INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION & ENHANCED OIL RECOVERY PROJECT

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ABSTRACT

A consortium of research partners led by the Southwest Regional Partnership on Carbon Sequestration and industry partners, including CAP CO₂ LLC, Blue Source LLC, Coffeyville Resources, Nitrogen Fertilizers LLC, Ash Grove Cement Company, Kansas Ethanol LLC, Headwaters Clean Carbon Services, Black & Veatch, and Schlumberger Carbon Services, conducted a feasibility study of a large-scale CCS commercialization project that included large-scale CO₂ sources. The overall objective of this project, entitled the “Integrated Mid-Continent Carbon Capture, Sequestration and Enhanced Oil Recovery Project” was to design an integrated system of US mid-continent industrial CO₂ sources with CO₂ capture, and geologic sequestration in deep saline formations and in oil field reservoirs with concomitant EOR. Findings of this project suggest that deep saline sequestration in the mid-continent region is not feasible without major financial incentives, such as tax credits or otherwise, that do not exist at this time. However, results of the analysis suggest that enhanced oil recovery with carbon sequestration is indeed feasible and practical for specific types of geologic settings in the Midwestern U.S.

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EXECUTIVE SUMMARY

The overall objective of the Integrated Mid-Continent Carbon Capture, Sequestration and Enhanced Oil Recovery Project (IMCCS Project) was to design an integrated system of large-scale CO₂ sources with CO₂ capture, geologic sequestration in deep saline formations and in oil field reservoirs with concomitant enhanced oil recovery. The IMCCS Project evaluated fully-commercialized advanced technologies for capture and subsequent sequestration in underground formations. Added-value commercial benefits factored include large-scale enhanced oil recovery (EOR) and optimization of capture technologies, sequestration monitoring technologies and risk assessment protocols for commercial-scale deployment. We investigated the impact of CO₂ capture technology on plant operations, economics, and performance. Another major objective was to demonstrate geologic sequestration in multiple geologic horizons (“stacked storage”), including evaluation of costs, operational processes, and technical performance. The IMCCS Project incorporated state-of-the-art monitoring, verification & accounting (MVA) protocols in its assessment of sequestration in deep saline formations and operating oil and gas fields in Kansas.

The body of work summarized in this report should be considered an initial feasibility study to be followed by additional data gathering, field testing, and more rigorous modeling and simulation study. Results of this project suggest that deep saline sequestration is impractical and uneconomic, without additional (new) financial incentives. However, EOR analysis results of this project are encouraging and suggest a gravity-stable immiscible CO₂ EOR flood in select Midwestern oilfields would mobilize oil, form a horizontal oil bank, and could be commercially feasible. However, substantial additional work is needed on three fronts: 1) fill critical fluid property gaps, 2) improve assessments of geophysical and petrophysical properties including residual oil saturation, and 3) gain a better understanding of reservoir "plumbing systems" to insure that a gravity-stable approach could be effective in these reservoirs.

CHAPTER 1 – Lessons Learned

1.0 Introduction

The purpose of this report is to summarize the approach and results of the project entitled “Integrated Mid-Continent Carbon Capture, Sequestration, and Enhanced Oil Recovery Project,” or IMCCS, focusing especially on lessons learned during the brief project. The IMCCS team strove to respond carefully and objectively to a series of opportunities, constraints and criteria that changed multiple times during the course of the project. Regardless, the assembled team made its best effort in responding to the spirit of the the original solicitation and its special goals under auspices of ARRA.

One additional backdrop to this report is that between 2008 and 2010, world oil markets suffered a severe price drop from \$125/barrel down to \$35/barrel in the same period. One particular casualty in this period was the bankruptcy of Semgroup, a privately held entity in Oklahoma, whose loss impacted many oil companies in Kansas and the mid-continent region, and further exacerbated the tight market conditions. The sum of these factors, coupled with legislative uncertainty about carbon cap-and-trade and other policy options led the private equity markets in the oil industry to retreat. Financing options for large capital projects were scarce, and the DOE solicitation “Recovery Act: Carbon Capture and Sequestration from Industrial Sources and Innovative Concepts for Beneficial CO₂ Use” came at a time when it was perhaps the only option for credible backing of a commercial-scale opportunity. Many financial advisors recommended that we proceed with entrepreneurial-type ideas with long-term financing contingent upon the successful outcome of our Phase-II proposal. That strategy is what we tried to implement during the course of this project.

The remainder of this chapter breaks down each section of our project by function and highlights the key “Lessons Learned”:

- Overall Project Scoping
- CO₂ Capture
- CO₂ Transport
- CO₂ Enhanced Oil Recovery
- CO₂ Deep Saline Sequestration
- CO₂ Risk Assessment
- Commercial Viability

1.1 Overall Scoping

The original Department of Energy solicitation DE-FOA-0000015 stated an ultimate goal to capture and sequester at least 1-million metric tons per year of industrial-sourced carbon dioxide (CO₂) for either carbon sequestration (CCS) or enhanced oil recovery (EOR) purposes while utilizing new technologies to ‘push-the-envelope’ on latest CO₂ capture, transport, injection and MVA capabilities in the marketplace. The IMCCS team started its effort from a base EOR project involving capture and injection of 880,000 tons

CO₂ per year from Coffeyville Resource's Nitrogen Fertilizer facility. Our leadership team believed that to maximize the chance of commercial sustainability, we should strive to a) be opportunistic with new (even unfinanced) sources of CO₂, and b) seek to expand the sequestration potential beyond EOR to include CCS and possibly CO₂ enhanced coal-bed methane recovery. Towards this goal, we negotiated an additional teaming arrangement with Ash Grove Cement Company, the University of North Dakota, Neumann Systems Group and Black & Veatch Corporation to include a 1-million ton-per-year cement kiln capture project that could possibly deliver a breakthrough in low-cost but high purity CO₂ and was likely to lead to new development of coal-bed methane fields nearby that showed promise of using a blended 50%-pure CO₂ stream. During the course of the 5-month program, we also added a project involving gravity-stable CO₂ injection utilizing CO₂ sourced from Kansas Ethanol, LLC and their ethanol plant nearby. This "sub-project" was designed in collaboration with Epic Consulting, a division of Baker Hughes Canada, to extend the total industrial-sourced CO₂ volume to approximately 1-million tons per year. The risk of adding these sub-projects was that they were vetted rather quickly compared to the analysis of our base CO₂ EOR project. More importantly, these projects were not yet financed. However, they did help our DOE project effort more closely match the overall volumetric and technical advancement criteria associated with the original solicitation.

The IMCCS project team worked diligently to execute all goals of the "Phase-I" ICCS project, in collaboration with NETL. The final technical report and each sub-phase report are now published as part of the end-of-project deliverables. This chapter summarizes the key lessons learned and highlights issues for future project teams to consider in evaluating such an effort.

CO₂ Capture

The IMCCS team identified and negotiated three industrial CO₂ sources, each with different technological requirements for separation and capture of CO₂:

1.2.1 Nitrogen Fertilizer Facility

- The existing 99% high-purity CO₂ emission from the Coffeyville site is readily available (untreated) with only limited dehydration is required for pipeline transport. The delivery CO₂ (inlet) pressure is 2 psi at 60° F.
- The pet-coke gasifiers at Coffeyville emit a higher ratio of CO₂ than traditional gas powered ammonia facilities which may provide the facility a competitive incentive to sequester the CO₂, depending on possible future legislation.

1.2.2 Ethanol Facility

- Due to variations in the ethanol fermentation process, the variability in purity of the existing CO₂ emissions ranged between 91% and 98% over a single 18-hour test period. While this variation may be further minimized through leak reductions, the CO₂ emission stream will require

oxygen extraction techniques and dehydration to make the stream achieve the minimum specification for EOR injection. The delivery CO₂ inlet pressure is 14 psi at 60° F.

1.2.3 Cement Kiln Facility

- The existing quality of CO₂ emissions from the Ash Grove cement kiln was approximately 25% pure. The required process to filter, scrub and concentrate CO₂ using a state-of-the-art amine-based process would require a large-scale effort (although less complex than a typical power plant application). Capital investment for a commercial scale effort was estimated to require \$300 - \$600 million, plus fixed and variable operating costs for the CO₂ capture of between \$ 6 – 10 per ton.
- Breakthrough amine-based technology was explored by using a design by the Neumann Systems Group, currently configured in a pilot power plant facility in Colorado. However, the configuration would still require a very large capital investment and the cement kiln lacks the boiler heat needed to exploit this particular technology fully. The total capital required on this effort was still estimated to be at least \$250 million, and would result in at least a \$35 – \$70 per ton of capital costs in a best-case scenario.
- Due to the unlikely prospect that our team could finance a commercial-scale CO₂ capture project for the cement kiln (in the absence of a CO₂ emission tax or other such regulatory mandate), we decided to suspend the effort to capture the CO₂ from the cement kiln.

<u>CO₂ Cost per Metric Ton</u>		
	CO ₂ Capture	CO ₂ Transport
Ammonia	< \$1	\$30
Ethanol	\$2 - \$3	\$40
Cement	\$60 - \$88	\$35+
Kiln		

1.3 CO₂ Transport

The multiple options for CO₂ capture require different facilities for compression and different lengths of pipeline for transport after separation and capture. These different requirements are summarized with “bullet lists” in the following subsections.

1.3.1 Nitrogen Fertilizer Facility

- Estimated pipeline distance for Phase-I is 108 miles (174 kilometers).

- Existing oilfields and 100% access via existing right of way is expected.
- Estimated 8" steel pipeline and compression capital costs are at least \$116 million.
- Multi-stage compression requirements were estimated as high as 16,500 horsepower for a 40,000 mcf/day load of CO₂. Due to the flow rate, the design team recommends centrifugal compressors. The cost estimates include specifications for redundancy, SCADA, cathodic protection and leak detection. Refer to design report for further details.
- Due to the relatively shallow depths and warm reservoir temperatures, an alternative to extend the pipeline an additional 100 miles (161 kilometers) is also considered in the commercial viability section to potentially exploit additional oilfields for EOR.

1.3.2. Ethanol Facility

- Estimated pipeline distance from Kansas Ethanol is 15 miles (24 kilometers).
- Existing oilfields and 100% access via existing right of way is expected
- Estimated 4" steel pipeline and compression capital costs are at least \$30 million.
- Minimum multi-stage compression requirements were estimated to be 4,500 horsepower for a 8,000 mcf/day load of CO₂. Due to the low flow rate and efficiency level, the design team recommends reciprocating compressors and an oxygen removal unit capable of limiting O₂ levels to 10 parts per million by consuming 48 mcf/day of natural gas. The cost estimates include specifications for redundancy, SCADA, cathodic protection and leak detection. Readers are referred to the complete design report for further details.

1.3.3 Cement Kiln Facility

- Estimated distance from Ash Grove to oilfield interconnect is at least 40 miles (64 kilometers).
- Existing oilfields and 100% access via existing right of way is expected.
- Estimated 8" steel pipeline and compression capital costs are at least \$90 million.
- Multi-stage compression requirements were predicted to be similar to the Coffeyville CO₂ load, but would depend on the distance to potential interconnect destinations. Due to the high cost of CO₂ capture, the project team elected to not complete the compression analysis.

1.4 CO₂ Enhanced Oil Recovery

1.4.1 Prairie Hills (Deep Bartlesville EOR)

- Based on our technical analysis, temperatures in the Bartlesville sands oilfields of Greenwood County are too high and the reservoirs too shallow to provide an effective basis for a miscible CO₂ EOR flood. An estimated average working pressure range of 200 psi was insufficient as the basis for continuing CO₂ EOR investment. Additional analysis is needed to consider alternative tertiary recovery techniques.
- We reexamined non-Arbuckle oilfields in eastern Kansas and Oklahoma that are deeper than 3,000 feet and exhibit good waterflood histories. There are a number of oilfields in the vicinity of the Wellington field (Sumner County) that together comprise as much as 12 to 30 million barrels of EOR targeted oil recovery potential. However, they are small, dispersed, and logistically impractical to flood. Without a DOE grant or similar incentives or support to reduce financial risks of continuing investigation, projects in these fields are not viable at this time.

1.4.2 KEGE Energy (Geneseo Edwards Gravity Stable Flood)

- Based on our initial analysis, a 120-foot oil column at a depth of 3,100 feet may produce up to 6 million barrels over 7 to 12 years via an immiscible gravity-stable flood technique (utilizing a CO₂ gas-cap at the top of the zone, moving the oil downward) in two primary Geneseo Edwards oilfields analyzed.
- A simulation model developed by Epic Consulting shows a utilization rate of 1.6 mcf of CO₂ purchased per barrel of oil recovered via the gravity-stable flood technique, which is significantly better than traditional piston-drive EOR projects
- Additional 3D seismic analysis and pressure testing is essential to evaluate the fluid dynamics and confirm the vertical and horizontal connectivity prior to any commercial-scale project implementation.

1.5 CO₂ Deep Saline Sequestration

1.5.1 Arbuckle (below Deep Bartlesville EOR)

- The project team conducted preliminary model simulations of CO₂ storage in the Arbuckle beneath Thrall-Aagard over three, twenty and 50+ year periods. Results suggest that injected CO₂ would dissolve in the in situ brine and eventually exsolve to gaseous phase; plume migration extends to the west field boundary after 15 years.

- Results also suggest that salt precipitation (sodium chloride) is likely to occur after 2 years of CO₂ injection and would require freshwater mitigation techniques
- The commercial viability of CO₂ sequestration was predicted to be a net loss, and is not viable for financing by investors.

1.5.2 Arbuckle (below Geneseo Edwards Gravity Stable Flood)

- The project team also conducted preliminary model simulations of CO₂ storage in the Arbuckle beneath Geneseo-Edwards over three, twenty and 50+ year periods. Similar results suggest that CO₂ would dissolve in reservoir brine and eventually exsolve as gas. Plume migration here would extend past the dome structure after 9 years.
- Likewise, commercial viability of CO₂ sequestration was predicted to be a net loss, and could not be financed by investors.

1.6 CO₂ Risk Assessment

The overall risk assessment of the project is very closely tied to the commercial viability of the project. The project team suggests that the critical factors are:

- Certainty of a high-purity industrial sourced CO₂ supply, delivered at a market-sensitive economic cost, that does not undermine the profits of an EOR-project.
- Certainty of federal, state and local regulations impacting taxes, permitting, MVA, ownership rights (e.g. pore-space), and environmental indemnities.
- Oil field characteristics that indicate a strong likelihood that CO₂ enhanced oil recovery per acre is likely at efficient CO₂ utilization rates, and without extensive risk of wellbore integrity failure.
- Access to investment capital with financial backing based on a macro-view that oil price volatility will not undermine the other investment risks in a 10 to 20-year commercial scale project.

1.7 Commercial Viability

1.7.1 EOR – Enhanced Oil Recovery

Commercial viability of a CO₂ EOR project is still possible if sufficiently-large oilfields with appropriate reservoir characteristics in close proximity to proposed pipeline routes can be identified. After certain oilfields were ranked by our

engineering team as too risky – due to their relatively high temperatures and shallow depths – alternative (deeper) sites were then investigated. Such fields identified were prospective contingent only on funding to further explore their economic potential. In addition, the oilfield delivered cost of CO₂ for EOR purposes must be substantially reduced to \$15-\$20/metric ton to make any EOR initiative commercially viable. If such alternatives can be achieved, then financeable CO₂ EOR alternatives would likely reemerge.

Deep Saline Sequestration

The deep saline sequestration effort was not economically justified based on current anticipated value of eligible US tax credits (maximum \$20 per ton) and/or VER credits (starting at say \$5 per ton) in relation to the cost of deep saline sequestration operation. Industry investors associated with the IMCCS team suggested several insurmountable issues:

- 1) Continued regulatory uncertainty impacting the economic value of credits in the marketplace. IRS guidelines are in draft. Tax credits are due to expire based upon a maximum ceiling. VER credits exemptions may devalue the market's view of credits for several years (assuming a voluntary market to trade credits continues).
- 2) Continued regulatory uncertainty regarding the permitting of a sequestration well. Concern for pore-space rights. Concern for plume trespass onto adjoining acreage. Unclear stipulation of MVA requirements (e.g. 3D seismic every year vs. alternating years vs. simple surface monitoring techniques). The range of incremental MVA cost expectations from our own industry partners ranged from \$15 to \$40 per ton.
- 3) Opportunity cost of deep saline sequestration is very high when realistic EOR opportunities exist. Best projections showed operating losses of \$20 to \$55 per ton (for CCS without any DOE grant). Using CO₂ for permanent storage seems economically irrational if mature oilfields with EOR potential are in the vicinity. Options to explore CO₂ EOR or “huff-and-puff” or other alternative tertiary techniques seem more likely to be financed by industry partners. In light of the tenuous economics coupled with regulatory concerns, the IMCCS oil company and financing partners were unanimously opposed to funding this deep saline component of the project.

1.8 Conclusions

Industrial sources of low-purity CO₂ (i.e. 15% - 30% pure) such as cement kilns, refineries, power plants, etc. are not economic for a commercial scale CO₂ EOR project at this time. According to this IMCCS study in a “best case” scenario, under idealized conditions, CO₂ capture cost alone would be at least \$35 per metric ton before any cost to transport to any oilfield. We suggest that the cost is more likely to be \$50 – \$100 per metric ton, plus transport. Thus, many industrial CO₂ emission sources are far too expensive to finance at this time.

Our IMCCS project had exclusive rights to purchase all the CO₂ emissions from Coffeyville Resources, one of the largest industrial sources of the highest-purity CO₂ in the United States. Oilfield targets within ~120 miles (193 kilometers) from the site were explored and tested and found to possess more risk than traditional-style CO₂ floods (i.e. compared to the Permian Basin in west Texas), due to a) generally shallower depths, b) generally warmer reservoir temperatures, (both of which dictate minimum miscibility pressure, or MMP, and the working pressure range), c) less concentrated deposits of oil requiring a more dispersed infrastructure design, d) generally high delivered cost of CO₂ of more than \$15 - \$20 per metric ton (assuming \$70/barrel), and e) many old plugged wells which could contribute to MVA challenges. While each of these problems could be overcome with higher investments (i.e. less overall investor return), the ~ 50% level of DOE funding to “de-risk” the project became a mandatory basis for proceeding with the CO₂ enhanced oil recovery project. The IMCCS team did acquire contingent equity financing for the CO₂ EOR portion of the project, but the project was not selected for Phase-II and thus will not proceed at this time. At a time when market conditions become more favorable, then financeable CO₂ EOR alternatives may reemerge throughout Kansas and Oklahoma.

The gravity-stable CO₂ EOR flood opportunity studied by experts from a division of Baker Hughes Canada remains an interesting concept for the Central Kansas Uplift, but it will require additional substantial testing to verify the pressure and containment potential of each oil dome to be explored. Such testing represents a disruption to existing oil producers and thus a large-scale commitment must be in place first, before a meaningful experiment with this technology can be verified in the geology of Kansas.

Our oil industry advisors were unwilling to commit to the deep saline sequestration effort without a large federal subsidy to offset the loss for such a program. The IMCCS team repeatedly confronted opposition regarding lack of definitive CCS legislation, tax incentives, permitting requirements, MVA requirements, pore space rights, leakage (CO₂ trespass), 50-year indemnity, etc. The lack of profit potential for an investor precluded the deep saline effort, even if 50% of costs were borne by a NETL cooperative agreement.

CHAPTER 2 – CO₂ Capture

2.0 Introduction: CO₂ Purity of the IMCCS Sources

An essential feature of the proposed IMCCS project is its CO₂ capture technology suite. Details about the purity of CO₂ from the three IMCCS industrial CO₂ sources include:

Nitrogen Fertilizer Facility

The existing 99% high-purity CO₂ emission from the Coffeyville site is readily available (untreated) with only limited dehydration is required for pipeline transport. The delivery CO₂ (inlet(pressure is 2 psi at 60° F.

Ethanol Facility

Due to variations in the ethanol fermentation process, the variability in purity of the existing CO₂ emissions ranged between 91% and 98% over a single 18-hour test period.

Cement Kiln Facility

The existing quality of CO₂ emissions from the Ash Grove cement kiln was approximately 25% pure. The required process to filter, scrub and concentrate CO₂ using a state-of-the-art amine-based process would require a large-scale effort (although less complex than a typical power plant application). Breakthrough amine-based technology was explored by using a design by the Neumann Systems Group, currently configured in a pilot power plant facility in Colorado. However, the configuration would still require a very large capital investment and the cement kiln lacks the boiler heat needed to exploit this particular technology fully.

Because the cement kiln is the only CO₂ source requiring advanced separation technology, the remainder of this chapter will focus exclusively on this project component.

2.0.1 Purpose

The purpose of this chapter is to provide an overview of the costs and impacts of adding CO₂ capture and compression to the Ash Grove cement manufacturing plant in Chanute, Kansas, with the end goal of providing a range of expected values for the cost of captured and compressed CO₂ at the cement plant boundary.

2.0.2 Objectives

The objectives of this chapter are to provide an overview of the technical implications of adding a commercial-scale, amine-based CO₂ capture process to the Ash Grove cement plant and to estimate the cost of CO₂ produced from the plant at the plant boundary. Technical implications include the additional equipment (with associated space requirements), power requirements, impact on water requirements, and waste streams from the plant. The cost of CO₂ is a function of the capital and operating costs of

the CO₂ plant. To evaluate the expected cost of CO₂, the IMCCS team developed a factored cost estimate with an accuracy range of -30 to +40 percent.

2.0.3 Methodology

To evaluate the technical implications of adding CO₂ capture to the Ash Grove plant, The IMCCS team started with some basic assumptions about the operation of the existing plant, as described in Section 2.2. The information on the cement process and resulting flue gas was provided by the Ash Grove Cement Company. This information was used to develop process flow diagrams, mass balance information, energy balance information, an equipment list, and a plot plan. The mass and energy balance information was used to estimate the sizes of the various pieces of equipment shown in the process flow diagrams. These sizes, along with information on the materials of construction, were tabulated in an equipment list. The equipment list also served as the basis for an electrical one-line diagram and a plot plan. The expected additional electrical loads that the CO₂ process will add to the plant were taken into consideration in the energy balance information and the one-line diagram. The equipment list and plot plan were used to develop a capital cost estimate for the CO₂ capture process.

After the performance and cost estimates of the CO₂ process were developed, a present value cost of CO₂ was calculated, which represents the cost at which CO₂ would need to be sold to achieve a present value of zero for the project at the given discount rate.

2.1 Design Basis and Assumptions

This section presents a design basis for the Ash Grove cement plant (excluding CO₂ capture). The costs and impacts of retrofit CO₂ capture, presented in Sections 2.4, 2.5, and 2.6, reflect these assumptions.

The two main technologies that are being considered for post-combustion CO₂ capture are amine technologies and chilled ammonia. The IMCCS team suggests that amine technologies are closer to commercial scale feasibility and has chosen to use an unimproved MEA as the basis for the design and performance calculations of this study.

As an earlier part of this work, The IMCCS team also evaluated the Neumann Systems NeuStream™ technology. Although the technology shows promise for reducing the cost and space requirements of CO₂ capture systems, the IMCCS team suggests that it is uncertain whether the technology will be commercially available within five years and thus we did not consider it in this current study.

2.1.1 Location

The Ash Grove cement plant is located north of Chanute, Kansas, at the intersection of Old US 169 and Ash Grove Road. The main road to the plant is US Highway 169. The site is also accessible by rail.

2.1.2 Site Meteorological Conditions

Plant site meteorological assumptions are provided in Table 2-1. The IMCCS team used the performance ambient temperature for most calculations. The cooling equipment was sized on the basis of the 2 percent maximum dry-bulb temperature with its associated

wet-bulb temperature. The 2 percent maximum is a condition that will only be exceeded 2 percent of the hours during a typical year.

2.1.3 Cement Plant Description

The Ash Grove cement plant in Chanute, Kansas, was built more than 100 years ago. The plant produced its first cement in July 1908. The plant had an initial production capacity of 120,000 tons per year. The plant underwent several modifications during the 1960s to increase capacity to 500,000 tons per year. In 2001, the plant underwent another modernization to increase its annual capacity to 1.5 million tons. The Ash Grove plant is currently the largest cement plant in the state of Kansas; it has a workforce of 138 employees and an estimated annual economic impact in Kansas of more than \$41 million.

The process to produce cement involves combining limestone, clay, and sand in a

<i>Table 2-1 Plant Site Meteorological Basis</i>	
Elevation, feet above mean sea level (amsl)	958
Ambient Pressure, pounds per square inch absolute (psia)	14.7
Performance Ambient Temperature, °F	85
2 Percent Dry-Bulb Temperature, °F	91.4
2 Percent Wet-Bulb Temperature, °F	75.3

large rotating furnace known as a kiln. The kiln is a long, rotating steel cylinder sloped slightly downward. The kiln heats the raw materials to approximately 2,500° F. The heated raw materials react to form a clinker, which is collected at the lower end of the kiln. The

collected clinker is then cooled and ground into what is commonly known as cement.

The kiln can be heated using a variety of fuels. Coal, oil, natural gas, or liquid waste-derived fuels can all be used in combination to heat the kiln; therefore, the contaminants in the flue gas can vary depending on the type of fuel being used. NO_x emissions are controlled by using a low NO_x burner. Powdered limestone in the raw material helps to neutralize the acid gases (including sulfur) that may have formed in the kiln.

The flue gas exiting the kiln is cooled as it preheats the raw materials in vertical towers before they enter the kiln. The cooled syngas passes through a cyclone to reduce particulate before its pressure is increased in an induced draft fan. The plant typically operates with a raw material mill grinding the material being fed to the cement manufacturing process. When this mill is in operation, the flue gas exiting the fan is combined with gases from the mill, passed through a baghouse, and vented to the atmosphere.

2.1.4 Flue Gas Conditions

The information presented in this chapter is based on 90 percent CO₂ capture from the full plant capacity. The flue gas conditions, flow rates, and compositions are provided in Table 2-2.

Table 2-2 Flue Gas Conditions, Rates, and Compositions	
Temperature, °F	220
Pressure, psia	14.71
Mass Flow Rate, lb/h	1,552,520
Flue Gas Flow Rate, lbmol/h	51,974
Volumetric Flow Rate, acfm	429,180
Flue Gas Composition	
Oxygen, lb/h	166,290
Nitrogen, lb/h	799,690
CO ₂ , lb/h	434,540
Moisture, lb/h	149,800
Oxygen, lbmol/h	4,197
Nitrogen, lbmol/hr	28,540
CO ₂ , lbmol/h	9,874
Moisture, lbmol/h	8,315
Oxygen, % by volume, wet	10
Nitrogen, % by volume, wet	55
CO ₂ , % by volume, wet	19
Moisture, % by volume	16
Sulfur Dioxide (SO ₂) Mass Rate, lb/h	1,000
NO _x Mass Rate, lb/h	1,200

2.1.5 Economic Assumptions

The IMCCS team calculated the present value cost of CO₂ capture on the basis of the assumed economic criteria as provided in Table 2-3.

The CPI was applied uniformly to plant consumables such as fuel, electricity, and chemicals as well as staff salaries and O&M contracts. The tax rate was applied to revenues after taking into account depreciation. Although the Owner's cost can vary significantly, the IMCCS team chose 25 percent as a reasonable estimate based on the technology risk and the brownfield site.

