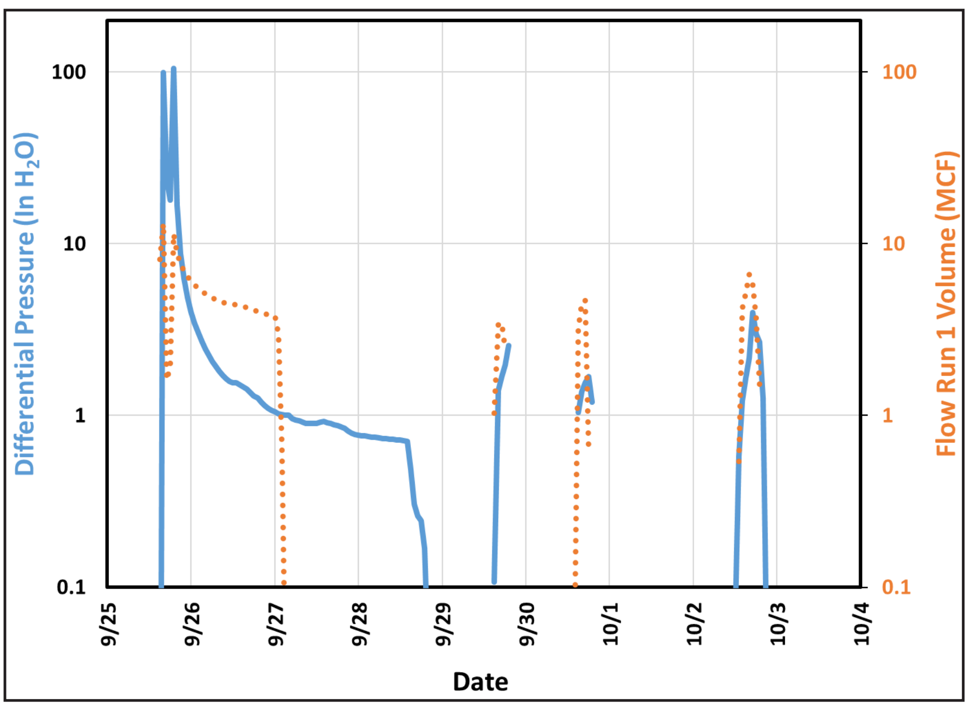


Figure 25. Differential pressure and flow-volume history during flowback of the SS-#1 well.

Three open perforations were identified (Table 5). Although the original well completion indicated the casing was perforated at a depth of 1,603 ft, the initial multi-arm caliper and spinner surveys failed to locate this perforation. During the spinner survey on the SS-#1 well, tubing pressure was 364 psi at the same time the pressure readout on the spinner tool indicated 30 psi. The ball valve isolating the data logger for the tubing pressure on the SS-#1 well had been closed at some time during rigging of the lubricator and logging tool. Once the valve was reopened, the pressure dropped to 28 psi, matching the readout on the spinner tool. CO_2 levels from the mud-gas analyzer were initially about 9.8 percent and dropped to 6.6 percent by the end of the spinner flow test. After the flowback operation, conducted over three days, tubing pressure on the gage of the SS-#1 well was 18.7 psi.

The tubing and packer were retrieved on Oct. 3. The pressure anomaly in the backside annulus observed on Sept. 12 was roughly equivalent to the shut-in tubing pressure, suggesting communication between the injected CO_2 and the tubing to casing annulus. Potential causes of the communication were packer failure or communication between formations through induced fractures (the well was fracture-stimulated using nitrogen) that led to gas produced through perforations above the packer from the Mississippian Sunbury Shale or Devonian Berea Sandstone entering the annulus. We therefore decided to terminate the injection phase of the test. When the packer was brought to

Table 5. Active perforations during flowback of the SS-#1 test well, Johnson County.

Depth (ft)	*Percentage of Observed Gas Flow*	*Gas Flow (Mcf/d)*	*Formation*
1,311	82.4	210	Cleveland Member, Ohio Shale
1,514.5	3.9	10	Middle Huron Member, Ohio Shale
1,595	13.7	35	Lower Huron Member, Ohio Shale
Total	100	255	

the surface, a visual inspection indicated it had set correctly and there was no failure of that equipment.

After the tubing and packer were retrieved, the surface data recorders were decommissioned and the downhole memory readout gages were recovered. The two redundant gages captured complete pressure and temperature records for the duration of the well test.

Discussion

Pressure and Temperature Records. Surface pressure and temperature for the SS-#1, SS-#1A, SS-#2, and SS-#4 wells were continuously monitored from Aug. 28–Sept. 28, using data loggers installed on the wellheads; redundant memory readout gages were installed in the SS-#1 well at a depth of 1,724 ft. The temperature records for the surface data loggers of all four study wells (Fig. 26) show the loggers were influenced by diurnal changes, likely caused by heating and cooling of the exposed wellhead assemblies. The pressure records for monitoring wells SS-#1A, SS-#2, and SS-#4 (Fig. 27) exhibited similar diurnal effects correlated to temperature.

The surface and downhole records for the SS-#1 well show an initial pressure build-up from 14 psi on Aug. 12, when the well was opened for installation of downhole equipment, to approximately 306 psi on Sept. 6, when CO_2 injection began at 9:00 a.m. (Fig. 28). There was a time lag of 59.583 min between pressure increases measured by the surface data logger and corresponding pressure increases recorded by the downhole memory readout gage (Fig. 29a). This lag is likely a clock issue related to time zone differences between clocks; surface data-logger times were adjusted forward by the lag time (Fig. 29b). Pressure data for the three tests show sharp pressure increases at the start of injection, followed by more gradual falloff. In general, each of the three

