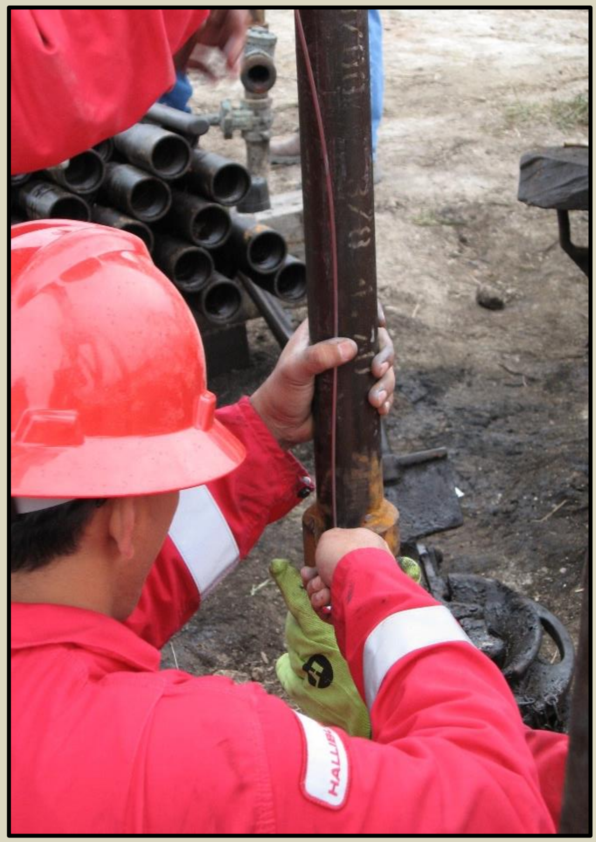
Guidelines for Designing Small-Scale Carbon Dioxide Enhanced Oil Recovery and Storage Pilot Projects

Scott M. Frailey and Charles C. Monson

Illinois State Geological Survey, Prairie Research Institute, University of Illinois at Urbana-Champaign, Champaign, Illinois



Circular 608 **2021**

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Front cover: *(Top left)* CO_2 *pump skid; (Bottom left) Tank battery at Mumford Hills Field, including tanks and pump house; (Right) Downhole sensor transmissions lines attached to injection tubing.*

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ILLINOIS STATE GEOLOGICAL SURVEY
Prairie Research Institute
University of Illinois at Urbana-Champaign
615 E. Peabody Drive
Champaign, Illinois 61820-6918
http://www.isgs.illinois.edu

Suggested citation:
Frailey, S., and C. Monson, 2021, Guidelines for designing small-scale carbon dioxide enhanced oil recovery and storage pilot projects: Illinois State Geological Survey, Circular 608, 22 p.

CONTENTS

ABSTRACT

Commercial-scale enhanced oil recovery (EOR) pilots are designed for a few years of operation, with a relatively large volume of CO_2 injected into several wells or patterns. The objective is to have direct field measurements of CO_2 EOR and net/gross utilization and storage. Conversely, smaller, publicly funded, research-focused pilots target the collection of reservoir and production information over a shorter period on a limited budget and must rely on making CO_2 EOR and storage estimates based on calibrated model projections. Moreover, many small-scale pilots are conducted where no infrastructure exists for CO_2 delivery or injection via pipeline, leaving these pilots with a different set of operational requirements than a commercial project in a traditional CO_2 EOR geographical area, such as West Texas. The Midwest Geological Sequestration Consortium (MGSC) conducted four small-scale CO_2 storage pilot projects—three EOR and one enhanced coal bed methane (ECBM)—in the Illinois Basin. From these projects, guidelines were developed for site screening, selecting, and designing a CO_2 storage research pilot that uses truck-delivered CO_2, beginning with site selection and proceeding to the point of pilot start-up. The MGSC CO_2 EOR pilots involved adapting developed sites at mature oil fields to the needs of a CO_2 EOR project by installing portable CO_2 injection and production equipment at the site. Geologic and reservoir modeling was conducted for all selected sites by using existing data to predict CO_2 EOR and storage and the behavior of injected and in situ gas, oil, and CO_2. Additionally, proper preparation ensured an effective monitoring, verification, and accounting program, which made it possible to safeguard the environmental health of the site and track the fate of the injected CO_2. Although the research pilot guidelines in this paper are based on the MGSC CO_2 EOR and ECBM pilots, these guidelines are also applicable to CO_2 injection into brine-saturated formations.

INTRODUCTION

Several CO_2 storage pilot projects are in progress or have been completed in the United States (NETL 2012) and internationally, and widespread interest exists in starting additional projects around the globe. Small-scale, publicly funded research pilots, such as those related to enhanced oil recovery (EOR) or enhanced coal bed methane (ECBM), differ from commercial-scale, privately funded projects primarily in their objectives and approach. Both types of pilots typically seek to secure data that can be used to calibrate models. However, commercial-scale projects are generally carried out by organizations that have the economic resources to inject at multiple sites over multiple years, and their ultimate goal is to facilitate successful, cost-effective implementation of a full-field project by reducing risk via field characterization learned from commercial pilots. Research pilots, in contrast, are intended to gather reservoir and operational information over a short injection period on a limited budget, with the objective of securing data that can be used as “proof of concept.” Moreover, research pilots act as a gauge to predict the potential for commercial-scale carbon dioxide (CO_2) storage in regions where no such infrastructure exists; thus, a subsequent full-field implementation is not necessarily a project objective.

Another significant difference is that commercial-scale operations are owned by the private sector or overseen by a specific government agency in countries with national oil companies. Pilots carried out by an owner or operator require no other partnerships. However, publicly funded storage projects require partnering with the private sector or a different government agency, which will not have all the same goals and priorities. The relationship between project management and oilfield management is the most important consideration when designing and implementing small-scale, publicly funded CO_2 injection pilots.

Considerable documentation exists on design and management strategies for commercial CO_2 injection projects (e.g., CO_2 EOR, Jarrell et al. 2002), but very little published literature focuses on the special management requirements and design challenges of research pilots. Teletzke et al. (2010) provided an excellent overview of best practices for commercial EOR pilots, based on experience from more than 50 ExxonMobil projects. These pilots encompassed a range of EOR processes, from CO_2 to surfactants and steam drives, divided into four primary project types: (1) nonproducing, (2) small-scale unconfined, (3) small-scale confined, and (4) multipattern producing. Many of the broader recommendations outlined by Teletzke et al. (2010) are valid for small research pilots like those described here. In particular, Teletzke et al.’s discussion of pilot objectives, considerations for successful design, and interpretation of results are recommended for anyone planning an EOR research pilot, as is their detailed breakdown of the pros and cons of specific pilot design choices (confined vs. unconfined, observation well placement, etc.). However, the breadth of their discussion and their focus on commercial application leaves finescale planning considerations for CO_2 storage research pilots unaddressed.

Hill et al. (2013) provided some discussion of CO_2 EOR pilot concerns, such as wellbore integrity and injectivity, in the context of a high-level summary of the historical background, execution, and potential of CO_2 storage through EOR. Hill et al. included granular recommendations regarding risk management steps (including proper field characterization techniques) and monitoring activities. Documentation relating to the Citronelle carbon capture, CO_2 EOR, and geologic storage project in Alabama (Esposito et al. 2010; Koperna et al. 2013) includes some detailed discussion of pilot design choices, but in the context of a specific project that is larger and more complex than a typical research pilot. General information and recommendations on research pilot design (i.e., all planning up to but not including commencement of CO_2 injection) based on multiple pilot experiences are largely absent from the literature, and this circular seeks to fill that gap.

The present publication is based on experience accrued during four CO_2 storage pilot projects completed by the Midwest Geological Sequestration Consortium (MGSC) in the Illinois Basin (ILB). These pilots were short-duration projects (one week to one year of active CO_2 injection, followed by one year of monitoring) designed to determine the CO_2 injection rates, storage, and ECBM or EOR potential of oil fields or coal seams in the ILB. All projects used CO_2 delivered by tanker truck. Three EOR pilots were carried out: (1) a “huff ‘n’ puff,” or CO_2 injection into the tubing–casing annulus of an oil-producing well (MGSC 2009); (2) a miscible pattern flood (Frailey et al. 2012a); and (3) an immiscible area flood (Frailey et al. 2012c). One ECBM project was also completed (Frailey et al. 2012b). These projects offer a framework for the design and operation of prospective pilots of similar scale. This publication focuses on recommendations for three stages of pilot project development: site screening, selection, and design generalized from these four projects.; Individual project reports (MGSC 2009; Frailey et al. 2012a, b, c) should be referenced for further planning and operational details, as well as for information on operational lessons learned over the course of the pilots. Although this manuscript focuses on EOR pilots, most of the recommendations are applicable to ECBM and storage in brine-saturated geologic formations.

The use of the terms *pilot site screening, selection,* and *design* are not universal and, arguably, may overlap during the process of maturing a site to active pilot injection. In this publication, site screening describes the process of starting with a large number of sites (which could be specific wells in an oilfield or different oilfields) or a region reduced to a smaller subset (which could be one). However, if pilot site screening results in a single site, then the process of site screening and selection have overlapped. There are some criteria unique to each project development stage, but many criteria are applicable to all three stages. Use of data and advanced analysis methods (e.g., reservoir simulation) may be more manageable with fewer sites than the initial stage of screening.

OVERVIEW OF MIDWEST GEOLOGICAL SEQUESTRATION CONSORTIUM CARBON DIOXIDE ENHANCED OIL RECOVERY PILOTS

The majority of oil production in the ILB is from Mississippian and Pennsylvanian siliciclastic reservoirs, although various carbonate reservoirs also produce oil. The Basin has been dominated by waterflooding for decades but currently lacks a CO_2 EOR infrastructure, has no known naturally occurring CO_2 sources, and has few available commercial sources of CO_2 (MGSC 2005). Oil cuts at mature oilfields vary, but a 1 to 3% oil cut is common with water production making up the balance. The active oil fields have wells that have been abandoned, shut-in, or permitted for uses other than CO_2 injection.

For site selection of the MGSC CO_2 EOR pilots, existing oil field choices were relatively abundant. With little to no coal bed methane (CBM) production and no ECBM in the ILB, site selection was more difficult for the ECBM pilot. For this reason, it was difficult to find an operator interested in CBM or ECBM gas production. The following four sites were chosen (Figure 1):

1. *Huff ‘n’ puff*: Loudon Field in Fayette County, Illinois, Cypress Sandstone (Mississippian System, Chesterian Series) reservoir (MGSC 2009);
2. *Miscible flood*: Bald Unit in the Mumford Hills Field in Posey County, Indiana, Clore Formation (Chesterian) reservoir (Frailey et al. 2012a);
3. *Immiscible flood*: Sugar Creek Field in Hopkins County, Kentucky, Jackson Sandstone (Chesterian) reservoir (Frailey et al. 2012c);
4. *ECBM*: Tanquary Farms site, Wabash County, Illinois, Springfield Coal Member (Pennsylvanian System, Carbondale Formation) target seam (Frailey et al. 2012b).