Table 2-3
Economic Assumptions

Plant life	20 years
Present worth discount rate	7.0 percent
Capacity factor	80 percent
Current cost of electricity	\$50/MWh
CPI	2.5 percent
Owner's costs	25 percent
Fuel for steam generation	Natural gas at \$4.50/MBtu
Depreciation	Straight line over life of the plant
Tax rate	35 percent
Gypsum from FGD	Sold at cost

2.2 CO₂ Capture and Compression Process Description

Flue gas from the cement plant stack would be rerouted to the new CO₂ recovery process equipment. The flue gas will contain an appreciable amount of SO₂, which will degrade the amine that is used to absorb the CO₂. The SO₂ must be removed upstream of the amine absorber. To do this, the rerouted flue gas enters the flue gas desulfurization (FGD) unit (10-PK-0101) module, where it is contacted in a large tower with a slurry that contains reagent and byproduct solids. The SO₂ is absorbed into the slurry and reacts with the calcium to form CaSO₃•1/2H₂O and CaSO₄•2H₂O. The SO₂ reacts with limestone reagent by the following reactions:

The flue gas leaving the absorber is saturated with water. Because of the chlorides present in the mist carry-over from the absorber and the pools of low-pH condensate that can develop, the conditions downstream of the absorber are highly corrosive to most materials of construction. Highly corrosion-resistant materials are required for the downstream ductwork.

The reaction products are typically dewatered by a combination of hydrocyclones (or gravity thickeners) and vacuum filters. The resulting filter cake is suitable for landfill disposal. Air is bubbled through the reaction tank and nearly all of the CaSO₃•1/2H₂O can be converted to CaSO₄•2H₂O, which is commonly known as gypsum. This step is termed "forced oxidation." Dewatered gypsum can be landfilled. The wet FGD

processes are characterized by high efficiency (greater than 95 percent) and high reagent utilization (95 to 97 percent). The absorbers handle large volumes of abrasive slurries. The overhead flue gas from the FGD is then sent to a blower that feeds the quench column.

Any sulfur left in the flue gas will react with MEA in the downstream amine absorber. This reaction will form heat stable salts that must be removed from the system and replaced with fresh amine. Although 10 ppm sulfur out of the FGD is fairly typical, the allowable concentration of sulfur in the flue gas is subject to economic optimization. NO_x may also form heat stable salts, and it may be necessary to reduce the NO_x concentration in the flue gas using selective catalytic reduction. The current cement plant controls NO_x by using low NO_x burners. The IMCCS team did not evaluate the NO_x levels in the flue gas and we did not factor any post-combustion NO_x controls in this study.

The most commonly applied amine for a CO₂ capture system is monoethanolamine (MEA). MEA is a simple alkanolamine with a hydroxyl group and an amine group and has the following chemical structure:

The hydroxyl group reduces the vapor pressure of the MEA and increases its solubility in water. The amine group provides the alkalinity that is required to absorb acid gases. MEA chemically absorbs CO₂ from a gas stream to form an amine salt according to the following reaction:

Because the product in this reaction has an appreciable vapor pressure, the composition of the equilibrium solution varies with the partial pressure of the CO₂. For example, an MEA solution at 77° F goes from a CO₂ vapor pressure of 0.07 psia to about 0.3 psia as the MEA weight percent goes from 10 percent to 60 percent¹. The vapor pressure of the product also increases with temperature, so CO₂ absorption takes place at a low temperature and stripping takes place at a higher temperature. The stripping process requires significant quantities of low-pressure process steam. In addition to the main reversible reaction with CO₂, MEA also undergoes irreversible reactions with sulfur compounds, limiting its effectiveness in treating gas streams with appreciable quantities of these sulfur compounds.

Simple MEA solutions suffer from several operational disadvantages. MEA is a viscous and corrosive liquid that provides relatively limited absorption capacity (mass of CO₂ absorbed per mass of solution) and requires a relatively large amount of heat to regenerate the lean solution. MEA also chemically degrades over time by reaction with oxygen and requires the addition of large quantities of replacement amine. Suppliers of

¹Kohl, A. L., *Gas Purification*, Third Edition, Gulf Publishing Company, 1979.

amine-based CO₂ capture systems have applied significant research efforts to developing improved amine formulations that minimize the problems associated with MEA. These proprietary amines include the Mitsubishi Heavy Industries amines marketed under the trade names of KS-1 and KS-2, Fluor's Econamine FG and FG Plus, and Cansolv's (now owned by Shell) DC-103². Some of these improved amines can be used as 30 percent by weight solutions or higher. This aspect alone reduces the required solvent circulation rate substantially. Efforts to develop improved amines with higher absorption capacity, better chemical stability, and improved handling characteristics can be expected to continue and intensify as technology suppliers strive to bring improved CO₂ capture systems to the marketplace.

The MEA solution can be very corrosive, particularly if its concentration exceeds 20 percent by weight and if the solution is heavily laden with acid gases. A 20 percent by weight MEA solution at 120° F has a pH of 12. The corrosive nature of MEA typically requires corrosion-resistant ferrous alloys or nonferrous metals. The high vapor pressure of MEA can cause significant vaporization losses, but this can be minimized via water wash treatment of the purified gas.

Figure 2-1 is a block flow diagram of a typical CO₂ removal process using MEA solvent. The CO₂ capture plant consists of flue gas preparation in an air quality control system that consists of a wet FGD unit, a quench cooling process, CO₂ absorption, CO₂ stripping, and CO₂ compression with dehydration.

After the flue gas is cleaned of contaminants in the FGD unit, it is routed to the quench water system. The gas is cooled by direct contact cooling with a countercurrent flow of circulating quench water through 24 feet of structured packing within the quench column (10-T-0101). This water removes sensible heat and condenses water vapor in the gas while cooling it from approximately 135° F to 128° F. The flue gas leaves the top of the column and is routed to the amine absorber. The water in the bottom of the column is pumped through its circulation loop at approximately 9,660 gpm by quench water pumps (10-P-0101A/B) to the quench water cooler (10-E-0101), where it is cooled to 125° F. The cooled quench water then flows through the quench water filter (10-U-0101) before either being recycled to the quench column or purged. Water purge from the quench loop is sent to makeup water treatment and is used for the makeup cooling water requirements of the plant.

The cooled flue gas from the quench column passes to the amine absorber (20-T-0101). The gas is contacted with an MEA solution in two 21 foot packed beds of the tower, allowing the amine to selectively capture CO₂ from the flue gas. The design circulation rate of the MEA solvent (30 percent by weight) is 11,315 gpm. The flow is regulated by a controller sensing the level in the amine absorber and a flow valve mounted near the stripper inlet nozzle. The lean amine solvent enters the amine absorber at a temperature of approximately 125° F.

²Shell recently purchased the CO₂ technology previously marketed by Cansolv. Earlier technical literature references for this system would be found under the Cansolv name.

Figure 2-1
MEA Block Flow Diagram

The flue gas exiting the amine absorber is washed with water to recover any amine compounds and recover water. The flue gas is then discharged from the top of the amine absorber through to the stack and dispersed into the atmosphere. The main component of the water wash loop is the 12 foot packed section to recover amine that is entrained in the overhead flue gas. Recycle wash water is pumped from the amine absorber to the wash water cooler (20-E-106), cooling it down to 125° F. The trim cooler (20-E-107) further cools the water to 100° F, before it is returned to the amine absorber.

The rich amine with captured CO₂ is sent to the stripper for regeneration. Rich amine is routed through the rich amine pumps (20-P-0101A/B) to the tubes of the lean/rich exchanger (20-E-0102). The rich solvent is heated in the lean/rich exchanger from approximately 140° F to 210° F by lean solvent as it flows to the feed tray of the stripper (20-T-0102).

The stripper overhead, at 13 psig and 205° F, is cooled to 125° F by ambient air in the condenser (20-E-0104); the condensed water is subsequently separated from the acid gas in the reflux drum (20-V-0101). The CO₂-rich gas leaving the reflux drum is controlled at 11.5 psig through a control valve as it is sent to the compression process. The overhead liquid is pumped out of the reflux drum by the reflux pumps (20-P-0103A/B) at a rate used to maintain a constant liquid level in the drum as well as a constant flow back to the stripper. Liquid is purged from the pump discharge as needed to maintain the amine concentration. The purge is sent to the makeup water treatment plant.

Lean amine is removed below the bottom tray of the stripper and sent to the amine reboiler (20-E-0105), which uses 50 psig saturated steam to produce stripping steam that is used across 32 trays to strip the CO₂ from the solvent. Lean MEA at approximately 259° F leaves the bottom of the stripper through the lean amine pumps (20-P-0102A/B) on its way to the amine absorber. A slip stream of 1 to 5 percent of the circulating lean amine will be routed to the amine reclaimer (20-E-0103). MEA degrades over time, decreasing its efficiency for CO₂ capture. The amine reclaimer removes degradation products and recovers MEA for reuse. The 150 psig steam generated from the packaged boiler is used as the heat transfer medium for the reclaimer. The lean solvent leaving the pump is cooled first in the shell side of the lean/rich exchanger (20-E-0102) to 188° F and then by ambient air in the amine cooler (20-E-0101) to 125° F. Ten percent of the cooled lean amine is then sent through a set of filters and a carbon bed before combining with the main flow and passing through a flow control valve at the inlet of the absorber. The filters and carbon bed will remove hydrocarbons, corrosion products, and other solids, minimizing any foaming tendency in the stripper/absorber.

CO₂ from the stripper is routed to the last steps of compression and dehydration before being sent to sequestration. The compression process consists of four 6-stage, integrally geared compressors (30-C-0101A-D). The four compressors operate in parallel. The first compression stage takes the CO₂ from 11.5 psig to 48 psig. CO₂ discharged at about 300° F is cooled to 125° F in the first-stage cooler and then sent to the first-stage knockout drum, where liquids are removed and sent to the makeup water treatment plant. The same step is repeated in the second, third, fourth, and fifth stages. CO₂ discharges from the fifth stage at 985 psig. It undergoes cooling and water knockout and is then routed to the dehydration section before being compressed one last time to the desired pressure of 2,210 psig.

At 985 psig, the CO₂ stream has a water content of 173 lb water/MMscf. CO₂ is dehydrated at this pressure because its water content is at its lowest point. This helps reduce the size of the downstream dehydration system. The water in the CO₂ will need to be reduced to a maximum of 30 lb water/MMscf through dehydration with molecular sieve beds. The CO₂ dehydrators (40-V-0101/2/3) contain molecular sieve material that removes water by adsorption. During adsorption, water binds to the sieve material in small pores. When all of the pores become occupied, additional water removal cannot be achieved. The sieve is then regenerated by passing a slip stream of dehydrated, heated CO₂ across the sieve to remove the adsorbed water. The regenerated sieve is then placed back into adsorption service. In this process, two beds are in adsorption service and one bed is in regeneration service.

The inlet gas enters from the bottom of the dehydrators, 40-V-0101 and 40-V-0102 (assumed to be in adsorption service). Gas flows upward through the sieve bed where the water is adsorbed and dry gas exits from the top. The gas exiting the dehydrators feeds the dehydrator afterfilter (40-U-0101A/B). Over time, the molecular sieve will begin to degrade and crush, producing small dust particles that could plug downstream equipment. Ten percent of the dry gas from the dehydrators going to the afterfilter is sent to the regeneration gas heater (40-F-0101) to be heated to approximately 450° F. The heater is a fuel gas fired heater, and effluent gas is discharged to the heater gas stack (40-S-0101). The hot regeneration gas flows downward through 40-V-0103 to remove the adsorbed water and is then cooled in the regeneration gas cooler (40-E-0101) to 125° F. Water is condensed from the gas and separated in the regeneration gas knockout drum (40-V-0104). The condensed water is routed to the makeup water treatment plant. The water saturated regeneration gas is then recompressed in the regeneration gas compressor and sent back to the beds that are in adsorption mode. The dehydrator cycle time is 24 hours, with 12 hours for adsorption and 12 hours for regeneration.

Dry CO₂ is then routed back to the compression section, where the last compression stage compresses the CO₂ to 2,210 psig, which is suitable for transportation in a CO₂ pipeline. The high-pressure CO₂ is then cooled to 125° F and sent to the pipeline.

Fresh amine is stored in the amine storage tank (50-TK-0101). This makeup amine is pumped by the amine makeup pump (50-P-0102) to the suction of the rich amine pump when needed. Various drains of amine are collected in the amine sump (50-V-0101). Collected amine can then be pumped back to the rich amine pump suction by the amine sump pump (50-P-0101).

Cooling water return from all users at an approximate temperature of 120° F is routed to the cooling water tower (50-W-0101). The cooling tower cools the water to 90° F.

In general, amine-based CO₂ capture is well understood in industrial applications, such as ammonia and hydrogen production. However, commercial-scale CO₂ capture for flue gas from a cement kiln has not been demonstrated. The addition of amine-based, post-combustion CO₂ capture is not expected to significantly alter the operation of the kiln. The primary gas path modifications (not including the steam, power, and cooling modifications) required for adding CO₂ capture to an existing plant would be in the ductwork from the pollution control equipment to the stack.

Because cement plant operations do not have a source of steam, a natural gas fired process boiler must be installed to produce the steam required for stripping the CO₂ from the rich amine in the regenerator. Alternatively, the plant could install a larger boiler and

a back-pressure steam turbine. The boiler would produce superheated steam that could be expanded through a small turbine to the pressure required by the reboiler (approximately 50 psia). In addition to providing the steam necessary for CO₂ capture, this configuration would also provide power for the large electrical loads required for CO₂ capture and compression. To simplify the calculations and reduce capital costs, the IMCCS team assumed that steam would be produced in a package boiler and power would be purchased from the grid.

2.3 Preliminary Design Information

2.3.1 Process Flow Diagrams

The IMCCS team produced preliminary process flow diagrams that show the interconnections between major pieces of equipment. The following process flow diagrams are included in Appendix 2-A:

- 167238-1001-P1000--FGD & QUENCH SECTION.
- 167238-2001-P1000--ABSORBER & STRIPPER SECTION.
- 167238-3001-P1000--CO₂ COMPRESSION.
- 167238-4001-P1000--CO₂ DEHYDRATION.
- 167238-5001-P1000--COOLING WATER TOWER, AMINE SUMP, AMINE TANK.
- 167238-6001-P1000--STEAM SYSTEM.
-

2.3.2 Equipment List

The IMCCS team developed an equipment list that is based on the process design and the process flow diagrams listed in Section 2.3.1. The equipment list is provided in Appendix 2-B.

2.3.3 Plot Plan

Based on the preliminary design and the equipment list described in Section 2.3.2, the IMCCS team suggests that the CO₂ capture and compression equipment will require approximately 4 acres. The most suitable location for the equipment is north of the existing kiln, preheater tower, and raw mill. Some care will be needed to avoid the existing conveyors in that area. Constructability optimization has not been considered as part of this study. A plot plan of the CO₂ equipment in relation to the existing cement plant equipment is shown in Appendix 2-C.

2.3.4 One-Line Diagram

An electrical one-line diagram of the CO₂ capture and compression plant (Drawing ESDSP-167238-E-1001) is included in Appendix 2-D.

The city of Chanute provides electrical power to the Ash Grove cement plant through a 69 kV transmission line. The existing electrical load for the plant during typical operation is 25 MW. The electrical power requirement for the CO₂ capture and compression system is expected to be approximately 40 MW. An auxiliary power transformer must be added to serve this load. To achieve this, the new transformer needs to be fed at 69 kV from the transmission line presently feeding the plant.

The transformer will be located adjacent to the carbon capture equipment, with an underground circuit that would be installed from the 69 kV transmission line tap point to the new transformer. Only one transformer will be installed, meaning that if the transformer is out of service, the CO₂ capture equipment will be unavailable.

The new transformer will be sized to have 25 percent spare capacity, with a top rating of 60 MVA. The transformer will have three windings, the primary winding and two secondary windings and have two different secondary output voltages to accommodate the different voltage requirements of the large motors and the smaller motors. In general, very large motors (5,000 horsepower and above) will be served at 13,800 volts, and motors between 200 and 5,000 hp served at 4160 volts. Therefore, the transformer primary winding would be 69 kV, and the two secondary windings would be 13.8 kV and 4.16 kV. The transformer would feed two medium voltage switchgear buses that are located adjacent to the new loads. The current rating of the medium voltage buses will depend on the electrical load served from that bus.

A 480 volt motor control center is to be provided to serve motors 200 hp and below. Two step-down transformers will each serve one 480 volt switchgear bus, with each bus serving six motor control centers.

A dedicated dc and essential ac power system will be provided for the capture system. The function of the dc power is to provide 125/250 VDC to the control and instrumentation system and to provide the normal power source for the essential ac power source.

No emergency generator will be provided.

2.4 Performance Summary

A summary of the performance of the Ash Grove cement plant with amine-based capture is presented in Table 2-4. The capture process is removing 90 percent of the CO₂ from the lime kiln flue gas, but the additional CO₂ produced by the CO₂ stripping equipment results in a net effective capture of 67 percent. The performance data are for 85° F ambient conditions with the raw mill running. The IMCCS team did not calculate performance for the plant when the raw mill is off.

Table 2-4 Performance Summary of the Ash Grove Cement Plant with CO₂ Capture	
CO ₂ in lime kiln flue gas, tons per hour (tph)	217
CO ₂ from new steam generator and molecular sieve heater, tph	74
Total CO ₂ , tph	291
Lime kiln flue gas to CO ₂ capture, percent	100
CO ₂ captured, tph	195
CO ₂ to atmosphere, tph	96
Net power for CO ₂ capture, compression, and air cooling, MW	33
Wet cooling tower duty, MBtu/h	115
Air cooling duty, MBtu/h	737
Net additional cooling duty, MBtu/h	852
Water condensed from flue gas and CO ₂ , gallons per minute (gpm)	177
Additional makeup water, gpm	172

2.4.1 Mass Balance Information

Before the flue gas enters the amine scrubbing unit, its temperature must be approximately 125° F and the SO₂ and nitrogen dioxide (NO₂) contaminants need to be minimized. On the basis of the information provided, the IMCCS team suggests that a wet FGD unit will be required to reduce the SO₂ concentration in the flue gas to about 10 ppmv. The temperature of the flue gas exiting the wet FGD will need to be cooled in a direct contact cooler before being passed to the amine column. The direct contact cooler will also remove particulates, fluorides, and chlorides from the flue gas.

The IMCCS team estimated gas path information including flow rates, compositions, temperatures, and pressures as the flue gas passes through the CO₂ removal equipment. Pertinent stream information is provided in Table 2-5. A full material balance is provided in Appendix 2-E.

Table 2-5 Gas Path Stream Information for 90 Percent CO₂ Capture				
Medium		Raw Flue Gas	Polished Flue Gas	Flue Gas
From		Preheater	Cooler	Amine Column
To		Wet FGD	Amine Column	Atmosphere
Mole-flow	lbmol/h	51,974	50,264	39,949
Mass-flow	klb/h	1,553	1,521	1,104
Volume-flow	MMscfd	473	458	364
Pressure	psia	14.7	16.1	15.0
Temperature	° F	220	128	125
Composition				
N ₂	%mole	55	57	71
CO ₂	%mole	19	20	3
O ₂	%mole	10	10	13
H ₂ O	%mole	16	13	13
SO ₂ +SO ₃	%mole	0.03	0.00	0.00

2.4.2 Energy Balance Information

The addition of CO₂ capture will require steam heating and will increase the total electric load of the plant.

Heat duties required for amine regeneration from the reboiler and reclaimer, respectively, are the most significant demand on medium- and low-pressure steam. The boiler package generates 937,602 lb/h of superheated 150 psig steam, which is desuperheated for medium-pressure saturated steam use. A portion of the steam generated is let down to 50 psig for low-pressure saturated steam users. Condensate from process heating is collected in a condensate drum and is sent back to the boiler package. Steam from the condensate drum is condensed in an air cooler and returned to the system to reduce required makeup water. Table 2-6 summarizes the process requirements for the medium- and low-pressure steam systems.

Table 2-6
Steam System Requirements

			150 psig 450.0 F 1245.7 Btu/lb	150 psig 365.9 F 1196.0 Btu/lb	150 psig 365.9 F 338.6 Btu/lb	150 psig 365.9 F 338.6 Btu/lb	50 psig 297.7 F 1179.3 Btu/lb	50 psig 297.7 F 267.3 Btu/lb	174 psig 110.0 F 78.5 Btu/lb	174 psig 212.0 F 180.6 Btu/lb	0 psig 212.0 F 180.1 Btu/lb	0 psig 212.0 F 1150.3 Btu/lb	0 psig 212.0 F 180.1 Btu/lb			
			MP Steam System				LP Steam System						Losses			
ITEM			SuperHtMP Steam (lb/hr)	MP Sat'd Steam (lb/hr)	MP Sat'd Cond (lb/hr)	MP Blowdown (lb/hr)	LP Sat'd Steam (lb/hr)	LP Sat'd Cond (lb/hr)	LP BFW Makeup (lb/hr)	LP BFW (lb/hr)	BFW Export (lb/hr)	LLP Sat'd Steam (lb/hr)	Blowdown To Atm (lb/hr)	Lost to Process (lb/hr)	Balance check	
Tag No.	Name	Duty (MMBtu/hr)													Mass (lb/hr)	Energy (MMBtu/hr)
20-E-0103	Amine Redalmer	224.647		-262,006	+ 262,006										+ 0	0.000
20-E-0105	Amine Reboiler	666.402					-730,758	+ 730,758							+ 0	0.000
40-F-0101	Regeneration Gas Heater	2.044					-1,733							+ 1,733	+ 0	0.000
50-PK-0101	Boiler Package	1005.303	+ 937,602			+ 26,988			-19,750	-946,810					+ 0	0.000
	Boiler PackageMP Desuperheater		-937,602	+ 983,557					-45,955			+ 0	0.000			
	Boiler PackageLP Desuperheater			-721,550		+ 732,491		-10,941			+ 0	0.000				
60-E-0101	Steam Condenser	105.222									+ 108,462	-108,462			+ 0	0.000
60-V-0101	Condensate Drum				-262,006			-730,758			+ 894,303	+ 108,462			+ 0	0.000
60-P-0101A/B	BFW Pumps	0.417								+ 992,764	-992,764				+ 0	0.000
Net Production (+) or Consumption (-)				+ 0	+ 0	+ 0	+ 26,988	+ 0	+ 0	-30,731	+ 0	+ 0	+ 0	+ 1,733	+ 0	+ 0.000

BLACK & VEATCH

					MICCS Carbon Capture Project Heat Balance Steam, Condensate, Blowdown and BFW				
A	ISSUED FOR REVIEW	DAO	5/21/10						
NO.	REVISION	BY CHECKED	DATE APPROVED						
					JOB NO. 167238.0210	SHEET NO. 1 of 1	DATE 05/29/10	ISSUE A	DATE 28 May 2010

The electric load is most significantly affected by CO₂ compression. Compression increases the pressure of the CO₂ stream from about 12 to 2,210 psig. There are four compressors in parallel, each with six stages of compression. Between each stage of compression is common air cooling. The total motor load for CO₂ compression is 32,000 hp. The next most significant demand on electric power is the amine system, which requires 5,065 hp to power the air cooler motors and pumps. Table 2-7 lists the expected electrical loads of the CO₂ capture process.

Table 2-7 Process Electrical Load Summary			
Tag No.	Equipment Name	Conn ected	Opera ting
Compressors			
10-B-0101A M	Flue Gas Blower	5,500 hp	4,641 hp
10-B-0101B M	Flue Gas Blower	5,500 hp	
30-C-0101A-D M	CO ₂ Compressor Stage 1		6,436 hp
30-C-0101A-D M	CO ₂ Compressor Stage 2		6,456 hp
30-C-0101A-D M	CO ₂ Compressor Stage 3		5,776 hp
30-C-0101A-D M	CO ₂ Compressor Stage 4		5,976 hp
30-C-0101A-D M	CO ₂ Compressor Stage 5		2652 hp
30-C-0101A-D M	CO ₂ Compressor Stage 6	32,000 hp	4,376 hp
40-C-0101 M	Regeneration Gas Compressor	20 hp	19.6 hp
Pumps			
10-P-0101 AM	Quench Water Pump	600 hp	598 hp
10-P-0101 BM	Quench Water Pump	600 hp	
20-P-0101 AM	Rich Amine Pump	800 hp	735 hp
20-P-0101 BM	Rich Amine Pump	800 hp	
20-P-0102 AM	Lean Amine Pump	1,250 hp	1,118 hp

Table 2-7 (Continued) Process Electrical Load Summary			
Tag No.	Equipment Name	Conn ected	Opera ting
20-P-0102 BM	Lean Amine Pump	1,250 hp	
20-P-0103 AM	Reflux Pump	25 hp	21 hp
20-P-0103 BM	Reflux Pump	25 hp	
20-P-0104 AM	Wash Water Pump	600 hp	513 hp
20-P-0104 BM	Wash Water Pump	600 hp	
50-P-0101 M	Amine Sump Pump	5 hp	4 hp
50-P-0102 M	Amine Makeup Pump	20 hp	16 hp
50-P-0103 AM	Cooling Water Circulation Pump	400 hp	377 hp
50-P-0103 BM	Cooling Water Circulation Pump	400 hp	
Pumps (continued)			
60-P-0101 AM	Boiler Feedwater Pump	350 hp	313 hp
60-P-0101 BM	Boiler Feedwater Pump	350 hp	
Air Coolers			
10-E-0101	Quench Water Cooler – 14 Motors (40 hp)	560 hp	475 hp
20-E-0101	Amine Cooler – 40 Motors (40 hp)	1,600 hp	1,344 hp
20-E-0104	Condenser – 16 Motors (40 hp)	640 hp	539 hp
20-E-0106	Wash Water Cooler – 24 Motors (40 hp)	960 hp	775 hp
30-E-0101	First-Stage Cooler – 10 Motors (40 hp)	400 hp	311 hp
30-E-0102	Second-Stage Cooler – 8 Motors (30 hp)	240 hp	229 hp

Table 2-7 (Continued) Process Electrical Load Summary			
Tag No.	Equipment Name	Conn ected	Opera ting
30-E-0103	Third-Stage Cooler – 6 Motors (30 hp)	180 hp	166 hp
30-E-0104	Fourth-Stage Cooler – 6 Motors (25 hp)	150 hp	142 hp
30-E-0105	Fifth-Stage Cooler – 4 Motors (30 hp)	120 hp	103 hp
30-E-0106	Sixth-Stage Cooler – 4 Motors (40 hp)	160 hp	122 hp
40-E-0101	Regeneration Gas Cooler – 2 Motors (5 hp)	10 hp	7.4 hp
60-E-0101	Steam Condenser – 6 Motors (40 hp)	240 hp	205 hp
	Total Motor Load	56,355 hp	44,446 hp
	Total Process Electrical Load	56,3 55 hp	44,4 46 hp

2.4.3 Water Balance Information

The addition of CO₂ capture will affect the existing plant water mass balance and treatment equipment. Primary impacts are as follows:

- Overall increase in heat rejection load and evaporative cooling capacity
 - Redistribution of existing heat rejection load sources
 - Treatment of process waste streams:
 - Quench purge
 - Amine system purge water
 - Water from compressor knockout drums
 - Water from dehydration system
 - Additional raw water treatment
 - Increased wastewater disposal from cooling tower blowdown

Because raw water to the site is limited to about 200 gpm, air cooling and condensate generated from cooling the flue gas minimize the amount of makeup water derived from the raw source. Without air cooling, approximately 1,800 gpm of additional raw water would be required. Air cooling and condensate from the flue gas will reduce the raw water demand to about 172 gpm.