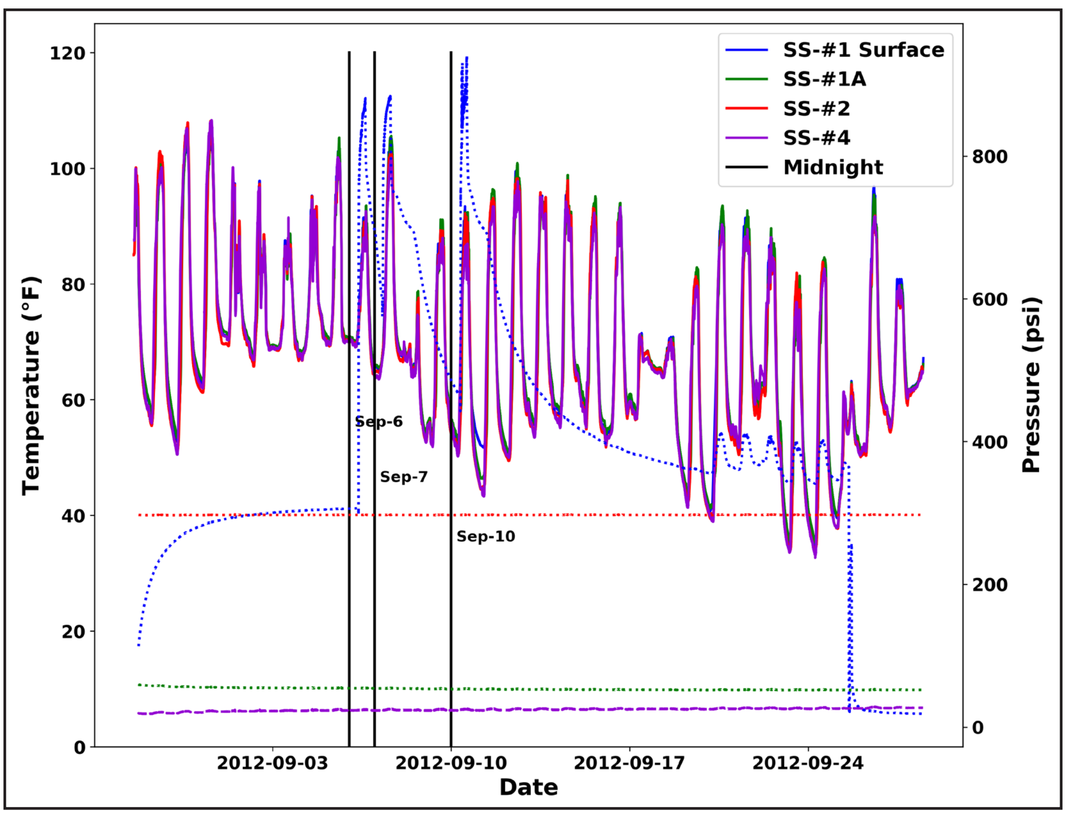


Figure 26. Temperature (solid lines) and pressure (dotted lines) records of the surface data loggers for the study wells (SS-#1, SS-#1A, SS-#2, SS-#4), showing primary influence of diurnal changes (except for SS-#1 pressure). Vertical lines indicate 12:00 a.m. on the injection test days.

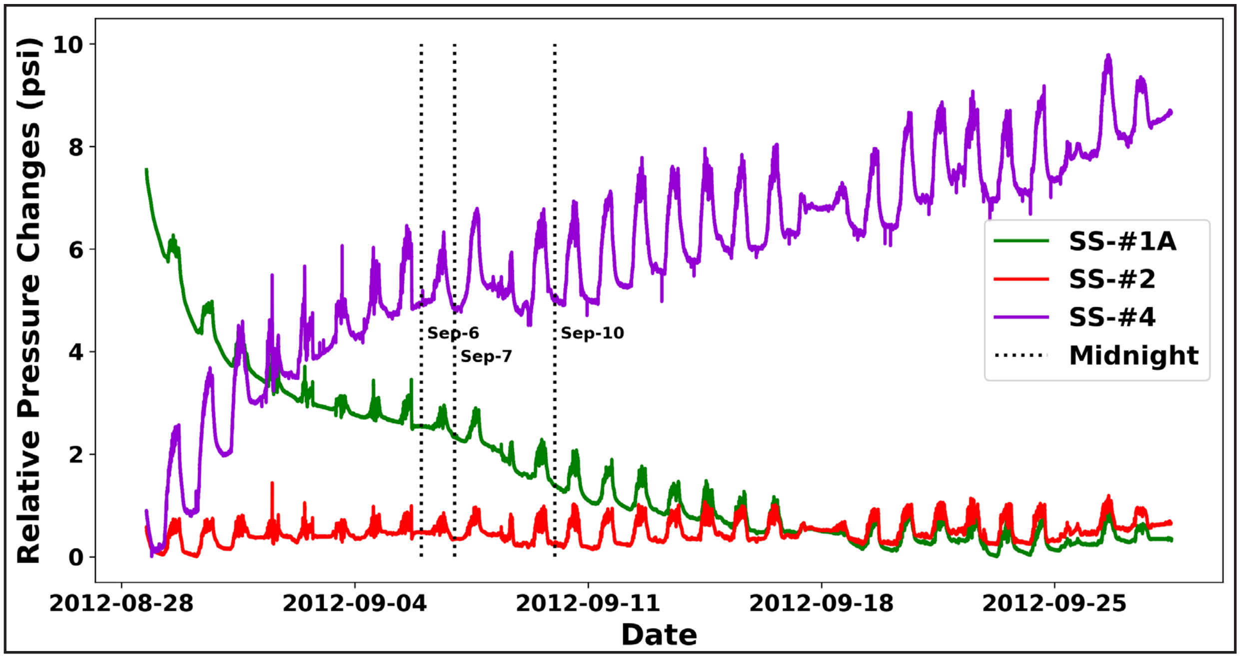


Figure 27. Record of pressure changes measured by the surface data loggers for the monitoring wells (SS-#1A, SS-#2, and SS-#4) relative to minimum pressure recorded by each instrument, showing primary influence of diurnal changes. Dotted vertical lines indicate 12:00 a.m. on the injection test days.