The primary difference among the three EORs was the anticipated miscibility type of each (i.e., miscible or immiscible), which was based on the current (i.e., at the time of the pilot) reservoir pressure and temperature. Except where explicitly stated, the design elements described in this publication are based on the three CO_2 EOR pilots.

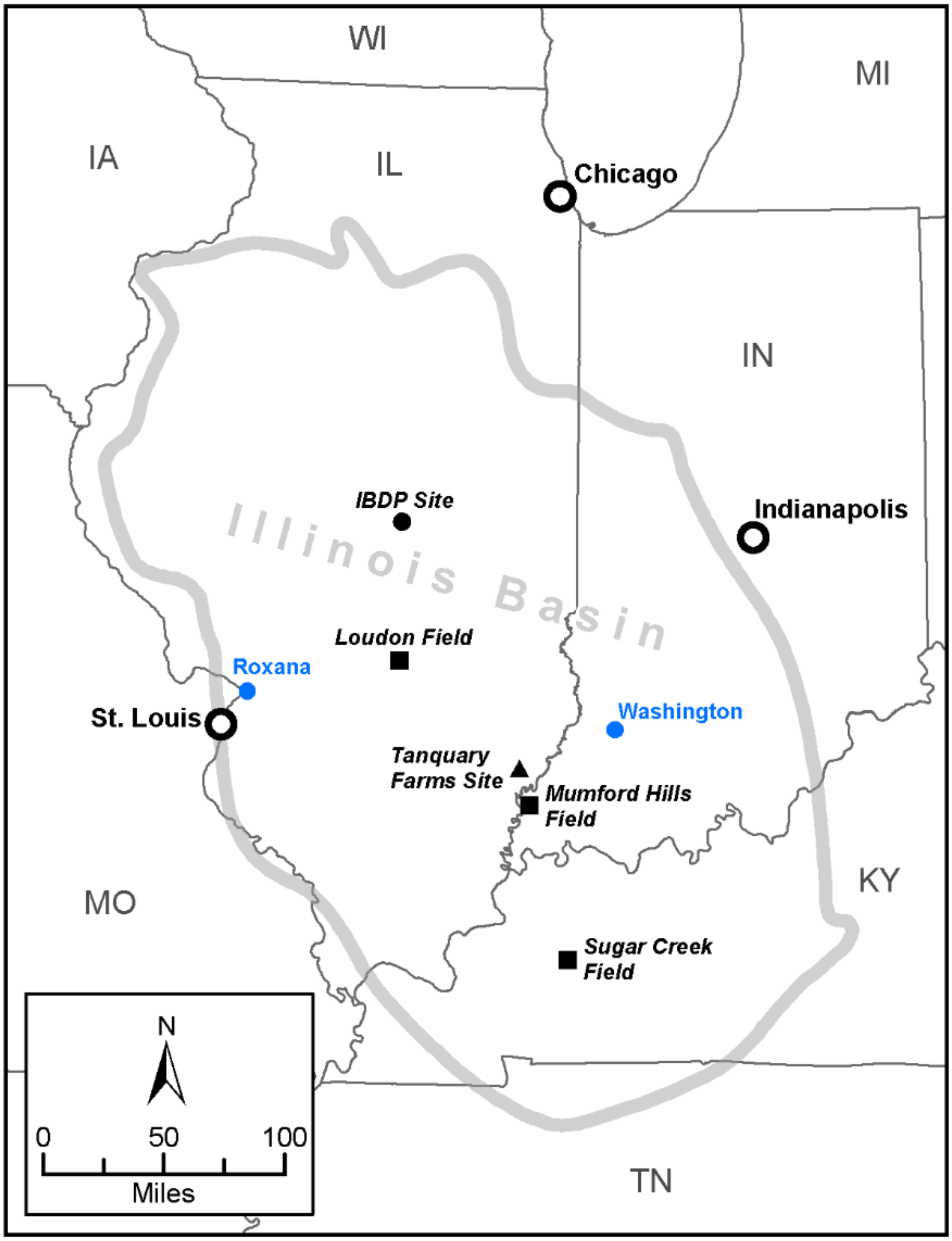

Figure 1 Map of the Illinois Basin (outlined in gray), with locations of the Tanquary Farms ECBM pilot site (black triangle), Loudon Field huff 'n' puff, Mumford Hills miscible CO_2 EOR pilot, and the Sugar Creek immiscible CO_2 EOR pilot (black squares). Two CO_2 processing plants at Roxana, Illinois and Washington, Indiana (blue circles), which Air Liquide owned at the time of the pilots, provided the CO_2. The Illinois Basin–Decatur Project (IBDP, black circle), a large-scale demonstration project, is also noted. Image credit: Christopher Korose, Illinois State Geological Survey.

PLANNING AND SCHEDULING

The planning process for a small-scale CO_2 injection pilot begins at least several months to more than a year before on-site operations commence. The long duration of the preplanning stage is dictated by the necessity of drilling new wells and collecting pre-CO_2-injection baseline data. The objective is to create an operational plan that integrates the pilot goals with the logistical requirements at the selected sites, the budget, and project deadlines.

The pilot plan helps identify the expertise required and define the functions of the pilot team, which will likely be as follows:

- Project management
- Reservoir engineering and modeling
- Geology
- Monitoring, verification, and accounting (MVA; geochemistry, petrophysics, seismology)
- Pilot coordination and logistics
- Field supervision
- Data acquisition
- Data management

The following general support personnel are required at various stages during which the injection equipment and data acquisition electronics are deployed:

- Electrician
- Backhoe operator
- General oilfield labor (roustabouts, pumpers, production foreman)
- Well service provider (pulling units, workover units, wireline, pumping)
- Data acquisition (electronics) technician
- CO_2 plant supervisor, truck drivers, and dispatchers

The result of a successful planning process is a dynamic and flexible schedule for each part of the pilot. The schedule needs to be adaptable to real-time changes, including well-thought-out contingencies for those tasks that may cause significant start-up delays or budget overruns. Depending on the project specifics, a formal risk management assessment may be beneficial.

A single-well pilot with a few surrounding injection zone monitoring wells involving less than 100 tons of CO_2 injected over a week will require up to 6 months from start to finish of on-site operations (i.e., from the first equipment installation to reclamation of the site). Small-scale pilots with less than 10,000 tons of planned injection that involve several injection zone production or monitoring wells, or both, will likely take up to 2 to 3 years. Appendix 1 presents an example schedule based on the MGSC pilots.

Background site monitoring to establish baselines for the MVA program should begin early to ensure adequate characterization. An inherent conflict exists between interests in collecting pre-CO_2 injection baseline data and the urgency to begin CO_2 injection to meet funding agency deadlines and budgets; therefore, it is important to consider that baseline characterization can be expansive and cannot be completed in only a few weeks. For example, groundwater chemistry parameters may fluctuate seasonally because of variations in precipitation quantities, recharge, and anthropogenic disturbances other than CO_2, and variations in oilfield operations can alter the reservoir brine chemistry. Because of the site-specific nature of the MVA techniques deployed and the unique variation of baseline data for each technique, this publication does not suggest an explicit MVA baseline time period, but the pilot design should consider seasonal and temporal variations in measured parameters when selecting the duration of the preinjection period of baseline monitoring (several months, ideally). To estimate CO_2 EOR, a clear and established oil production baseline is necessary so that the oil production incremental to the baseline projection can be clearly demonstrated and attributed to CO_2 injection (i.e., the CO_2 EOR). This can be particularly difficult if other well activity (e.g., pumping a shut-in well, well stimulation) increases oil production before CO_2 injection. (The increase in oil production attributable to the project but not to CO_2 injection may be referred to as “improved oil recovery.”)

In the United States, to comply with the National Environmental Policy Act, research pilots funded by the federal government are required to submit Environmental Questionnaires detailing the potential environmental effects of planned project operations. Some projects may be allowed to proceed without further review based on the strength of the initial Environmental Questionnaire, but others may require significant additional work and changes to the operational plan. Consequently, the Environmental Questionnaire should be submitted as early as possible in the planning process.

SITE SCREENING AND SELECTION

The oilfield owner or operator is the most important participant in site screening and selection for publicly funded small-scale pilots requiring a partner or subcontractor. Discussions with the operator can provide insight into the most appropriate, cost-effective equipment and techniques. Having the operator participate directly will result in having the support staff and third-party relationships necessary to provide oilfield services and supplies, which can decrease the risk of long periods of noninjection and overall delays of any kind. Moreover, open communication with the land- and homeowners during preinjection allows concerns about environmental impacts to be addressed early on and prevents later interruptions in the injection schedule. Good relations with township, city, and county officials build the foundation for these relationships. Selecting an owner or operator that has good standing in the community and a good reputation is paramount to the success of a pilot. Any or all of these characteristics of operators can be used as screening criteria.

The first step in site screening is soliciting operators to nominate geologic formations within oil fields for consideration. Finding fully committed operators or owners is a necessity; this process involves addressing their technical concerns and, assuming positive results are obtained, their financial capability to expand the pilot to parts or the entirety of their fields. (In an area such as the ILB, where CO_2 EOR has not been carried out on a large scale, it may be necessary to overcome negative preconceptions about the workability of such operations in the area (Frailey et al. 2013). For the MGSC CO_2 EOR projects, ILB owners or operators nominated more than 40 sites. Given the specific objectives of an individual pilot and the importance of the owner or operator, the list of candidate sites solicited may include screening criteria, such as for a specific geologic formation, previously permitted water injection, and oil reservoirs without brine aquifers (to avoid losing CO_2 to the aquifer). In the case of the MGSC pilots, nominated fields were screened to those producing from one of the three most prolific oil-producing formations (or geologically analogous formations). Once sites that did not fit the criterion for a specific pilot were removed from consideration, a tiered selection process was used to select the most suitable sites among the remaining nominees. The MGSC tiers (Figure 2) were CO_2 flood classification, operation and development history, surface conditions, wellbore conditions, and geologic and reservoir modeling.