An overall water management diagram for the CO₂ capture process is shown on Figure 2-2. Raw river water will need to be treated with lime softening clarification before being used in the cooling tower, boiler package, and process. Process waste streams will also undergo a treatment step before being reused. Effluent water from demineralized water treatment and the boiler blowdown lift station will supplement makeup water to the cooling tower. The amine system will not require makeup water. Condensate from the wash water loop on the absorber will generate water, which will be reused in the amine system. A purge water stream from the stripper reflux drum containing water, some CO₂, and other impurities will be treated and reused in the process.

The amine reclaimer will be flushed periodically with a caustic solution and will contain minimal water. It is recommended that this effluent be disposed of at an offsite facility. Associated disposal costs will be dependent on the waste stream's hazardous classification and have not been included in the O&M impact costs.

On the basis of the additional cooling duty required, the IMCCS team suggests that two to four cooling tower cells would be required at design conditions. The expected cooling duty is about 115 MBtu/h for cooling water to the wash water trim cooler to the amine absorber. All other process cooling will be air-cooled.

Blowdown from the cooling tower is approximately 52 gpm and is expected to be discharged to a nearby 5 acre evaporation pond. Intake and discharge permits will need to be reviewed and revised as necessary before any changes are made. If disposal to a pond is not permitted, partial wastewater recovery or zero liquid discharge may need to be considered.

Notes:
1. Flows are in gallons per minute (GPM).

REBALANCE CASE	0	COMBUSTION FUEL		CONDENSER COOLING	Wet Cooling Tower	 BLACK & VEATCH <small>Building a better world</small> 10000 1st Ave., Suite 400, Denver, CO 80202 Tel: 303.733.1000 Fax: 303.733.1001 Email: info@blackveatch.com	MCCS Ash Grove Cement Plant CO2 Capture WATER MASS BALANCE Project: 167238 Revision: WMB-1 Date: 20 May 10 Status: PRELIMINARY		
COMBINED CYCLE COMBUSTION	N/A	NOMINAL PLANT OUTPUT (MMW)	0	CYCLES OR CONCENTRATION	5				
EVAPORATIVE COOLERS	OFF	CONDENSATOR (PERCENT)	0%	CYCLE MAKEUP RATE (PERCENT)	3%				
CRYSTALLIZATION	Not Applicable	DRY-BULB TEMPERATURE (°F)	94						
DUCT FLOW	0%	RELATIVE HUMIDITY (PERCENT)	44%						

Figure 2-2
Water Mass Balance

2.5 Costs

The capital expenditures required for retrofitting the Ash Grove cement plant with CO₂ capture and compression systems will be significant. This section provides an order-of-magnitude overnight capital cost for 90 percent CO₂ capture.

2.5.1 Capital Costs

The IMCCS team developed a +40/-30 percent EPC factored cost estimate for 90 percent CO₂ capture equipment and installation, based on current location-specific cost considerations for the Ash Grove cement plant in Chanute, Kansas. The overnight (first quarter 2010 US dollars) cost is for all furnished and installed major equipment and bulks within the new unit boundary (550 feet by 550 feet).

Field costs include all piperack and interconnecting pipe, electrical and instrumentation cable, and trays. Many cost allowances were included for undefined, but probable elements of cost such as drains and vents, unloading/loading stations, CO₂ discharge metering, utility piping and stations, site preparation with a minor allowance for demolition/relocation, a new DCS in a shared structure, a new main substation connected to the grid complete with switchgear, transformers, motor control centers, and catalyst and chemicals.

This estimate was prepared using AspenTech Capital Cost Estimator (CCE – V7.1), which is consistent with AACE International Class 4 guidance.

Process equipment costs were developed in CCE or by using other internal information based on the sized process equipment list. Considerations included capacities, design temperature and pressure, materials of construction, and other cost-impacting information developed in the process design. Equipment costs in CCE were comparable to recent project costs or data of IMCCS industry partners.

CCE estimates the components required within the equipment envelope, such as foundations, piping, instruments, or insulation. Additionally, CCE uses specified or internally developed electrical and control systems criteria from the process equipment. It includes a library to size and price the electrical equipment. The unit costs in CCE's library are conceptually comparable to current industry standards, which allows the estimator to focus more on scope identification and less on pricing.

The direct field costs from CCE for the equipment and all components within the equipment envelope were compared with internally-developed factors to ensure consistency and reasonableness of all estimated process unit costs.

Scope components were added to the estimate for the balance-of-plant costs such as sitework, metering, interconnecting pipe and piperacks, buildings, and initial fill. The source for this scope includes the plot plan and equipment arrangement drawings and confirmed extensive assumptions provided by members of the IMCCS project team.

A single common labor rate of \$65 was included in the direct labor costs, which includes burden and benefits, temporary construction, and other field labor markups. Costs were estimated separately for freight, construction equipment, and scaffolding, which are included in the field indirects. A construction field labor productivity adjustment of 5 percent was added as a location adjustment.

Significant exclusions for this estimate include the following:

- Escalation beyond first quarter 2010.
- Future expansion and capacity.
- Offsite haul or access roads and bridges.
- Owner's costs.

Table 2-8 presents a breakdown of the expected total installed cost between direct and indirect costs.

<i>Table 2-8 Capital Cost for 90 Percent CO₂ Capture Equipment and Installation</i>	
Direct Costs, \$ million	271
Indirect Costs, \$ million	108
Total Installed Cost, \$ million	379

2.5.2 O&M Costs

Estimated O&M costs for the CO₂ equipment include solvent replacement, water treatment, additional staff, and maintenance materials and contracts. A significant unknown in the amine-based operating cost estimate is the amine degradation and, therefore, the amount of replacement amine that would be required. Table 2-9 provides estimates of the O&M costs based on an estimated low rate of amine degradation, an estimated high rate of amine degradation, and the average of the two. Costs for fuel, makeup power, and the disposal of waste products are excluded.

Table 2-9 O&M Costs for 90 Percent CO₂ Capture (\$ million 2010 US)			
	Low	High	Average
Fixed			
Number of Staff	15	15	15
Staff Costs, \$ million/yr	1.8	1.8	1.8
Other Fixed Costs, \$ million/yr	0.5	0.5	0.5
Total Fixed O&M Costs, \$ million/yr	2.3	2.3	2.3
Variable			
Maintenance Materials and Contracts, \$ million/yr	3.0	3.0	3.0
Non-solvent Chemicals and Consumables, \$ million/yr	1.2	2.2	1.7
Amine Solvent Cost, \$million/yr	1.0	5.0	3.0
Total Variable O&M Costs, \$ million/yr	5.2	10.2	7.7
Total O&M Costs, \$million/yr	7.5	12.5	10.0

2.5.3 Economic Analysis

Present value costs of CO₂ capture are provided in Table 2-10. The present value cost was determined by taking the net present value of the capital and O&M costs over a 20 year time period and solving for the required selling price of CO₂ that gives a break-even net present value. To set boundaries on the price of CO₂, the IMCCS team calculated the low CO₂ price using the low capital cost (estimated at -30 percent) with the low O&M cost estimate and the high CO₂ price using the high capital cost (estimated at +40 percent) with the high O&M cost estimate. The capital costs listed in this section include 25 percent for Owner's costs.

Table 2-10 Low and High Present Value Costs of CO₂		
	Low	High
Capacity Factor, percent	80	80
Overnight Capital Cost, \$million	332	663
Current Cost of Natural Gas, \$/MBtu	4.50	4.50
Current Busbar Cost, \$/MWh	50	50
Current O&M Cost, \$million/year	5.2	10.2
Present Value Price of CO ₂ , \$/ton	60	88

2.6 Conclusion

The Ash Grove CO₂ capture plant operating at 80 percent capacity factor and capturing 90 percent of the CO₂ generated would capture approximately 1.4 million tons (1.27 million tonnes) per year. We suggest that the primary technology concern with adding CO₂ capture to the Ash Grove plant is that amine-based CO₂ scrubbing technology has not yet been demonstrated at the proposed scale. Because this technology has not been demonstrated at scale in the cement manufacturing industry, there is a scale-up risk associated with implementing amine-based, post-combustion CO₂ capture in its current state of development. However, given the smaller scale of the cement plant when compared to most power plants, and the fact that significant modifications would be required to the steam cycle to integrate CO₂ capture into a conventional power plant, this could represent a good opportunity for a commercial-scale demonstration of an amine-based technology. We also suggest that improvements and optimizations will be forthcoming from current and future development work, and that large-scale amine-based capture systems will be commercially available in about 5 years.

The cement plant would require significant modification to add CO₂ capture and compression. In addition to the CO₂ equipment, a package boiler would be needed to provide the steam required for stripping. Flue gas emissions control equipment would need to be added to reduce the sulfur compounds and possibly the NO_x in the flue gas to a level where they would not produce excessive heat stable salts by reaction with the amine. The IMCCS team suggests that additional water treatment equipment would be needed to treat the raw water and the wastewater from the system.

At this time, the capital and operating costs are extremely high. However, opportunities exist to reduce these costs somewhat as the process and solvents are improved. Based on the assumptions described in this chapter and the upper and lower limits to the capital and O&M cost estimates, the IMCCS team suggests that the CO₂ produced in this system would have to be sold for between \$60 and \$88 per ton in order to produce a break-even net present value for the project. Even for the low value of CO₂, we do not believe that the cost would be competitive in future CO₂ markets.

CHAPTER 3 – Transportation

3.0 Thrall-Aagard Field

3.0.1 PIPELINE ROUTING

3.0.1.1 General

Refer to the Drawings Section of this report, Appendix 3-A, Drawing Numbers 2703-M-001 to 02703-M-007 for Overview Maps of the proposed Thrall-Aagard pipeline route. Refer to Drawing Numbers 2703-M-101 to 02703-M-125 for the Alignment Sheets showing detailed sections of land ownership, environmental restrictions, plan view, ground profile, general material specifications, etc.

The pipeline will originate at the Coffeyville Resources Fertilizer Plant (CVR) and generally traverse in a north-westerly direction paralleling existing pipeline corridors for 59 miles (95 kilometers). It will then traverse 49 miles (79 kilometers) in a north-easterly direction following existing pipeline corridors where it will terminate at the Thrall-Aagard Oil Field (TAF).

3.0.1.2 Alternate Routes

While selecting the route for the CVR-TAF pipeline, two substantially alternate routes were considered. The first alternate route followed existing pipeline corridors in a north-easterly direction from Coffeyville, and then turned in a north-westerly direction at approximately Mile Post 56, towards the Thrall-Aagard Oil Field. This route was approximately the same distance as the proposed route. This northern route was not selected due to the higher percentage of cultivated land use and a higher population density than the proposed route.

The second alternate route followed over-head power line corridors, and was more direct than the proposed route or the northern alternate route. This alternate was approximately 8 miles (13 kilometers) shorter than the proposed route. Since this route paralleled over-head power lines, additional cathodic protection measures would be required to protect the pipeline from alternating currents (AC), such as a zinc ribbon. This would add unnecessary cost, complexity, and safety concerns to the project.

In addition to the above analysis, the proposed route also provides better opportunity to expand the carbon dioxide supply to other oil fields in Kansas and Oklahoma, such as the El Dorado Field.

3.0.1.3 Right-of-Way Acquisition

A desktop review of the pipeline right-of-way indicates that 100% of the right-of-way is private. The right-of-way includes mostly cultivated and prairie lands. This study includes estimated costs for obtaining easements from the private land owners to install the proposed pipeline. The precise number of land owners and parcels was not determined during this study. Only the creek crossings, roads, highways, etc. are not privately owned, and come under state and federal guidelines.

Disturbance would occur within a 75-foot wide temporary ROW construction corridor. This width should be sufficient to accommodate construction in most areas. However, additional construction space would be required if another pipeline must be crossed, to temporarily store pipe and equipment, and/or to accommodate construction requirements for a certain area (e.g., road and river crossings, steep slopes).

New access roads would not be required for the project during construction. Construction access would be via the pipeline ROW and existing regional access roads. However, during construction it may be determined that additional access is needed.

3.0.1.4 Permitting

Numerous Federal, State and County permits will be required for the construction of the CVR-TAF Pipeline.

For example, some of the permits required under Federal jurisdiction shall be National Environmental Policy Act (NEPA), Corps of Engineers Nationwide Permit, United States Fish and Wildlife Services. Some of the permits required under the State of Kansas jurisdiction shall be Department of Health and Environment, (Air Quality, Water Discharge, General), National Historic Preservation Act, Wildlife and Parks, Kansas Highway Department. Some of the permits required under the County jurisdiction shall be Road and Bridge Departments. Only permits required for construction have been included within this estimate, therefore the NEPA permit, COE, etc. have been excluded from this budget.

3.0.2 Pipeline System Description

The purpose of the CVR-TAF Pipeline is to transport compressed high-purity CO₂ via a 8" steel intra-state pipeline from the Coffeyville Resources Fertilizer Plant to the Thrall-Aagard Oil Field for both sequestration and enhanced oil recovery purposes.

The pipeline will be designed, constructed and operated in accordance to Title 49, Part 195, "Transportation of Hazardous Liquids by Pipeline" – Department of Transportation, rules and regulations.

The pipeline will be composed of 8.625" O.D., 0.500" wall thickness, API 5L, PSL2, Electric Resistance Welded (ERW) steel line pipe, coated with 14-16 mils of Fusion Bond Epoxy for external corrosion protection. The pipeline will be designed to be operated at a Maximum Operating Pressure of 2,800 PSIG, with an ANSI 1500 flange rating.

All road, railroad and creek crossing pipes will be manufactured to Seamless line pipe specifications instead of ERW to further mitigate fracture propagation.

Carbon Dioxide must be compressed to approximately 2,548 PSIG at the Coffeyville Resources Fertilizer Plant in order to deliver it to the Thrall-Aagard Oil Field at 1,400 PSIG. These operating pressures were utilized to provide a reasonable margin between the operating pressures in the pipeline and the critical pressure of carbon dioxide, which is approximately 1,100 PSIA at 50 °F. Operating at pressures above the critical pressure ensures that the carbon dioxide is transported in the dense phase and that no phase changes occur in the pipeline system. Transporting carbon dioxide in dense-phase is the most efficient means of transportation since it allows for smaller pipeline sizes at high flow rates.

Isolation Block Valves will be strategically located in the pipeline system, as shown in Table 3-1 to isolate the pipeline and blow the Carbon Dioxide down in case of an emergency.

Table 3-1 CVR-TAF Estimated Isolation Block Valves

No.	Pipeline Station	Mile Post
1	115+00	MP 2.18
2	215+00	MP 4.07
3	505+00	MP 9.56
4	1095+00	MP 20.74
5	1590+00	MP 30.11
6	2055+00	MP 38.92
7	2640+00	MP 50.00
8	2790+00	MP 52.84
9	2880+00	MP 54.55
10	3140+00	MP 59.47
11	3695+00	MP 69.98
12	3940+00	MP 74.62
13	4000+00	MP 75.76
14	4200+00	MP 79.55
15	4705+00	MP 89.11
16	5020+00	MP 95.08
17	5080+00	MP 96.21
18	5305+00	MP 100.47

Crack arrestor will be installed at every half mile (0.8 kilometers) on the steel pipeline to mitigate fracture propagation. It is anticipated that Clock Springs, or similar product, will be utilized as crack arrestors. This type of product has been successfully utilized as crack arrestors on existing carbon dioxide pipelines.

The pipeline will be designed and constructed to accommodate intelligent pigs. Pig launcher and receiver will be installed into the system.

3.0.3 PIPELINE HYDRAULICS

3.0.3.1 Purpose

The purpose of this pipeline hydraulic calculation was to analyze the predicted performance of the Coffeyville Resources Nitrogen Fertilizer Plant to Thrall-Aagard oil field (CVR-TAF) carbon dioxide pipeline under various operating scenarios. In general, the results from the hydraulic calculation include resulting pressures, resulting temperatures, resulting velocities, and line size confirmation. Hydraulic scenarios were completed for three potential line sizes.

3.0.3.2 Pipeline Routing

The scope of the hydraulic study was limited to the preferred route. This route heads in a north-westerly direction from Coffeyville and turns north-east at approximately Mile Post 58 towards the Thrall-Aagard oil field. The preferred route is approximately 108.2 miles (174 kilometers) in length. The carbon dioxide delivery point

at the Thrall-Aagard Oil field is located at the north-west corner of Section 31, Township 23S, Range 10E.

3.0.3.3 Hydraulic Modeling Software

PIPEPHASE Version 9.4 was used to model the hydraulics of the carbon dioxide pipeline. This software has the capability of predicting the mechanical and thermodynamic properties of dense-phase carbon dioxide and can model steady-state carbon dioxide flow in pipeline networks.

3.0.3.4 Hydraulic Design Basis - Pressure Requirements

For this hydraulic study, the delivery pressure at the Thrall-Aagard oil field was fixed at 1,400 PSIG. This pressure was utilized to provide a reasonable margin between the operating pressures in the pipeline and the critical pressure of carbon dioxide, which is approximately 1,100 PSIA at 50 °F. Operating at pressures above the critical pressure ensures that the carbon dioxide is transported in the dense phase and that no phase changes occur within the pipeline.

At the Thrall-Aagard oil field, a pressure reduction valve will be installed to reduce the pressure of the carbon dioxide from the 1400 PSIG to the well head injection pressure of approximately 1,100 PSIG.

The carbon dioxide pipeline will be designed and constructed per CFR 49 Part 195 "Transportation of Hazardous Liquids by Pipeline." A design factor (F) of 0.72 was used for allowable stress calculations and determination of the Maximum Operating Pressure (MOP). Based on the hydraulic results, an appropriate ANSI rating for the pipeline was selected.

3.0.3.5 Hydraulic Design Basis - Capacity Requirements

The baseline capacity for the pipeline design is 40 MMSCFD. This corresponds to the maximum anticipated carbon dioxide availability from the Coffeyville Resources Nitrogen Fertilizer Plant at its current configuration. Initial hydraulic runs were also completed to confirm that the selected line size is capable of additional capacity, with the addition of intermediate pump stations.

3.0.3.6 Hydraulic Design Basis - Fluid Temperatures

It is anticipated that the carbon dioxide discharge temperature from the originating compressor / pump station at Coffeyville will be a maximum of 120°F. Therefore, the design temperature for the pipeline system was selected to be 130°F.

In the hydraulic model, an ambient ground temperature of 50°F was selected based on research of soil temperatures published by the USDA. The USDA has published maps of soil temperature regimes for the contiguous United States (http://soils.usda.gov/use/thematic/temp_regimes.html). Based on this map, the project area is located near the boundary of the Mesic and Thermic soil temperature regimes. The Mesic soil regime is defined as having a mean annual soil temperature between 8°C (46.4°F) and 15°C (59.0°F). The Thermic soil regime is defined as having a mean annual soil temperature between 15 °C (59.0°F) and 22°C (71.6°F). Since the project

area is on the boundary of these two regimes, the mean annual soil temperature was assumed to be 15°C (59.0°F).

Using the mean annual soil temperature and anticipated depth of burial, the amplitude of seasonal soil temperature change can be determined. For dry soil at a burial depth of 4 feet, the amplitude of seasonal temperature change is approximately ± 10 °F (<http://www.geo4va.vt.edu/A1/A1.htm>). Therefore, the lowest anticipated soil temperature is approximately 50 °F, which was taken as the ambient soil temperature in the hydraulic model.

3.0.3.7 Hydraulic Design Basis - Carbon Dioxide Composition Analysis

The anticipated composition of fluid stream was provided by Coffeyville Resources Nitrogen Fertilizer Plant and is included as Appendix 3-A to this report. These compositions were modified to reflect the dehydration process needed to meet the dehydrated carbon dioxide specification of 10 lb H₂O / MMSCFD allowable. The below composition (Table 3-2) corresponds to the fluid stream anticipated in the pipeline, which was used in the hydraulic model.

Table 3-2 CVR-TAF Pipeline Compositional Analysis

Component	Mole Fraction
N ₂	0.000000
CO ₂	0.998890
H ₂ O	0.000211
AR	0.000040
CO	0.000100
COS	0.000020
O ₂	0.000000
H ₂	0.000700
CH ₄	0.000040
TOTAL	1.000000

3.0.3.8 Hydraulic Design Basis - Assumed Mechanical and Thermodynamic Properties

The table below (Table 3-3) contains the mechanical and thermodynamic parameters that were assumed in the hydraulic model of the carbon dioxide pipeline. The parameters were selected based on various published charts and tables, and project specific requirements.

Table 3-3 Assumed Mechanical and Thermodynamic Parameters

Design Parameter	Value
Steel Absolute Roughness	0.00360 IN
Flow Efficiency Factor	95.00 PERCENT
Steel Heat Conductivity	26.500 BTU/HR-FT-°F
Soil Heat Conductivity	0.960 BTU/HR-FT-°F
Ground Temperature	50 °F
Burial Depth	48.0 IN (4 FT)
Pressure Drop Correlation	BEGGS-BRILL WITH MOODY FRICTION FACTOR
Bulk Modulus of Pipe	30,000,000 PSI
Bulk Modulus of CO ₂	22,888 PSI

3.0.3.9 Hydraulic Design Basis - Elevation Profile

The elevation profile utilized in the hydraulic model was created from available digital elevation models (DEM's) for the project area. The same elevation profile can be found on the attached Alignment Sheet drawings. No field survey data was gathered to create the pipeline elevation profile.

3.0.3.10 Hydraulic Design Basis - Surge Pressure

Surge pressure, also known as water hammer, is the result of a rapid increase in pressure which occurs when the liquid velocity is suddenly changed in a closed piping system. Per CFR 49 Part 195, temporary pressure excursions must be limited to less than 110% of the design pressure. Surge pressure in dense-phase carbon dioxide pipelines is not well documented; therefore, the standard surge pressure equations were used in the hydraulic model, with appropriate substitutions for liquid density and bulk modulus. The bulk modulus of a fluid is the ratio of the pressure stress to the volumetric strain. The bulk modulus of carbon dioxide was estimated from property tables, calculated by considering the change in density corresponding to a change in pressure.

Surge pressures in dense phase carbon dioxide pipelines are not as great as that in water pipelines, due to the compressibility of the fluid. This is evident in the bulk modulus of carbon dioxide compared to the bulk modulus of water.

3.0.3.11 Results

This section summarizes the results obtained from the hydraulic modeling of the carbon dioxide pipeline. Table 3-4 defines the parameters for the various hydraulic cases.

Table 3-4 Hydraulic Case Definitions

Parameter	Case 1 - 8"	Case 2 - 10"	Case 3 - 12"
Volumetric Flowrate	40 MMSCFD	40 MMSCFD	40 MMSCFD
Mass Flowrate	193,124 lb/hr	193,124 lb/hr	193,124 lb/hr
Pipeline Outer Diameter	8.625"	10.750"	12.750"
Pipeline Wall Thickness	0.500"	0.438"	0.375"
Corrosion Allowance	1/8" (0.125")	1/8" (0.125")	1/8" (0.125")
Effective Wall Thickness	0.375"	0.313"	0.250"
Pipeline Grade	X-65	X-65	X-65
Design Factor	0.72	0.72	0.72
Required System MOP	2,800 PSIG	2,100 PSIG	1,800 PSIG
Pipe MOP	4,069 PSIG	2,725 PSIG	1,835 PSIG
ANSI Class	ANSI 1500	ANSI 900	ANSI 900
ANSI Rating at 130 °F	3,606 PSIG	2,161 PSIG	2,161 PSIG

The resulting operating pressures and maximum surge pressures are summarized in Table 3-5. Hydraulic charts, showing the ground elevation, pressure, and surge pressure, have also been completed and are included as Appendix 3-B to this report.

Table 3-5 Pipeline Pressure Results

Parameter	Case 1 - 8"	Case 2 - 10"	Case 3 - 12"
CVR Discharge	2,548 PSIG	1,878 PSIG	1,726 PSIG
Mile Post 10	2,427 PSIG	1,831 PSIG	1,694 PSIG
Mile Post 20	2,308 PSIG	1,774 PSIG	1,652 PSIG
Mile Post 30	2,267 PSIG	1,792 PSIG	1,684 PSIG
Mile Post 40	2,063 PSIG	1,650 PSIG	1,555 PSIG
Mile Post 50	1,960 PSIG	1,607 PSIG	1,527 PSIG
Mile Post 60	1,730 PSIG	1,439 PSIG	1,373 PSIG
Mile Post 70	1,656 PSIG	1,425 PSIG	1,373 PSIG
Mile Post 80	1,594 PSIG	1,423 PSIG	1,384 PSIG
Mile Post 90	1,642 PSIG	1,530 PSIG	1,505 PSIG
Mile Post 100	1,510 PSIG	1,459 PSIG	1,448 PSIG
TAF Delivery	1,400 PSIG	1,400 PSIG	1,400 PSIG
Min Pipeline Pressure	1,385 PSIG	1,381 PSIG	1,348 PSIG
Max Pipeline Pressure	2,546 PSIG	1,878 PSIG	1,728 PSIG
Max Surge Pressure	2,599 PSIG	1,923 PSIG	1,761 PSIG

The resulting temperatures are summarized in the table below (Table 3-6).

Table 3-6 Pipeline Temperature Results

Parameter	Case 1 - 8"	Case 2 - 10"	Case 3 - 12"
CVR Discharge	120 °F	120 °F	120 °F
Mile Post 10	79 °F	84 °F	86 °F
Mile Post 20	61 °F	64 °F	65 °F
Mile Post 30	54 °F	56 °F	56 °F
Mile Post 40	51 °F	51 °F	52 °F
Mile Post 50	50 °F	50 °F	50 °F
Mile Post 60	49 °F	49 °F	49 °F
Mile Post 70	50 °F	50 °F	50 °F
Mile Post 80	50 °F	50 °F	50 °F
Mile Post 90	51 °F	51 °F	51 °F
Mile Post 100	50 °F	50 °F	50 °F
TAF Delivery	50 °F	50 °F	50 °F

The resulting velocities are summarized in the table below (Table 3-7). Results for pipeline segment inlet velocity are reported in feet per second (fps).

Table 3-7 Pipeline Velocity Results

Parameter	Case 1 - 8"	Case 2 - 10"	Case 3 - 12"
CVR to MP 10	3.14 fps	2.69 fps	1.99 fps
MP 10 to MP 20	3.07 fps	1.93 fps	1.33 fps
MP 20 to MP 30	2.93 fps	1.81 fps	1.23 fps
MP 30 to MP 40	2.88 fps	1.76 fps	1.20 fps
MP 40 to MP 50	2.87 fps	1.75 fps	1.19 fps
MP 50 to MP 60	2.88 fps	1.74 fps	1.19 fps
MP 60 to MP 70	2.90 fps	1.75 fps	1.19 fps
MP 70 to MP 80	2.92 fps	1.76 fps	1.19 fps
MP 80 to MP 90	2.93 fps	1.76 fps	1.19 fps
MP 90 to MP 100	2.93 fps	1.76 fps	1.19 fps
MP 100 to TAF	2.94 fps	1.76 fps	1.19 fps

3.0.3.12 Recommendation

Based on the hydraulic results, it is recommended that 8" x 0.500" Wall Thickness, Grade X-65 pipe be utilized for the CVR-TAF pipeline. This corresponds to the hydraulic results from Case 1 in the above tables. The operating pressures for this case are within common operating pressures of other existing carbon dioxide pipelines.