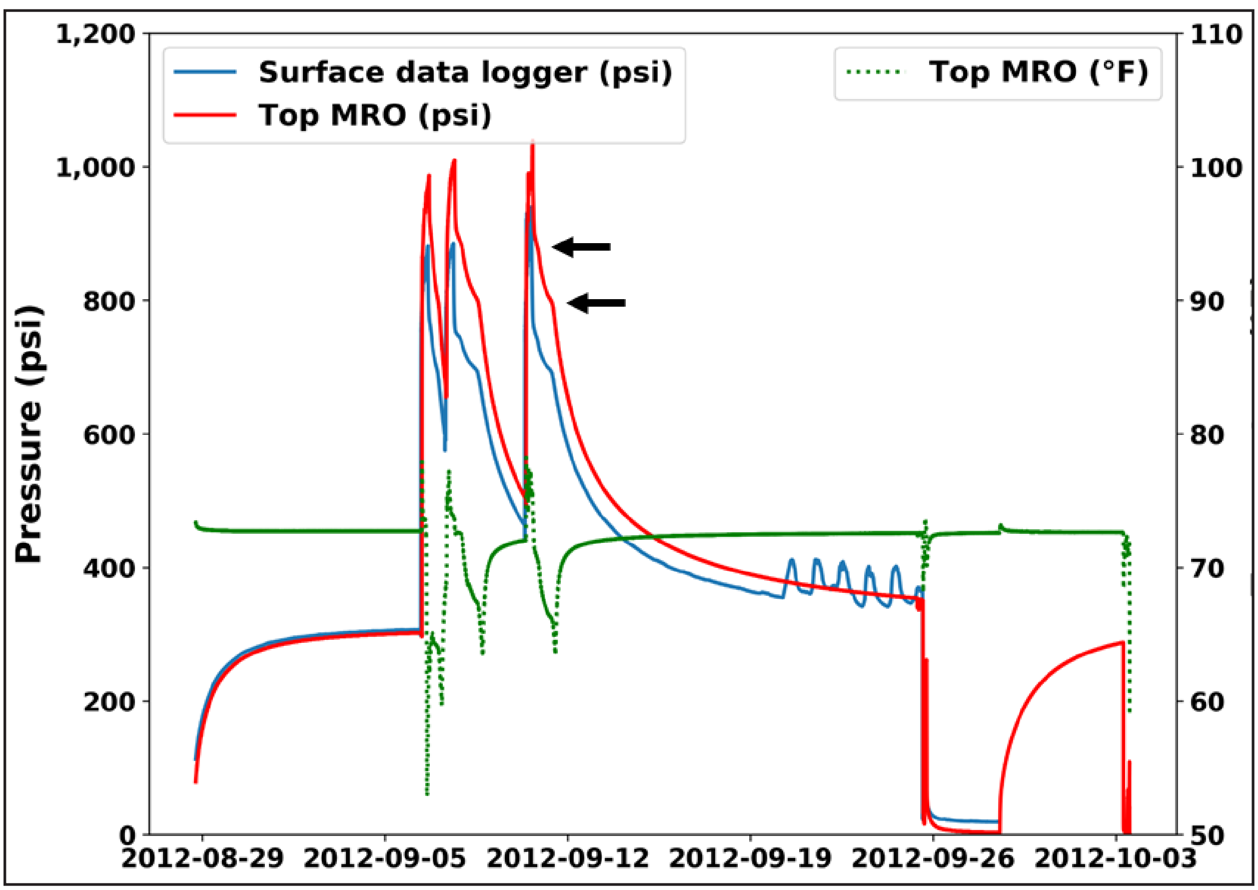


Figure 28. Pressure and temperature history of the SS-#1 well from the memory readout gage installed at a depth of 1,724 ft (Top MRO) and the pressure recorded by the surface data logger. Arrows indicate anomalies in pressure falloff observed on the installed memory readout gages (see also Figure 30).

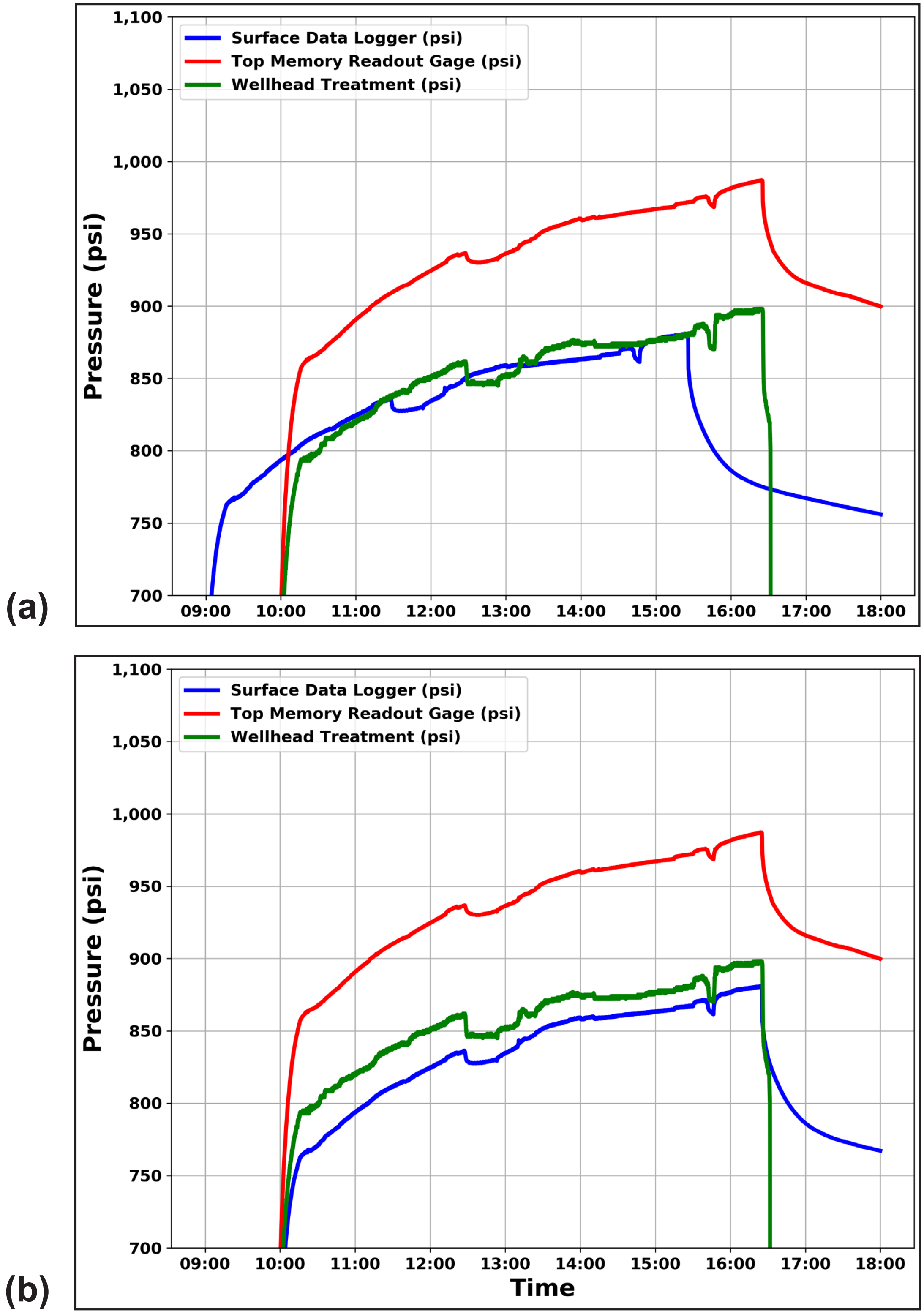


Figure 29. Comparison of test pressure data for CO_2 injection recorded Sept. 6, 2012, from the three instruments installed in the SS-#1 well, showing time difference between the surface data logger and downhole memory readout gages (a) and time-corrected data (b).

injections proceeded in the same basic fashion over time (Fig. 30). The falloff curves shown in Figure 30 each exhibit two flexures, or shoulders, which proved to be a problem for pressure-transient modeling. The pressure record for day 3 in the SS-#1 well (inset, Fig. 30) also exhibits early perturbations related to rigging in and running the spinner tools through the tubing and a second set of anomalies related to increasing the pump rates by shifting gears. The final pressure increase resulting from doubling the CO_2 pump rate from 2.5 tons/hr to 5 tons/hr is clear, as are fluctuations associated with gear changes on the pump truck.