Because the permitting process is well established for injection wells in areas with historical oil production, the application process and permit criteria were not directly considered in the screening or selection processes. This could be significantly different in other areas, especially for pilots with CO_2 injection into brine-saturated geologic formations.

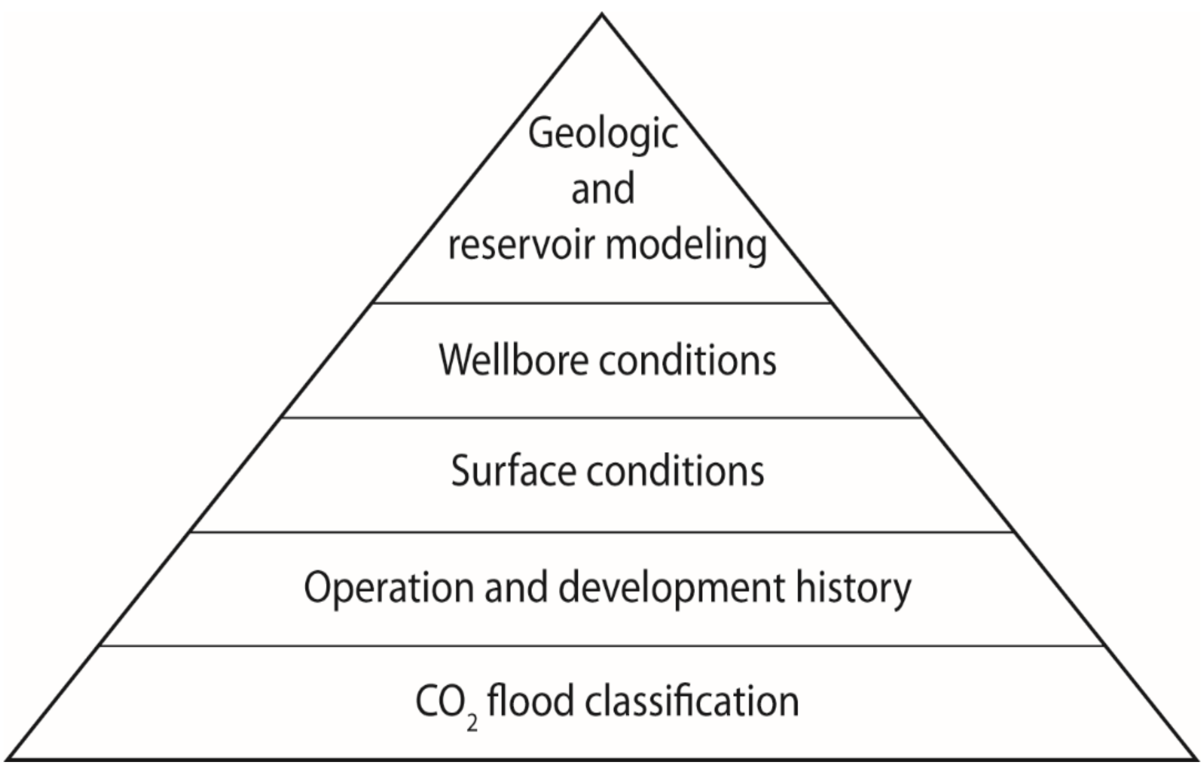

Figure 2 This pyramid represents the five tiers used to select pilot sites. The pilot selection process begins at the base of this pyramid by classifying which type of CO_2 flood will be used and ends with the results of geologic and reservoir modeling of the reservoir at the top of the pyramid (Frailey and Finley 2008).

Carbon Dioxide Flood Classification and Geologic Considerations

The first tier for site selection is CO_2 Flood Classification. The projected CO_2–crude oil interaction in the chosen reservoir at each site is classified as immiscible gas or miscible liquid based on reservoir pressure and temperature in relation to the pressure–temperature diagram of pure CO_2 (Figure 3). Selection is based primarily on the current reservoir pressure and temperature, API gravity (Taber et al. 1996), and geologic formation. Uncertain miscibility classifications should be avoided for purposes of pilot selection. For a project with a relatively low amount of budgeted CO_2, the formation pressure cannot be too low, or in situ energy will be inadequate to permit CO_2 dissolution in the oil. In other words, very low-pressure oil reservoirs (<250 psia; <1.72 MPa) would require a relatively large volume of CO_2 to enhance oil recovery and would likely be deemed a failure, but only because of poor planning. In the case of the MGSC huff ‘n’ puff test (MGSC 2009), the range was 300–700 psia (2.07–4.83 MPa). This pressure range can limit options for certain geologic formations (Figure 3).

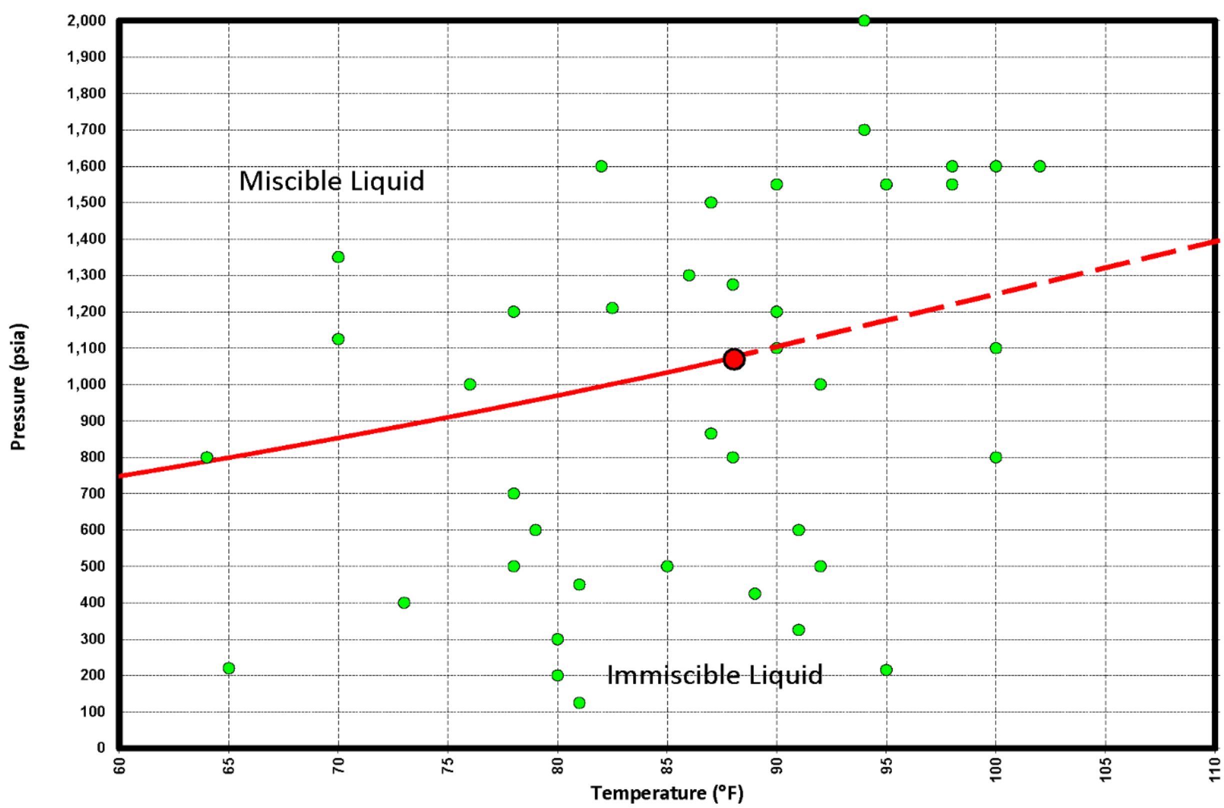

Figure 3 Current pressure and temperature of reservoirs (green circles) nominated for MGSC pilot projects. The red line is the vapor pressure line of pure CO_2, which terminates to the right at the critical point (modified from Frailey et al. 2004). The red dashed line is the pressure and temperature that yields a CO_2 density equal to the critical density.

Operation and Development History

The Operation and Development History is the second tier and includes the number of geologic formations open to the injector. Ideally, a single injection well will be centrally located and surrounded by four producing wells. Additionally, the oil, water, or gas production at the surrounding wells should be factored into the seletion process. The surface injection pressure and water injection rate (barrels of water per day, bwpd) should be considered in this tier as well. A small-scale test must be designed to directly record adequate data from field production that can be attributed to CO_2 and calibrated to a model for forecasting CO_2 EOR and storage. Consequently, knowing the average daily volume and magnitude of the daily fluctuations of fluid production in the surrounding wells is important to understand the magnitude of CO_2 EOR required. This information is needed to clearly identify the additional oil production as being EOR and not random or resulting from some other process (e.g., preinjection well stimulation).

Consideration should be given to the wells surrounding the five wells making up the injection pilot. These wells may determine how much of the injected CO_2 stays within the pilot area, and they can be used to infer the CO_2 EOR response from the four producing wells. In the case of a miscible CO_2 EOR, the surrounding wells will need to be water injection wells so that reservoir pressure is maintained at the miscibility pressure. Instrumentation and monitoring of these surrounding wells should be included in the pilot so that the presence of any CO_2 moving out of the immediate area of the pilot can be measured and properly accounted for in the storage and EOR estimates from the four producing wells.

Surface Conditions

The surface conditions of the nominated pilots constitute the third selection tier. The area surrounding the injector needs to be suitable for injection equipment and regular CO_2 tanker truck delivery. Depending on the project, year-round CO_2 delivery may be required. Surface features, such as lakes, ponds, floodplains, homes, and major roads, should be considered; specifically, sites on floodplains or those located too close to houses and bodies of water should be rejected. Road conditions are a major concern for sites with no pipeline infrastructure because the delivery of CO_2 depends on the ability of CO_2 tanker trucks to use local roads daily. Road access may dictate the placement of injection equipment by the tank batteries—rather than near the injection well—if the lease roads leading to the injection well are not rated for tanker truck traffic (i.e., oil tanker truck). Each of the MGSC projects had significant unplanned hiatuses in CO_2 injection or a considerable impact on pilot design because of winter road restrictions or public versus private road access and weather conditions. Direct communication with the county and township road commissioners is necessary to avoid or mitigate these issues.

Wellbore Conditions

The fourth tier consists of the depths of multiple geologic formations open in the injection well and the ability to isolate formations within the wellbore. Type of completion—cased and perforated or open-hole—is important. Surveillance of productivity and injectivity from wells completed in a single zone or isolated to a single zone is more certain than commingled production and injection from multiple zones, so fields producing from a single zone should be favored. These were ultimately chosen for all three MGSC EOR pilots. Additionally, the amount of CO_2 injected needs to be significantly larger for a multiple-zone oil field with wells completed in all zones; failure to consider the number of zones can adversely affect the budget and project goals.