Cost metrics (dollar per inch-mile for pipeline and dollar per horsepower for stations) were applied to the various pipeline and station scenarios, and it was determined that the additional cost to install the larger diameter pipeline was not offset by the reduced horsepower requirement. The below table (Table 3-8) summarizes this cost comparison. This method will give an approximate, order of magnitude, cost difference for the various options. A detailed cost estimate has been created for the recommended 8" option (Case 1) and is included in Appendix 3-C of this report.

Table 3-8 Pipeline Cost Comparison

Parameter	Case 1 - 8"	Case 2 - 10"	Case 3 - 12"
Pipeline Metric	\$35,000 /in-mi	\$35,000 /in-mi	\$35,000 /in-mi
Pipeline Diameter	8.625"	10.75"	12.75"
Pipeline Length	108 miles (174 kilometers)	108 miles (174 kilometers)	108 miles (174 kilometers)
Station Metric	\$3,000 per BHP	\$3,000 per BHP	\$3,000 per BHP
Differential BHP	503 BHP	302 BHP	225 BHP
Approx Differential Cost	Baseline	\$7,400,000	\$14,760,00

Note that the above listed horsepower requirements do not include the horsepower of the blower or the initial compression to 1,400 PSIG, since these are the same for all three scenarios.

Additional preliminary hydraulic cases were completed to confirm that the 8" pipeline would be capable of additional capacity at a future date. It was confirmed that the 8" pipeline could transport 80 MMSCFD, with the addition of two intermediate booster stations, at Mile Post 36 and Mile Post 72.

3.0.4 COMPRESSION AND PROCESS STUDY

3.0.4.1 General Facility Description

Prior to delivery of the carbon dioxide to the Thrall-Aagard Oil Field, the raw vapor stream off of the Coffeyville Resources amine plant will need to be processed to facilitate miscibility with the crude oil and boosted to pipeline pressure to allow the purified carbon dioxide stream to be transported as a supercritical fluid rather than in the vapor phase, minimizing both pipeline diameter and horsepower requirements, as well as providing the necessary pressure for injection in the oil reservoir. The compression and processing facilities on the CVR-TAF pipeline will require compression and pumping equipment to take the raw carbon dioxide stream from approximately 2 psig to the required pipeline discharge pressure of 2,548 PSIG and dehydration to take the water content to a concentration of less than 200 ppm. Three blower compressors will be installed near the ammonia plant process unit within the Coffeyville plant, and will transport the carbon dioxide through a 24" HDPE conduit to the proposed compressor site. At the proposed compressor site, an integrated centrifugal compressor / pump package will be installed. Inter-stage coolers and dehydration equipment will also be installed. For more detail, see the Process Flow Diagram, 02703-F-001. Controls and operation of the CVR compression facilities will be located in a common, pre-engineered, electrical Power Distribution Center ("PDC") located on-site with the specified compression and processing equipment. A process flow diagram and conceptual site layout have been provided in the drawings section of this report.

3.0.5 Reciprocating and Centrifugal Compressor Comparison Study

3.0.5.1 General

Transportation of dense phase carbon dioxide is growing application in the oil and gas industry and incorporates three primary compression technologies: reciprocating

compressors, centrifugal compressors, and recently integrally geared solutions. Prior to selection of the specified compression equipment for this application, a study was completed to compare these technologies, including their associated annual and 9-year operation and maintenance costs.

3.0.5.2 Discussion

Reciprocating compressors consist of one or more cylinders, each with a piston or plunger which displaces a positive volume of gas with each stroke. Centrifugal compressors consist of a rotating element, typically an impeller or bladed rotor, which accelerates the gas as it passes through the compressor, converting the velocity head into static pressure. Both types of compressors are available in single and multi-stage configurations. Centrifugal compressors approximate a constant head-variable volume machine, while reciprocating compressors approximate a constant volume-variable head machine.

In general, the advantages of a centrifugal compressor over a reciprocating unit are:

- Typically lower installed costs
- Typically lower maintenance costs
- Greater continuity of service and reliability
- Less operating attention
- Greater volume capacity for the footprint

In general, the advantages of a reciprocating compressor over a centrifugal unit are:

- Better flexibility in capacity and pressure range
- Higher compressor efficiencies, lower power costs
- Ability to deliver higher pressures
- Ability to handle smaller volumes
- Less sensitive to changes in composition and density

The following provides a comparison of key design criteria for reciprocating and centrifugal compressor packages based upon standard manufacturer designs and materials.

Capacity

- Reciprocating – Reciprocating compressors are positive displacement machines, therefore, their capacity is determined by cylinder size, the number of throws, or locations on the crankcase where a cylinder can be attached, and driver speed. Capacity may be controlled via speed control, clearances on a cylinder (i.e. addition of fixed or variable volume pockets), cylinder end deactivation, and system recycle. Turndown on a reciprocating compressor can be high as 80-90%.
- Centrifugal – Centrifugal compressors can be sized for an inlet flow capacities as low as 500 acfm upto 400,000 acfm in a single body, and is

limited by the choke point, or point at which the flow through any part of the compressor nears a velocity of Mach 1. Unlike a reciprocating compressor where minimum flow is solely a function of compressor geometry and speed, the minimum flow for a centrifugal compressor is limited by surge, which is a function of not only compressor geometry and speed, but also aerodynamic gas conditions and system resistance. Turndown on a centrifugal compressor can be as high as 40-50%.

Suction Pressure

- Reciprocating – Reciprocating compressors can take suction pressures as low as atmospheric, or even a slight vacuum. In vacuum applications, precautions must be taken to prevent atmospheric air from leaking into the cylinder through the piston rod packing.
- Centrifugal – Centrifugal compressors are suitable for service with sub-atmospheric inlet pressures with special seals and buffering designs to prevent atmospheric air from being drawn into the compressor.

Discharge Pressure

- Reciprocating – Reciprocating compressors are suitable for discharge pressures up to approximately 12,000 psi.
- Centrifugal – Centrifugal compressors are suitable for discharge pressures up to 1,450 psi with a horizontally split case design and up to 15,000 psi for radially split designs.

Discharge Temperatures

- Reciprocating – Reciprocating compressors discharge limits will depend upon the application and the seal material selected. API 618 limits the discharge temperature in hydrogen rich applications to 275 °F and for natural gas service to 350 °F. Most standard manufacturer designs will limit the discharge temperature on each stage to 300 °F.
- Centrifugal – Centrifugal compressors discharge temperature limits are based upon the compressor design and typically range from 400 to 450 °F. Higher discharge temperatures are available with special design considerations.

Compression Ratio

- Reciprocating – The compression ratio on each stage of a reciprocating compressor is limited by the resulting discharge temperature and piston rod load. Typical compression ratios range from 1.2 to 4.0 per compression stage.
- Centrifugal – The compression ratio limit for centrifugal compressors is a function of the process fluid physical properties, including molecular weight

and compressibility, as well as the compressor speed, stage geometry, and total number of stages.

Efficiency

- Reciprocating – Reciprocating compressor efficiency is affected by compression ratio, the respective cylinder's ratio of valve flow area to main bore diameter, and piston speed. Reciprocating compressors typically follow a very characteristic adiabatic curve. High speed reciprocating compressors (900 to 1800 rpm) typically have an adiabatic efficiency of approximately 82%. Lower speed reciprocating compressors (300 to 700 rpm) typically have an adiabatic efficiency of approximately 85%.
- Centrifugal – Centrifugal compressor efficiency is typically reported as polytropic rather than adiabatic and are heavily dependant upon inlet volume. Typical polytropic efficiencies range from 60% at 100-500 inlet acfm to as high as 85% at 7,500 acfm or greater. Average reported polytropic efficiencies are however between 70 – 75% at the 7,500 acfm or more inlet flow rate.

Reliability

- Reciprocating – Reciprocating compressor reliability is far less than that of centrifugal compressors. Reciprocating units have many more moving parts incorporating more wear and require more frequent replacement. Wear life of seals and valves are significantly effected by the cleanliness of the process fluid and tend to have much longer operational life with process gas free of liquids and debris.
- Centrifugal – Centrifugal compressor reliability approached 98% to 99% with proper routine maintenance.

Maintenance Intervals

- Reciprocating – Maintenance intervals for reciprocating compressors vary significantly with the application. Seal and valve maintenance intervals may be as short as a few months and as long as 3-5 years, depending upon the cleanliness of the process gas. Major overhauls may be required every 10 years or more.
- Centrifugal – Centrifugal compressors designed per API 617, are required to be designed for a minimum 5-year uninterruptable service life. In clean gas service, centrifugal compressors may operate continuously for 10-years or more without major maintenance requirements.

Capital & Operating Costs

- Reciprocating – Generally, a reciprocating compressor will have a lower base package cost but overall higher installed and operating cost than centrifugal compressors.

- Centrifugal – Centrifugal compressors have more complex geometry than a reciprocating compressor and therefore typically have a higher up front capital cost, but have fewer moving parts resulting in lower operating costs.

Integrally geared compressors are gaining popularity in carbon dioxide service, however are not as proven as their reciprocating and centrifugal counterparts. Integrally geared packages incorporate a bull gear and up to six (6) high speed pinions, each with one or more centrifugal compressors mounted on the pinion shaft. Optimal impeller speed and the ability to inter-cool compression phases provide much higher efficiencies than typical centrifugal compression units and typically incorporate very high reliabilities.

3.0.5.3 Analysis

At the Coffeyville Resources compression facility, the 40 MMSCFD carbon dioxide feed stream will be supplied at the suction to the selected compression package at approximately 10 PSIG and 110°F, equating to an inlet flow rate of approximately 18,120 acfm.

With a required 2,548 PSIG discharge pressure, the total horsepower requirement can be optimized by utilizing compression to take the raw CO₂ feed stream to approximately 1,400 PSIG and then utilizing a centrifugal pump to boost the discharge stream from 1,400 PSIG to pipeline pressure at 2,548 PSIG. This would require the selected compression package to provide a compression ratio of approximately 140, therefore, a multi-stage unit will be required. Multi-stage reciprocating compressors are normally considered for inlet volumes between 1 and 9,000 acfm, so to accommodate the 18,120 acfm feed rate, multiple multi-stage reciprocating compressors would be required. Multi-stage centrifugal compressors are normally considered for inlet volumes between 500 and 200,000 inlet acfm, but are limited to the total developed head available in a single unit. Therefore, a multi-stage, multi-unit compressor configuration will be required for the CVR application.

3.0.5.4 Recommendation

Although, either compressor type may be considered for the CVR compression application, a centrifugal compressor / centrifugal pump integrated package is recommended for the CVR compression facility.

An integrated solution will allow multiple centrifugal compressors as well as a centrifugal pump to be packaged together on a common skid utilizing a single driver with multiple gear boxes. A centrifugal compressor / pump package will provide lower initial costs as well as lower overall long term maintenance costs than multiple reciprocating units. It will also minimize the overall electrical construction requirements, reducing the number of 4160V SSRV's and 500KV cable. In addition, it is also anticipated that the source gas from the facility will be provided at a consistent rate and composition, and therefore the flexibility of capacity and pressure provided in a reciprocating compressor will not be required. The longer duration between maintenance periods of the centrifugal compressor will also allow for these activities to be better coordinated with the plant turn-around period. Information for this analysis was derived from reliable and publicly

available sources³.

3.0.6 Compressor Sizing & Selection

Several compressor configurations were evaluated as part of the desktop study. Viable configuration options, both with and without redundancy in the design, have been summarized in tables 3-9 and 3-10 below and on the following page:

Table 3-9 CVR Compression Facility Compression Configuration Option – No Redundancy

Option No.	Configuration	Total bhp	Total Capital Cost
1a	Two (2) 50% Recip + One (1) 100% Centrif. Pump	14,656	\$17,798,000
2a	One (1) 100% Centrif. + One (1) 100% Centrif. Pump	15,000	\$11,000,000
3a	One (1) 100% Int. Gear + One (1) 100% Centrif. Pump	15,000	\$13,000,000
4a	Three (3) 33% Recip. + One (1) 100% Centrif. Pump	13,027	\$6,798,000
5a	Two (2) 50% LP Recip + Two (2) 50% HP Recip Plus.....One (1) 100% Centrif. Pump	12,502	\$7,798,000
6a	Seven (7) LP Screw + Two (2) 50% HP Recip Plus.....One (1) 100% Centrif. Pump	17,430	\$11,148,000

Table 3-10 CVR Compression Facility Compression Configuration Option – With Redundancy

Option No.	Configuration	Total bhp	Total Capital Cost
1b	Three (3) 50% Recip + Two (2) 100% Centrif. Pump	22,562	\$27,096,000
2b	Two (2) 100% Centrif. + Two (2) 100% Centrif. Pump	30,000	\$22,000,000
3b	Two (2) 100% Int. Gear + Two (2) 100% Centrif. Pump	30,000	\$26,000,000
4b	Four (4) 33% Recip. + Two (2) 100% Centrif. Pump	18,140	\$9,596,000
5b	Three (3) 50% LP Recip + Three (3) 50% HP Recip Plus.....Two (2) 100% Centrif. Pump	19,331	\$12,096,000
6b	Eight (8) LP Screw + Three (3) 50% HP Recip Plus.....Two (2) 100% Centrif. Pump	22,973	\$14,996,000

³ GPSA Engineering Data Book, Twelfth Edition, 2004
John M. Campbell, CO2 Surface Facilities, Version #PF81-P-03-02-06

Based upon discussions with Blue Source, LLC., Option #2a was selected for the CVR compression facility. This provides for three blowers that will feed a single integrated centrifugal skid package comprised of three (3) multi-stage centrifugal compressors paired with a single centrifugal pump with a single 4160V, 15,000 hp, electric motor. The integrated centrifugal package will include a separate scrubber / cooler skid incorporating both inter-stage and after-coolers. The use of forced draft fin-fan coolers would be anticipated, adding an auxiliary load of approximately 100 hp.

Typical operations and maintenance costs for this package would run approximately \$65,000 / year.

3.0.7 Process Equipment

Dehydration Unit

Water vapor from the raw carbon dioxide feed stream would be removed utilizing a single tri-ethylene glycol (TEG) dehydration skid package comprised of a gas fired 3.5 MMBTU / Hr re-boiler and 60" diameter contactor tower.

The initial fill for start-up of the system is anticipated to require approximately 300 gallons of TEG and has been included in the capital costs provided with this study. Annual TEG losses are estimated at less than 1%, excluding upset conditions, with estimated annual operating costs of \$300,000.

3.0.8 Electrical Design

Power for the CVR compression and processing facilities are anticipated to be available from the Coffeyville Refinery sub-station located approximately 250 ft. NE of the proposed CVR compression facility site. Brining power to the CVR compression facility will require construction of an overhead 13.8 KV power line between the CVR substation and compressor site and will terminate at a new 13.8 KV / 4160V transformer before stepping down to 4160V to feed the main switchgear for the compression facility. 4160 V / 3-Phase power shall be used as the secondary service, with additional transformation down to 480V / 3-Phase and 208V / 120V for auxiliary equipment and lighting. All power and controls for the new facility would be incorporated into a pre-engineered metal power distribution center, including a 4160V cutler-hammer, or equivalent, switchgear, 4160V solid state reduced voltage starter, 480V motor control center, Programmable Logic Controller, and miscellaneous power and lighting equipment.

Table 3-11 below summarizes the overall electric loads and estimate annual cost at the CVR compression facility. The electric rate of \$0.0732/KW-HR used is the average commercial electric rate paid in the state of Kansas in 2009 (Report No.: DOE/EIA-0226).

Table 3-11 CVR Facility Annual Electric Loads and Costs

Description	Number of Units	BHP Each	Total BHP
Blower, GD Suitorbuild 8000	3.0	500 BHP	1,500 BHP
API Centrifugal Compressor / Pump	1.0	15,000 BHP	15,000 BHP
Intercoolers and Aftercoolers	1.0	100 BHP	100 BHP
TEG Dehydration Package	1.0	15 BHP	15 BHP
TOTAL BHP			16,615 BHP
TOTAL KW-HR/YR			103,108,000 KW-HR/YR
COST PER KW-HR			\$0.0732 /KW-HR
ANNUAL COST			\$7,548,000

3.0.9 SCADA Design

The Supervisory Control And Data Acquisition (SCADA) system on the CVR-TAF pipeline will consist of four main components which are the 1) Programmable Logic Controllers (PLC) to be located at all the station and valve sites connected to the instruments, 2) Operator Interface and data collection system which is the SCADA software, 3) Leak detection system, and 4) Communications system which will tie all the parts together.

The communication system will be composed of an armored fiber optic cable installed in the most appropriate method adjacent to the pipeline. The cable could be installed in the same ditch as the pipeline, direct buried, in duct strapped to the pipe at crossings, or plowed into the ground. The SCADA system which communicates through a fiber optic cable will have a very high uptime and the capability for fast and reliable communication between the stations and the main line valves. These features will enable the fast integrated control system to automatically operate more safety.

The PLC at each compressor and main line valve site will be a GE 90-30 or company approved equal and will be housed inside a small building to enable support personnel to program and maintain them in inclement weather.

The SCADA software will have a primary system installed at the primary control center on one end of the pipeline and there will be a backup SCADA host at the facility at the other end of the pipeline. Costs for SCADA vendor services were also included. SCADA vendor services include project management, design specification documents, SCADA communications programming, SCADA screen programming, factory tests, installation onsite, onsite tuning of the software, commissioning tests, operations and the maintenance manual, training support for operators and technicians.

The Leak Detection System will communicate with each station to analyze the pipeline for leaks and report to the SCADA software for operator notification. Leak Detection vendor services were also included. Leak Detection vendor services include project management, design specification documents, communications programming, graphical user interface screen programming, factory tests, installation onsite, tuning of the software, commissioning tests, operations and the maintenance manual, training

support for operators and technicians.

3.0.10 Cathodic Protection and AC Mitigation

Cathodic protection of the 8" steel pipeline system will be accomplished using an impressed current system with either deep-well and/or surface anode ground beds. In order to quantify the soil resistivity in the area, a soil investigation will be required once the pipeline has been installed. The cathodic protection system will be designed accordingly depending upon the soil resistivity. The system will consist of either high-silicon cast iron anodes set in deep wells and/or treated graphite surface anodes. The quantity and dimension of the deep well anodes and/or surface ground beds will be determined during detailed design of the cathodic protection system. Either system will be powered by a rectifier which will also be sized during detailed design of the cathodic protection system.

Alternate Current (AC) mitigation will be required where pipelines are in close proximity to overhead power lines. AC mitigation will be accomplished using zinc anode ribbon buried alongside the pipeline system. In order to determine the amount of zinc ribbon required for AC mitigation a soil investigation will be required during detailed design to quantify the soil resistivity in the areas of concern. Based on the soil resistivity, proximity and voltage of overhead power lines, and the operating lifespan of the project, the AC mitigation system will be designed to protect the pipeline system from stray currents imposed by overhead power lines.

3.0.11 Typical Construction Method

Standard pipeline construction procedures and BMPs would be followed during construction. The centerline of the ROW would be staked prior to construction. The following discussion provides a brief overview of the construction process.

All equipment and vehicular access into the pipeline project would be confined to existing roads and the established ROW corridor. No major reconstruction or rerouting of these roads is intended.

The following are the general steps in the construction process:

- Surveying and staking of the ROW
- Right-of-way (ROW) clearing and grading, topsoil stockpiling
- Ditching
- Pipe stringing, and bending
- Pipe welding
- Pipe Jeeping
- Pipe lowering in
- Backfilling of trench
- Testing of pipeline and facilities
- Clean up and revegetation

All construction materials would be hauled to the job site by truck, as needed, and strung along the ROW as they arrive. Pipe would be strung in such a manner as to cause the least interference with the normal use of the land crossed by the ROW. The construction ROW would be limited to a 75-foot width. As a general rule (except for

steep slope areas), clearing would be limited to 75 feet: 55 feet on the working side and 20 feet on the stockpile side of the trench. Grading of the entire ROW would occur only in areas where equipment access is not possible without ROW clearing. The top 6 inches of topsoil would be removed and stockpiled off of the trench line and any areas to be graded. Top soils would be stockpiled separately from trench spoils.

Construction or routine maintenance activities will not be allowed during periods when soil is too wet to adequately support construction equipment. If such equipment creates surface ruts in excess of 6 inches deep, the construction supervisor would deem that soil conditions are too wet to adequately support construction equipment. Construction activities would not be allowed until soil conditions improve. The pipeline trench would be excavated using a wheel trencher, or a track-hoe excavator. The wheel trencher pulverizes the soil as the trenching progresses, stacking the spoil in a pile along the side of the trench. In the event weather conditions warrant, the spoil pile can be worked by driving a tracked dozer over the spoil and working it with the blade, breaking up frozen soils. Breaking up the frozen soils would mitigate the issue of the ditch settling. A small mound of soil (6-10 inches high) would be placed on top of the trench line to accommodate minor settling.

A wheel trencher or track hoe would be used to dig a trench to an average depth of 60 inches, stacking the dirt beside the ditch. After the pipe is placed in the ditch a motor grader or caterpillar would be used to push the dirt back into the trench. The fill on the trench would then be tamped into place with the grader wheels, leaving a berm of 6 to 10 inches to accommodate settling. Disturbance of the topsoil within the ROW would be kept to a minimum. In areas of excessively steep hillsides, or to provide a smooth approach to a cut or gully, as well as at stream bank crossings and at established work stations, some blading may be required to provide a safe and suitable working area for the equipment and workers. When this occurs the top 6 inches of soil would be stockpiled on the side of the ROW and spread back over the area from which it was taken, after the final grading. Before seeding any disturbed areas, the ROW would be restored to its original form, slope, contour, and soil density to the extent practicable.

3.0.12 Rock Ditch

Throughout the course of the pipeline construction, solid rock may be encountered during the excavation. When the rock cannot be excavated with the typical track hoe, additional equipment or blasting may be required. In these areas, construction cost will increase due to the additional equipment and slower installation productivity. Typically, an additional cost for installation is added for every foot of rock ditch encountered. A construction contractor, who has installed pipelines in the project area, estimated that there will be significant amounts of rock encountered on the CVR-TAF pipeline route. In the cost estimate, it was assumed that 45% of the total route would be considered rock ditch, as recommended by the contractor. The precise amount of rock cannot be determined until construction of the pipeline.

3.0.13 Crossings

A detailed review of the required pipeline crossings was completed. The locations where the proposed route crossed an Interstate, Highway, State Road, Other Paved Roads, Dirt Roads, Railroads, Lakes, Rivers, and creeks were identified. The below table (Table 3-12) summarizes the number of each type of crossings, as well as the estimated

total length of each type of crossing.

Table 3-12 KE-GE Road, Railroad, and Waterway Crossing Tally

TYPE	TOTAL NO. CROSSINGS	TOTAL LENGTH
Interstate	0	0 ft
Highway / State Rd	5	500 ft
Other Paved Road	17	1,275 ft
Dirt Road	64	3,200 ft
Railroad	6	600 ft
Lake / River	4	800 ft
Creek	37	1,380 ft
TOTAL	133	7,755 ft

In general, it is proposed that paved roads or railroads that require a crossing length of 100 feet or greater, be crossed using a Horizontal Directional Drill (HDD). It is proposed that paved roads or railroads that require a crossing length of 100 feet or less, be crossed using an un-cased slick bore. It is proposed that all dirt roads be open cut. Regarding waterway crossings, it is proposed that waterways that require a crossing length of 100 feet or greater, be crossed using a Horizontal Directional Drill (HDD). It is proposed that waterways that require a crossing length of 100 feet or less, be crossed using an un-cased slick bore.

During the detailed design portion of the project, each crossing would need to be analyzed on a site specific basis, and a detailed crossing plan and profile be developed.

3.0.14 Long Lead Materials

Most of the materials required for the construction of the CVR-TAF Pipeline Project are considered long lead items. Long lead items are described as items that are not in stock at the time of purchase. These items include the compressors, pumps, dehydration process equipment, valves, actuators, steel pipe, materials for the launchers and receivers and their fabrications, and other miscellaneous fittings. Deliveries are based on budgetary quotes for material received on August 1, 2010.

Budgetary bids have been received from vendors for the blower compressors, with an anticipated delivery of 14-16 weeks after receipt of order.

Budgetary bids have been received from vendors for the integrated centrifugal compressor / pump package, with an anticipated delivery of 60 weeks after receipt of order.

Budgetary bids have been received from vendors for the dehydration process equipment, with an anticipated delivery of 25 weeks after receipt of order.

Budgetary bids have been received from vendors for the 8" steel line pipe and ANSI 1500 valves and required actuators for the pig launchers/receivers. Anticipated delivery of valves and actuators is 12-26 weeks after receipt of order (ARO).

Budgetary bids have been received from vendors for the steel line pipe. Line pipe will be mill rolled and coated with FBE coating. Anticipated delivery of the line pipe is 20-30 weeks after receipt of order (ARO). Line pipe will be mill rolled and coated with FBE coating.

Budgetary bids have been received from vendors for the launchers and receivers. Anticipated delivery is 12-14 weeks after purchase orders have been issued. Lead times include material procurement, fabrication and testing and shipping.

Budgetary bids have also been received from vendors for bends for the piggable pipeline systems. Deliveries are anticipated to be 2-3 weeks ARO.

3.0.15 Capital Cost Estimate

See the attached Appendix 3-C – Pipeline Estimate prepared for the CVR-TAF Pipeline Systems. See also Appendix 3-D – Estimate Basis Memorandum for more information regarding the estimate.

3.0.16 Project Schedule

See Appendix 3-E - Project Schedule prepared for the CVR-TAF Pipeline Systems.

3.1 Geneseo-Edwards Field

3.1.1 PIPELINE ROUTING

3.1.1.1 General

Refer to Appendix 3-G – Feasibility Drawings of this report, Drawing Number 2702-M-001 “Kansas Ethanol LLC Plant to the Geneseo-Edwards Oil Field – Overview Sheet 1 of 1.” Refer to Drawing Numbers 2702-M-101 to 02702-M-104 for the Alignment Sheets showing detailed sections of land ownership, environmental restrictions, plan view, ground profile, general material specifications, etc.

The pipeline will originate at the Kansas Ethanol LLC (KE) Plant and generally traverse in a Northerly direction paralleling existing pipeline corridors for 14 miles (23 kilometers). It will then traverse 1.77 miles (2.8 kilometers) in a South Easterly direction following existing roads and pipeline corridors where it will terminate at the Geneseo-Edwards (GE) Oil Field.

3.1.1.2 Alternate Routes

While selecting the route for the KE-GE pipeline, it was important that existing right of ways be utilized to the greatest extent possible. The pipeline corridor that was selected provides a relatively direct route, without approaching the populated areas of Lyons, Kansas, which is located approximately 1.5 miles (2.4 kilometers) to the west of the route. An alternate existing corridor was available; however, it passes through much more populated areas, and was therefore eliminated.

3.1.1.3 Right-of-Way Acquisition

A desktop review of the pipeline right-of-way indicates that 100% of the right-of-way is private. The right-of-way includes mostly cultivated and prairie lands. This study includes estimated costs for obtaining easements from the private land owners to install the proposed pipeline. The precise number of land owners and parcels was not

determined during this study. Only the creek crossings, roads, highways, etc. are not privately owned, and come under state and federal guidelines.

Disturbance would occur within a 75-foot wide temporary ROW construction corridor. This width should be sufficient to accommodate construction in most areas. However, additional construction space would be required if another pipeline must be crossed, to temporarily store pipe and equipment, and/or to accommodate construction requirements for a certain area (e.g., road and river crossings, steep slopes).

New access roads would not be required for the project during construction. Construction access would be via the pipeline ROW and existing regional access roads. However, during construction it may be determined that additional access is needed.

