Scoping Outline for Testing Enhanced Gas Recovery (EGR) from the Devonian Black Shales of Kentucky using CO_2 Injection

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Purpose:

This document is intended to provide a framework for a project designed to test the concept of using injected CO_2 to enhance natural gas production from the black, organic-rich Devonian Ohio Shale in eastern Kentucky. The Ohio Shale of the Appalachian Basin and its equivalents, the Chattanooga Shale (south east Kentucky, Cincinnati Arch) and New Albany Shale (Illinois Basin), represent a continuous, low permeability gas reservoir and underlie about two-thirds of Kentucky. While not productive everywhere it occurs, natural gas has been produced from the shale in the Big Sandy Gas Field area of eastern Kentucky since the late 1800's and the shale remains Kentucky's most prolific natural gas resource. Research at the Kentucky Geological Survey has demonstrated that CO_2 is preferentially adsorbed onto the organic matter in these shales. CO_2 injection for enhanced gas recovery has been demonstrated in the Fruitland Coals of the San Juan Basin, New Mexico which lends credibility to the concept.

Gas production in the low permeability shale is long-lived with some wells producing for at least 50 years with a total gas volume exceeding 1 billion cubic feet (bcf) (Figure 1). Shale wells are designed and drilled to maximize communication of the well bore with the natural fracture system. The wells are often completed by isolating the more organic-rich zones in the shale and using foamed nitrogen injected under pressure to induce fracturing and increase the likelihood of intersecting the natural fractures; a sand proppant is used to maintain an open fracture system. The production history of a shale well shows three general phases (Figure 2) and is usually described by a hyperbolic decline model. The first phase is characterized by a rapidly declining production rate as free gas from the natural fracture system is produced. As reservoir pressure drops, gas adsorbed on the fracture faces desorbs and is produced. Finally, desorption and diffusion of gas through the shale matrix into the fracture system provides a long period of relatively stable, but relatively low, rate of production.

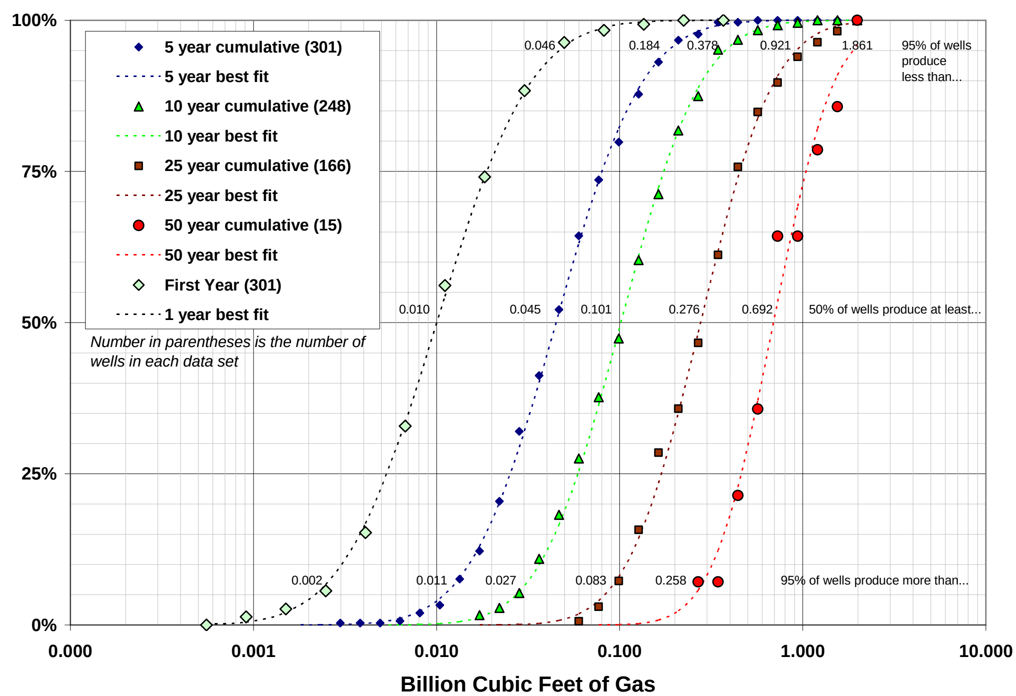

Figure 1. Devonian Shale gas cumulative production.