The injection pressure history over the most recent few months should be reviewed to determine whether the desired miscibility type can be maintained during the planned life of the pilot. Knowing the present and historical conditions of the wells is critical; the workover type and frequency, sizes of casing, and sizes of any casing liners (for consideration in the placement of an injection-tubing packer) are indications of the likelihood of interruptions and downtime during the pilot. Wells that have been plugged and abandoned can still be considered for repurposing as either injectors or producers as long as they have had no previous reports of problems (e.g., major casing leaks) and the casing condition, diameter, type of lining, and packer location are suitable for the desired test. Later in the project, when wells are being prepared for injection, it may be desirable to run pressure-transient tests to gain further information on near-wellbore characteristics (skin) as well as information on intrawell connectivity, which will help refine the geologic and reservoir models.

Geologic and Reservoir Modeling

Generally, depending on the time and resources available for a small-scale pilot, rigorous geologic and reservoir modeling are not part of site screening but are necessary for the selection process. (To the contrary, a large-scale project with a larger capital investment may require rigorous models as part of the site selection.) Consequently, the results of reservoir modeling based on simplistic geologic models make up the fifth and final tier. Depending on the CO_2 volume available and the time specified for the pilot, more attention should be given to injection patterns and models that give measurable, quantifiable oil production and pressure changes that can be attributed to CO_2 injection. Direct field data that indicate an increase in oil recovery are important. A small-scale pilot likely cannot directly measure the full CO_2 EOR potential of a reservoir, whereas commercial-scale pilots with two to three years of injection and multiple injection patterns are more likely to measure these data. Consequently, the small-scale pilot design should have a definitive and measurable field response (e.g., increased oil production) that can be used to calibrate a rigorous geologic and reservoir model to estimate CO_2 EOR for the pilot and field. Well shut-ins early in on-site operations—after wellbore tubulars and downhole equipment have been pulled, inspected or replaced, and rerun—will furnish information on current reservoir pressure and static fluid levels, which can be used to refine the models.

PILOT SITE DESIGN AND WELL ARRANGEMENT

After completing the five tiers of the selection process, the next step is to design the pilot specific to the sites selected. Subobjectives may be developed or addressed that could be relevant to the specific pilot, reduce uncertainty in scaling pilot results to the field, or assess the CO_2 EOR resources and storage of an entire basin. For example, if a specific injection pattern (e.g., inverted or regular five-spot) would be more applicable to a basin, then that pattern would be desirable for the pilot. In the case of the ILB, wells were typically on 10-acre spacing and waterflood patterns were 20-acre, regular five-spot patterns. As a result, this pattern was given a higher ranking when the CO_2 EOR pilot site was selected.

Note that a regular five-spot pattern is a centrally located production well surrounded by four equally spaced injection wells, whereas an inverted five-spot is an injection well centrally located between four production wells. Because the oil response is the most important consideration, the regular five-spot is ideal because the CO_2 from all four injectors is directed toward the producer. In contrast, an inverted five-spot with a single injector is directed in all directions and not necessarily toward the producers. In addition, four injection wells will require four times the CO_2 budget and well conversion compared with the inverted five-spot pattern.

If waterflood operations at the selected field use an area flood or other irregular pattern rather than a regular injection pattern, such as a five-spot, it may be necessary to convert wells from producers to injectors. The MGSC Mumford Hills pilot project (Frailey, 2013a) had only one water injection well on the southern edge of the unit, so an inverted five-spot pattern was created by converting a producing well between four other producers into a CO_2 injection well. The MGSC Sugar Creek pilot was undergoing an area waterflood before CO_2 injection began; a water injection well was surrounded by eight producers, some of which had been drilled slightly farther away from the injector than the typical offset pattern because of topography (a modest hill) between the tank battery and injector.

The availability of electricity, including at a specified phase and voltage, is an important general consideration. Most existing water injection wells do not have electricity at or near the wellhead, whereas most production wells that have some type of artificial lift (e.g., pumping unit) require a motor and electricity very near the wellhead. Additionally, tank batteries do not generally have electricity unless it is for lighting, whereas the water injection facility has water pumps (e.g., centrifugal pumps) with electric motors. Locating the CO_2 injection equipment near an existing electrical source will reduce overall costs and the time to begin injection. Alternatively, new electrical line and meters can be installed, or a portable diesel-fueled electric generator can be used, provided the project can support the added costs and delivery of diesel fuel. The ECBM and huff 'n' puff projects used diesel generators, and the pattern and area floods used electricity directly from power lines located at the water injection plant.

Site Logistics

Injector wells should be chosen based on their proximity to oil-producing wells, either active or temporarily abandoned, and their lack of wellbore- or injection-related problems. In mature fields with wells of various ages, wells drilled more recently are likely to have better casing integrity. Typical ILB wells are in cropland, forested areas, and floodplains. These wells can be located a significant distance (hundreds of meters) from the production tank battery and may be accessible only via unpaved lease roads that cannot support tanker truck traffic. The delivery of CO_2 via tanker trucks must be made on roads that regularly support oil tanker truck traffic.

Because oil tanker trucks are required to drive to tank batteries and transfer oil from tanks to the tanker truck, placing the injection equipment (specifically the CO_2 storage tanks) near the tank battery may be the only option (Figure 4). However, this arrangement may require laying a new injection line designed for CO_2 service between the injection equipment and the injection well. Alternatively, an existing water injection flow line can be used to pump the CO_2 to the injection well, depending on whether the composition and pressure rating of the existing water injection line are equal to the demands of CO_2 injection. If the existing water injection flow line does not have a composition (such as fiberglass) that is compatible with CO_2 or does not have a pressure rating well above the injection pressure, it must be replaced. Because the huff ‘n’ puff and ECBM pilots were short term and had an equipment operator present 24 hours per day, an injection pipeline (i.e., tubing) was laid on the ground surface. One project used an existing fiberglass water injection pipeline to an existing water injection well. The oil well converted to CO_2 injector required a new underground fiberglass CO_2 injection pipeline.

The oil-producing wells generally have power nearby that can be used for data acquisition. Alternatively, batteries recharged via solar panels are an affordable and effective means of providing power to the data acquisition equipment used to monitor pressure, temperature, and produced fluid rates at individual wells. The general terrain of the land between wells and the injection or production facilities should be considered in relation to data transmission from on-site data loggers and remote access to data via cell phone technology (e.g., broadband). Most data loggers require a line of sight between devices such that the effects of obstacles (e.g., a hill) between transponders and receivers is reduced by hardwiring, by placing the receiver or transponder on a pole, or by changing the configuration for direct communication.

Water injection periods following CO_2 injection are advisable at EOR pilots to maintain the required reservoir pressure (e.g., to sustain miscibility), continue to displace CO_2 to producers, and gather additional information for model calibration, specifically to observe whether post-CO_2 water injectivity matches the pre-CO_2 water injection rates. (Water injection following CO_2 injection is expected to decrease and is important to evaluate for full-field development.) The existing water injection pumps and accessories in the field (e.g., meters and filters) can be used for this purpose.

Given the level of infrastructure development at the typical small field in areas such as the ILB and the relatively low volume of fluids and gases involved in a small-scale pilot, it probably will not be practical to attempt natural gas liquid recovery or to capture and recycle produced CO_2. However, at a pilot project motivated in part by the desire to test CO_2 storage, it is important to estimate the amount of CO_2 produced at wellheads and the tank battery (see the Tank Battery Adaptations and Well Preparation sections).

Office trailers can be used to provide office and laboratory space and equipment storage. Pilots that take place in isolated areas with little artificial lighting benefit from the placement of diesel-powered, stand-alone light towers to improve security and accommodate the 24/7 operations used at some sites. The value of security cameras on the office trailers should be considered. Office trailers should be secured to the ground to withstand high winds. When choosing the location of the office trailer, consideration should be given to prevailing winds, parking, and general operations. Emergency evacuation plans should be made and reviewed periodically.

Tank Battery Adaptations

In areas where crude oil production has little associated gas production, gas is typically vented to the atmosphere at the wellhead, stock tanks, or both, rather than being collected and reinjected. Because the casing annulus of the producing wells on rod pumps or some other types of artificial lift can be opened to the atmosphere, CO_2 at individual wells may be separated from the reservoir liquids (oil and brine) near the bottom of the wellbore and produced at the surface from the casing–tubing annulus. However, downhole packers, when present, prevent gas venting at individual production wells. Under these conditions, all CO_2 (free or dissolved in oil and water at bottomhole pressure and temperature) is produced through the tubing and pumped through the production flow lines to the tank battery.

If CO_2 is produced through the tubing with all other fluids, a gas and liquid separator, placed in series upstream of the existing oil and water separator, should be installed to separate and measure the produced CO_2. The simplest and most reliable gas meters are orifice plate types (e.g., gas provers and well testers) that require pressure and temperature measurements to calculate the volumetric flow rate of CO_2. Data acquisition equipment (e.g., data loggers) and a power source are required. Gas metering on the oil or water stock tanks may be necessary to improve the estimate of produced CO_2; however, a stock tank operated at atmospheric pressure and temperature generally has very little dissolved gas. For the ILB pilots, two floods metered gas at the individual wellheads and two metered CO_2 at the tank battery.