Godec (2013) conducted pressure-transient analysis to model the performance of the injection test and found that a traditional injection falloff test could not be performed because of pressure anomalies at approximately 750 and 690 psi. The analysis indicated that the effective permeability in the black shale in this well appears greater than for representative samples, likely because of short, infinite-conductivity fractures resulting from natural or induced fracturing. Godec (2013) concluded that the observed combination of circumstances suggests communication between the Ohio black shale and the overlying Berea. A plot of the pressure and temperature data from the topmost[5] of the downhole memory readout monitors on a CO_2 phase diagram (Fig. 31) indicates that during the peak pressures observed while injecting, CO_2 shifted to a liquid phase (upper leftmost part of each trace) and then reverted to a vapor during the pressure falloff (lower rightmost part of each trace). The liquid-to-gas phase change during pressure falloff does not exactly coincide with the CO_2 saturation line. The gas in the borehole was assumed to be a mixture of mostly CO_2, some CH_4, and possibly some heavier hydrocarbon gases; the resulting mixture does not exhibit ideal gas behavior. Whether any liquid CO_2 accumulated in the borehole during injection remains unknown. The study suggests the pressure anomalies during the falloff periods are likely related to these CO_2 phase changes, which would affect permeability relative to vapor and liquid phases.

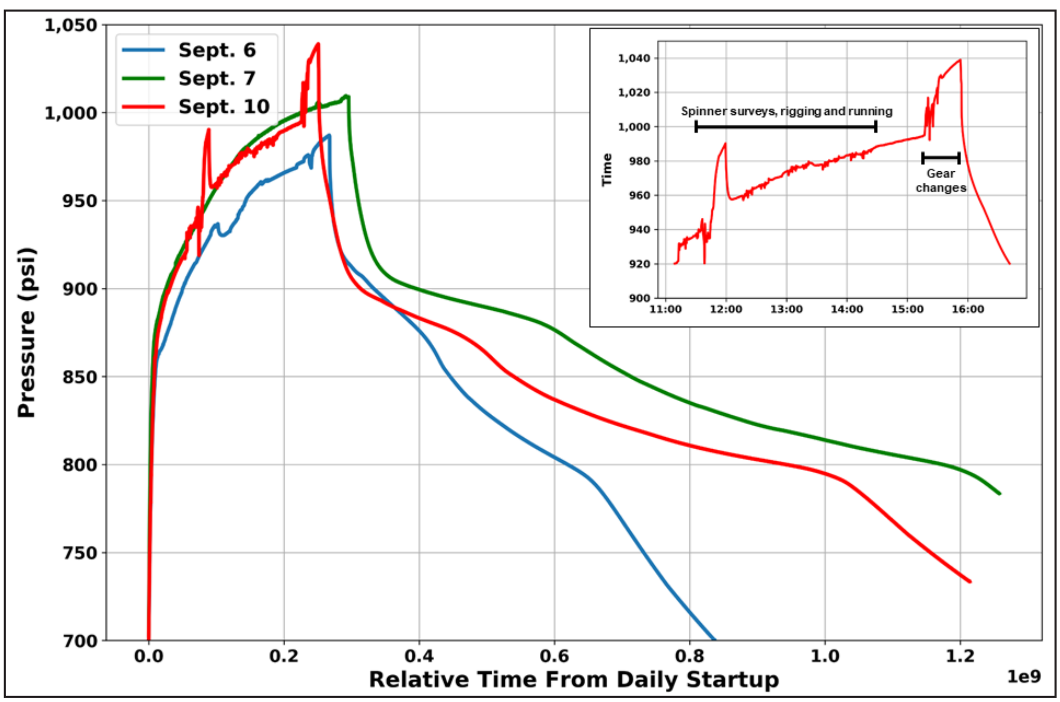


Figure 30. Comparison of daily CO_2-injection and pressure-falloff data from the memory readout gage in the SS-#1 well at a depth of 1,724 ft. Inset emphasizes changes resulting from operational conditions on Sept. 10.

[5]The pressure and temperature records for the two downhole memory readout instruments were identical. The data recorded by the topmost instrument was selected as representative of both instruments.

Pressure data from the monitoring wells were used to investigate well integrity and the outcome of the test. Pressure anomalies in the monitoring wells were used to determine if the injected CO_2 influenced production in the monitoring wells. Such changes would indicate the injected CO_2 influenced the nearby wells, possibly indicating enhanced production. An increase in magnitude of the observed pressure in the SS-#1A well could indicate vertical migration out of the test zone or a casing failure. For the SS-#2 well, a pressure change indicates the arrival of a pressure pulse that could indicate successful displacement of methane. The pressure record of the SS-#4 well appears to indicate the wellbore is fluid-filled, which would likely suppress a measurable pressure response; therefore, the SS-#4 well was not included in the analysis. These responses are expected to take place at some later time and with a different magnitude than pressure changes caused simply by solar heating of the wellheads. By plotting relative pressure changes throughout one day (midnight to midnight) and overlaying these plots, the data from multiple days before, during, and after injection can be compared. Figure 32 shows the relative pressure data for the SS-#1A and SS-#2 wells for Sept. 5–13. The data show that the relative pressure change on a daily basis appears consistent in initiation, magnitude, and duration for each day's record. Overall, the pattern of daily change suggests that the observed pressure records are primarily controlled by ambient temperature changes and lack noticeable shifts or magnitude changes that could be related to CO_2 injection in the SS-#1 well.

Log Analysis. Pulsed-neutron logging in sigma mode measures the relative ability of materials to absorb the free neutrons produced by the tool, known as the capture cross section of materials or simply "sigma." The primary use of the tool is to detect formation waters behind casing, based mostly on dissolved chlorine in the formation brines, and is thus an analog for formation resistivity (Albertin and others, 1996). Natural gas and CO_2 have very low capture cross sections and cannot generally be differentiated. A further complica-