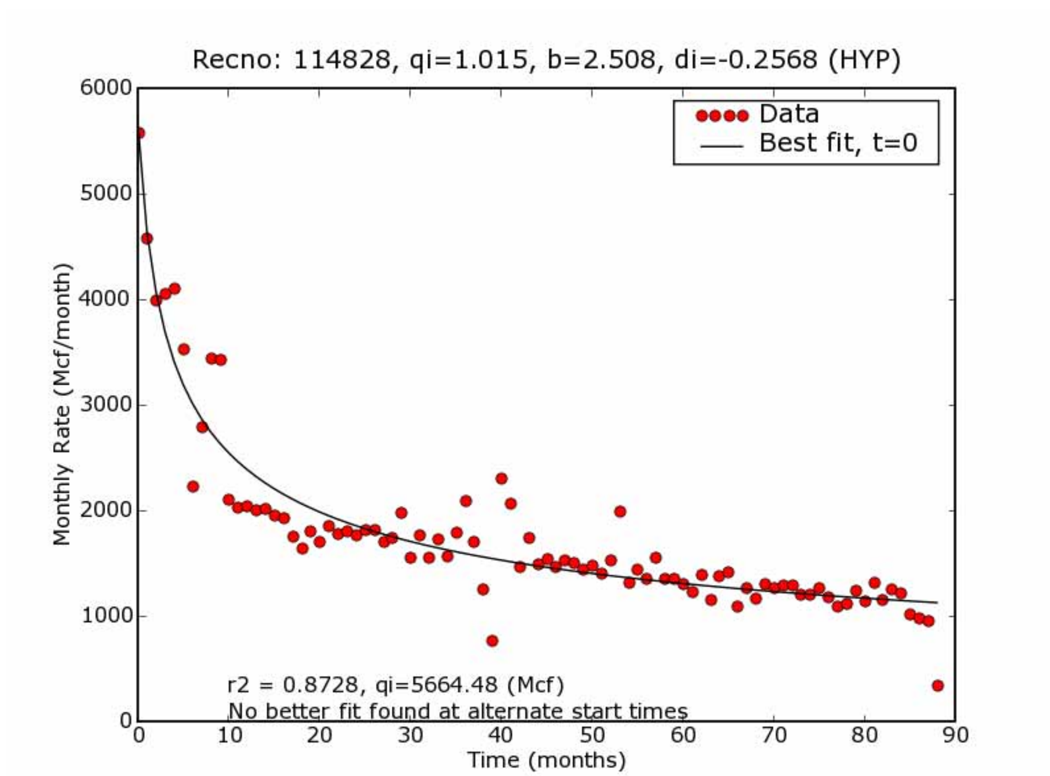

Figure 2. Devonian Shale production curve exhibiting hyperbolic decline.

Objectives:

- Test enhanced gas recovery in the Devonian black shale of Kentucky
- Test enhanced gas recovery in areas that make practical sense (in or near areas of existing gas production)
- Extend the current knowledge base with data and modeling
- Find answers:
  - Can you inject CO_2 into the shale?
  - Can that injection result in enhanced gas recovery?

Task 1: Planning and Modeling

Reservoir modeling and simulated injection should be investigated to better understand and predict the process of CO_2 injection into shales. The Comet 3 software from Advanced Resources International is a multi-porosity, multi-permeability, multi-component simulator for investigation of fractured reservoirs. Insights gained from these simulations can be used to refine the design of injection tests.

Two injection scenarios present opportunities for testing and each should be modeled. Both scenarios will require a pilot injection well and access to up to 4 surrounding wells for monitoring. Modeling may indicate a preferred scenario and can provide information on such details as volume of CO_2 to be injected, time-span of experiment for effective assessment, number of injection cycles, and others.

- Huff-n-Puff: This is a cyclic injection process using a single well for both injection and production. A quantity of CO_2 would be injected and maintained under some pressure between the current shut-in pressure and the maximum breakdown pressure of the shale. After the soak period, the well would be opened for production and assessment.

- CO_2 flood: Continuous injection of CO_2 over time into one well may displace natural gas toward surrounding wells, especially those wells that offset the injector in the direction of the major regional natural fracture system. It is particularly important to test this scenario with respect to sequestration of the continuous emissions from coal to liquids and coal gasification facilities.

Regardless of scenario, immediate surrounding wells will require monitoring for potential increases in gas production, pressures, or compositional changes.

Public outreach should include the affected County's Judge Executive, local newspapers, and the local community.

Timing: It will likely require 6 months to one year to accomplish the suggested modeling.

Task 2: Background Data Acquisition

For assessment of any injection test, preliminary data must be acquired. Once access to wells is obtained, pilot-scale, project specific data will be used to further refine the modeling and predict project performance. Some of the data needs listed are inconsistent with testing many existing wells: cores and certain logs can't be acquired in cased holes.