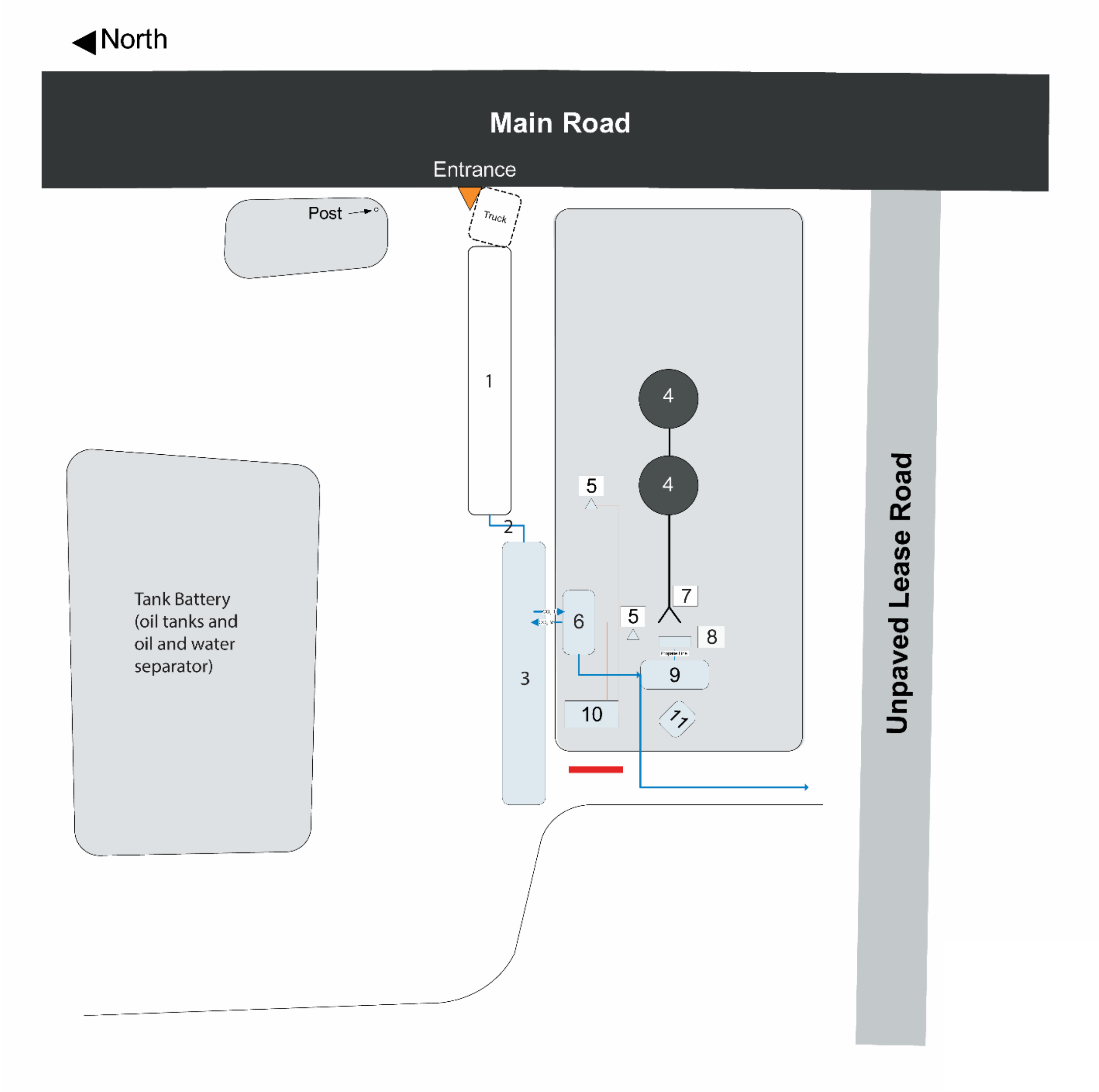

Figure 4 Layout of the huff'n'puff injection equipment site, showing the proximity of injection equipment to the tank battery and paved road (modified from MGSC 2009). The tank battery was next to a main road. Number key: [1] Air Liquide Truck and CO_2 Delivery Tanker (50'0" x 8'0"); [2] Truck Delivery Line (6'4.5" x 5'0"); [3] Air Liquide CO_2 Storage Tank (49'0" x 8'0"); [4] Waste Tank; [5] Ambient CO_2 Sensor; [6] Liquid CO_2 Pump Skid (12'0" x 6'0"); [7] Wind Sock on Post; [8] Propane Tank; [9] Inline Heater (12'9" x 5'5.004"); [10] Portable Generator; [11] Lights with Generator. [3] is connected to [6] by CO_2 liquid (3→6) and CO_2 vapor (6→3) lines; [8] is connected to [9] by a propane line. Red lines = 110V power lines; line connecting northernmost [5] to southern [5] is 5' 0.821" + -38' 10.851"; line connecting southern [5] to [10] is -2' 8.607" + -14' 6.565"; line connecting [6] to [10] is 2' 8" + -14' 7.5"; Grey rectangles represent gravel berms, the largest of which (at right) measured 46'0" x 101'0". Drawing scale: 3/32" = 1'; red scale bar = 10 ft.

Returning Abandoned or Temporarily Shut-In Wells to Production

It is desirable to have as much information as possible about pre-CO_2-injection production rates and pressure for the wells in the pilot area, and this may necessitate returning some wells to production that might contribute to CO_2 EOR. This process should be carried out a few months before CO_2 injection commences to allow ample time to gather production information that can be included in the pre-CO_2 fluid production baseline. Well preparation procedures depend on the condition of the field and the individual wells. For example, if a well with low reservoir pressure is temporarily abandoned because of low fluid production, high water cut, or both, the operator may leave the rods, tubing, and pump in the wellbore without a downhole packer. Returning the well to production will require pulling the downhole equipment and reconditioning the pump. At a field where higher reservoir pressure is maintained via water injection, a producing well may be temporarily abandoned with a downhole tubing packer to isolate reservoir pressure from the casing. This type of temporarily abandoned well is relatively simple to return to production. A well that was permanently abandoned requires significantly more effort, expense, and risk to return to production; it will likely be necessary to drill out cement, cast-iron plugs, or both, and pressure test the casing.

Observation Wells

To detect out-of-pattern CO_2 migration, observation wells immediately outside the pilot areas are desirable. Suitably located, temporarily abandoned production wells with only the tubing and packer inside the casing can be instrumented to measure the surface and downhole pressure and temperature. The data collected can be supplemented with surface tubing pressure data from noninstrumented wells (mechanical gauges), which many operators periodically record manually as part of routine field operations. If an observation well is filled to the surface with brine, an estimate of downhole pressure can be obtained based on the surface pressure and brine density. If the well is not liquid-filled to the surface, the pressure and temperature probe should be lowered to a depth within the tubing that is well below the lowest anticipated level of fluid during the injection and postinjection monitoring periods. Adding water to a well will create a pressure disturbance, and the baseline will need to be reestablished. Depending on the reservoir pressure, the additional liquid may enter the formation and the liquid level will fall. This can be partially offset if the liquid added has a lower density than the brine (e.g., diesel fuel), but this will be a significant expense compared with adding brine.

Well Preparation

If cased-hole logging is part of the MVA program, it should be integrated into the preinjection well-preparation program. Cased-hole logging requires pulling the rods, pumps, and tubing from the wells. (Other types of artificial lift may be better at handling excessive gas, i.e. CO2, and not require pulling rods and pumps to run cased-hole logs.) After logging, downhole assemblies designed for CO_2 and higher gas rates (because of CO_2 breakthrough) should be installed to prevent gas locking (pumping failure and stuck valves), which can be caused by excessive gas entering the pump. A typical downhole assembly consists of a gas anchor at the bottom of the tubing and a mud anchor at the bottom of the pump (Figure 5). The anchors separate gas from liquid at the bottom of the wellbore before fluids enter the downhole pumps.

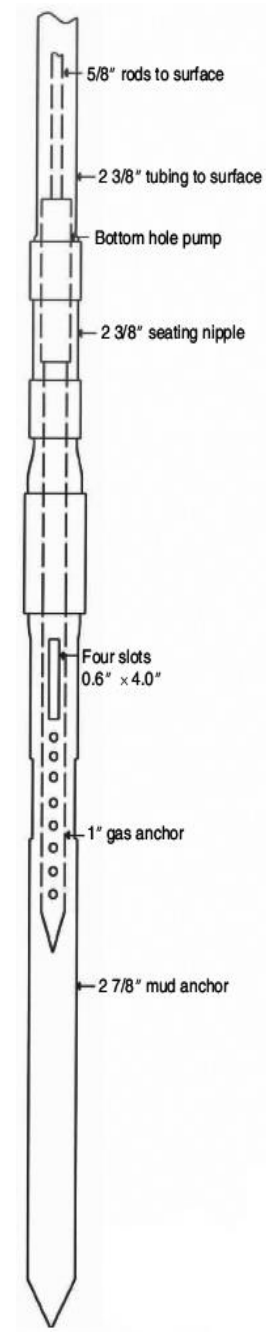

Figure 5 Schematic diagram of a downhole assembly from the MGSC immiscible flood pilot (Frailey et al. 2012c).

At the surface, special stuffing boxes (seals between the wellhead and polished rod-on-rod pumped wells) adapted for higher gas rates and pressure might be considered, depending on operational conditions, but these proved unnecessary at the MGSC pilot projects. If the existing rods and tubing are in good condition, they can be run back into production wells after logging, but plastic-lined tubing designed for brine injection should be replaced with unlined steel tubing for CO_2 injection. Packers, when used at the MGSC pilots, were the same AD-1 type packers used for water injection but with a harder rubber element (60-durometer elastomer vs. 80-durometer). Packers cannot be used at huff ‘n’ puff wells because CO_2 is injected through the casing valve and into the casing–tubing annulus.

Baseline oil production data are necessary to clearly identify production changes resulting from CO_2 injection. The performance of well treatments (e.g., stimulations) and other pre-CO_2 preparatory well work, which can affect daily production rates, complicates efforts to establish this baseline. Nevertheless, it may be necessary to treat some or all of the producing and injecting wells in the planned pilot. In the ILB, for example, scaling (solid precipitation) is common and acidizing wells is a regular aspect of maintenance. Several months should elapse between preinjection well work and the start of operations to facilitate identification of a fluid production baseline from the treated wells. Otherwise, the change in fluid production resulting from the well work must be included in the baseline.

To accurately account for CO_2 produced from an oil field, casing gas production at individual wells can be measured with a gas prover (e.g., an orifice plate, which is a metal disc with a small hole in the center) placed at the end of a short length of pipe attached to the wellhead (Figure 6). Pressure and temperature gauges placed in the pipe upstream of the prover allow calculation of the gas flow rate as a function of the surface pressure and temperature and the size of the orifice. These gauges can also be used to monitor pressure changes caused by the breakthrough of CO_2 at individual wells during active CO_2 injection. Selection of the orifice size is based on the gas flow rate, with each size being used for a range of gas rates. It may need to be changed from a smaller size used to measure low-pressure pre-CO_2 injection hydrocarbon gas rates to a larger size for high-pressure, high-volume CO_2 rates following CO_2 breakthrough at an oil-producing well. This change must be explicitly noted and coordinated in the database (or with the database manager) so that the correct gas rates are calculated.

Corrosion Treatment Plan: Chemical and Mechanical

Carbon dioxide with brine can be corrosive to the tubulars, wellhead, downhole equipment, and surface facilities of a well. The increased fluid production predicted from CO_2 injection as well as the CO_2 itself can place additional demands on equipment. Depending on the routine field operations at the site, which may already include some form of regular chemical treatment for brine-related corrosion, an expanded treatment regime should begin in anticipation of CO_2 injection. This procedure can involve adding an additional corrosion inhibitor to the current treatment plan or simply increasing the amount of chemical already applied if it inhibits CO_2 corrosion. Any other existing treatment plans, such as the application of emulsion breakers or antiscaling compounds, should be continued during the project.