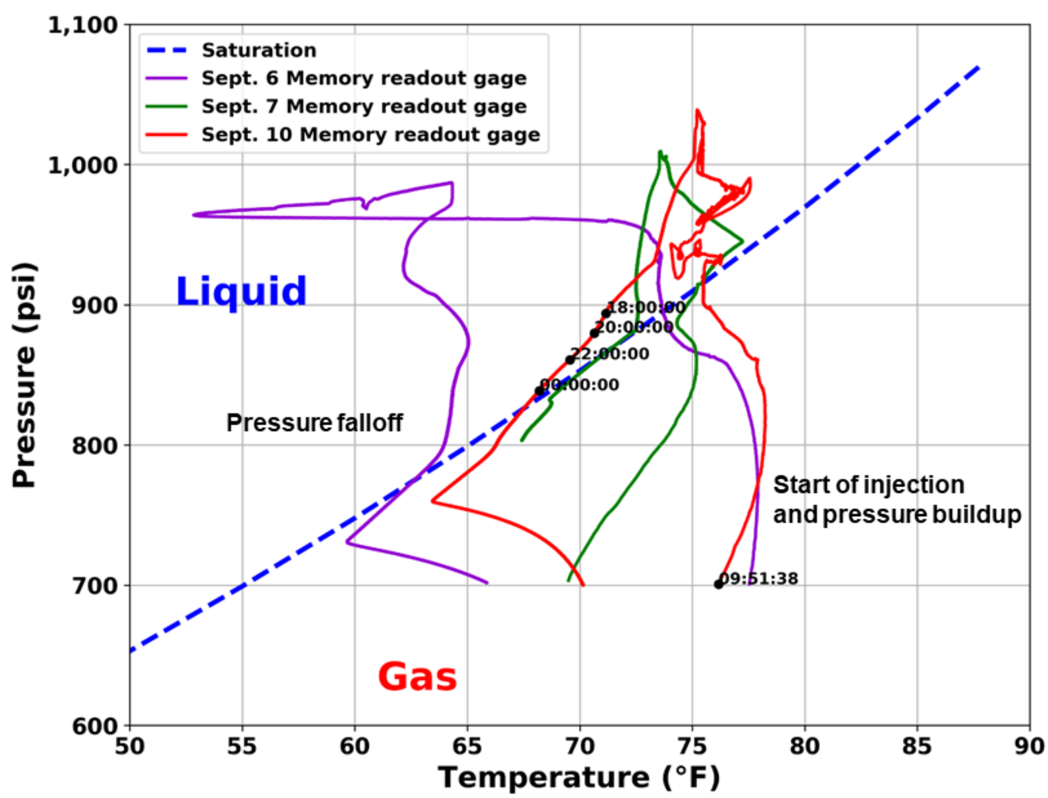
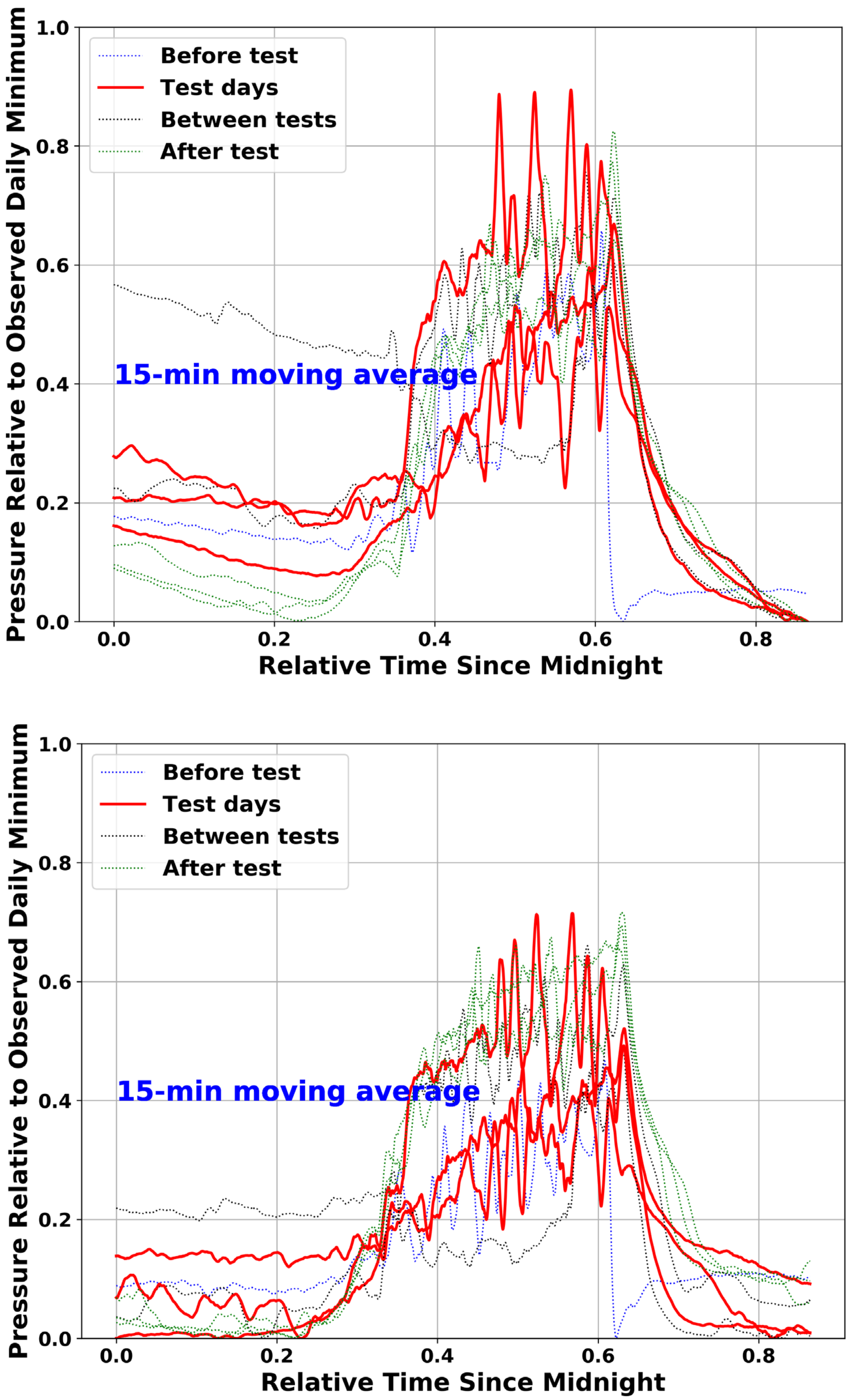


Figure 31. Pressure-temperature plot of the memory readout gage in the SS-#1 well at a depth of 1,742 ft, showing CO_2 gas-to-liquid phase changes over the time of injection and pressure falloff testing. Time marks are shown for the Sept. 10 test. Saturation line for ideal gas from www.chemicalogic.com/Pages/DownloadPhaseDiagrams.aspx (accessed 05/24/2019).



(a)

(b)

Figure 32. Overlay of daily pressure readings from the surface data loggers for the SS-#1A (a) and SS-#2 (b) wells. No compelling influence related to CO_2 injection was observed in the SS-#1 well. Daiily pressure records for days with injection operations (red) are shown against a background of records for days before, between, and after testing.

tion is that this production tool is normally run in fluid-filled holes. Corrections must be made to any acquired sigma data to compensate for a gas-filled hole. Changes in sigma values from the pre- and post-injection logging runs in the SS-#1 well were expected to indicate gas displacement of bound water within the formation; that is, entry and retention of CO_2 (Robert Butsch, Schlumberger Carbon Services, personal communication, 2012).

Initial formation analysis was performed using SpectroLith (software by Schlumberger) with raw data from the open-hole log suite and the pulsed-neutron log in lithology (inelastic collision) mode to determine basic percentages of components of the shale matrix. The sigma trace from this initial run was depth-matched with the sigma trace from the post-injection logging run and analyzed for indications of displacement of CH_4 by CO_2 (Fig. 33). CO_2 has a smaller capture cross section (±0.5 capture units, or "cu") than does CH_4 (3–10 cu); thus, CO_2 appears more like a gas than CH_4 does. Several factors complicated the analysis: the volume of the gas-filled borehole, the low contrast between the sigma values for natural gas and CO_2, the relatively small amount (87 tons) of CO_2 injected, and the short shut-in period. The change in pre- and post-test water saturations computed from the pulsed-neutron data is consistent with CO_2 interactions with gas in the formation, but is not definitive.