3.1.1.4 Permitting

Numerous Federal, State and County permits will be required for the construction of the KE-GE Pipeline.

For example, some of the permits required under Federal jurisdiction shall be National Environmental Policy Act (NEPA), Corps of Engineers Nationwide Permit, United States Fish and Wildlife Services. Some of the permits required under the State of Kansas jurisdiction shall be Department of Health and Environment, (Air Quality, Water Discharge, General), National Historic Preservation Act, Wildlife and Parks, Kansas Highway Department. Some of the permits required under the County jurisdiction shall be Road and Bridge Departments. Only permits required for construction have been included within this estimate, therefore the NEPA permit, COE, etc. have been excluded from this budget.

3.1.2 PIPELINE SYSTEM DESCRIPTION

The purpose of the KE-GE Pipeline is to transport compressed high-purity CO₂ via a 4" steel intra-state pipeline from the Kansas Ethanol LLC Plant to the Geneseo-Edwards Oil Field for both sequestration and enhanced oil recovery purposes.

The pipeline will be designed, constructed and operated in accordance to Title 49, Part 195, "Transportation of Hazardous Liquids by Pipeline" – Department of Transportation, rules and regulations.

The pipeline will be composed of 4.5" O.D., 0.237" wall thickness, API 5L, PSL2, Electric Resistance Welded (ERW) steel line pipe, coated with 14-16 mils of Fusion Bond Epoxy for external corrosion protection. The pipeline will be designed to be operated at a Maximum Operating Pressure of 1,700 PSIG, with an ANSI 900 flange rating.

All road, railroad and creek crossing pipes will be manufactured to Seamless line pipe specifications instead of ERW to further mitigate fracture propagation.

Carbon Dioxide must be compressed to 1,587 PSIG at the Kansas Ethanol LLC Plant in order to deliver it to the Geneseo-Edwards Oil Field at 1,400 PSIG. These operating pressures were utilized to provide a reasonable margin between the operating pressures in the pipeline and the critical pressure of carbon dioxide, which is approximately 1,100 PSIA at 50 °F. Operating at pressures above the critical pressure ensures that the carbon dioxide is transported in the dense phase and that no phase changes occur in the pipeline system. Transporting carbon dioxide in dense-phase is

the most efficient means of transportation since it allows for smaller pipeline sizes at high flow rates.

Isolation Block Valves will be strategically located in the pipeline system, as shown in Table 3-13 to isolate the pipeline and blow the Carbon Dioxide down in case of an emergency.

Table 3-13 KE-GE Estimated Isolation Block Valves

No.	Pipeline Station	Mile Post
1	80+00	MP 1.52
2	90+00	MP 1.70
3	380+00	MP 7.20
4	540+00	MP 10.23

Crack arrestor will be installed at every half mile (0.8 kilometers) on the steel pipeline to mitigate fracture propagation. It is anticipated that Clock Springs, or similar product, will be utilized as crack arrestors. This type of product has been successfully utilized as crack arrestors on existing carbon dioxide pipelines.

The pipeline will be designed and constructed to accommodate intelligent pigs. Pig launcher and receiver will be installed into the system.

3.1.3 Pipeline Hydraulics

3.1.3.1 Purpose

The purpose of this pipeline hydraulic calculation was to analyze the predicted performance of the Kansas Ethanol to Geneseo-Edwards oil field (KE-GE) carbon dioxide pipeline under various operating scenarios. In general, the results from the hydraulic calculation include resulting pressures, resulting temperatures, resulting velocities, and line size confirmation. Hydraulic scenarios were completed for three potential line sizes.

3.1.3.2 Pipeline Routing

The scope of the hydraulic study was limited to the preferred route. This route heads in a north-easterly direction from the Kansas Ethanol facility and turns north at approximately Mile Post 2. The pipeline route continues north and is located approximately one (1) mile (1.6 kilometers) east of the city of Lyons, Kansas. The preferred route is approximately 15.8 miles (25 kilometers) in length. The carbon dioxide delivery point at the Geneseo-Edwards oil field is located at the center of Section 24, Township 18S, Range 8W.

3.1.3.3 Hydraulic Modeling Software

PIPEPHASE Version 9.4 was used to model the hydraulics of the carbon dioxide pipeline. This software has the capability of predicting the mechanical and thermodynamic properties of dense-phase carbon dioxide and can model steady-state carbon dioxide flow in pipeline networks.

3.1.3.4 Hydraulic Design Basis - Pressure Requirements

For this hydraulic study, the delivery pressure at the Geneseo-Edwards oil field was fixed at 1,400 PSIG. This pressure was utilized to provide a reasonable margin between the operating pressures in the pipeline and the critical pressure of carbon dioxide, which is approximately 1,100 PSIA at 50 °F. Operating at pressures above the critical pressure ensures that the carbon dioxide is transported in the dense phase and that no phase changes occur in the pipeline system. Transporting carbon dioxide in dense-phase is the most efficient means of transportation since it allows for smaller pipeline sizes at high flowrates.

At the Geneseo-Edwards oil field, a pressure reduction valve will be installed to reduce the pressure of the carbon dioxide from the 1,400 PSIG to the well head injection pressure of approximately 1,100 PSIG.

The carbon dioxide pipeline will be designed and constructed per CFR 49 Part 195 "Transportation of Hazardous Liquids by Pipeline." A design factor (F) of 0.72 was used for allowable stress calculations and determination of the Maximum Operating Pressure (MOP). Based on the hydraulic results, an appropriate ANSI rating for the pipeline was selected.

3.1.3.5 Hydraulic Design Basis - Capacity Requirements

The baseline capacity for the pipeline design is 8 MMSCFD. This corresponds to the maximum anticipated carbon dioxide availability from the Kansas Ethanol Facility. No allowance for future capacity was considered.

3.1.3.6 Hydraulic Design Basis - Fluid Temperatures

It is anticipated that the carbon dioxide discharge temperature from the originating compressor / pump station at Kansas Ethanol will be a maximum of 120 °F. Therefore, the design temperature for the pipeline system was selected to be 130 °F.

In the hydraulic model, an ambient ground temperature of 50 °F was selected based on research of soil temperatures published by the USDA. The USDA has published maps of soil temperature regimes for the contiguous United States (http://soils.usda.gov/use/thematic/temp_regimes.html). Based on this map, the project area is located near the boundary of the Mesic and Thermic soil temperature regimes. The Mesic soil regime is defined as having a mean annual soil temperature between 8 °C (46.4 °F) and 15 °C (59.0 °F). The Thermic soil regime is defined as having a mean annual soil temperature between 15 °C (59.0 °F) and 22° C (71.6 °F). Since the project area is on the boundary of these two regimes, the mean annual soil temperature was assumed to be 15 °C (59.0 °F).

Using the mean annual soil temperature and anticipated depth of burial, the amplitude of seasonal soil temperature change can be determined. For dry soil at a burial depth of 4 feet, the amplitude of seasonal temperature change is approximately ± 10 °F (<http://www.geo4va.vt.edu/A1/A1.htm>). Therefore, the lowest anticipated soil temperature is approximately 50 °F, which was taken as the ambient soil temperature in the hydraulic model.

3.1.3.7 Hydraulic Design Basis - Carbon Dioxide Composition Analysis

Kansas Ethanol provided the anticipated compositions of fluid stream. Note that the composition dated October 24, 2009 was utilized and is included as Appendix 3-B to this report. It was assumed that the mole percentage not accounted for in the provided composition was Nitrogen. This composition was modified to reflect the dehydration process needed to meet the dehydrated carbon dioxide specification of 10 lb H₂O / MMSCFD allowable. The below composition (Table 3-14) corresponds to the fluid stream anticipated in the pipeline, which was used in the hydraulic model.

Table 3-14 KE-GE Pipeline Compositional Analysis

Component	Mole Fraction
N ₂	0.085482
CO ₂	0.905110
H ₂ O	0.000210
AR	0.000000
CO	0.000000
COS	0.000000
O ₂	0.009198
H ₂	0.000000
CH ₄	0.000000
TOTAL	1.000000

3.1.3.8 Hydraulic Design Basis - Assumed Mechanical and Thermodynamic Properties

The table below (Table 3-15) contains the mechanical and thermodynamic parameters that were assumed in the hydraulic model of the carbon dioxide pipeline. The parameters were selected based on various published charts and tables, and project specific requirements.

Table 3-15 Assumed Mechanical and Thermodynamic Parameters

Design Parameter	Value
Steel Absolute Roughness	0.00360 IN
Flow Efficiency Factor	95.00 PERCENT
Steel Heat Conductivity	26.500 BTU/HR-FT-°F
Soil Heat Conductivity	0.960 BTU/HR-FT-°F
Ground Temperature	50 °F
Burial Depth	48.0 IN (4 FT)
Pressure Drop Correlation	BEGGS-BRILL WITH MOODY FRICTION FACTOR
Bulk Modulus of Pipe	30,000,000 PSI
Bulk Modulus of CO ₂	22,888 PSI

3.1.3.9 Hydraulic Design Basis - Elevation Profile

The elevation profile utilized in the hydraulic model was created from available digital elevation models (DEM's) for the project area. The same elevation profile can be

found on the attached Alignment Sheet drawings. No field survey data was gathered to create the pipeline elevation profile.

3.1.3.10 Hydraulic Design Basis - Surge Pressure

Surge pressure, also known as water hammer, is the result of a rapid increase in pressure which occurs when the liquid velocity is suddenly changed in a closed piping system. Per CFR 49 Part 195, temporary pressure excursions must be limited to less than 110% of the design pressure. Surge pressure in dense-phase carbon dioxide pipelines is not well documented; therefore, the standard surge pressure equations were used in the hydraulic model, with appropriate substitutions for liquid density and bulk modulus. The bulk modulus of a fluid is the ratio of the pressure stress to the volumetric strain. The bulk modulus of carbon dioxide was estimated from property tables, calculated by considering the change in density corresponding to a change in pressure.

Surge pressures in dense phase carbon dioxide pipelines are not as great as that in water pipelines, due to the compressibility of the fluid. This is evident in the bulk modulus of carbon dioxide compared to the bulk modulus of water.

3.1.3.11 Results

This section summarizes the results obtained from the hydraulic modeling of the carbon dioxide pipeline. Table 3-16 defines the parameters for the various hydraulic cases.

Table 3-16 Hydraulic Case Definitions

Parameter	Case 1 - 6"	Case 2 - 4"	Case 3 - 3"
Volumetric Flowrate	8 MMSCFD	8 MMSCFD	8 MMSCFD
Mass Flowrate	37,355 lb/hr	37,355 lb/hr	37,355 lb/hr
Pipeline Outer Diameter	6.625"	4.500"	3.500"
Pipeline Wall Thickness	0.280"	0.237"	0.216"
Corrosion Allowance	1/8" (0.125")	1/8" (0.125")	1/8" (0.125")
Effective Wall Thickness	0.155"	0.112"	0.091"
Pipeline Grade	X-52	X-52	X-60
Design Factor	0.72	0.72	0.72
Required System MOP	1,600 PSIG	1,700 PSIG	2,100 PSIG
Pipe MOP	1,751 PSIG	1,863 PSIG	2,246 PSIG
ANSI Class	ANSI 900	ANSI 900	ANSI 900
ANSI Rating at 130 °F	2,161 PSIG	2,161 PSIG	2,161 PSIG

The resulting operating pressures and maximum surge pressures are summarized in Table 3-17. Hydraulic charts, showing the ground elevation, pressure, and surge pressure, have also been completed and are included as Appendix 3-C to this report.

Table 3-17 Pipeline Pressure Results

Parameter	Case 1 - 6"	Case 2 - 4"	Case 3 - 3"
KE Discharge	1,433 PSIG	1,587 PSIG	2,032 PSIG
GE Delivery	1,400 PSIG	1,400 PSIG	1,400 PSIG
Min Pipeline Pressure	1,379 PSIG	1,391 PSIG	1,400 PSIG
Max Pipeline Pressure	1,433 PSIG	1,587 PSIG	2,032 PSIG
Max Surge Pressure	1,482 PSIG	1,680 PSIG	2,142 PSIG

The resulting temperatures are summarized in the table below (Table 3-18).

Table 3-18 Pipeline Temperature Results

Parameter	Case 1 - 6"	Case 2 - 4"	Case 3 - 3"
KE Discharge	120 °F	120 °F	120 °F
GE Delivery	51 °F	51 °F	49 °F

The resulting velocities are summarized in the table below (Table 3-19). Results for pipeline segment inlet velocity are reported in feet per second (fps).

Table 3-19 Pipeline Velocity Results

Parameter	Case 1 - 6"	Case 2 - 4"	Case 3 - 3"
KE Discharge	2.93 fps	5.57 fps	6.59 fps
GE Delivery	0.87 fps	1.97 fps	3.36 fps

3.1.3.12 Recommendation

Based on the hydraulic results, it is recommended that 4" x 0.237" Wall Thickness, Grade X-52 pipe be utilized for the KE-GE pipeline. This corresponds to the hydraulic results from Case 2 in the above tables. The operating pressures for this case are within common operating pressures of other existing carbon dioxide pipelines.

Cost metrics (dollar per inch-mile for pipeline and dollar per horsepower for stations) were applied to the various pipeline and station scenarios, and it was determined that the additional cost to install the larger diameter pipeline was not offset by the reduced horsepower requirement. However, since the cost difference between the 3" and 4" options are minimal, it is recommended that the 4" pipe be selected. The below table (Table 3-20) summarizes this cost comparison. This method will give an approximate, order of magnitude, cost difference for the various options. A detailed cost estimate has been created for the recommended 4" option (Case 2) and is included as Appendix 3-H of this report.

Table 3-20 Pipeline Cost Comparison

Parameter	Case 1 - 6"	Case 2 - 4"	Case 3 - 3"
Pipeline Metric	\$35,000 /in-mi	\$35,000 /in-mi	\$35,000 /in-mi
Pipeline Diameter	6.625"	4.500"	3.500"
Pipeline Length	15 miles (24 kilometers)	15 miles (24 kilometers)	115 miles (185 kilometers)
Station Metric	\$3,000 per BHP	\$3,000 per BHP	\$3,000 per BHP
Differential BHP	9 BHP	41 BHP	95 BHP
Approx Differential Cost	\$1,380,000	\$360,000	Baseline

Note that the above listed horsepower requirements are differential, and do not include the additional horsepower requirements that would be the same for all three scenarios.

3.1.4 COMPRESSION AND PROCESS STUDY

3.1.4.1 General Facility Description

Prior to delivery of the carbon dioxide to the Geneseo-Edwards Oil Field, the raw vapor stream off of the Kansas Ethanol plant will need to be processed to facilitate miscibility with the crude oil and boosted to pipeline pressure to allow the purified carbon dioxide stream to be transported as a supercritical fluid rather than in the vapor phase, minimizing both pipeline diameter and horsepower requirements, as well as providing the necessary pressure for injection in the oil reservoir. The compression and processing facilities on the KE-GE pipeline will require compression to take the raw carbon dioxide stream from approximately atmospheric (13.8 psia) pressure to the required pipeline discharge pressure of 1,587 PSIG, an Oxygen Removal Unit ("ORU") to remove oxygen from the raw feed stream to a desired concentration of less than 10 ppm, and dehydration to take the water content to a concentration of less than 75 ppm. Controls and operation of the KE compression facilities will be located in a common, pre-engineered, electrical Power Distribution Center ("PDC") located on-site with the specified compression and processing equipment. A process flow diagram and conceptual site layout have been provided in the drawings section of this report.

3.1.5 Compression Study

3.1.5.1 General

Transportation of dense phase carbon dioxide is growing application in the oil and gas industry and incorporates three primary compression technologies: reciprocating compressors, centrifugal compressors, and recently, integrally geared solutions. Prior to selection of the specified compression equipment for this application, a study was completed to compare these technologies, including their associated annual and 9-year operation and maintenance costs.

3.1.5.2 Discussion

Reciprocating compressors consist of one or more cylinders, each with a piston or plunger which displaces a positive volume of gas with each stroke. Centrifugal compressors consist of a rotating element, typically an impeller or bladed rotor, which

accelerates the gas as it passes through the compressor, converting the velocity head into static pressure. Both types of compressors are available in single and multi-stage configurations. Centrifugal compressors approximate a constant head-variable volume machine, while reciprocating compressors approximate a constant volume-variable head machine.

In general, the advantages of a centrifugal compressor over a reciprocating unit are:

- Typically lower installed costs
- Typically lower maintenance costs
- Greater continuity of service and reliability
- Less operating attention
- Greater volume capacity for the footprint

In general, the advantages of a reciprocating compressor over a centrifugal unit are:

- Better flexibility in capacity and pressure range
- Higher compressor efficiencies, lower power costs
- Ability to deliver higher pressures
- Ability to handle smaller volumes
- Less sensitive to changes in composition and density

The following provides a comparison of key design criteria for reciprocating and centrifugal compressor packages based upon standard manufacturer designs and materials.

Capacity

- Reciprocating – Reciprocating compressors are positive displacement machines, therefore, their capacity is determined by cylinder size, the number of throws, or locations on the crankcase where a cylinder can be attached, and driver speed. Capacity may be controlled via speed control, clearances on a cylinder (i.e. addition of fixed or variable volume pockets), cylinder end deactivation, and system recycle. Turndown on a reciprocating compressor can be high as 80-90%.
- Centrifugal – Centrifugal compressors can be sized for an inlet flow capacities as low as 500 acfm up to 400,000 acfm in a single body, and is limited by the choke point, or point at which the flow through any part of the compressor nears a velocity of Mach 1. Unlike a reciprocating compressor where minimum flow is solely a function of compressor geometry and speed, the minimum flow for a centrifugal compressor is limited by surge, which is a function of not only compressor geometry and speed, but also aerodynamic gas conditions and system resistance. Turndown on a centrifugal compressor can be as high as 40-50%.

Suction Pressure

- Reciprocating – Reciprocating compressors can take suction pressures as low as atmospheric, or even a slight vacuum. In vacuum applications, precautions must be taken to prevent atmospheric air from leaking into the cylinder through the piston rod packing.
- Centrifugal – Centrifugal compressors are suitable for service with sub-atmospheric inlet pressures with special seals and buffering designs to prevent atmospheric air from being drawn into the compressor.

Discharge Pressure

- Reciprocating – Reciprocating compressors are suitable for discharge pressures up to approximately 12,000 psi.
- Centrifugal – Centrifugal compressors are suitable for discharge pressures up to 1,450 psi with a horizontally split case design and up to 15,000 psi for radially split designs.

Discharge Temperatures

- Reciprocating – Reciprocating compressors discharge limits will depend upon the application and the seal material selected. API 618 limits the discharge temperature in hydrogen rich applications to 275 °F and for natural gas service to 350 °F. Most standard manufacturer designs will limit the discharge temperature on each stage to 300 °F. Inter-coolers and after-coolers are often used between stages and at the compressor discharge to improve efficiencies and meet required design temperatures of downstream equipment.
- Centrifugal – Centrifugal compressors discharge temperature limits are based upon the compressor design and typically range from 400 to 450 °F. Higher discharge temperatures are available with special design considerations. Inter-coolers and after-coolers are often used between stages and at the compressor discharge to improve efficiencies and meet required design temperatures of downstream equipment.

Compression Ratio

- Reciprocating – The compression ratio on each stage of a reciprocating compressor is limited by the resulting discharge temperature and piston rod load. Typical compression ratios range from 1.2 to 4.0 per compression stage.
- Centrifugal – The compression ratio limit for centrifugal compressors is a function of the process fluid physical properties, including molecular weight and compressibility, as well as the compressor speed, stage geometry, and total number of stages.

Efficiency

- Reciprocating – Reciprocating compressor efficiency is affected by compression ratio, the respective cylinder's ratio of valve flow area to main bore diameter, and piston speed. Reciprocating compressors typically follow a very characteristic adiabatic curve. High speed reciprocating compressors (900 to 1800 rpm) typically have an adiabatic efficiency of approximately 82%. Lower speed reciprocating compressors (300 to 700 rpm) typically have an adiabatic efficiency of approximately 85%.
- Centrifugal – Centrifugal compressor efficiency is typically reported as polytropic rather than adiabatic and are heavily dependant upon inlet volume. Typical polytropic efficiencies range from 60% at 100-500 inlet acfm to as high as 85% at 7,500 acfm or greater. Average reported polytropic efficiencies are however between 70 – 75% at the 7,500 acfm or more inlet flow rate.

Reliability

- Reciprocating – Reciprocating compressor reliability is far less than that of centrifugal compressors. Reciprocating units have many more moving parts incorporating more wear and require more frequent replacement. Wear life of seals and valves are significantly affected by the cleanliness of the process fluid and tend to have much longer operational life with process gas free of liquids and debris.
- Centrifugal – Centrifugal compressor reliability approached 98% to 99% with proper routine maintenance.

Maintenance Intervals

- Reciprocating – Maintenance intervals for reciprocating compressors vary significantly with the application. Seal and valve maintenance intervals may be as short as a few months and as long as 3-5 years, depending upon the cleanliness of the process gas. Major overhauls may be required every 10 years or more.
- Centrifugal – Centrifugal compressors designed per API 617, are required to be designed for a minimum 5-year uninterruptable service life. In clean gas service, centrifugal compressors may operate continuously for 10-years or more without major maintenance requirements.

Capital & Operating Costs

- Reciprocating – Generally, a reciprocating compressor will have a lower base package cost but overall higher installed and operating cost than centrifugal compressors.

- Centrifugal – Centrifugal compressors have more complex geometry than a reciprocating compressor and therefore typically have a higher up front capital cost, but have fewer moving parts resulting in lower operating costs.

Integrally geared compressors are gaining popularity in carbon dioxide service, however are not as proven as their reciprocating and centrifugal counterparts. Integrally geared packages incorporate a bull gear and up to six (6) high speed pinions, each with one or more centrifugal compressors mounted on the pinion shaft. Optimal impeller speed and the ability to inter-cool compression phases provide much higher efficiencies than typical centrifugal compression units and typically incorporate very high reliabilities.

3.1.5.3 Analysis

At the Kansas Ethanol compression facility, the 8 MMSCFD carbon dioxide feed stream will be supplied at the suction to the selected compression package at approximately 13.8 PSIA and 58 °F, equating to an inlet flow rate of approximately 5,895 acfm. With a required 1,587 PSIG discharge pressure, the selected compression package will need to provide a compression ratio of approximately 116, therefore, a multi-stage unit will be required. Multi-stage reciprocating compressors are normally considered for inlet volumes between 1 and 9,000 acfm. Multi-stage centrifugal compressors are normally considered for inlet volumes between 500 and 200,000 inlet acfm. Therefore, either a reciprocating or centrifugal compressor could be considered for the KE application.

Efficiencies of multi-stage reciprocating compressors are heavily dependent on speed. High speed reciprocating compressors (900 to 1800 rpm) typically have an efficiency of approximately 82%. Lower speed reciprocating compressors (300 to 700 rpm) typically have an efficiency of approximately 85%. Due to the high gas density of carbon dioxide (resulting from its high molecular weight), slow rotation and piston speeds are usually recommended in reciprocating compressors. Recent experience has shown efficiencies of reciprocating compressors in carbon dioxide service to be below 75%.

Efficiencies of multi-stage centrifugal compressors are heavily dependant on inlet volume. Centrifugal compressors typically have lower efficiencies at inlet volumes below 7,500 acfm than reciprocating units, primarily due to the geometric design required to develop the higher head at the lower flow.

3.1.5.4 Recommendation

Although, either compressor type may be considered for the KE compression application, the 5,895 acfm inlet flow rate is at the lower end of the centrifugal compressor service range and therefore requires a very small impeller resulting in a lower overall efficiency than that of the reciprocating compressor, therefore, a reciprocating compressor is recommended for the KE compression facility.

3.1.6 Compressor Sizing & Selection

Several compressor configurations were evaluated as part of the desktop study. Viable configuration options, both with and without redundancy in the design, have been summarized in tables 3-21 and 3-22 below and on the following page:

Table 3-21 Kansas Ethanol Compression Facility Compression Configuration Option – No Redundancy

Option No.	Configuration	Total bhp	Total Capital Cost
1a	Two (2) 50% Recips.	2,720	\$3,500,000
2a	One (1) 100% Recips.	2,680	\$3,750,000
3a	One (1) 100% Low Pressure Recips, plus... One (1) 100% High Pressure Recips	2,421	\$2,900,000
4a	Two (2) 50% Low Pressure Screw Compressors, plus.. One (1) 100% HP Recips	4,236	\$2,550,000

Table 3-22 Kansas Ethanol Compression Facility Compression Configuration Option – With Redundancy

Total No. Units	Configuration	Total bhp	Total \$
1b	Three (3) 50% Recips.	4,080	\$5,250,000
2b	Two (2) 100% Recips.	5,360	\$7,500,000
3b	Two (2) 100% Low Pressure Recips., plus.. Two (2) 100% High Pressure Recip	4,842	\$5,800,000
4b	Three (3) 50% Low Pressure Screw Compressors, plus.. Two (2) 100% High Pressure Recips	6,972	\$4,250,000

Based upon discussions with Blue Source, LLC., Option #1b was selected for the KE compression facility. This provides three (3) 50% capacity GE FS-706, 6-Stage reciprocating compressors, or equivalent, with 4160V, 1,360 hp electric motors, operating in parallel with one another and provides a single 50% capacity unit for back-up to facilitate the required maintenance schedule associated with the selected reciprocating compressor package. Each compressor package would include scrubbers on each stage and both inter-stage and after coolers. The use of forced draft fin-fan coolers would be anticipated, adding an auxiliary load of approximately 30 hp.

Typical maintenance for these units will incorporate routine inspections and checks every 6 months with annual maintenance and extended checks that may include checking main, connecting rod, and crankshaft thrust bearings, inspection of valves, replacement of packing, etc. A copy of the manufacturer's recommended maintenance guide has been provided in Attachment 4 – Compressor Maintenance Information. Typical operations and maintenance costs for these units would run approximately \$80,000 / year. Properly maintained, this unit should operate 10-years or more without a major rebuild, but should one become necessary, the estimated cost to do so would be approximately \$200,000 / overhaul.

3.1.7 Process Equipment

Oxygen Removal Unit

The oxygen removal system for the KE compression and processing facility is based on the catalytic combustion of oxygen. Since the raw carbon dioxide feed stream does not contain any hydrocarbons to “burn” the oxygen, the stream will need to be seeded with natural gas. The amount of natural gas will need to be approximately twice the stoichiometric ratio with the excess being used to ensure the complete combustion of the oxygen. Therefore, if the stream contains 1% oxygen it will need to have natural gas injected to a concentration of approximately 1%. Based upon the anticipated feed stream composition, it is estimated the approximately 48,000 SCF of natural gas will be required to remove the oxygen to less than 10 ppm for 8 MMSCFD of carbon dioxide. A process flow diagram and high level description of the process is provided on the following page (Figure 3-1).

Figure 3-1 Oxygen Removal Unit (“ORU”) Process Flow Diagram

The inlet gas is introduced into a particulate filter after liquids separation. The removal of fine particulates prevents the clogging of the catalyst. The gas goes through a heat exchanger where the gas is heated to the required reaction temperature during steady state operation. There is a cool gas bypass to allow for the control of the temperature going to the reactor. During startup, the electric heater is used to heat the gas to the required reaction temperature. The heater can also be used continuously when there is not enough oxygen to maintain inlet reactor temperatures. The reactor contains the catalyst and is designed to have

sufficient volume of catalyst necessary to “burn” the amount of oxygen required. This system does not require the high temperature coolers that are shown in the figure above. The gas flows through the heat exchanger where it is cooled and is then introduced into the final air cooler. Condensed water is removed in a separator and the gas exits the system.