Figure 6 Gas prover (aluminum pipe on the far left) set up at an MGSC test site (Frailey et al. 2012c).

The chemicals can be administered continuously or in batch treatments that vary in application, depending on the well completion. Production wells flowing to the surface through tubing generally have a downhole packer in place, which prevents the application of chemicals circulated from the surface down through the casing–tubing annulus and up the tubing. Consequently, it may be necessary to pull the rods and downhole pump from the tubing of the well to be treated. The chemicals can then be pumped down the tubing of production wells and a soaking period can be allowed for the corrosion inhibitor to coat the inside of the tubing.

For the miscible test with packers, the wells were not treated with chemicals, but chemicals were added to the flow lines to protect the tank battery and separator. After 10 months of post-CO_2 water injection at the miscible flood pilot site, four of the wells had their tubing and packers pulled; none of the packers showed corrosion. The tubing string on one of the four wells had damage attributable to CO_2, specifically small, randomly distributed holes. Thus, a chemical treatment should have been used and definitely is recommended for longer term tests. In contrast, producing wells with rods and pumps (no packers) at the immiscible flood pilot site had an unexpectedly low workover rate relative to their typical operating conditions, and this was attributed to the regular chemical treatment plan. Continuous and batch treatments were used on all producing wells. Corrosion coupons were placed in the flow lines of each well to monitor conditions in producing wells. The CO_2 compatibility of existing production flow lines between wells and the tank battery needs to be checked. Additionally, a corrosion coupon should be in the flow line near the tank battery to monitor and protect the stock tanks and separators. Generally, if no corrosion is noted at individual wells, no corrosion would be expected in the flow lines and the tank battery.

Replacement of the elastomers previously used for water injection with new ones that are compatible with CO_2 should be considered. Some specific components in wellheads should also be replaced with metallurgy compatible with CO_2 (Jarrell et al. 2002). Carbon dioxide delivered via tanker trucks is generally dry with respect to water and is not corrosive. Consequently, bare oilfield steel is acceptable for dedicated CO_2 injection wells and the injection flow lines; however, a joint compound compatible with CO_2 should be used. If fiberglass or PVC is used, attention should be given to the type of elastomers that may be present in the couplings or joints. During the transition period between CO_2 and water injection into the same well, corrosion can be a problem; however, this was not observed at the MGSC pilots.

Preinjection Reservoir Modeling

As part of the site selection process, simple geologic models are used for reservoir modeling to provide general design specifications, such as the CO_2 injection rate; peak CO_2, oil and water production rates and duration; injection pressure; CO_2 distribution (in the subsurface); time to CO_2 breakthrough at producing wells; and amount of CO_2 followed by water injection that would be required to cause a measurable oil production response in the producing wells within the pilot area. Model sizes for the MGSC EOR projects ranged from 40 to 400 acres (16 to 161 ha), depending on the well arrangement (the smallest model was for the single-well huff 'n' puff), with vertical dimensions of the models based on the average elevation of reservoir tops taken from geophysical well logs. Permeability and porosity values were based on core data (when available), field performance, and normalized spontaneous potential logs. Core data and modern logs were generally scarce or unavailable because of the age of the fields, so a procedure was developed for obtaining porosity–permeability estimates from spontaneous potential logs (MGSC 2009). Vertical-to-horizontal permeability ratios (k_v/k_h) were based on general Mississippian reservoir trends.

A general ILB oilfield reservoir model was used with a simple geologic model for each EOR pilot to determine CO_2 injection rates per day and to predict the time until CO_2 breakthrough, the quantity of CO_2 followed by water injection required to cause a significant production response at the offset wells, and the increase in peak production. As an example, CO_2 injection rates of 8 to 13 tons (7 to 12 tonnes) per day or 140 to 200 million standard cubic feet per day (scf/d; 4 to 5.7 million standard cubic meters per day [scm/d]) and 5 to 7 months until CO_2 breakthrough were projected for the immiscible flood (Frailey et al. 2012c). The reservoir model suggested that 6,000 to 8,000 tons (5,000 to 7,000 tonnes) of CO_2 followed by water injection would be required to cause a measurable oil production response in some of the offset wells. Consequently, contingent plans were made to have up to three wells converted to CO_2 injection to have about one year of active injection. Injection of CO_2 followed by water was not considered likely to influence oil production at wells that were a significant distance from the injector. At peak oil production, an increase in oil production of 5 to 10 stock tank barrels per day (stb/d; 0.8 to 1.6 scm/d) was projected based on model results.

Initial pilot CO_2 injection rates exceeded predicted injection rates and totals, and only one injection well was needed. Actual CO_2 injection rates at the immiscible flood generally ranged from 20 to 30 tons (18.2 to 27.3 tonnes) per day, for a total of 7,230 tons (6,560 tonnes) over the yearlong injection period. Breakthrough occurred after only one week at a well south of the injector, but wells to the north, west, and southeast had breakthrough times of 4 to 5 months, falling much closer to the projected times. The early breakthrough at the southern well (and at another well nearby, which had breakthrough in about a month) was attributed to a previously unknown fracture network. A peak increase of 10 stock tank barrels per day (stb/d; about 1.6 scm/d) was achieved within 3 months of commencing CO_2 injection and lasted for 3 months before being interrupted by weather-related CO_2 delivery disruptions and an injection line leak. As projected, wells located farther from the injector did not have increases in oil production.

Carbon Dioxide Injection Permits

Depending on the previous use of the wells in the pilot area, it may be necessary to obtain a permit for injection, which includes a mechanical integrity test for injection wells. If the well was not originally permitted for injection, permits must be obtained after a mechanical integrity test or pressure falloff tests, or both, to determine the maximum surface injection pressure and maximum bottomhole pressure. If the intended CO_2 injector was previously permitted as a brine injection well, an increased surface pressure will be required to match the same regulated bottomhole pressure because CO_2 density is less than brine density. A mechanical integrity test (pressure test on the tubing–casing annulus to at least 300 psia [4.93 MPa] with less than 3% pressure loss in 30 min) was required before water injectors could be permitted as CO_2 injectors for the MGSC projects.

Monitoring, Verification, and Accounting Strategies

The success of a CO_2 EOR and storage project depends, in part, on accurately documenting the fate of CO_2 in the subsurface and demonstrating that the project is an effective greenhouse gas control technology (NETL 2009). Moreover, it is important that the project be conducted in an environmentally safe manner. Attainment of these broad goals is achieved through a portfolio of protocols and measurements generally called monitoring, verification, and accounting (MVA). The MVA program at the MGSC's pilot projects have been discussed elsewhere (Frailey et al. 2012a,b,c) and will not be revisited in detail here, but it is important to note that a successful MVA program requires three stages of monitoring: before, during, and after CO_2 injection. Preinjection MVA work focuses on characterizing ambient aqueous fluid and gas chemistry and developing a baseline data set against which changes attributable to CO_2 interactions can be documented. Monitoring, verification, and accounting work during injection provides the basis for documenting types and magnitudes of CO_2–water–rock interactions and their in situ spatial distribution. Postinjection MVA work focuses on documenting the extent to which oil reservoir and groundwater fluid chemistry, gas composition, and gas isotopic content return to preinjection values within the monitoring period, as well as ensuring that CO_2 did not migrate into groundwater.

The pilot coordinator, MVA coordinator, and field supervisor need to establish communication protocols to manage their respective aspects of the pilot. For example, gas sampling the same day or day after application of the corrosion inhibitor can interfere with the results. Likewise, brine sampling during a period relatively close to the time of an acid stimulation may be a safety concern. Even if all the CO_2 is obtained from a single vendor, the source of the CO_2 may change over the course of the project. Carbon dioxide captured at ethanol plants has a different isotopic signature from CO_2 captured at ammonia plants, and this will lead to erroneous interpretations of data if the source is not included in the analyses; hence, it is important to maintain good communication with the CO_2 vendor in order to be made aware of any change in CO_2 supply over the course of the project.

As an example of the importance of geochemical baseline to project results, at the immiscible site, the pre-CO_2-injection water chemistry baseline exhibited two unique water sources. One was identical to the brine used for water injection; the other was from wells near a downdip brine aquifer (from the oil reservoir). Because of this observation, a stronger aquifer was used in the geologic model to give pressure support to the oil reservoir. If this pre-CO_2 observation had not been made, the water chemistry difference may have been incorrectly attributed to some geochemical reaction with CO_2.

Health and Human Safety

A project-specific health and safety plan (HASP) should be developed for each pilot to assign staff responsibilities, establish safety standards and procedures, and address contingencies that might arise during operation. A HASP contains the emergency telephone numbers for the local first responders (fire, law enforcement, and ambulance services) and a map that shows the nearest clinic and major hospital. Additional information covered in the plan is a list of risks inherent to any outdoor work (severe weather, pest-borne disease, and other dangers), work with heavy machinery, and risks specific to CO_2 handling (such as high pressures, asphyxiation, or skin damage from exposure to cold).

Providing project information to local officials before field operations helps increase preparedness in case of an emergency and answers any concerns from the community. Likewise, in preparation for liquid CO_2 delivery and removal from the site, local first responders should be given maps of the oil field, project managers' contact information, and a summary of project operations.

All employees who visit or work at project sites must attend a HASP training session, and a printed copy of the HASP should be kept on-site during injection activities. Level D personal protective equipment, which includes safety glasses, hard hats, gloves, steel-toed boots, and hearing protection where appropriate, should be required for all workers. In the immediate area of the injection equipment, air quality sensors can be used to monitor CO_2 levels in real time, and alarms can be set to go off if ambient CO_2 exceeds a certain level.

Carbon Dioxide Injection Equipment

Pumping equipment at pilot projects includes portable CO_2 storage tanks, the main pump skid, a booster pump to reduce vapor locking, and an in-line heater to control the temperature, and hence phase (e.g., gas or liquid), of the injected CO_2 (Figure 7) per pilot specifications. CO_2 is delivered and stored on site as gas and liquid at its vapor pressure; liquid CO_2 is taken from the bottom of the tank using pumps. Because CO_2 vapor and liquid are in equilibrium in the storage tanks, the pressure at the vapor–liquid interface is the pressure of CO_2 (Frailey et al. 2012a). The booster pump, located between the outlet of the storage tank and the inlet to the main pump, reduces the risk of vapor locking the main pump by increasing the inlet pressure above the vapor pressure of CO_2. McKaskle and Sexton (2012) provide complete documentation of the equipment used at the MGSC pilots.