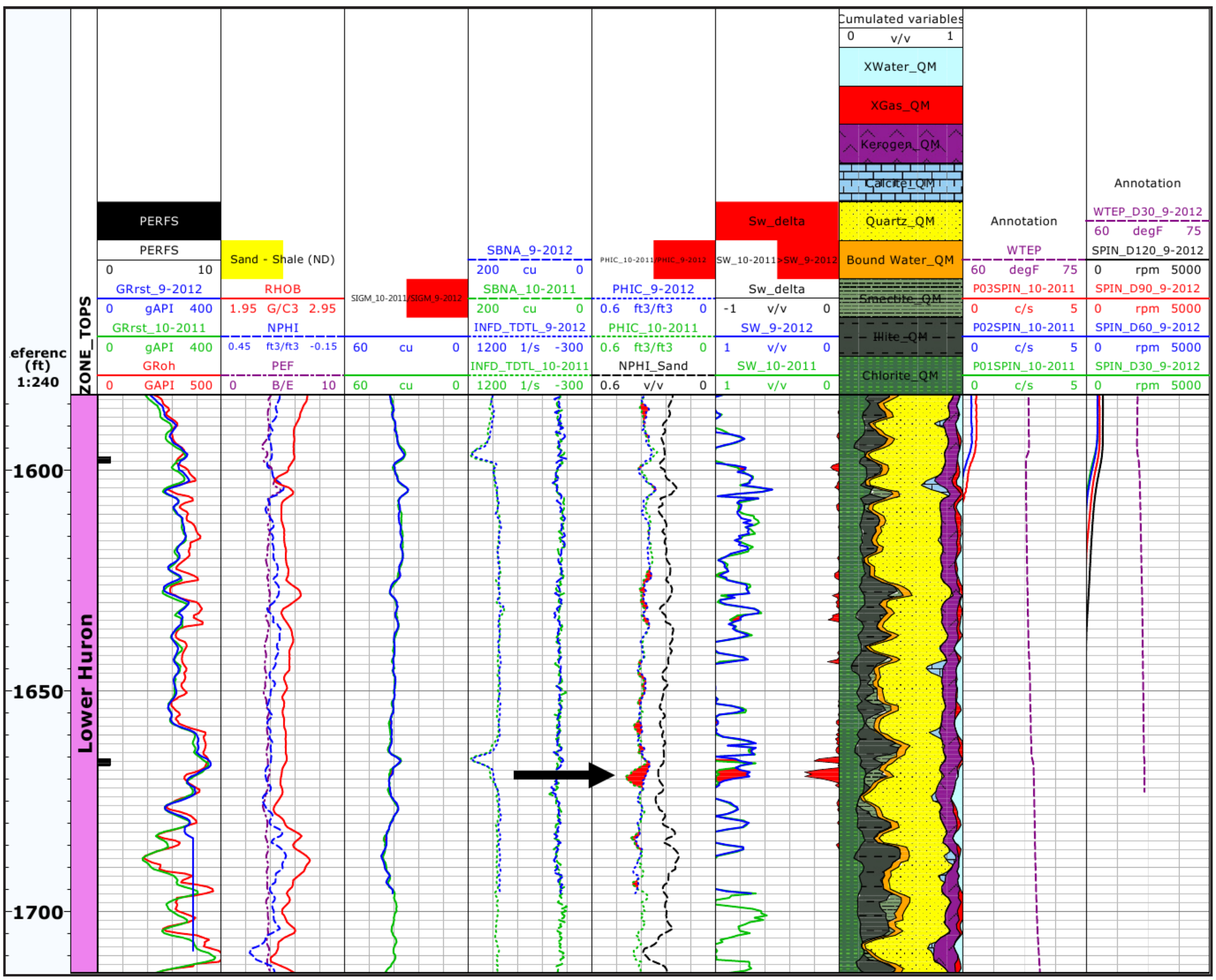


Figure 33. Extract of the composited pulsed-neutron and spinner survey logging runs (October 2011 and September 2012) for the Lower Huron interval in the SS-#1 test well, showing porosity (NPHI) changes consistent with CO_2 displacement of CH_4 (red shaded areas from 1,666–1,672 ft [indicated by arrow] opposite perforation at 1,666 ft).

Observations and Lessons Learned

The primary goal of the project was to demonstrate CO_2-enhanced natural-gas recovery in organic-rich black shale; we hoped to accomplish this by observing an increase in natural-gas production and adsorption of CO_2. For the most part, this objective was not met. The well selected for study (1) was shut-in and had no historic production data for comparison, (2) was cased, precluding recovery of core material for lithology, petrology, and shale rock-properties data, and (3) was fracture-stimulated in formations above the Ohio black shale. After an extensive search, the SS-#1 well was what was available for moving the project forward given the limited funding.

- The project demonstrated that CO_2 can be monitored and pumped at low (below fracture gradient) rates and pressures using an oilfield-standard nitrogen pump truck.
- A mud-gas analyzer can be used to monitor the composition of gas during flowback, but atmospheric contamination must be prevented.
- The observed effective permeability indicates greater permeability than other representative shales. This appears to be the result of an effective nitrogen fracture stimulation when the SS-#1 well was originally completed.
- Linear flow indicates an open induced or natural fracture system developed across much of the stimulated zone.
- Communication through those fractures from the Ohio Shale to the Berea was the most likely cause for the pressuring and CO_2 observed in the tubing and casing annulus.
- Analysis of pre- and post-injection pulsed-neutron logging data indicates CO_2 displacement of bound water; i.e., CO_2 retention in the reservoir was identified.

We learned much about the selection of a study well and conduct of the flowback operations. The ideal sequence of events should include drilling, coring, logging, completion, and production of a dedicated well. The well completion should be confined to a single black-shale unit. After the initial decline, production logging and flow profiling should be performed before monitoring and CO_2 injection operations. The well should be shut-in for a sufficient period to allow for CO_2 adsorption. Finally, during and after a monitored flowback, flow profiling and production logging should be acquired for comparison with the pre-injection data. A mud-logging unit is adequate for real-time monitoring of the gas composition of the flowback, but any expansion chamber installed to protect the unit should be incorporated some distance away from the discharge end of any meter run used for measuring flow volumes. The orifice selected for the gas flow meter in this project should have been smaller, which would have provided a longer flowback time and possibly minimized the noisy compositional data acquired during flowback.

Acknowledgments

This project could not have been accomplished without the generous assistance and participation of Denny Rohrer of Crossrock Drilling, Pikeville, Ky., who provided access to the SS-#1 well, rig services for running and pulling the tubing and packer, and support personnel in the field. Mike Godec, George Koperna, and David Reistenberg of Advanced Resources International provided petroleum engineering support, data analysis, and on-site monitoring and advice for planning throughout the project. Schlumberger Carbon Services provided discounted logging services, and Bob Butsch performed the petrophysical analysis of wireline data to identify CO_2 in the shale. Neeraj Gupta of Battelle Memorial Institute provided access to Midwest Regional Carbon Sequestration Partnership piggyback funds that helped offset the cost of acquiring sidewall core and advanced wireline logs in the K-2605 well.