This process utilizes a platinum based catalyst with a life expectancy of 5-7 years. Replacement catalyst costs will be dependant upon the price of platinum at the time of replacement, with credit for the remaining platinum in the base charge credited to the purchase of the replacement catalyst. Preliminary discussions with the ORU manufacturers suggested replacement costs can be expected to be approximately 50% of the original catalyst costs.

In this system, the resulting gas stream will have a residual amount of hydrocarbons. The exact amount can be minimized by reducing the natural gas feed in the feed stream to the minimum required to meet the outlet oxygen specification. Through detailed design, a system that varies the natural gas flow rate into the raw CO₂ stream can be developed.

Dehydration Unit

Water vapor from the raw carbon dioxide feed stream would be removed utilizing a single tri-ethylene glycol (TEG) dehydration skid package comprised of a gas fired 125 MBTU / Hr re-boiler and 24” diameter contactor tower.

The initial fill for start-up of the system is anticipated to require approximately 150 gallons of TEG and has been included in the capital costs provided with this study. Annual TEG losses are estimated at less than 1% excluding upset conditions with estimated annual operating costs of \$175,000.

3.1.8 Electrical Design

Power for the KE compression and processing facilities are anticipated to be available from the existing Kansas Ethanol plant. 4160 V / 3-Phase power shall be used as the secondary service, with additional transformation down to 480V / 3-Phase and 208V / 120V for auxiliary equipment and lighting. All power and controls for the new facility would be incorporated into a pre-engineered metal power distribution center, including a 4160V cutler-hammer, or equivalent, switchgear, 4160V solid state reduced voltage starter, 480V motor control center, Programmable Logic Controller, and miscellaneous power and lighting equipment.

Table 3-23 below summarizes the overall electric loads and estimate annual cost at the KE compression facility. The electric rate of \$0.0732/KW-HR used is the average commercial electric rate paid in the state of Kansas in 2009 (Report No.: DOE/EIA-0226).

Table 3-23 KE Facility Annual Electric Loads and Costs

Description	Number of Units	BHP Each	Total BHP
Compressor, Reciprocating, GE FS-706, 6-Stage	2.0	1,360 BHP	2,720 BHP
Inter-coolers and After-coolers	2.0	30 BHP	60 BHP
Oxygen Removal Unit, 8 MMscfd, 3% Maximum O2	1.0	15 BHP	15 BHP
TEG Dehydration Package	1.0	5 BHP	5 BHP
TOTAL			2,800 BHP
TOTAL KW-HR/YR			17,376,000 KW-HR/YR
COST PER KW-HR			\$0.0732 /KW-HR
ANNUAL COST			\$1,272,000

3.1.9 SCADA Design

The Supervisory Control And Data Acquisition (SCADA) system on the KE-GE pipeline will consist of four main components which are the 1) Programmable Logic Controllers (PLC) to be located at all the station and valve sites connected to the instruments, 2) Operator Interface and data collection system which is the SCADA software, 3) Leak detection system, and 4) Communications system which will tie all the parts together.

The communication system will be composed of an armored fiber optic cable installed in the most appropriate method adjacent to the pipeline. The cable could be installed in the same ditch as the pipeline, direct buried, in duct strapped to the pipe at crossings, or plowed into the ground. The SCADA system which communicates through a fiber optic cable will have a very high uptime and the capability for fast and reliable communication between the stations and the main line valves. These features will enable the fast integrated control system to automatically operate more safety.

The PLC at each compressor and main line valve site will be a GE 90-30 or company approved equal and will be housed inside a small building to enable support personnel to program and maintain them in inclement weather.

The SCADA software will have a primary system installed at the primary control center on one end of the pipeline and there will be a backup SCADA host at the facility at the other end of the pipeline. Costs for SCADA vendor services were also included. SCADA vendor services include project management, design specification documents, SCADA communications programming, SCADA screen programming, factory tests, installation onsite, onsite tuning of the software, commissioning tests, operations and the maintenance manual, training support for operators and technicians.

The Leak Detection System will communicate with each station to analyze the pipeline for leaks and report to the SCADA software for operator notification. Leak Detection vendor services were also included. Leak Detection vendor services include project management, design specification documents, communications programming, graphical user interface screen programming, factory tests, installation onsite, tuning of the software, commissioning tests, operations and the maintenance manual, training support for operators and technicians.

3.1.10 Cathodic Protection and AC Mitigation

Cathodic protection of the 4" steel pipeline system will be accomplished using an impressed current system with either deep-well and/or surface anode ground beds. In order to quantify the soil resistivity in the area, a soil investigation will be required once the pipeline has been installed. The cathodic protection system will be designed accordingly depending upon the soil resistivity. The system will consist of either high-silicon cast iron anodes set in deep wells and/or or treated graphite surface anodes. The quantity and dimension of the deep well anodes and/or surface ground beds will be determined during detailed design of the cathodic protection system. Either system will be powered by a rectifier which will also be sized during detailed design of the cathodic protection system.

Alternate Current (AC) mitigation will be required where pipelines are in close proximity to overhead power lines. AC mitigation will be accomplished using zinc anode ribbon buried alongside the pipeline system. In order to determine the amount of zinc ribbon required for AC mitigation a soil investigation will be required during detailed design to quantify the soil resistivity in the areas of concern. Based on the soil resistivity, proximity and voltage of overhead power lines, and the operating lifespan of the project, the AC mitigation system will be designed to protect the pipeline system from stray currents imposed by overhead power lines

3.1.11 Typical Construction Method

Standard pipeline construction procedures and BMP's would be followed during construction. The centerline of the ROW would be staked prior to construction. The following discussion provides a brief overview of the construction process.

All equipment and vehicular access into the pipeline project would be confined to existing roads and the established ROW corridor. No major reconstruction or rerouting of these roads is intended.

The following are the general steps in the construction process:

- Surveying and staking of the ROW
- Right-of-way (ROW) clearing and grading, topsoil stockpiling
- Ditching
- Pipe stringing, and bending
- Pipe welding
- Pipe Jeeping
- Pipe lowering in
- Backfilling of trench
- Testing of pipeline and facilities
- Clean up and revegetation

All construction materials would be hauled to the job site by truck, as needed, and strung along the ROW as they arrive. Pipe would be strung in such a manner as to cause the least interference with the normal use of the land crossed by the ROW. The construction ROW would be limited to a 75-foot width. As a general rule (except for steep slope areas), clearing would be limited to 75 feet: 55 feet on the working side and 20 feet on the stockpile side of the trench. Grading of the entire ROW would occur only in areas where equipment access is not possible without ROW clearing. The top 6 inches of topsoil would be removed and stockpiled off of the trench line and any areas to be graded. Top soils would be stockpiled separately from trench spoils.

Construction or routine maintenance activities will not be allowed during periods when soil is too wet to adequately support construction equipment. If such equipment creates surface ruts in excess of 6 inches deep, the construction supervisor would deem that soil conditions are too wet to adequately support construction equipment. Construction activities would not be allowed until soil conditions improve. The pipeline trench would be excavated using a wheel trencher, or a track-hoe excavator. The wheel trencher pulverizes the soil as the trenching progresses, stacking the spoil in a pile along the side of the trench. In the event weather conditions warrant, the spoil pile can be worked by driving a tracked dozer over the spoil and working it with the blade, breaking up frozen soils. Breaking up the frozen soils would mitigate the issue of the ditch settling. A small mound of soil (6-10 inches high) would be placed on top of the trench line to accommodate minor settling.

A wheel trencher or track hoe would be used to dig a trench to an average depth of 60 inches, stacking the dirt beside the ditch. After the pipe is placed in the ditch a motor grader or caterpillar would be used to push the dirt back into the trench. The fill on the trench would then be tamped into place with the grader wheels, leaving a berm of 6 to 10 inches to accommodate settling. Disturbance of the topsoil within the ROW would be kept to a minimum. In areas of excessively steep hillsides, or to provide a smooth approach to a cut or gully, as well as at stream bank crossings and at established work

stations, some blading may be required to provide a safe and suitable working area for the equipment and workers. When this occurs the top 6 inches of soil would be stockpiled on the side of the ROW and spread back over the area from which it was taken, after the final grading. Before seeding any disturbed areas, the ROW would be restored to its original form, slope, contour, and soil density to the extent practicable.

3.1.12 Rock Ditch

Throughout the course of the pipeline construction, solid rock may be encountered during the excavation. When the rock cannot be excavated with the typical track hoe, additional equipment or blasting may be required. In these areas, construction cost will increase due to the additional equipment and slower installation productivity. Typically, an additional cost for installation is added for every foot of rock ditch encountered. A construction contractor, who has installed pipelines in the project area, estimated that there will be minimal amounts of rock encountered on the KE-GE pipeline route. In the cost estimate, it was assumed that 5% of the total route would be considered rock ditch. The precise amount of rock cannot be determined until construction of the pipeline.

3.1.13 Crossings

A detailed review of the required pipeline crossings was completed. The locations where the proposed route crossed an Interstate, Highway, State Road, Other Paved Roads, Dirt Roads, Railroads, Lakes, Rivers, and creeks were identified. The below table (Table 3-24) summarizes the number of each type of crossings, as well as the estimated total length of each type of crossing.

Table 3-24 KE-GE Road, Railroad, and Waterway Crossing Tally

TYPE	TOTAL NO. CROSSINGS	TOTAL LENGTH
Interstate	0	0 ft
Highway / State Rd	1	100 ft
Other Paved Road	2	150 ft
Dirt Road	19	950 ft
Railroad	2	200 ft
Lake / River	1	100 ft
Creek	1	25 ft
TOTAL	26	1,525 ft

In general, it is proposed that paved roads or railroads that require a crossing length of 100 feet or greater, be crossed using a Horizontal Directional Drill (HDD). It is proposed that paved roads or railroads that require a crossing length of 100 feet or less, be crossed using an un-cased slick bore. It is proposed that all dirt roads be open cut. Regarding waterway crossings, it is proposed that waterways that require a crossing length of 100 feet or greater, be crossed using a Horizontal Directional Drill (HDD). It is proposed that waterways that require a crossing length of 100 feet or less, be crossed using an un-cased slick bore.

During the detailed design portion of the project, each crossing would need to be analyzed on a site specific basis, and a detailed crossing plan and profile be developed.

3.1.14 Long Lead Materials

Most of the materials required for the construction of the KE-GE Pipeline Project are considered long lead items. Long lead items are described as items that are not in stock at the time of purchase. These items include the compressors, pumps, dehydration process equipment, oxygen removal process equipment, valves, actuators, steel pipe, materials for the launchers and receivers and their fabrications, and other miscellaneous fittings. Deliveries are based on budgetary quotes for material received on August 1, 2010.

Budgetary bids have been received from vendors for the compressors, with an anticipated delivery of 26 weeks after receipt of order.

Budgetary bids have been received from vendors for the dehydration process equipment, with an anticipated delivery of 15 weeks after receipt of order.

Budgetary bids have been received from vendors for the oxygen removal process equipment, with an anticipated delivery of 26 weeks after receipt of order.

Budgetary bids have been received from vendors for the ANSI 900 valves and required actuators for the pig launchers/receivers. Anticipated delivery of valves and actuators is 12-26 weeks after receipt of order (ARO).

Budgetary bids have been received from vendors for the steel line pipe. Line pipe will be mill rolled and coated with FBE coating. Anticipated delivery of the line pipe is 20-30 weeks after receipt of order (ARO). Line pipe will be mill rolled and coated with FBE coating.

Budgetary bids have been received from vendors for the launchers and receivers. Anticipated delivery is 12-14 weeks after purchase orders have been issued. Lead times include material procurement, fabrication and testing and shipping.

Budgetary bids have also been received from vendors for bends for the piggable pipeline systems. Deliveries are anticipated to be 2-3 weeks ARO.

3.1.15 Capital Cost Estimate

See the attached Appendix 3-I – Pipeline Estimate prepared for the KE-GE Pipeline Systems. See also Appendix 3-J – Estimate Basis Memorandum for more information regarding the estimate.

3.1.16 Project Schedule

See Appendix 3-K - Project Schedule prepared for the KE-GE Pipeline Systems.

CHAPTER 4 – Reservoir Modeling and Simulation

4.0 Thrall-Aagard Field – Deep Saline Sequestration Analysis

4.0.1 Model Grid

4.0.1.1 Description of Study Area

The Thrall-Aagard site for the CO₂ enhanced oil recovery and deep saline aquifer sequestration project is located in the northern half of the Thrall-Aagard oil field. The IMCCS team developed a geologic model of the field and conducting numerical simulations to demonstrate and evaluate the potential for long-term secure and safe storage of CO₂ within a saline aquifer. For this goal, the IMCCS team focused on developing a site-specific geologic model to better understand and design CO₂ storage, specifically targeted to Cambrian-Ordovician Arbuckle Formation at the Thrall-Aagard site. Simulation of deep saline aquifer sequestration of CO₂ in the Thrall-Aagard included injection of up to 100,000 metric tons CO₂ per year with a maximum twenty-year injection period.

Geographic location of the study area in the Thrall-Aagard field is illustrated in Figure 4-1. Stratigraphic, petrophysical, and geophysical data used for building the geologic model of the Thrall-Aagard deep saline aquifer were provided by industry partners as well as public databases. However, less information is available for the deep saline formations than for the relatively shallow oil reservoirs targeted for the demonstration of CO₂ EOR operation. Currently, there are only a limited number of formation tops available for the Arbuckle and overlying formations due to previous lack of economic interest in this area. No wells directly penetrate the Precambrian Granite have been found within the study area. In detail, there exist only 6 wells containing the top picks for the Granite (basement rock) regionally, and we used these six data points to interpolate the top horizon of the Granite within the model area based on the assumption of a monocline structure identified in the Arbuckle Formation. These data were assembled and processed into an information database for the geologic model development and numerical simulation. We suggest a relatively large uncertainty for many aspects of the deep saline CO₂ sequestration project, primarily due to the paucity of data including stratigraphic, petrophysical, hydraulic, and geochemical properties of the intended target formation and caprock.

Figure 4-1. Location of the study area and wells containing top picks of the Viola, Simpson, Arbuckle, and Granite Formations.

The Arbuckle Formation is an upper member of the lower unit of the Ozark plateau aquifer system [Carr et al., 2005]. Mineralogically, the Arbuckle formation primarily consists of shallow-shelf dolomites with locally-contained siliceous minerals and exhibits enhanced porosity and permeability due to the repeated prolonged subaerial exposure and extensive karst processes before subsequent burial [Cansler and Carr, 2001]. Economically, the Arbuckle Formation is a major oil producing formation in Kansas as well as oil field by-products disposal (produced water), which implies a potential for CO₂ sequestration. Carr et al. [2005] suggest that the Arbuckle formation is underpressurized due to the extensive hydraulic connectivity to the recharge surface at the Ozark plateau, approximately 200 miles (322 kilometers) to the east of the Thrall-Aagard site. Overlying the Arbuckle is the Simpson Formation, which is composed of green shales and minor amounts of interbedded carbonates and sandstone [McClellan, 1930; Walters, 1958]. Overlying the Simpson is the Ordovician Viola Formation, a series of limestone and dolomite, which is slightly less porous and permeable than the Arbuckle rock.

4.0.1.2 Model Grid Development

The Petrel™ software package, a 3-D integrated reservoir modeling tool from Schlumberger, was used for the geologic model and associated grid. First, a static geologic model was established based on the available formation tops tied to isochore data. The resulting structural model within the model boundary is shown in Figure 4-2. The model domain is approximately 6.76 km by 5.79 km (4.2 miles by 3.6 miles) in the x

and y directions, respectively (Figure 4-1). The present model contains three geologic formations starting with the Viola Formation at the top, the Simpson Formation in the middle, and the Arbuckle Formation at the bottom (Figure 4-2). Although the Simpson Formation is believed to act as the primary caprock above the Arbuckle formation, its lateral continuity and integrity as a seal is questionable given the available data at the proposed site. Therefore, we included two overlying formations, and then, set the top of the Viola Formation (secondary cap rock) as a no flow boundary to represent the bottom of the Mississippian Kinderhook shale as the uppermost confinement of the model domain.

Figure 4-2. Model grid for deep saline CO₂ sequestration in Thrall-Aagard field. Vertical exaggeration is 10x.

Each cell is equally spaced with a size of 91 m (300 ft) in the x and y directions. The subdivision of the three formations of interest into 20 and 3 layers was performed for the target and two overlying formations, respectively, according to the equal volume fraction. Consequently, the model grid consists of a total of 123,136 cells (74x64x26). This static model exhibits the Arbuckle Formation as slightly dipping upward to east with a gradient of less than 0.01. The average thickness of Arbuckle Formation within the model area is found to be approximately 188 m (618 ft).

Having established the 3-D structural model of the geologic formations, geologic properties such as porosity and permeability values were assigned to the model. However, due to the lack of directly-available data and large lateral distances between the measurements, we assumed homogeneity in the petrophysical properties in each formation for this generalized scoping study. Based on the available porosity logs existing outside of the model domain, average porosity values for each formation were determined and used for the uniform porosity values for each formation. Average porosity values of 0.06, 0.01, and 0.08 were uniformly assigned to the Viola, Simpson, and Arbuckle Formations, respectively. Although the porosity of the Arbuckle is less than values commonly found in oil reservoirs (0.1~0.2), we used this lower average value for the Arbuckle porosity in order to be more conservative in terms of CO₂ storage.

4.0.1.3 Grid Conversion for TOUGH2 and PFloTran Simulator

Two different simulators were utilized for the flow simulation work. For 2-D numerical simulation of CO₂ injection in the deep saline aquifer, we used TOUGH2 [Pruess et al., 1999], a general-purpose numerical simulator for multiphase, multicomponent fluid and heat flow in porous and fractured media. Detailed descriptions of TOUGH2 simulation and the predicted model results are described in Section 4.1 of this chapter. For the 3-D model, we utilized PFloTran, a massively parallel subsurface multiphase, multi-component reactive transport flow simulator based on the PETSc, SAMRAI and MPI packages [Lu and Lichtner, 2006]. PFloTran's capabilities have been adopted to demonstrate the various flow and transport processes in relation to subsurface contaminant and geological CO₂ sequestration [Hammond et al., 2007]. The detailed application of the PFloTran simulator is described in Section 3 of this chapter.

Figure 4-3. Orthogonal grid setting implemented for PFloTran simulator with the location of proposed CO₂ injection well. Vertical exaggeration is 10x.

Since PFloTran can only run using an orthogonal grid model, we conducted a grid conversion and remapped the porosity distribution into a new orthogonal grid by a volume-weighted averaging methods to preserve the overall volume between the two grids. The new orthogonal grid setting consists of two different vertical zones (fine and coarse grid) depending on the required cell resolution to maintain the structural geometry while minimizing the total number of cells in the model domain (Figure 4-3). The fine-grid zone is the upper 60 m (200 ft) interval with a cell thickness of 3 m (10 ft), which covers the vertical range from the top of the Viola formation to the top horizon of the Arbuckle formation. The lower coarse-grid zone is 168 m (550 ft) thick with a 7.6 m (25 ft) cell thickness, representing the Arbuckle formation below the Simpson-Arbuckle contact horizon. The proposed CO₂ injection well will be placed approximately 1,220 m (4,000 ft) southwest from the center of model domain or the center of CO₂ EOR area (Figure 4-3). The new orthogonal grid top starts from an elevation of 430 m (-1415 ft).

Each cell size has been maintained with the same horizontal cell dimension such as 91 m by 91 m (300 ft x 300 ft) in the x and y directions. Note that due to the refinement in the cell thickness, the total number of cells was increased to 198,912 (74x64x42) from 123,136. Figure 4-4 illustrates the updated porosity distribution mapped onto the orthogonal grid setting after the volume-weighting method for the PFloTran simulator.

Figure 4-4. Porosity distribution in the orthogonal grid setting for the PFloTran simulator. Vertical exaggeration is 10x.

4.0.2 Flow Model: Two-Dimensional Radial CO₂ Injection Test

4.0.2.1 Descriptions of TOUGH2 Simulator, Equations of State (EOS) Algorithms, and Conceptual Model

The potential CO₂ plume migration and associated heat/drying-out processes were investigated by simulating CO₂ injection into a 2-D radially-symmetric domain (Figure 4-5). The maximum radial extent of this model is 5 km with logarithmic increase of lateral distance and the formation thickness is 182.9 m divided with 30 layers. In the model, the pressure, temperature, NaCl concentration, and CO₂-saturation are respectively assigned as 6.89 to 8.39 MPa, 41.7 °C, 15 % of NaCl mass fraction, with zero CO₂ saturation, which represent the current *in situ* condition of the Arbuckle formation. Two scenarios were developed with different injection rates. In the first scenario, supercritical-phase CO₂ is injected at the constant rate of 0.05 million metric tons per year during three years in the injection well, which partially penetrates the 24.4 m thickness in the bottom of the Arbuckle formation. In the latter one, the injection rate is increased twice. The right-side boundary is assumed as the Dirichlet boundary where thermophysical properties on this boundary remain constant during simulation. The detailed model parameters including the initial/boundary conditions are given in Figure 4-5.

Figure 4-5. 2D radial model representing the Arbuckle formation under the Thrall-Aagard reservoir.

Our numerical simulation of CO₂ sequestration potential in the Arbuckle formation with TOUGH2 [Pruess *et al.*, 1999] included application of an equation of state package called ECO2N [Pruess, 2005]. ECO2N is designed to treat two-phase (liquid, gas) transport including three-component [water, salt (NaCl), supercritical-phase CO₂] systems in suitable pressure and temperature regimes (10°C ≤ T ≤ 110°C, P ≤ 60 MPa, salinity up to full halite saturation) for CO₂ sequestration processes. In TOUGH2/ECO2N, the properties of supercritical-phase CO₂ are calculated from the correlations developed by Altunin [1975] and the water properties are obtained from IFC [1967]. Mutual partitioning between supercritical-phase CO₂ and water are calculated with *Spycher et al.* [2003]. In addition, to account for the heat disequilibrium processes during CO₂ injection, the enthalpy (H_{mix}) of the CO₂-laden fluid is calculated by adding the heat of CO₂ dissolution to the ideal mixing equation of the supercritical-phase CO₂ and brine, which is a similar approach implemented in the ECO2N module within TOUGH2 [Battistelli *et al.*, 1997; Pruess, 2005].

$$H_{mix} = (1 - X_{CO_2})H_b + X_{CO_2}(H_{CO_2} + \Delta H_{sol}). \quad (\text{Eq. 1})$$

Here, H_{CO_2} [Altunin, 1975] and H_b [Pruess, 2005] are the enthalpy of supercritical-phase CO₂ and brine, respectively. X_{CO_2} is the dissolved CO₂ mass fraction in brine [Spycher *et al.*, 2003] and ΔH_{sol} is the heat of CO₂ dissolution [Battistelli *et al.*, 1997]. Similarly, the enthalpy state of the supercritical-phase CO₂ (H_{sc}) due to water vaporization is calculated with the following equation:

$$H_{sc} = (1 - Y_{H_2O})H_{CO_2} + Y_{H_2O}(H_b + \Delta H_{vap}). \quad (\text{Eq. 2})$$

Here, Y_{H_2O} is the mass fraction of water in the supercritical-phase CO₂, calculated from *Spycher et al.* [2003] and ΔH_{vap} is heat of water vaporization [Wagner and Prub, 2002]. Both Eq. 1 and 2 completely describe the thermal changes resulting from CO₂ dissolution into brine and water vaporization into supercritical-phase CO₂.

The changes to brine density caused by varying CO₂ concentration were predicted by Garcia [2001]. Finally, the relative permeability and capillary pressure developed by Corey [1954] and van Genuchten [1980] were used without considering the hysteretic effects.

4.0.2.2 Vertical/Horizontal CO₂ Plume Extension Associated with Time Scale

Results from two injection scenarios (0.05 and 0.10 million metric tons per year) are presented at Figures 4-6a-c and 4-6d, respectively. The injected CO₂ in the Arbuckle formation has a strong tendency of vertical migration, mainly because the reservoir pressure is low resulting in the smaller CO₂ density. The measurement of bottom-hole pressure in the field indicates that the range of reservoir pressure was 6.89 to 8.39 MPa from reservoir top to bottom, indicating that the pressure condition of top of the Arbuckle formation is smaller than the critical pressure (7.1 MPa). Consequently, the injected CO₂ is potentially stored as gas phase at the top of Arbuckle formation.

Figure 4-6. Distributions of CO₂ plume saturation: (a), (b), and (c) represent the scenarios with 0.05 million metric tons of CO₂ injection during 3 years, and (d) shows the 0.10 million metric tons of CO₂ injection during 3 years.

Due to a strong buoyant condition, the front of CO₂ plume in the small injection scenario migrates vertically after 10 years (Figure 4-6b) and reaches 20 m less distance under the top of the Arbuckle formation. Within 50 years, all CO₂ is hydrostratigraphically trapped under the caprock (Figure 4-6c). In the larger injection scenarios, the shape of CO₂ plume is simply the same but extends longer laterally (Figure 4-6d).

Geographically, the outcrop of the Arbuckle formation appears at the Ozark dome, Missouri State, indicating that the calculated regional gradient of the Arbuckle formation was less than 0.01 but the local gradient could be greater. Therefore, a CO₂ plume, after reaching the top of the Arbuckle formation, is likely to migrate slowly towards the Ozark dome. However, simulation results suggest that the dipping effect is minimal. The

radius of the CO₂ plume after 50 years is approximately 400 m and 600 m in the small and larger injection scenarios, respectively.

Historically, the Arbuckle formation was the major disposal formation of produced brines from oil-fields under vacuuming condition, indicating that the wellhead pressure is typically larger than formation pressure [Carr et al., 2005]. Since the reservoir pressure is low, the concern of injection-induced pressure would likely not be significant for operating commercial scale CO₂ disposal in the Arbuckle formation. However, this underpressured condition could potentially result in relatively reduced density of injected CO₂, and correspondingly, may reduce capacity and increase the distance of CO₂ plume migration under the caprock. Therefore, in these simulations, we investigated the possible range of CO₂ densities and its phase state (Figures 4-7a-f). During the injection period in the small injection scenario, the range of CO₂ densities within the plume is approximately from 300 kg/m³ and 700 kg/m³ (Figure 4-7a), and all CO₂ existed as supercritical fluid (Figure 4-7d) because injection activity increased reservoir pressure above the critical pressure. However, within 50 years, the built-up pressure due to the injection activity reached hydrostatic pressure. As such, the rate of pressure dissipation was rapid in the Arbuckle formation since this formation is hydrologically connected to open surface, the Ozark Plateau aquifer system in Missouri. Consequently, the range of CO₂ densities radically dropped. After 50 years, the predicted CO₂ density was 200 kg/m³ at top and 300 kg/m³ at bottom, respectively (Figure 4-7b). In the larger injection scenario, the pressure built-up was larger, resulting that the distribution of CO₂ density was increased over 700 kg/m³ adjacent to the injection well (Figures 4-7c).

Figure 4-7. Distribution of CO₂ density (kg/m³) shown in (a), (b), and (c). Both (a) and (b) represent the small injection scenario and (c) is from the larger injection scenario. States of fluid phase shown in (d), (e), and (f). Both (d) and (e) represent the small injection scenario and (f) is from the larger injection scenario.