The total footprint of this pumping equipment was approximately 759 ft^2 (70.5 m^2) at the huff 'n' puff site, 1,132 ft^2 (105 m^2) at the immiscible flood site, and 1,204 ft^2 (112 m^2) at the miscible flood site; the differences were primarily due to the size and number of the storage tanks used at each site. (The immiscible and miscible flood sites had two storage tanks, and the huff 'n' puff site had only one.) The total equipment footprint includes 2 ft (0.6 m) added to each dimension (length and width) of each object to ensure a minimum 4 ft (1.2 m) gap between each piece of equipment. Office trailers were present at two of the three sites but are not included in the equipment footprint. The total area of the huff 'n' puff well site was 70 × 95 ft (21 × 29 m), or 6,650 ft^2 (618 m^2; Figure 8; MGSC 2009). At the immiscible and miscible flood sites, the tank battery areas (where the injection equipment was located) were each approximately 164 × 75 ft (50 × 23 m), or 11,250 ft^2 (1,045 m^2). This included short gravel service roads immediately adjacent to the tanks or pump house, or both, but not the main (e.g., township or county) road leading to the tank battery. It should be noted that, in contrast to the huff 'n' puff site, space limitations at the immiscible and miscible flood sites (particularly the former) required some of the equipment to be located adjacent to the tank battery area as opposed to within its boundaries. For example, the arrangement of the tank battery at the immiscible flood site—specifically, less convenient road access—required the storage tanks to be kept in a pasture adjacent to the tank battery.

The largest components of the CO_2 injection equipment are the storage tanks (45 ft [14 m] long, 8 ft [2.4 m] wide, and 13 ft [4.0 m] high, weighing approximately 45,000 lb [20,000 kg] when empty). They require a larger area at the site and the ability of a truck driver to maneuver the empty storage tanks into place. The daily volume of CO_2 planned for injection, the anticipated daily availability of CO_2 from the CO_2 supply company, and the planned injection period and budget will determine the number and size of storage tanks required. For the two larger MGSC pilots, two tanks were required at each site. The immiscible flood had a slightly lower injection rate, and two 50-ton (45-tonne) tanks were used; the miscible flood had slightly higher anticipated injection rates, and two 60-ton (54-tonne) tanks were used. The second CO_2 storage tank provided extra on-site CO_2 storage in case of temporary disruptions to the daily CO_2 delivery schedule and could be isolated from the system when unloading CO_2 from delivery trucks. Prior to having a second storage tank, frequently unloading CO_2 from the delivery truck to the storage tank would cause disruption to the CO_2 at the main pump and cause a shutdown, requiring operator intervention to restart the injection process.

The injection equipment was installed at the tank battery for the miscible and immiscible pilots. The existing pump house infrastructure at oil fields can be used during the water injection phase of the pilots (following CO_2 injection), but CO_2 pumps need to be brought to the site on pump skids. Pumping equipment should be pressure-tested before injection.

In a commercial project, produced CO_2 might be captured and reinjected. In a research-scale pilot with no gas capture infrastructure, it is more practical to continue the practice of permissible venting of produced gas to the atmosphere through the gas separator, individual wellheads, or both.

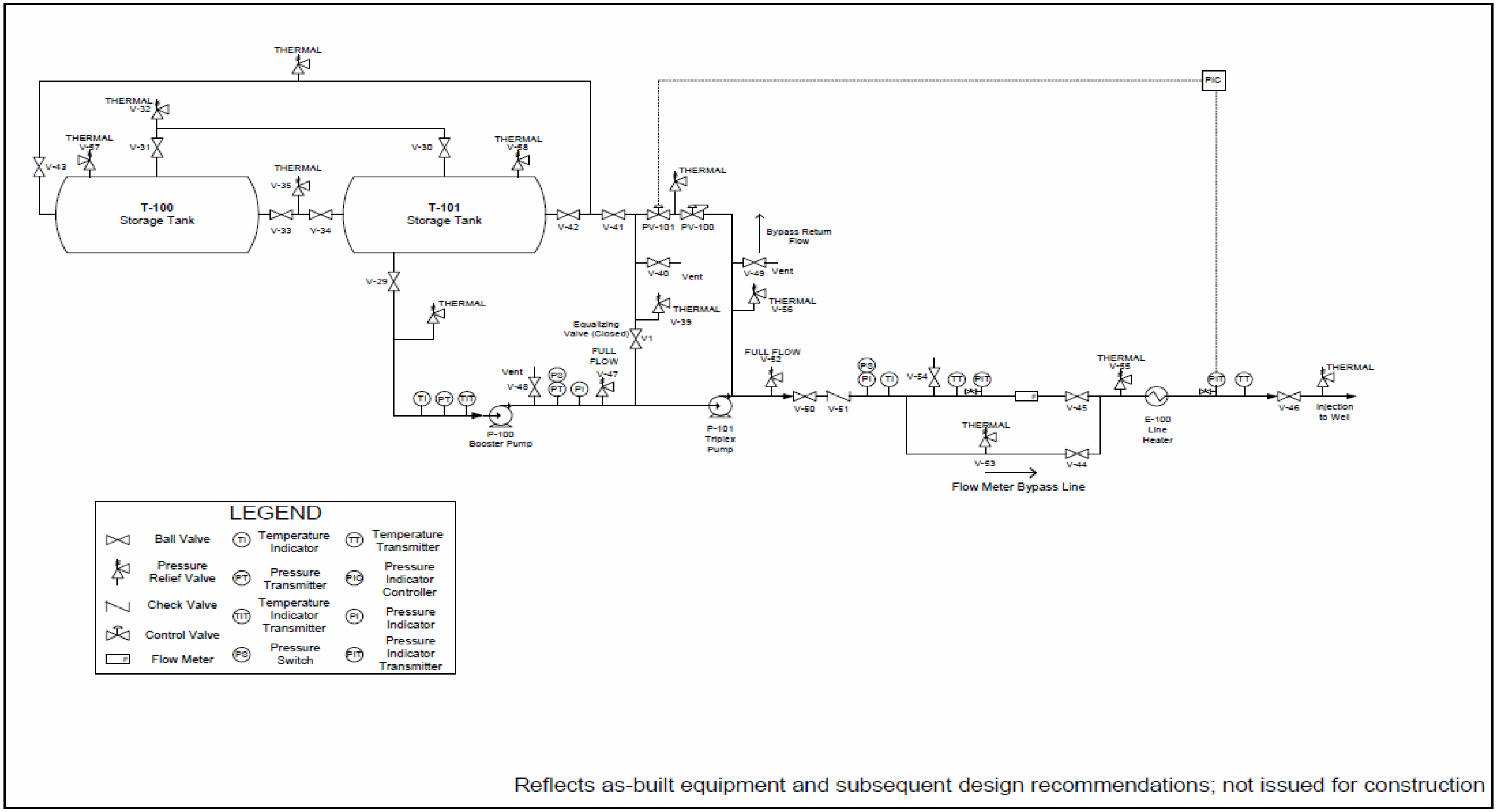

Figure 7 Schematic diagram of the equipment design at the miscible flood site. The immiscible flood site had a similar layout (McKaskle and Sexton 2012).

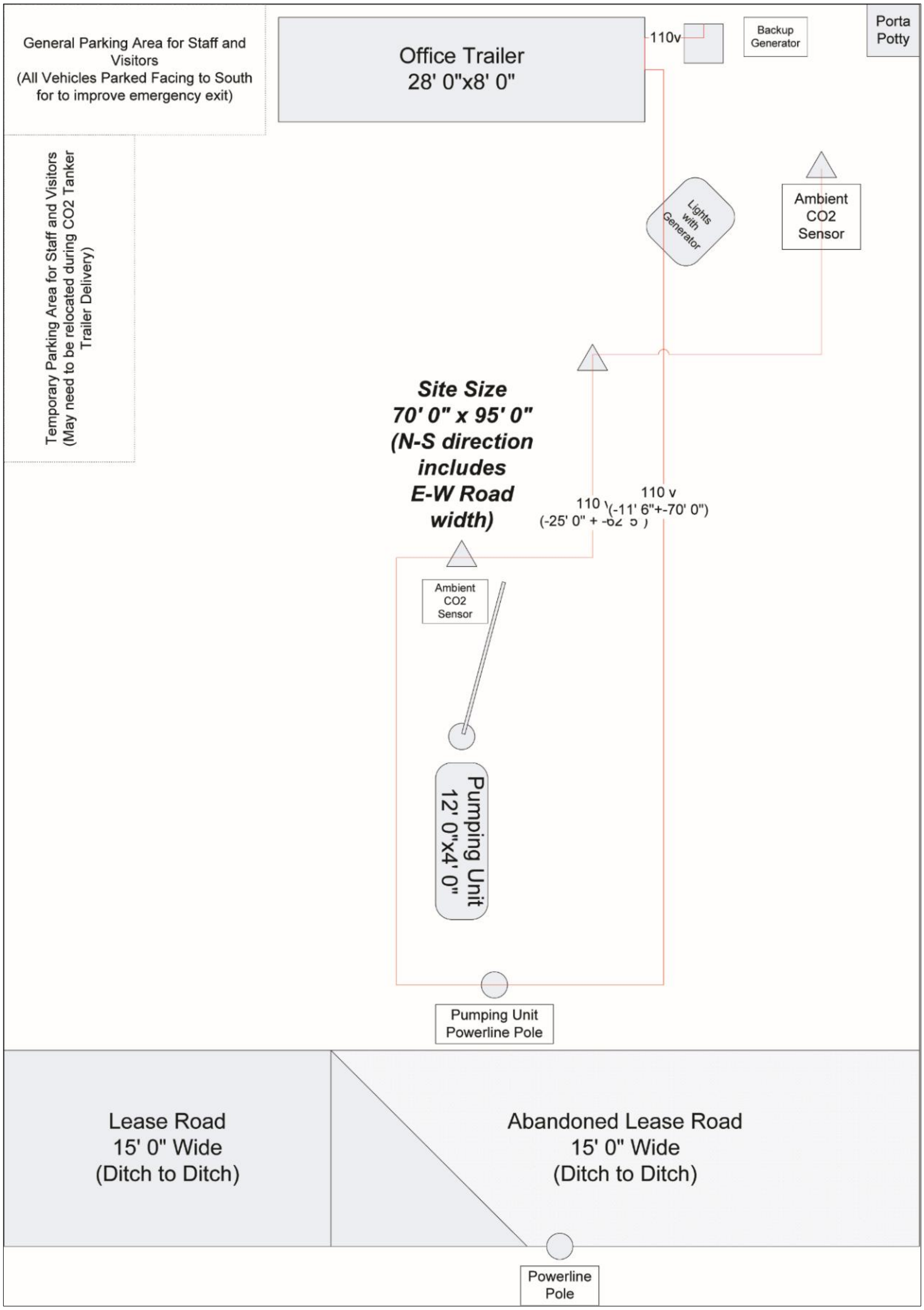

Figure 8 Sketch of the well site layout for the huff 'n' puff pilot (modified from MGSC 2009). The red line is the data acquisition line to the ambient CO_2 sensors and the wellhead pressure and temperature sensors.