Afterword

My father was a successful independent consultant in the oil patch of western Kentucky and southern Illinois. When he generated a good prospect, he often retained a portion, but when he generated what he felt was a great prospect, he would try to sell an interest in the well to my uncles. Any time one of my uncles broke down and invested in the deal, the resulting well was a duster. It just goes to show that you can always drill a dry hole.

Disclaimer

In this report, the use of a company name or the name of a product or service provided by a company serves only to document this research project and does not constitute an endorsement of the company, product, or service.

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Links to Appendices

Appendix 1: Reference Wells

- ReferenceWells.xlsx

Appendix 2: Pike-Letcher (Interstate) Panther Land Corp. No. 3 Well Data

- R00102403_GRD.las

Appendix 3: Rosewood Resources Ted Bargo No. 02 Well Data

- Bargo, Ted 02 Frac Data.pds
- Bargo, Ted 02 Frac Data.tif
- Bargo, Ted 02 Rock Mech Rpt.doc
- Bargo, Ted 02 Routine Core Analysis.pdf

Appendix 4: Blue Flame Batten and Baird No. K-2605 Well Data

- aaa K2605 info.xlsx
- K2605 Blue Flame Petrology Report.pdf
- K2605 Blue Flame ROCK EVAL TOC.xlsx
- K2605 Blue Flame Tight Rock Analysis.xlsx
- k2605 cross section.jpg
- K2605 RSCT-samples

Images

- .picasa.txt
- Thumbs.db

SEM

Blue Flame K-2605 SN 03 - 4319.7

- 1- Blue Flame K-2605 - 4319_7 ft X2300 - SN 03 sei.bmp
- 2- Blue Flame K-2605 - 4319_7 ft X4000 - SN 03 sei.bmp
- 3- Blue Flame K-2605 - 4319_7 ft X1500 - SN 03 sei.bmp
- 4- Blue Flame K-2605 - 4319_7 ft X800 - SN 03 sei.bmp
- 5- Blue Flame K-2605 - 4319_7 ft X1000 - SN 03 sei.bmp
- 6- Blue Flame K-2605 - 4319_7 ft X5000 - SN 03 sei.bmp
- Thumbs.db

Blue Flame K-2605 SN 05 - 4373.7

- 1- Blue Flame K-2605 - 4373_7 ft X1000 - SN 05 sei.bmp
- 2- Blue Flame K-2605 - 4373_7 ft X2200 - SN 05 sei.bmp
- 3- Blue Flame K-2605 - 4373_7 ft X600 - SN 05 sei.bmp
- 4- Blue Flame K-2605 - 4373_7 ft X600 - SN 05 bec.bmp
- 5- Blue Flame K-2605 - 4373_7 ft X700 - SN 05 bec.bmp
- 6- Blue Flame K-2605 - 4373_7 ft X2000 - SN 05 bec.bmp
- 7- Blue Flame K-2605 - 4373_7 ft X9000 - SN 05 sei.bmp
- 8- Blue Flame K-2605 - 4373_7 ft X1000 - SN 05 bec.bmp
- Thumbs.db

Blue Flame K-2605 SN 07 - 4612.7

- 1- Blue Flame K-2605 - 4612_7 ft X3000 - SN 07 bec.bmp
- 2- Blue Flame K-2605 - 4612_7 ft X3000 - SN 07 sei.bmp
- 3- Blue Flame K-2605 - 4612_7 ft X1000 - SN 07 sei.bmp
- 4- Blue Flame K-2605 - 4612_7 ft X1600 - SN 07 sei.bmp
- 5- Blue Flame K-2605 - 4612_7 ft X2000 - SN 07 sei.bmp
- 6- Blue Flame K-2605 - 4612_7 ft X2000 - SN 07 sei.bmp
- 7- Blue Flame K-2605 - 4612_7 ft X1700 - SN 07 sei.bmp
- 8- Blue Flame K-2605 - 4612_7 ft X1700 - SN 07 bec.bmp
- Thumbs.db

Thin Section

- 4398-10x-ppl.tif
- 4672-04x-ppl.tif
- 4672-04x-xn.jpg
- 4672-20x-ppl.tif
- 4672-40x-ppl.tif
- Blue Flame K-2605_SN1_4015ft_100x.jpg
- Blue Flame K-2605_SN1_4015ft_100x.tif
- Blue Flame K-2605_SN4_4348ft_100x.jpg
- Blue Flame K-2605_SN4_4348ft_100x.tif
- Blue Flame K-2605_SN4_4348ft_500x.tif
- Blue Flame K-2605_SN8_4672ft_100x.jpg
- Blue Flame K-2605_SN8_4672ft_100x.tif
- Blue Flame K-2605_SN8_4672ft_500x.tif
- Blue Flame K-2605_SN10_4796ft_25x.jpg
- Blue Flame K-2605_SN10_4796ft_25x.tif
- Blue Flame K-2605_SN10_4796ft_100x.jpg
- Blue Flame K-2605_SN10_4796ft_100x.tif
- Thumbs.db

Well Logs

- K2605 Blue Flame Shale_Montage_wCore_DCS.las
- K2605 Blue Flame Shale_Montage_wCore_Revised_DCS.lmu
- K2605 Blue Flame Shale_Montage_wCore_Revised_DCS.pds
- K2605 Blue Flame Shale_Montage_wCore_Revised_DCS.tif
- K2605_RUN1_MAIN_PASS_AIT_TLD_MCFL_CNL_014PUP.DLIS
- K2605_RUN1_MAIN_PASS_AIT_TLD_MCFL_CNL_014PUP.las
- K2605_RUN3_MAIN_PASS_ECS_024LUP.las
- K2605_RUN3_MAIN_PASS_ECS_024LUP_v2.DLIS
- aaa K2605 info.xls
- K2605 Blue Flame Petrology Report.pdf
- K2605 Blue Flame Rock EVAL TOC.xls
- K2605 Blue Flame Tight Rock Analysis.xls
- k2605 cross section.jpg
- K2605 RSCT-samples.pdf

Appendix 5: Interstate Fee SS-#1 Well Data

CO2 Pump

- 9-7-2012.pdf
- 9-10-2012.pdf
- SS-1_20120906_NABORS.xls
- SS-1_20120907_NABORS.xls
- SS-1_20120910_NABORS.xls

Gas Analyses

- CO2 as delivered.pdf
- GasAnalyses.xlsx

20111018

- 20111018 Sulpher Springs Gas Samples.pdf
- Isotech_Job16666.pdf
- SS-#1.pdf
- SS-#2.pdf
- SS-#4.pdf
- Thumbs.db

20120113

- SS#1.pdf
- SS#4.pdf

20120809

- 20120809 Crossrock BTU Samples.pdf

20121022

- SS-#1 Isotech.pdf
- SS-#1 Isotech.xls

Paraffins

- GC_HiTemp_G4120683.D__-_BH-61157.xlsx
- SARA_Crossrock Drilling SS-#1 Interstate Natural Gas_BH-61157_130110.xlsx