Figures 4-7d-f shows the distribution of CO₂ phase state. CO₂ stays as supercritical fluid during injection period (Figure 4-3d). However, since the pressure dissipation rate

is rapid in the Arbuckle formation, soon CO₂ stays as gaseous phase under the caprock in both scenarios (Figures 4-7e and 4-7f).

Figure 4-8. Distribution of dissolved CO₂ mass fraction in (a) and (b) and NaCl solid saturation (c) and (d). Both (a) and (c) represent the small injection scenario and both (b) and (d) represent the larger injection scenario.

4.0.2.3 Convective Mixing due to Density Instability and Injectivity Changes

Density of CO₂–dissolved brine becomes greater as more CO₂ dissolves. For example, Garcia [2001] suggested that the density of CO₂–dissolved brine could be as much as 2–3% greater than surrounding brine. Consequently, CO₂–dissolved brine will sink and create density instability resulting in convective transport mixing after several hundred years [Ennis-King and Paterson, 2005; 2007; Xu et al., 2006; Yang and Gu, 2006]. In this generalized scoping study, we investigated the potential of convective mixing and associated time scales applicable to the Arbuckle formation. The time scale of convective mixing is closely related to the mass-transfer processes between CO₂ and brine.

In the Arbuckle formation, the solubility of supercritical CO₂ is small since it is underpressured. Furthermore, solubility of gaseous CO₂ is even smaller. Consequently, less CO₂ dissolves into brine, and this causes a slower process of convective mixing. In both scenarios, we predicted that on-set convection did not occur even after 10,000 years, suggesting that the potential for the convective mixing is extremely slow in this formation.

Drying-out processes due to brine evaporation at the vicinity of injection well can cause NaCl solid to be precipitated and potentially reduce porosity/permeability [Andre et al., 2007; Giorgis et al., 2007; Pruess and Muller, 2009]. In this work, the mutual

solubility consideration was evaluated with the approach developed by Spycher and Pruess [2003], and we estimated the amount of NaCl precipitation during the injection period (Figures 4-8c and 4-8d). Simulation results showed that NaCl solid saturation was 0.07 after 3 years of CO₂ injection. Because the initial porosity of model was 0.1, NaCl solid is precipitated in more than half of pore volume. In addition, the radial extent of NaCl solid precipitation was approximately 8 m in the small injection scenario but extended to over 10 m in the large injection scenario. Recently, Pruess and Moller [2009] suggested that pore clogging due to salt precipitation could be prevented by injecting freshwater and displacing saline brine prior to the CO₂ injection. If freshwater is present in the vicinity of injection well, water vaporization into supercritical CO₂ will not precipitate NaCl solid and, consequently, will not reduce the injectivity of the injection well. In practice, as suggested by previous researchers, freshwater injection is suggested to prevent such injectivity reduction prior to CO₂ injection.

4.0.2.4 Thermal Disequilibrium Processes

Injection of CO₂ may perturb subsurface temperatures, leading to a dynamic temperature system in the storage formation and adjacent seal strata. In most cases, the individual effects from wellbore dynamics, solvation reactions, and phase changes are incremental, but collectively these relevant processes may cause temperature changes compared to ambient conditions. In this work, we evaluated several potential non-isothermal effects resulting from CO₂ injection activity. These include the Joule-Thomson cooling effects, exothermic CO₂ dissolution, and heat changes associated with concomitant water vaporization.

The spatial distribution of temperature altered by Joule-Thomson cooling, water vaporization, and exothermic CO₂ dissolution is plotted in Figures 4-9a-c representing the small injection scenario. As compressed CO₂ flows from the injection well into the targeted formation, the forced pressure field dissipates. Due to pressure reduction, the CO₂ entering the reservoir formation experiences Joule-Thomson cooling by adiabatic expansion. Simulation results suggest that the zone where Joule-Thomson cooling dominates appears between 0 to 70 m; reservoir temperature becomes cooler than its initial temperature (41.67°C). At the same time, water vaporization cools the reservoir fluid temperature in this zone since this process is endothermic. Interestingly, this process locally occurs distance between 10 to 40 m and shows the direction dependency, indicating that water vaporization was significant to the direction of the CO₂ plume front. Finally, from 70 to 100 m, CO₂ dissolution into brine is the major mass-transfer mechanism, and the associated heat effects govern the temperature profile. Since this process is exothermic, the resulting fluid temperature is slightly higher than the reservoir temperature (41.67°C). In Figure 4-9d, the larger injection scenario is plotted, showing that thermal disturbance becomes larger.

Figure 4-9. Thermal disequilibrium processes caused by CO₂ injection: Distributions of CO₂ plume saturation: (a), (b), and (c) represent the small injection scenario, and (d) shows the larger injection scenario.

Based on our understanding of non-isothermal processes, there can be certain changes in the subsurface temperature caused by CO₂ sequestration. Recently, Hurter et al. [2007] suggested using a distributed temperature-sensing system in a CO₂ sequestration test, which successfully monitored the dynamic changes of temperature during injection and production operations in oil fields [Brown et al., 2004; Lanier et al., 2003]. This distributed temperature sensing system was applied to the CO₂SINK project in Germany where CO₂ was injected into a saline aquifer with an anticlinal structure [Forster, 2006]. Although the definite cause observed in temperature signal is still being investigated, the distributed temperature sensing system successfully measured the largest temperature increase ($\Delta 25^{\circ}\text{C}$) close to the injection wellhead during the injection period [Giese et al., 2009] while the temperature increase within the injection zone was about $\Delta 5\text{-}10^{\circ}\text{C}$. In summary, CO₂ injection into the Arbuckle formation are expected to disturb the temperature regimes in the target formations, and such temperature changes could be detected by installation of temperature sensors in injection and observation wells.

4.0.3 Flow Model: PFLOTTRAN 3D CO₂ Injection Test in Thrall-Aagard Saline Reservoir

4.0.3.1 Descriptions of PFLOTTRAN Simulator, Grid Generation, and Formation Parameters Assessment

Section 4.0 detailed the procedures and methodology of grid construction and conversion. Figure 4-10 showed the converted grid with porosity distribution to illustrate the equivalence of the conversion. For sake of multi-processor simulations, we utilized the PFOTRAN simulator for all 3-D simulations. As briefly described in the previous section, PFLOTTRAN qA developed by Los Alamos National Laboratory under the support of the DOE SCiDAC (Scientific Discovery through Advanced Computing) program. It is a massively parallel, subsurface multiphase, multi-component reactive flow transport simulator. Its parallel efficiency has been demonstrated on various platforms, ranging from desktop-class workstations to supercomputing clusters.

Figure 4-10. Reconstructed structured orthogonal grid contoured with porosity.

The porosity distribution is illustrated in Figure 4-10 for this homogeneous model, which clearly shows the distinct geologic layers (i.e. Viola, Simpson and Arbuckle Formations). For simplicity, the porosity values were assumed to be 0.06, 0.01 and 0.08 for these 3 formations, respectively. Likewise, permeability values were assumed to be 100, 0.1 and 10 mD for the 3 formations, respectively, each with an unisotropic ratio of 10. The formation properties are summarized in [Table 4-1](#). The relative permeability and

capillary pressure values have not been determined. The van Genuchten [1980] model was

$$P_c = \frac{1}{\alpha} \left(s_e^{-1/m} - 1 \right)^{1/n} \quad (\text{Eq. 3})$$

adapted to evaluate capillary pressure, P_c , with . Relative permeability was evaluated with formulas implemented by [Doughty, 2007]:

$$k_{rw} = s_e^{1/2} [1 - (1 - s_e^{1/m})^m]^2 \quad (\text{Eq. 4})$$

$$k_{rg} = (1 - s_e)^{1/2} \left[1 - \left(1 - s_e^{1/m} \right)^m \right]^2 \quad (\text{Eq. 5})$$

No hysteresis effects were considered for capillary pressure or relative permeability. Parameters of Eqs (1-3) and are listed in Table 4-1 as well.

Table 4-1. 4 Formation properties (Formations were ordered from top to bottom)

Formation	porosity	permeability	Swir	Sgir	α	m
Viola	0.06	10	0.25	0.1	0.001	0.75
Simpson	0.01	0.1	0.25	0.1	0.001	0.75
Arbuckle	0.08	100	0.25	0.1	0.001	0.75

Initially, the saline reservoir was set at hydrostatic conditions with the top pressure and temperature at 6.893 MPa and 40°C, respectively. The salinity and geothermal gradient were assigned at 1 m/kg H₂O and 0.025°C/m, respectively. Constant hydrostatic pressure was assigned as the boundary condition for all 4 surrounding sides.

Table 4-2. 4 injection scenarios.

Scenario	Total injection rate (metric tons per yr)	Injection period (yr)
1	100,000	3
2	100,000	20
3	50,000	3
4	50,000	20

Four injection scenarios were simulated with each scenario differing in injection rate and period (Table 4-2). The injection point was designed to be located in grid cell (25,39,39) (counting from east to west, north to south and top to bottom) with the center coordinates at (2241m, 3520m, 202 m). At this location, the top of the Arbuckle Formation is deeper than surrounding regions (basin shaped). It could be expected that the gaseous CO₂ plume will migrate in both the east and west directions though the dip on the east is greater resulting in preferential CO₂ migration in this direction.

Figure 4-11. CO₂ saturation profiles at year 15 of Scenario 2: (a) isosurface with Sg=0.01 and (b) x-z plane slice through injection point

4.0.3.2 Horizontal and Vertical CO₂ Plume Migration

The simulation period was 50 years after the cessation of CO₂ injection. Among the 4 scenarios, the total injection amount of CO₂ for the second scenario was the highest. Numerical simulations of Scenario 2 indicate that the CO₂ plume reached the west boundary of the computational domain during 15th year of injection, as shown in Figure 4-11. As described in the previous section, the injection point is located closer to the west boundary. Though the CO₂ plume migrated farther to the east, it still reached the west boundary due to the large injection amount. Simulations beyond 15 years for Scenario 2 were not meaningful since the total mass of injected CO₂ could not be maintained; the simulation on Scenario 2 was terminated at 15 years.

Figure 4-12. CO₂ saturation profiles of Scenario 1: (a) isosurface with $S_g=0.01$ at year 3, (b) slice through injection point at year 3, (c) isosurface with $S_g=0.01$ at year 50, and (d) slice through injection point at year 50.

Figure 4-13. CO₂ saturation profiles of Scenario 3: (a) isosurface with $S_g=0.01$ at Year 3, (b) slice through injection point at year 3, (c) isosurface with $S_g=0.01$ at year 50, and (d) slice through injection point at year 50.

Simulations on Scenarios 1, 3 and 4 were conducted for a total of 100 years, slightly longer than the planned period. Figure 4-12 to Figure 4-14 show the saturation profiles at the end of each injection period (3 years for Scenarios 1 and 3 and 20 years for Scenario 4) and the end of each simulation period (53 years for Scenarios 1 and 3 and 20 years for Scenario 4).

Figure 4-14. CO₂ saturation profiles of Scenario 4: (a) isosurface with $S_g=0.01$ at year 3, (b) slice through injection point at year 3, (c) isosurface with $S_g=0.01$ at year 50, and (d) slice through injection point at year 50.

In all 4 simulations, the plume of SC/gaseous CO₂ migrated greater than 152 m (500 feet) from the injection point and reached the top of the Arbuckle Formation within 2 years. The increased CO₂ mobility was increased because of the relatively high permeability and greater density contrast between the SC/gaseous CO₂ and the formation fluid. After each plume reached the top of the Arbuckle Formation, further upward migration was impeded by the low permeable Simpson Formation caprock; horizontal plume migration dominates. Driven by buoyancy, the SC/gaseous plume spreads beneath the Simpson Formation caprock and forms thin layers only occupying several (<3) vertical grid blocks. Figure 4-15 showed that the fast buoyancy-driven migration has two distinct stages: 1) within 2 years, the plume reaches the top of the Arbuckle Formation and; 2) while the plume spreads horizontally, the depth to the top of the plume continuously decreases because of the dip of the Arbuckle Formation. Because of the

non-zero irreducible gas saturation, there are small amounts of CO₂ remaining in the deeper section of the Arbuckle Formation that form cylinder-shaped plumes, showing the migration path of injected CO₂.

Figure 4-15. Depth of plume top.

Figure 4-16 is the area of review for the 4 different scenarios, showing the horizontal area (NOT volume) of each SC/gaseous plume. The plume of the 2 scenarios with smaller total injection quantities (Scenarios 1 and 3) were almost stabilized after 60 years because of residual trapping (non-zero S_{gir} , in this study) and dissolution effects (discussed in the next section). The 2 scenarios with larger total injection quantities continued to spread throughout the entire simulation period finally reaching the side boundary. Future investigations should probably exploit larger domains to assess migration of larger amounts of CO₂.

Figure 4-16. Area of review of SC/gaseous plume.

Figure 4-17 shows the length of the plume in the x direction (east-west direction); the x -coordinate represents the greatest distance of the plume from the injection point, eastward is the positive direction. As discussed in Section 4.1, the plumes spread toward the west and east side simultaneously with the east side the dominant direction of migration. The plume in Scenario 4 ceased westward migration shortly after the injection stopped and subsequently reached the east boundary at approximately 32 years from the initiation of injection.

Figure 4-17. Spreading distance in the west—east direction.

Within the simulation period of all 4 scenarios, there was no noticeable penetration of the SC/gaseous phase CO₂ plume into and through the Simpson Formation caprock. These results confirm the caprock integrity and its hydrostratigraphic trapping efficiency.

Figure 4-18. CO₂ phase state in Scenario 4. Darker color indicates gaseous state. Lighter color indicates SC state.

4.0.3.3 Fluid Properties and CO₂ Distribution Between Phases

As discussed in previous 2D simulations, the pressure at the injection point is always above the CO₂ critical pressure (P_c). At the formation top immediately above the injection point, the pressure is greater than P_c only during the injection period, due to pressure build-up induced by injection. Shortly after the well shut-in, the pressure at the formation top begins to drop below the P_c . Figure 4-18 showed the phase state of the CO₂ plume in Scenario 4. At year 25 of the simulation period, the pressure at the formation top is already lower than the P_c . While the plume spreads along the formation top, more CO₂ exists in the gas phase. Figure 4-19 showed the pressure-time evolution at the injection point as well as the formation top; both are consistent with previous simulation results.

Figure 4-19. Pressure at the injection point and Arbuckle Formation top above the injection point.

Since PFLOTTRAN assumes local thermodynamic equilibrium, the injected CO₂ continuously dissolves into the formation brine while it migrates. In this study, the amount of dissolved CO₂ is greater than that existing in the SC/gaseous phase because of the long migration distance of the CO₂ plume and the large volume of grid cells, as shown in Figure 4-20. The total amount of CO₂ begins to drop at approximately year 32 of the simulation because the plume reaches the boundary at this time.

Figure 4-20. CO₂ distribution in SC/gaseous phase and aqueous phase.

4.0.4 Dynamic Flow Model: 3D CO₂ Injection Test in Thrall-Aagard Saline Reservoir

4.0.4.1 Descriptions of Model Grid and Workflow

Simulation analyses described in previous sections of this chapter utilized the TOUGH2 and PFloTran simulators. However, all oil reservoir simulations, described in sections to follow, utilized the Eclipse300 simulator. Thus, for sake of facilitating comparison of deep saline reservoir simulation results to oil reservoir simulation results (e.g., to check consistency), we also developed 3-D models of the deep saline reservoir option in the Eclipse300 simulator. This generalized modeling study was based primarily on a model grid that included reservoir structural and property information of the saline reservoir. Figure 4-21 shows the static model (grid) that covers an area of 2,600 square km (1,000 square miles). On the other hand, the gridded area in the figure represents the dynamic simulation model.

The dynamic simulation work in this study has been carried out by making use of the CO₂ storage feature of the Eclipse300 simulator. It has been specifically designed for the modeling CO₂ storage in subsurface formations and was added to the simulator in the 2006 commercial release. It allows the fluids in the pore space be modeled in two phases: a CO₂-rich phase (labeled gas phase), an H₂O-rich phase (labeled liquid phase) and a separate solid phase (salt contents). Additional information about these features are provided by the Technical Description ECLIPSE manual.

Figure 4-21. Eastern Kansas Arbuckle saline reservoir model

Saline reservoir model for CO₂ storage simulation typically covers an extended area (>100 square kilometers) in order to ensure the pressure pulse caused by the injection is not overly restricted by the model boundary. In this case, a model grid with over 20 million cells and covering a vast area (2,600 square kilometers) has been prepared. The first step in a typical CO₂ storage modeling workflow is to prepare a suitable simulation grid. A number of gridding schemes for dynamic simulation were tested to determine the optimum areal extent as well as the grid spacing. The grid prepared as a result of this process is large enough to simulate the movements of the pressure pulse and sufficiently fine in the area expected to be eventually covered by the CO₂ plume. Figure 4-21 shows the grid for simulation (gridded area in the figure) cover an area of 1350 square km (520 square miles). The fine grid area is populated with 145m by 145m (476ft by 476ft) grid and dimensions of the largest grid cells are 3,000m by 3,000m (10,000ft by 10,000ft).

The following are the assumed input values in this model:

1. Reservoir temperature = 49°C (120°F)
2. Reservoir pressure = 8.3 MPa (1,200 psia)
3. Water salinity = 30,000 ppm

The salinity data can be used to determine the initial water and salt mole fraction values as illustrated in Table 4-3.

Table 4-3. Salt content in water

	Proportion by weight	Molecular weight	Proportion by mole
Water	1	18.01	0.9908
Sodium Chloride	0.03 (or 30,000 ppm)	58.44	0.0092

4.0.4.2 Simulation Results

Simulations were performed for two different scenarios, one for a 3-year CO₂ injection period and the other for a 20-year injection period. In each case, 50,000 tons of CO₂ are assumed to be available for storage each year. Figure 4-22 shows the location of the injection well in the model relative to the grid. The well penetrates the reservoir model at about 860 m (2,810 ft) below ground and, at normal hydrostatic gradient, the reservoir pressure at the depth is estimated to be 8.3 MPa (1,200 psia). CO₂ at this pressure level is likely to be in gaseous phase and in order to increase the likelihood of injecting the CO₂ as a supercritical fluid; the model well is completed in the lower part of the reservoir penetration as shown in Figure 4-22.

Two reservoir property scenarios have been performed:

- High permeability case: average permeability = 100 md
- Low permeability case: average permeability = 10 md

Figure 4-22. CO₂ injection well completion in the model

Figure 4-23 and Figure 4-24 show the plume growth in the high permeability cases. In these cases, the CO₂ tends to travel upward to the top of the Arbuckle structure very rapidly. This is attributed to the relatively low pressure required to deliver the CO₂ into the formation and, therefore, resulting in much of this CO₂ in gaseous phase as indicated by the low density there.

Figure 4-23. Simulated plume growth – high permeability/3-year injection case.

Figure 4-24. Simulated plume growth – high permeability/20-year injection case.

On the other hand, Figure 4-25 and Figure 4-26 show the corresponding plume growth in the low permeability cases. It can be noted that the CO₂ in these cases has a higher tendency to accumulate near the injection completion and thus leading much smaller plume. The overall growths in plume size in these cases are also summarized in Figure 4-27.

Figure 4-25. Simulated plume growth – low permeability/3-year injection case

Figure 4-26. Simulated plume growth – low permeability/20-year injection case

Figure 4-27. Plume size and growth rate versus time

4.1 Geneseo-Edward Field – Combined Deep Saline and EOR Sequestration Simulation Analysis

4.1.0 Model Grid

4.1.1.1 Description of Study Area and Data Processing

The study area for the deep saline model analysis was extended well past the EOR injection site in the Geneseo Edwards. The boundary for this model was selected to encompass the entirety of the Geneseo-Edwards structural high (Figure 4-28). This size model allowed any size dynamic model to be selected out of the completed property model as need dictated. The property model covers most of T17S-R8W, T18S-R8W, and T19S-R8W; and partially covers T16S-R8W, T17S-R7W, T18S-R7W, and T19S-R7W.

Data for the model was exported from a Petra database provided by industry partners and all well locations, well tops, cultural polygons, and structural grids were imported to *Petrel*. The well logs received were porosity logs based on neutron curves calibrated to core data. All well locations and tops were verified by the IMCCS team and erroneous data points were eliminated from the data set. Well tops not used in the model are listed in Table 4-4. Additionally, tops picked by IMCCS geologists were added to the data set. Those tops added to the data set are listed in Table 4-5.

Figure 4-28. Geneseo-Edwards location map. Black dots are the well locations. Orange dots are wells with data. The purple boundary is the property model boundary and the orange boundary is the dynamic model boundary.

Table 4-4. Tops received from CAP-CO2 and not used in the Geneseo-Edwards structural model. Tops are either too high or too low when compared to adjacent tops and are removed from surface calculation.

UWI(API)	Surface	MD	UWI(API)	Surface	MD
1505301006	Arbuckle	3147	15053013670000	Arbuckle	3616
1505302215	Arbuckle	560	15053013680000	Arbuckle	3290
1505319183	Arbuckle	3178	15053350840000	Arbuckle	3134
1515903930	Arbuckle	3273	15159000490000	Arbuckle	3251
1515905570	Arbuckle	4251	15159006100000	Arbuckle	3295
1515905843	Arbuckle	4322	15159017820000	Arbuckle	3228
1515906284	Arbuckle	2534	15159062460000	Arbuckle	3336
1515920414	Arbuckle	4383	15159062560000	Arbuckle	3253
1515920896	Arbuckle	3309	15159216180000	Arbuckle	3247
150530026400	Arbuckle	3354	15159218150000	Arbuckle	3158
150530079000	Arbuckle	3186	15159703510000	Arbuckle	3174
150530079500	Arbuckle	3217	K-1006513568	PRECAMBRIAN	3425
150530080500	Arbuckle	3186			

Table 4-5. Tops not initially received from CAP-CO2 and added to the Geneseo-Edwards structural model.

UWI(API)	Surface	MD
15159204730000	Arbuckle-31	3346.47
15159204730000	Arbuckle-19	3439.76
15159204730000	Arbuckle-10	3630.2
15159204730000	Arbuckle-4	3800.74
15159204730000	Arbuckle-1	3957.47

4.1.1.2 Structural Grid, Property Model, and Volumetric Calculation

The structural grid is based on the Arbuckle top surface. The well top control for the area of interest suggests that a normal fault with about 300ft (91.44m) of displacement exists on the west side of the structure. This fault located in the model by identifying the inflection on the Arbuckle and Arbuckle 19 surfaces and extrapolated though the entire Arbuckle Formation.

The final stratigraphic horizons used in the model were the result of several iterations due to data inconsistency. Both the Arbuckle and Precambrian tops are erosional surfaces and have the most control across the region. The top of the Arbuckle was created first from Petra grids and well tops (Figure 4-29).

Figure 4-29. Arbuckle top surface for the Geneseo-Edwards model. Black dots are well top control points used in the model. Contour interval 25ft (7.62m).

The Arbuckle-19 horizon was created by isochore from the Arbuckle top; however, because the data were only in the area of interest, all areas outside the well control were heavily smoothed to remove artifact highs and lows inherited from the Arbuckle top surface (Figure 4-30).

Figure 4-30. Arbuckle-19 surface for the Geneseo-Edwards model. Black dots are well top control points used in the model. Contour interval 25ft (7.62m).

This method isochore and smoothing ensures that the data is honored and reduces structural errors for the other horizons that were built from the Arbuckle isochore. The Arbuckle-31 structural surface was built by isochore up from Arbuckle-19 (Figure 4-31). The Arbuckle-10, 4, 1 surfaces and the Precambrian surface were built by isochore down (Figures 4-32, 4-33, 4-34 and 4-35 respectively).

Figure 4-31. Arbuckle-31 surface for the Geneseo-Edwards model. Black dots are well top .control points used in the model. Contour interval 25ft (7.62m).

Figure 4-32. Arbuckle-10 surface for the Geneseo-Edwards model. Black dots are well top control points used in the model. Contour interval 25ft (7.62m).

Figure 4-33. Arbuckle-4 surface for the Geneseo-Edwards model. Black dots are well top control points used in the model. Contour interval 25ft (7.62m).

Figure 4-34. Arbuckle-1 surface for the Geneseo-Edwards model. Black dots are well top control points used in the model. Contour interval 25ft (7.62m).

Figure 4-35. Precambrian surface for the Geneseo-Edwards model. Black dots are well top control points used in the model. Contour interval 25ft (7.62m).

Two significant unconformities exist in the stratigraphic column. First, there is a disconformity at the top of the Arbuckle that erodes into the top of the Arbuckle-31 zone.

Second, there is a nonconformity at the top of the Precambrian basement that has resulted in an absence of the Arbuckle 1 zone to the north. Figures 4-36a and 4-36b show East-West and North-South cross sections of the zones through the southern structural high of the Geneseo-Edwards, the location of the dynamic model.

Figure 4-36 (a) East-West cross section through the zones for the southern structure and the dynamic model area. Note fault cut in the middle of the section and (b) North-South cross section through the zones for the southern structure and the dynamic model area

The size of the study area dictated that a 300ft by 300ft (91.44m by 91.44m) cell horizontal cell size was the smallest possible for the structural model, creating 49,494 2D cells for the model area. Layering of the zones was tied to the distribution of data. Above the Arbuckle-19 there were more well logs and a 5ft cell height was selected. Below the Arbuckle-19, a 10ft cell size was selected. For the entire modeled area a total of 6,335,232 cells were created with 146 in the i-direction, 339 in the j-direction, and 128 in the k-direction.

The porosity curves calculated from neutron logs were upscaled to the structural grid using the arithmetic averaging method. The locations of the data wells were rather far apart and geostatistical methods to analyze the data was found to be questionable. To better fit the geological conceptual model, the default *Petrel* settings for distribution were used; 5000ft (1524m) for the major range, 5000ft (1524m) for the minor range, and 10ft (3.05m) for the vertical range. Figures 4-37a and 4-37b show east-west and north-south cross sections of the porosity through the southern structural high of the Geneseo-Edwards, the location of the dynamic model. Figure 4-38 is the histogram comparing the distribution of well log (red), upscaled (green), and 3D grid (blue).

(a)

(b)

Figure 4-37. (a) East-West cross section of porosity through the dynamic model area. Note fault cut in the middle of the section and North-South cross section of porosity through the dynamic model area.

Figure 4-38. Histogram comparing the distribution of porosity on different scales; well log (red), upscaled (green), and 3D grid (blue).

The porosity and permeability core data from two wells were used to make correlations to input to permeability into the property model. Four porosity/permeability trend lines were created from the data by modifying the range of data (Figure 4-39). The blue trend line used all the data provided from CAP-CO2 and other industry partners. The blank permeabilities were estimated with a trend line equation:

$$k_{blue} = 1778154.23\phi^{5.66}, R^2=0.65$$

Where K is permeability and Φ is porosity. Removing the estimated permeability values (green) the trend line equation is:

$$k_{green} = 275904.63\phi^{4.31}, R^2=0.47$$

To get a better fit to the upper cloud of data, porosity bins were established to average the porosity and permeability for all data. Using all of the data, including the permeability estimates, the bins were 0.02 porosity units (red). The data without the estimates were binned in 0.03 porosity units (yellow). In both cases the averaged data for the bins better fits a power function with an R^2 value greater than 90. The trend line equations are:

$$k_{red} = 1688910.48\phi^{4.59}, R^2=0.909$$

$$k_{yellow} = 173272.82\phi^{3.29}, R^2=0.91$$

Figure 4-39. Cross-plot of porosity and permeability core data for the Geneseo-Edwards. Blue dots are for all core data and estimated data. Green dots are all core data with no estimated data. Red dots are the binned porosity and permeability averages for all core data and estimated data. Yellow dots are the binned porosity and permeability averages for all core data with no estimated data. Trend lines are in corresponding colors to the data.