- Detailed data for the proposed injection well and immediate surrounding wells

- Full core (preferred) or rotary sidewall cores through the shale sequence in the injection well for CH_4 and CO_2 adsorption isotherms, bulk and clay mineralogy, total organic carbon content, and direct measurement of porosity and permeability.
- Digital log suite in LAS and tiff image formats (GR, RHOB, DPHI, NPHI, PE, temperature, caliper, density correction, array induction, gas entry detection, etc.). Data need to be sufficient to identify changes in shale mineralogy (particularly TOC) and qualitatively assess natural fracturing. A fracture identification and other advanced shale modeling logs (ECS) should be available or acquired as part of this research effort. Crosswell tomography could be acquired to better characterize reservoir properties that might change over time with injection and distance between wells.
- Stimulation data: perforations, injection volumes, rates, injection pressures, breakdown pressures, flowback and cleanup, etc. Microseismic data collection for modeling induced fracture propagation and geometry.
- Production data: at least monthly production rate data (due to time constraints, daily production rate data is preferred); operational details affecting production (curtailments, shut-in, recompletions, etc), pressure data (line pressure, flowing pressure, shut-in pressures, etc)
- Gas analyses: It will be important to establish the gas composition and whether that composition is naturally changing over time. If the gas contains CO_2, isotopic analyses will be required to accomplish differentiation of natural CO_2 and injected CO_2.
- MMV: Methane and CO_2 must be monitored at the surface for leak detection. Gas chemistry and seasonal fluxes, including isotopic composition, should be monitored at the soil surface and shallow subsurface (up to 10 meter depths). It is likely this task will serve only to establish background seasonal fluxes due to the small volumes of CO_2 and short duration of the tests.

- A CO_2 source must be identified that can supply the required quantity of CO_2. For a huff-n-puff test, the quantity is expected to be relatively smaller (certainly under 1,000 tons) than the quantity required for continuous injection.

NB: for a pilot test in low-permeability shales, it is not expected that a surface reflection seismic survey would be required. Sufficient well control exists to adequately characterize the stratigraphy of the shale. Injecting CO_2 into the shale is not expected to create a sufficient velocity contrast to enable 4D seismic assessment of plume volume or migration.

Timing: It will likely require at one year to 18 months identify candidate wells, acquire and analyze logs and samples, refine the injection project simulation, and acquire pre-injection background data (soil gas flux, gas production and analyses, etc.).

Task 3: Injection and Monitoring

- MMV will continue throughout the performance period of the project. Consideration should be given to continue MMV for some time period after injection ceases.
- Collect injection volume, rate, and pressure data.
- At least 1 monitoring well should be equipped with a vertical seismic array for monitoring microseismic events associated with injection.
- Production data: daily production rate data and operational details affecting production (curtailments, shut-in, recompletions, etc), pressure data (line pressure, flowing pressure, shut-in pressures, etc).
- Produced gas analyses. Gas composition and isotopic analyses are required to monitor changes over time with respect to CO_2. For the huff-n-puff case, this analysis should be done at high frequency during the initial flowback/cleanup period to determine a CO_2 “mass balance” (injected volume vs produced volume).

Timing: It will require at least one year for injection, data collection, analysis, and final report preparation. A longer-term continuing effort may be required to track detailed gas production over time to establish benefit of CO_2 injection.

Candidate well(s) selection criteria:

- Be uncased through the Devonian Shale section for logging and sample acquisition
- Be completed using prevailing nitrogen/foam or slickwater fracturing with a sand proppant (i.e., normal shale completion)
- Have a standard suite of open-hole nuclear logs (digitial log data, LAS, preferred)
- Be available for re-entry for sidewall coring and addition log acquisition
- Have a detailed record of gas production
- Be accessible for gas sampling
- Have a location with sufficient size to potentially support CO_2 storage tanks, pumping units, analytical equipment, etc
- Be accessible for CO_2 delivery (route, road surface, and grade must likely meet conditions established by the company supplying CO_2, no low underpasses, weight-limited bridges, low-water fords, and others)
- Be operated by a company willing to put the future production of the research-related wells at risk.
- Legal control of and access to all wells within the “area of review” as established by the U.S. EPA (UIC primacy) for monitoring and Class II or Class V permitting as required.

Notes:

- A publicity and public outreach program needs to be active during the project.

- DOE National Labs (Los Alamos or Sandia) may be interested in participating in the microseismic data acquisition and analysis.
- Data of interest that suggest this project is likely to succeed are published in:
    - Yost II, A. B., R. L. Mazza, and J. B. Gehr, 1993, *CO2/Sand Fracturing in Devonian Shales*: Journal of Petroleum Technology (SPE paper 26925)
    - Nuttall, B. C., J. A. Drahovzal, C. F. Eble, and R. M. Bustin, 2006, *Analysis of the Devonian Black Shale in Kentucky for Potential Carbon Dioxide Sequestration and Enhanced Natural Gas Production*, Final Report: Kentucky Geological Survey, Web page http://www.uky.edu/KGS/emsweb/devsh/final_report.pdf.
- Liability issues (other than long-term fate of injected CO_2)
    - If the oil and gas estate or surface are not owned in fee, operator must provide legal assurances of right of access from surface owner and agreement by all royalty and working interest owners.
    - Operator should assume liability for loss of future gas production as a direct consequence of CO_2 injection (the project might not work and the well may be lost after the experiment). Project will likely have to pay for tool insurance (logging equipment).