Permeability

- WellID_and_Tops.xls

Ashland Skaggs Johnson County

- Pages from ZielinskiEtAl_1980.xlsx

Blan Hancock County

- HH-43630 Shale Rock Properties Report.xlsx
- KGS Marvin Blan No. 1 5A Hg Inj HH-43630 11-25-09.xlsx
- KGS Marvin Blan No. 1 Threshold Pressure HH-43630 9-30-09.xlsx
- KGS No 1 Blan Rock Mech Report HH-43630.xlsx

Jude Martin County

- Interstate Jude No. 3 Core Data H-33385 6-8-05.pdf
- UK Jude No. 3 Hg Inj Combo H-33385 6-30-05.xlsx
- UK Jude No. 3 Hg Inj Sample 1 H-33385 6-30-05.xlsx
- UK Jude No. 3 Hg Inj Sample 2 H-33385 6-30-05.xlsx
- UK Jude No. 3 Hg Inj Sample 3 H-33385 6-30-05.xlsx
- UK Jude No. 3 Hg Inj Sample 4 H-33385 6-30-05.xlsx
- UK Jude No. 3 Hg Inj Sample 5 H-33385 6-30-05.xlsx

PT Records

- SS-1_21011095.xlsx
- SS-1_Hourly Orifice Meter 2012.xlsx
- SS-1A_21011173.xlsx
- SS-2_21011175.xlsx
- SS-4_21011080.xlsx
- WellheadPressureReadings.xlsx

Well Logs

Other

- R00124373_SS2.las
- R00124373_SS2.tif
- R00124683_SS3.las
- R00124683_SS3.tif
- R00130702_SS4.las
- R00130702_SS4.tif
- R00130798_SS7.las
- R00130798_SS7.tif

SS1

- aaa_listoflogs.txt
- CAFM0111_Interstate SS 1_Run 1_PBMS PT_1000to1700_V1_Combined_RST Baseline PT.pdf
- CAFM0111_Interstate SS 1_Run 1_PBMS PT_1000to1700_V1_Combined_RST Baseline PT.pds
- CAFM0111_Interstate SS 1_Run 1_RST Sigma_1000to1700_V1_Combined_V1.pdf
- CAFM0111_Interstate SS 1_Run 1_RST Sigma_1000to1700_V1_Combined_V1.pds
- CAFM0111_Interstate SS 1_Run 2_PFCS Spinner_1260to1675_Combined_PFCS_V1.pdf
- CAFM0111_Interstate SS 1_Run 2_PFCS Spinner_1260to1675_Combined_PFCS_V1.pds
- CAFM0111_Interstate SS 1_Run 2_PT Pass After Flow_1260to1675_Combined_PT_PostFlow.pdf
- CAFM0111_Interstate SS 1_Run 2_PT Pass After Flow_1260to1675_Combined_PT_PostFlow.pds
- CAFM0111_Interstate SS 1_Run 2_PT Pass before flow_1260to1675_Combined_PT_BeforeFlow.pdf
- CAFM0111_Interstate SS 1_Run 2_PT Pass before flow_1260to1675_Combined_PT_BeforeFlow.pds
- Crossrock_Interstate_SS1_PSP_PL_Interp_Final_Rpt_PTS_saa.pdf
- FCS_PSP_MergedUp_040PUC.las
- FCS_PSP_MergedUp_040PUC_spin.las
- Interstate SS 1_Run 1_PBMS PT Main_0to1700RST_PSP_063PUP-GenericV12.las
- Interstate SS 1_Run 1_RST Sigma Main_1000to1700_RST_PSP_011PUP-GenericV12.las
- Interstate SS 1_Run 1_RST Sigma Repeat_1000to1700_RST_PSP_012PUP-GenericV12.las
- Interstate SS 1_Run 2_PFCS Spinner 30Down_1260to1675FCS_PSP_047PUP-GenericV12.las
- Interstate SS 1_Run 2_PFCS Spinner 30UP_1260to1675_FCS_PSP_035PUP-GenericV12.las
- Interstate SS 1_Run 2_PFCS Spinner 60Down_1260to1675FCS_PSP_048PUP-GenericV12.las
- Interstate SS 1_Run 2_PFCS Spinner 60UP_1260to1675FCS_PSP_036PUP-GenericV12.las
- Interstate SS 1_Run 2_PFCS Spinner 90Down_1260to1675FCS_PSP_049PUP-GenericV12.las
- Interstate SS 1_Run 2_PFCS Spinner 90UP_1260to1675FCS_PSP_037PUP-GenericV12.las
- Interstate SS 1_Run 2_PFCS Spinner 120Down_1260to1675FCS_PSP_050PUP-GenericV12.las
- Interstate SS 1_Run 2_PFCS Spinner 120UP_1260to1675FCS_PSP_038PUP-GenericV12.las
- Interstate_SS_1_ELAN_runs1-2_10-30-2012.pdf

- R00124374_SS1_CLPR.pdf
- R00124374_SS1_CLPR_report.pdf
- R00124374_SS1_ELAN_20120214.pdf
- R00124374_SS1_ELAN_20130410.las
- R00124374_SS1_ELAN_20130410.pdf
- R00124374_SS1_ELAN_20130410-2.las
- R00124374_SS1_OpenHole.las
- R00124374_SS1_OpenHole.tif
- R00124374_SS1_RST_20111026.pds
- R00124374_SS1_RST_20111026.tif
- R00124374_SS1_SPINNER_20111027.pds
- R00124374_SS1_SPINNER_20111027.tif
- R00124374_SS1_SPINNER_20111027_MergedDown.las
- R00124374_SS1_SPINNER_20111027_MergedUp_GR.las
- R00124374_SS1_SPINNER_20111027_MergedUp_Spin.las
- RST_PSP_Sigma_Main_031PUC.las FCS_PSP_30Down_033PDC.DLIS

DLIS

- FCS_PSP_30Up_034PUC.DLIS
- FCS_PSP_60Down_035PDC.DLIS
- FCS_PSP_60Up_036PUC.DLIS
- FCS_PSP_90Down_037PDC.DLIS
- FCS_PSP_90Up_038PUC.DLIS
- FCS_PSP_MergedDown_039PUC.DLIS
- FCS_PSP_MergedUp_040PUC.DLIS
- FCS_PSP_Station_1120ft_047PTC.DLIS
- FCS_PSP_Station_1138ft_046PTC.DLIS
- FCS_PSP_Station_1198ft_044PTC.DLIS
- FCS_PSP_Station_1269ft_043PTC.DLIS
- FCS_PSP_Station_1308ft_041PTC.DLIS
- FCS_PSP_Station_1320ft_042PTC.DLIS
- RST_PSP_IC_Pass1_028PUC.DLIS
- RST_PSP_IC_Pass2_030PUC.DLIS
- RST_PSP_Sigma_Main_031PUC.DLIS
- RST_PSP_Sigma_Repeat_032PUC.DLIS

PDS

- PSP_station_1198ft_055.pds
- PSP_station_1308ft_052.pds
- PSP_station_1320ft_053.pds