Data Acquisition

Surface and downhole pressures and temperatures in wells can be measured by using pressure and temperature transducers. Each sensor can be connected via cable to a data acquisition enclosure near each wellhead. Additionally, an atmospheric pressure and temperature sensor at the site should be part of the design. This sensor is useful when large casing pressure changes are recorded and attributed to atmospheric pressure changes. In addition, the use of gas provers with low pressure may be correlated to atmospheric pressure. Each data acquisition enclosure should be instrumented to have its own power source (battery and solar panel), data logger, radio transmitter to a central data logger, or a combination of these.

On the CO_2 injection pump skid, the pressure and temperature of the CO_2 were measured upstream and downstream of the main CO_2 injection pump. The temperature of the CO_2 exiting the in-line heater also was measured. The CO_2 injection flow rate was measured by using a liquid turbine flow meter installed downstream from main pump but upstream of the in-line heater. All pressure, temperature, and flow rate measurements at the pump skid and line heater were sent by a 4 to 20 mA signal to the pump skid data logger.

For data collection and remote monitoring, radio transmitters connected to a data logger sent pressure and temperature data to a common receiver. Collected data was available to the operator by cellular transmission at a chosen time interval. At the ECBM site, three types of meters were used: orifice, gas turbine, and liquid turbine. The injection rate was very low and depended highly on the pressure and temperature; at various times during injection, each meter was used to provide the actual injection rate.

CONCLUSIONS

Successful design and implementation of a small-scale CO_2 storage research pilot requires contributions from a wide range of specialists. Likewise, coordinating among contractors, landowners, and local regulators is necessary to ensure smooth operation over the duration of the project. Pilots conducted geographically outside of historical regions with CO_2 EOR and CO_2 pipelines pose a unique set of challenges, but the existing infrastructure can be adapted to the needs of a CO_2 injection pilot. This adaptation often requires modifying or adding to on-site equipment, specifically installing CO_2 pumping equipment at the site. Planning and starting operations far in advance provides time to resolve initial equipment failures or differences between model predictions and actual data gathered during start-up and sampling. Additionally, this provides time to collect baseline data, which is not only essential to the interpretation of project results, but also may later prove important in addressing any public concerns about the project. Anticipating these needs ensures injection can begin on the predicted start-up date and can alleviate any contingencies project managers may face. Moreover, if project objectives are emphasized at all stages of design and implementation, a successful pilot is more likely.

ACKNOWLEDGMENTS

The Midwest Geological Sequestration Consortium is funded by the U.S. Department of Energy through the National Energy Technology Laboratory (NETL) via the Regional Carbon Sequestration Partnership Program (contract number DE-FC26-05NT42588), the Illinois Department of Commerce and Economic Opportunity, Office of Coal Development through the Illinois Clean Coal Institute (cost share agreement), and the Commonwealth of Kentucky, through the Kentucky Consortium for Carbon Storage (KYCCS) at the University of Kentucky, Lexington.

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APPENDIX 1—CO_2 Injection Pilot Implementation Plan and Schedule

The table on the following pages shows an example of a CO_2 injection pilot implementation plan and schedule, which focuses on operations and was drawn up shortly before the injection cycle commenced. This example is based on a CO_2 EOR pilot, but most parts are applicable to an ECBM or saline pilot implantation plan.

In this table, Week 0 reflects work completed or well underway at the time the field deployment work begins during Week 1. The CO_2 injection phase is compressed into one line of the table and is listed in Week 6 for the purposes of presenting this information, but it can be scheduled for as long as necessary to meet the project objectives and stay within budget.

Week 0 items were grouped and were not assigned individual lead times before fieldwork because too many site- and staff-specific attributes affect the timing of these tasks. Examples of events that will affect the length of Week 0 are the duration of pre-CO_2-injection data (baseline) for all types of MVA techniques, which vary from site to site, and the previous experience of staff and operators.

If this is the first CO_2 pilot for most or all of the staff involved, the tasks labeled and planned for each week may take 2 weeks or longer. Additionally, elapsed time between certain tasks may need to be greater than this schedule implies; in particular, preinjection well work should be completed several months before the start of injection to facilitate identification of a fluid production baseline.

This schedule does not include specific MVA activities such as drilling groundwater monitoring wells or baseline sampling, but the MVA program should commence several months before injection activities to ensure adequate characterization of the geochemical baselines. Regular MVA field sampling is also not included.

Table A1 Example CO_2 injection pilot implementation plan and schedule

Week	Work description	Personnel
Week 0	Complete site screening and selection	Primary contractor
	Complete pilot design and well arrangement	Primary contractor
	Complete equipment and well site layout sketches	Primary contractor
	Complete a health and safety plan (HASP)	Primary contractor
	Complete a National Environmental Policy Act (NEPA)	Primary contractor
	Complete the injection permit process with the appropriate state or federal agency	Operator
	Obtain a groundwater monitoring well permit (if necessary for MVA)	Primary contractor
	Complete funding agency approval of the operational plan	Primary contractor
	Research pressure and temperature monitoring system options	Primary contractor
	Research a CO_2-compatible elastomer for the injection well packer	Operator
	Determine liquid CO_2 pump and storage tank specifications	Operator, primary contractor
	Determine types of cased-hole logs and contact the logging company to schedule times for logging runs	Operator, primary contractor
	Determine pressure and temperature data acquisition equipment specifications	Data acquisition and instrumentation company, operator
	Determine specifications for CO_2 meters and casing gas provers	Operator, primary contractor
	Determine all necessary power and fuel sources	Operator, primary contractor
	Obtain ambient CO_2 detectors (for the facility location, well site[s], or both)	Injection equipment design company
	Design the MVA program	Primary contractor
	Complete simple geologic and reservoir modeling	Primary contractor
	Complete contracts with the primary contractor and subcontractors	Primary contractor

Week 1	Schedule the CO_2 provider site visit and approval for truck delivery	CO_2 provider, operator, primary contractor
	Pull tubing, rods, packers, and pumps. Inspect and replace items as necessary. Consider a gas or mud anchor below the pump.	Oilfield service/supply company, contract pulling unit
	Convert wells from producers to injectors (if necessary)	Oilfield service/supply company
	Log wells and conduct initial background fluid sampling (MVA baseline)	Operator, well service provider, primary contractor
	Rerun wells and shut in all wells for 1 week; assess static fluid levels and estimate the reservoir pressure	Contract pulling unit/operator/ primary contractor
	Schedule a vadose zone drilling-probe truck (well site)	Primary contractor
	Contact landowners in the area	Primary contractor, operator
	Contact the road commissioner for all township, county, and state roads	Oilfield service/supply company, primary contractor
	Notify neighbors, county officials, and local officials, including emergency medical services	Primary contractor, operator
	Install subsurface monitoring equipment (pressure and temperature gauges)	Primary contractor, operator, data acquisition and instrumentation company
Week 2	Drill the groundwater monitoring well	Primary contractor
	Perform mechanical integrity test on injection well with the regulatory agency present (if necessary)	Operator
	Design and install wellhead assemblies for metering and monitoring produced gas volumes and the capability to sample; leave place for a possible chemical corrosion inhibitor treatment	Operator, primary contractor
	Install corrosion coupons in the flow lines of producing wells	Operator, chemical company, primary contractor
	Prepare access roads and sites for equipment (level and lay gravel as needed)	Operator
	Perform pressure transient tests and analysis as needed to characterize the reservoir, determine intrawell communication, and assess near-wellbore flow characteristics (skin)	Primary contractor, oilfield service/supply company
	Deliver an office trailer to the site and secure it to the ground	Primary contractor
	Locate a back-up office trailer generator at the site	Primary contractor
	Wire 110 V electricity to the office trailer	Oilfield service/supply company, primary contractor
	Locate a portable toilet at the site	Primary contractor
	Measure the baseline aerial, electromagnetic, and resistivity surveys, as needed	Primary contractor
	Install a new electrical line at the tank battery (if necessary)	Operator, primary contractor
	Wire a 220 V box for the injection pump	Operator, primary contractor
	Complete the data acquisition set-up	Data acquisition and instrumentation company
	Install the surface pressure and temperature sensors	Data acquisition and instrumentation company, operator
	Begin recording background data to establish the pre-CO_2 injection and production pressure and temperature of the reservoir and wells	Data acquisition and instrumentation company
Week 3	Collect background corrosion data (pre-CO_2 injection); analyze data and recommend a treatment chemical and method; adapt the wellheads to accommodate the treatment	Chemical company, operator
	Locate equipment at the injection site: pump skid, in-line heater, heater igniters, and storage tank	Operator
	Locate a propane tank at the site for the in-line heater	Operator
	Install propane plumbing from the tank to the in-line heater	Oilfield service/supply company

Week 4	Locate and install a gas and liquid separator; begin the preinjection production period	Primary contractor, operator
	Hold a HASP and CO_2 safety meeting	Primary contractor
	Install CO_2 injection plumbing from the storage tank to the pump skid, the pump skid to the propane heater, and the propane heater to the wellhead[1]	Operator, primary contractor
	Fill the CO_2 tank to "vapor pressure"	CO_2 provider
	Continue background fluid sampling	Primary contractor
	Perform surface equipment testing	Injection equipment design company, pumping company, operator, primary contractor
	Install electricity to the CO_2 alarm sensor and pump skid	Injection equipment design company
	Begin the chemical corrosion treatment and continue through the CO_2 injection phase	Chemical company
Week 5	Deliver a moderate volume of CO_2 to the site for testing (repeat as necessary)	CO_2 provider, injection equipment design company, primary contractor
	Deliver CO_2, 2–3 truckloads daily depending on the reservoir response	CO_2 provider
	Begin active CO_2 injection	Pumping company, operator, primary contractor
Week 6+		

[1]If the existing water injection line is not suitable for CO_2 injection, then this may need to be placed earlier in the plan.