The sets with no estimated values were selected to be propagated in the model to eliminate potential estimation error. The binned set is used as a high permeability case, while the correlation for the raw data is the low permeability case. Using the previously mentioned power function, the distributed porosity was used to create the high and low permeability properties. The distributed permeabilities are shown in cross sections in figures 4-40a-d. Figures 4-41a and 4-41b are the histograms for the low and high permeability distributions.

(a)

(b)

(c)

(d)

Figure 4-40. (a) East-West cross section of low permeability through the dynamic model area. Note fault cut in the middle of the section, (b) North-South cross section of low permeability through the dynamic model area, (c) East-West cross section of high permeability through the dynamic model area. Note fault cut in the middle of the section, and (d) North-South cross section of high permeability through the dynamic model area.

(a) Low permeability

(b) High permeability

Figure 4-41. Histogram of permeability distribution for 3D grid.

Water saturation was created by using the oil water contact (OWC) of -1500 ft TVDSS provided by CAP-CO2 and other industry partners. An estimated water saturation of 30% was used above the OWC. This value was used to initialize the dynamic model. Table 4-6 contains the maximum, minimum, and mean values for each of the properties.

Table 4-6. Minimum, maximum, and mean values for porosity, low permeability, high permeability, and water saturation.

Property	Minimum	Maximum	Mean
Porosity	0.000	0.260	0.098
Low Permeability (md)	0*	830	25
High Permeability (md)	0*	2059	121
Water Saturation	0.3	1.0	---

*Note: values are significantly close to zero and are products of the porosity-permeability transform.

Using the distributed porosity, water saturation, and an oil formation volume factor of 1.06 RB/STB ($0.169 \text{ m}^3/\text{m}^3$), a volume calculation was created for the property model. For the area of the dynamic model the pore volume is 130 MMbbl ($20.7 \times 10^6 \text{ m}^3$) with a

hydrocarbon pore volume of 88 MMbbl ($14.0 \times 10^6 \text{ m}^3$) and about 40 MMbbl ($6.4 \times 10^6 \text{ m}^3$) of recoverable oil is present. The Arbuckle and Arbuckle-31 zones contain the entire hydrocarbon amount. These numbers will require validation through dynamic modeling. Table 4-7 contains a listing of the volumetrics by zone.

Table 4-7. Volumetric calculation of STOIIP and Recoverable oil for the dynamic model area.

Zone	Bulk volume (MMbbl)	Net volume (MMbbl)	Pore volume (MMbbl)	HCPV oil (MMbbl)	STOI IP (MMbbl)	Recoverable oil (MMbbl)
Arbuckle	776	776	95	65	61	29
Arbuckle 31	322	322	35	23	22	10
Arbuckle 19*	0	0	0	0	0	0
Arbuckle 10*	0	0	0	0	0	0
Arbuckle 4*	0	0	0	0	0	0
Arbuckle 1*	0	0	0	0	0	0
Total	1098	1098	130	88	83	40

*Note: zone below oil water contact and no calculation for hydrocarbon was conducted.

Finally, using well tops, surface grids, core data, and well log data provided by industry partners and CAP-CO₂, structural and property models were created for dynamic simulation of the Geneseo-Edwards Field. The distribution of porosity was used to calculate permeability based upon power function transforms for the two different cases. The final model results in a hydrocarbon pore volume of 88 MMbbl ($14.0 \times 10^6 \text{ m}^3$) and approximately 40 MMbbl ($6.4 \times 10^6 \text{ m}^3$) of recoverable hydrocarbons.

4.1.2 Flow Model Simulation Analysis of Combined EOR and Deep Saline Sequestration in Thrall-Aagard Reservoirs

4.1.2.1 Descriptions of Model Grid and Workflow

This portion of the IMCCS conceptual study accesses the feasibility of the storage of CO₂ generated by a nearby ethanol plant and evaluates the feasibility of using the CO₂ for EOR (enhanced oil recovery) purposes. For this, a model covering the isolated Arbuckle domes in the Geneseo-Edwards Field is used. The field has been in production since 1935 with a total of 5.4 million m³ (33.7 million barrels) of oil recovered to date. The very strong bottom aquifer allows the production to proceed without the implementation of any secondary recovery process (e.g. water injection).

Figure 4-42. Geneseo-Edwards model area.

The simulation model area in this study covers a 12-section area most of which operated by Daystar Oil and Scheck Oil (see Figure 4-42). A total of 152 wells can be found in this area with 3.9 million m³ (24.8 million barrels) of oil recovered in the 75-year history.

The following are the data available for the dynamic simulation work:

- Static model (grid) providing reservoir structural and property information
- PVT data of an oil sample collected in a neighboring field
- Annual oil production rates by lease areas
- Barrel test data of some individual wells provided by Daystar Oil and Scheck Oil

Figure 4-43 The simulation model.

The dynamic simulation model (see Figure 4-43) was extracted from the static model grid with 91m x 91m (300ft x 300ft) grid cells and 87 layers each averaging 3m (10ft) in thickness. With the initial oil-water contact estimated to be at 458 m (1,503 ft) subsea, most of these layers cover the underlying saline aquifer. The CO₂ injected into the saline aquifer is expected to rise and eventually enters the swept oil zone from below. This phenomenon is included in the simulation with this integrated model.

An EOS (equation-of-state) for the Eclipse model was provided by University of Kansas and is based on a 33.3 API surface oil sample collected from a neighboring field (Ogallah Unit). On the other hand, the oil produced in the Geneseo-Edwards Field is closer to 37 API and this was achieved by slightly adjusting the EOS. The EOS was incorporated into the simulation model after mixing in a small amount of gas (21.4 m³/m³ or 120 scf/stb) numerically. This gave the resulting fluid a saturation pressure of 4.2 MPa (610 psia) at the average reservoir temperature of 47°C (117°F) as shown in Figure 4-44. With this, the model was initialized with initial water saturation shown in Figure 4-45 and estimates a total of 13.57 million m³ (85.4 million barrels) of oil initially in place.

Figure 4-44. Model fluid phase diagram

Figure 4-45. Initial water distribution

As previously mentioned, the field had been in operation for the past 75 years and only sketchy production data are available. These include annual oil production figures by lease area and barrel tests of individual wells provided by Daystar Oil and Scheck Oil. It is evident that the reservoir is subject to a strong aquifer support during the substantial amount of primary oil recovery with a relatively stable reservoir pressure. With these in mind, analytical aquifers have been attached to the side and to the bottom of the model as extensions to the water body within the model.

Well completion and production information (annual oil production rates by lease) was incorporated (see Figure 4-46) once the initial model setup was complete. This was then followed by adjustments of certain model parameters in order to calibrate it to the historical production data. This process is commonly known as history matching. In this case, the model was made to match the general historical trends in water cut measurements during the barrel tests of the wells in the Daystar and Scheck leases. Model parameters (oil-water contact depth, residual oil saturation and analytical aquifer volumes) were adjusted within reasonable ranges.

Figure 4-46. Production and pressure profiles.

Once a satisfactory match (see Figure 4-47) was achieved, the model could be used for simulating the effects of CO₂ injection in both the sweep oil zone (EOR) and the underlying saline aquifer (sequestration). It should be noted that the model calibration process is generally a non-unique one particularly when sparse field observations are sparse such as in this case. This typically necessitates an uncertainty analysis to evaluate the range of possible outcomes given the lack of data.

Figure 4-47 shows water breakthrough occurred rapidly and consistently throughout the field in the fifties and the sixties. This was caused by the encroaching water from the saline aquifer that also allowed the production to take place without significant observable reservoir pressure declines. Production in recent years has been associated with approximately 99% water cut levels indicating that vast majority of the oil produced came exclusively from the swept oil zone. The model is able to mimic these trends with the strong analytical aquifers attached. Once the simulation of the historical production has been completed, the model can be used to estimate the present day fluid (oil and water) distributions and Figure 4-48 shows three-dimensional water saturation distributions determined by the model at various points in time during the 75-year recovery process.

Figure 4-47. Barrel test water and calibrated model water cut profiles.

Figure 4-48. Aquifer encroachment progress shown with model generated water saturation distributions.

CO₂ injection processes simulated with the calibrated model involve two wells close to the center of the North Dome, one completed near the top of the Arbuckle formation and the other in the saline aquifer underneath (see Figure 4-49).

Figure 4-49. CO₂ injection well completions in the model.

4.1.2.2 Simulation Results

A total of 150,000 tons of CO₂ is assumed to be available from the ethanol plant annually. Two-third of this is injected into the upper part of the North Dome for EOR and the rest sequestered in the saline aquifer. Two injection cases have been performed to simulate the CO₂ plume development as a result, one for a 3-year injection period and the other for a 20-year injection period. All currently producing wells are assumed to maintain existing productions and the simulation continues for another 50 years in each of these cases to predict the post-injection plume movements.

Figure 4-50. Predicted CO₂ saturation distributions (3-year injection case)

Figure 4-50 shows predicted CO₂ saturation distributions at four points in time in the 3-year injection case. It shows that the injected CO₂ quickly reaches the base of the swept oil zone where it stays and accumulates for a period of time before further penetrating upward. This phenomenon only occurs during the injection of CO₂. Figure 4-51 shows the overall plume development with predicted pressure distribution within it. The figure shows the injected CO₂ injection to be total contained within the dome structure.

Figure 4-51. Predicted plume growth with pressure distributions (3-year CO₂ injection case)

Pressure in the swept oil zone is expected to be lower than in the aquifer due to the ongoing production activities. This leads to substantially lower density levels (see Figure 4-52) and the CO₂ is likely to be in gaseous phase.

Figure 4-52 - Predicted plume growth with CO₂ density distributions (3-year CO₂ injection case)

On the other hand, Figure 4-53 the progress of the CO₂ plume in the 20-year injection case. It shows the migration of CO₂ beyond the structure to begin after 9 years of injection. Figure 4-54 shows the overall production profiles predicted by the conceptual model. The decline in oil production is predicted to be somewhat slowed down during the CO₂ injection. However, the model also predicts a fairly rapid breakthrough of CO₂ at the producers largely due to the sub-miscible injection.

Figure 4-53. Predicted plume growth with CO₂ density distributions (20-year CO₂ injection case).

Figure 4-54. Predicted production profiles.

CHAPTER 5 – EOR with Sequestration Analysis

5.0 Geneseo-Edwards CO₂ Enhanced Oil Recovery Project

5.0.1 Description of Study Area – Regional Setting

The Geneseo-Edwards project area is situated on the eastern edge of the Central Kansas Uplift (CKU), a prominent structural feature that separates the Salina basin from the Hugoton Embayment of the Anadarko Basin (Figure 5-1). The CKU is predominately post-Mississippian, pre-Pennsylvanian structure formed during the development of the Anadarko basin and the Ancestral Rockies. In places, Precambrian granite is exposed beneath Pennsylvanian on the CKU and younger strata subcrop beneath the pre-Pennsylvanian unconformity away from the CKU (Figure 5-2). Cambrian-Ordovician-aged Arbuckle strata, the target oil producing zone in the Geneseo-Edwards project, subcrops beneath the Pennsylvanian in the project area as it does over much of the CKU.

Figure 5-1. Location of Geneseo-Edwards Project and major geologic structural features in Kansas. Modified after [Byrnes et al., 2003].

Figure 5-2. Central Kansas stratigraphy (After Cansler and Carr, 2001)

The Arbuckle is the most prolific oil producing strata in Kansas, having produced approximately 37% of the 6.3 Billion barrels (BBO) of production through 2000 (Figure 5-3). Of the 2.3 BBO cumulative oil in 2000, approximately 1.6 BBO had come from Arbuckle fields on the CKU. Figure 5-4 is a structure map on top of the Arbuckle that show the distribution of oil production from that strata. Most of the high producing fields are on the CKU as illustrated in Figure 5-5. The Geneseo-Edwards project area includes some of the more prolific production in the region.

Figure 5-3. Distribution of oil recovered from Kansas reservoirs (Byrnes et al., 2003).

Figure 5-4. Structure map on top of the Arbuckle Group. Arbuckle fields are dark green. (Gerlach 1998), http://www.kgs.ku.edu/DPA/Plays/ProdMaps/arbkc_oil.html)

Figure 5-5. Quality of Arbuckle oil production illustrated by cumulative oil per square-mile sections (Gerlach, 1998).

Arbuckle reservoirs are fracture-controlled karstic reservoirs with porosity and permeability influenced by basement structural patterns and subaerial exposure. Subaerial weathering

and secondary solution significantly enhanced porosity and permeability and created petroleum reservoirs in these strata (Walters 1958, Merriam 1963, Adler 1971, Franseen 1994, Steinhauft et al. 1998, Franseen et al. 2003, and 2004). Reservoir qualities were modified by karst processes during prolonged and repeated subaerial exposure that began after Arbuckle deposition and continued in some areas until the Pennsylvanian (Franseen, et al., 1995). The regional and stratigraphic extent of subaerial exposure and karstification in the Arbuckle was influenced by regional patterns of uplift and subsidence (Newell et al., 1987). The CKU, including the Geneseo-Edwards project area were more heavily karsted than downdip regions where younger strata cover the Arbuckle.

Oil migrated north from the source, the Woodford shale, in the deep Anadarko Basin, and into the prominent southeast northwest trending Central Kansas Uplift where it filled Arbuckle structures to the spill point (Walters, 1958) (Figure 5-6). Downdip fields filled with gas due to gravity separation and oil continued updip to fill karsted and faulted dome-like structures, including the Geneseo and Edwards fields (cross section F-G).

Figure 5-6. CKU oilfields in 1958 in map and cross section view. Cross-hatched patterns indicate oil fields and stippled pattern indicates gas fields.

5.0.2 CO₂ Source and Pipeline Plan

The source of CO₂ for the proposed project is the 40-million-gallon-per-year ethanol plant located 2 miles (3.2 kilometers) south of Lyons, Kansas, owned and operated by Kansas Ethanol. An average of 7.5 mmcf of ninety-six % CO₂ would be captured and compressed onsite to approximately 1600 psia and delivered by 16 miles (26 kilometers) of 4.5 inch OD steel pipeline to the project area at approximately 1400 psia. Fourteen of the 16 miles (26 kilometers) is on existing pipeline ROW corridors. A separation, capture and recycling system is part of the operations design plan.

5.1 Geneseo-Edwards EOR Site

The Geneseo-Edwards project site for EOR concurrent CO₂ sequestration is in the southern part of the 14-mile (23 kilometer) long, 1-1/2 mile (2.4 kilometer) wide Geneseo-Edwards field (Figure 5-7). The field is an active oil field situated in a gently rolling agricultural landscape comprised mostly of grasslands used for cattle grazing.

The field is a series of eight domed structures forming a narrow, faulted anticline. The project site encompasses the two southernmost domes (Figures 5-8 and 5-9). Project site leases have produced 30

million barrels of oil since 1936, 34% of field's 89 million barrels of cumulative oil production. Nearly all production has come from the upper part of the 600 ft-thick Cambrian-Ordovician Arbuckle Group. The two project domes have approximately 120 feet of structural closure and 120-ft original oil column at the apex. The drive mechanism is a strong bottom-water aquifer, bottom hole pressure is 1100 psi, and pressure has not been depleted by production. The current production rate for the 60 remaining active wells in the project area averages approximately 3 BOPD/well and 98% of the fluid produced is saltwater, which is disposed by injection into the lower Arbuckle, off structure, in Class II disposal wells. The lower Arbuckle has very high injectivity, with one well in the area accepting as much as 10,000 BWP on a vacuum. (Matt Osborne, Daystar Petroleum, personal communication).

5.1.1 Production History

Initial production in the project area was established in 1936 with a flurry of activity that spread to a total of 23 wells on 10 leases in the area shown in Figure 5-9. Production peaked in 1942 following significant expansion in development in the two prior years (Figure 5-10). Cumulative production for the area was 33.7 mmbo through 2009 with an estimate 85-90% of the oil having come from the Arbuckle. The balance of the oil is from the shallower Simpson and Lansing and Kansas City Groups. The two domes where the project is focused are estimated to have produced a combined 30.2 mmbo, of which 26.3 mmbo (87%) is estimated to have been produced from the Arbuckle. Production data was compiled from the Kansas Geological Survey database and publicly historical hard copy vendor data.

Figure 5-9. Arbuckle structure map in two-dome proposed Phase II project area. Proposed EOR project areas are outlined.

Figure 5-10. Annual production and well count for area shown in Figure 5-9.

5.1.2 Long-Term Implications

The proposed southern Geneseo-Edwards project is considered a proof-of-concept for developing a commercial market for much larger volumes of CO₂, and what could become a very large-scale CO₂ EOR/sequestration play. Based on preliminary modeling, discussed in Section 5.2, the project will use 3.5 years of CO₂ from the nearby ethanol plant (15 months to fill the smaller of the two domes and 27 months to fill the larger of the domes, shown in Figure 5-9) and produce 6 mmbo over a 10-12 year period. The proposed project plans to inject the CO₂ in the southern two of eight domes in the Geneseo-Edwards field. Should this project prove to be successful, an additional 12 mmbo could be recovered from the other six domes in the field, utilizing another 6.3 years supply of CO₂ from the ethanol plant and permanently storing an additional 0.9 million tonnes CO₂.

The overarching project plan contemplates securing additional sources of anthropogenic CO₂ and expanding to nearby fields (Figure 5-11). To be considered are extending a pipeline from Coffeyville Resources Fertilizer or aggregating CO₂ from ethanol plants in the Kansas-Nebraska region and bring that CO₂ to the Central Kansas

Uplift. Table 5-1 illustrates theoretical oil recovery and CO₂ stored from Geneseo-Edwards and nearby Arbuckle fields applying results from a preliminary engineering study conducted by CAP CO₂ and Epic Consulting, a division of Baker-Hughes Canada. From that study, the CO₂ utilization is 1.6 mcf purchased/BO recovered and the oil recovery factor works out to be 23% of cumulative oil

produced. It is estimated that 87% of the oil produced in the project area is from the Arbuckle and the balance from other zones, mostly the Lansing-Kansas City. To be conservative, an 80% factor is used on the other fields.

Figure 5-11. Geneseo-Edwards and other Arbuckle fields in the Phase II project area and cumulative production (million BO).

	Cumulative Oil (mmbo)			CO2 stored		Ethanol plant years
	Gross	Arbuckle	CO2 EOR	mmcf	Million Tonnes	
DOE Project	30.2	26.3	6.1	9,613	0.50	3.5
Balance Geneseo-Edwards	59.2	47.4	11.0	17,311	0.90	6.3
Stoltenberg	55.1	44.1	10.2	16,112	0.84	5.9
Bloomer	55.8	44.6	10.4	16,316	0.85	6.0
Kraft-Prusa	137.8	110.2	25.6	40,294	2.09	14.7
Chase-Silica	280.6	224.5	52.1	82,050	4.26	30.0
	618.7	497.1	115.3	181,695	9.4	66.4

Table 5-1. Theoretical recovery and CO₂ stored from Geneseo-Edwards and nearby Arbuckle fields. Production from public database: <http://www.kgs.ku.edu/PRS/petroDB.html>

Although the ethanol plant is adequate to supply CO₂ for the Geneseo-Edwards and process that field over a 10-year period, if successful at proving the concept, it is evident that just the other Arbuckle fields in the immediate vicinity are a sufficiently large enough market for a commercial pipeline the size of which would bring in CO₂ from Coffeyville Resources Nitrogen Fertilizer plant (40 mmcf/d). Fields in Figure 5-11 and Table 5-1 would require 12 years of CVR supply and they combine for approximate 31% of the Arbuckle production on the CKU. In addition to the Arbuckle, the Lansing-Kansas City has CO₂ EOR potential for horizontal, piston-style displacement in depleted waterfloods, particularly in the Hall-Gurney and Trapp fields located 40 miles (64 kilometers) to the northwest. Those fields and those in Table 5-1 and Figure 5-11 are listed as potential targets (Figure 5-12) in a DOE-sponsored White Paper report (2010).

Figure 5-12. Large fields amenable to CO₂ EOR based on ARI White Paper. (modified from ARI, 2010).

5.2 Pre-modeling Preliminary Gravity-Stable Feasibility Study

5.2.1 Study Objectives

EPIC Consultants, Calgary, a division of Baker-Hughes Canada, was selected to work with CAP CO₂ technical staff to conduct a preliminary engineering study for a potential gravity-stable CO₂ EOR project because of their experience in gravity-stable CO₂ flood projects in Canada. The full EPIC report is available in their March 2010 report, Genesee-Edwards Arbuckle Immiscible CO₂ Feasibility Study. The key objectives of the study were to address the following:

1. Estimate the efficiency of near-miscible effects. Reservoir pressure is fixed at 1100 psi and average MMP is 1389 psi.
2. Determine whether the flood could be operated in the CO₂ super-critical state
3. Evaluate the effectiveness of the bottom water drive for consistency in oil/water contact movement, in order to determine whether gravity-stable process is feasible
4. Basic volumetric and material balance engineering
5. Estimate residual oil saturation
6. Provide a preliminary forecast of CO₂ injectivity and overall requirements
7. Recommend a preliminary operational plan
8. Provide a preliminary flowstream forecast

5.2.2 Key findings

Key finding from EPIC report are shown in Figure 5-13, below:

- Present volumes were calculated at -1510 ft subsea oil-water-contact with three dome boundary polygons restricting some lower oil in the area

OOIP, original oil in place, within 3 dome boundaries (MMbbls)	ROIP, current oil in place (MMbbls)
66	38

- The proposed process will be a near miscible process with an MMP value of ~1350 psi, calculated by slim -tube tests and confirmed with correlations .
- Using correlations, the following results on residual saturation were found:

S_{orw} , residual oil saturation after waterdrive	S_{orm}/S_{orw}	S_{orm} , residual oil saturation after near miscible flood
0.38	0.46	0.175

Figure 5-13. Key findings 1, copied from Epic Consulting Services (written communication) report.

5.2.3 Discussion

The EPIC report included three domes, two of which were evaluated and included in this IMCCS study. Current water saturation was based on their internal proprietary algorithm (ResWorks ver.2008c©) that is based on empirical data (Stoain, 1996). Inputs are basic reservoir data including porosity (11%), average permeability (900 md), and initial water saturation (30%), and rock type (carbonate). EPIC's estimated S_{orw} = 38.1% is very close to CAP CO2's estimated S_{orw} = 38.9%, based on material balance, and also consistent with reservoir simulation (S_{orw} = 36%) in a 3D model by Schlumberger (Figure 5-14).

Figure 5-14. Present water saturation in 3D cellular model from numerical simulation performed by project partner Schlumberger Data and Consulting Services. Average water saturation is 64% ($S_{orw} = 36\%$).

The ratio of residual oil to immiscible CO_2 (S_{orm}) to S_{orw} was calculated using the Exxon/Lange solubility correlation in SPE 35425 (Lange, 1998; Teletzke, 2005). The Lange algorithm is based on empirical correlations and inputs are oil properties and reservoir conditions. Results for two oils sampled, one from each dome, show little variation in S_{orm} (Table 5-2.). Lange correlations would have predicted an MMP of 1338.5, very close to the lower of the two MMP's.

	<u>M (1356MMP)</u>	<u>M (1421MMP)</u>
α_{gas}	1.79	1.79
α_{oil}	6.54	6.55
$\alpha_{oil} - \alpha_{gas}$	4.76	4.77
S_{orm}/S_{orw}	0.46	0.46
$S_{orm} (\%)$	17.54	17.59

Table 5-2. Miscibility calculation results

Theoretical S_{orm} can only be attained in laboratory conditions and the efficiency of the sweep in a gravity-stable flood is, in part, a function of coning, or how consistently horizontal can the CO_2 gas cap / oil-water contact can be maintained (Patel, 1994). The

degree of coning is a judgment call. Based on a study of the movement of the oil/water contact through production history, EPIC estimates the coning factor (E_v , coning) to be 0.6. That is, the sweep efficiency is 60%, and 60% of the oil between S_{orw} and S_{orm} could be recovered. The last factor in estimating overall recovery is the sweep efficiency of the "waterflooding" or by the active water drive. The average for the three domes investigated was calculated to be 0.917. Calculation steps for estimating recovery from CO_2 are given below:

Recovery Factor after flooding (water drive)= $RF = E_d * E_v$

E_v is the only value a reservoir engineer can change

$$E_D = (S_{oi} - S_{orw}) / S_{oi} = (0.7 - 0.381) / 0.7 = 0.456$$

$$E_v = RF / E_D = 0.418 / 0.456 = 0.917$$

Recovery Factor after CO_2 Flood= $RF = E_d * E_v$

$$E_D = (S_{orw} - S_{orm}) / S_{orw} = (0.381 - 0.175) / 0.381 = 0.54$$

E_v , coning = 0.6

$$RF, CO_2 = E_d * E_v * E_{v,coning} = 0.54 * 0.917 * 0.6 = 0.30$$

5.2.4 Additional Key Findings

Additional key findings from EPIC report are shown in Figure 5-15, below:

- Water Drive Performance
 - The gravity viscous number indicates that the flow is gravity dominated.
 - The 1-D model of vertical flood assumes volumetric sweep efficiency, E_v = 60% for coning.
 - The OWC analysis concluded that more analysis of the water level is needed to analyze waterdrive recovery factor as separate domes, and that due to the high E_v , there may be a higher OOIP than originally recognized

- Target volumes for this vertical miscible flood calculated from a -1510 ft subsea oil-water-contact, within three dome boundary polygons.

Target Oil	Fraction of OOIP	Fraction of ROIP
11.3 MMbbls	17%	30%

- 6 field wide injectors are recommended for maximum solvent injection into the Geneseo-Arbuckle Field
- More monitoring, measurement, and simulation studies are highly recommended in this field before confident reservoir management can be obtained.

Figure 5-15. Additional key findings, copied from Epic March 2010 report.

5.2.5 Horizontal Oil-Water Contact

The single-most critical assumption is that the southern Geneseo-Edwards domes can be effectively processed by gravity-stable methods. For this to occur, it is imperative that a CO₂ gas cap can be built downward while maintaining a relatively flat gas/water-oil contact. Evidence for being able to do so:

- Oil water contact stayed relatively flat as it moved upward during the 80-year production history – documented by CAP CO₂ and detailed by EPIC consulting.
- Many cases where wells completed deep into the Arbuckle went to water, but when plugged back to shallower depths, returned to water-free oil or very low water cuts.
- Density and viscosity differences between CO₂ and oil and water are very large indicating high potential for gravity drainage (see EPIC report).
- The Lyons gas storage, located 6 miles (10 kilometers) southwest of the project areas operated by Northern Natural Gas (NNG) has similar geologic domed setting. It is rumored to have a strong bottom-water drive that moves up and down vertically during the gas storage cycles. NNG has not yet agreed to meet with us to discuss the reservoir dynamics.

There is contradictory data, however. Mullins and Ireland (1967) reported in SPE #1963 that the Arbuckle was stratified in the Northern Geneseo-Edwards field on Conoco Leases, 5 miles (8 kilometers) northwest of the proposed project. They reported deepening watered-out wells and encountering high oil cuts in deeper horizons separated by impermeable layers from the watered out zones above.

CAP CO₂ and EPIC analyzed well production, oil-water ratios, and perforation depth histories through time in approximately 30 wells in the two dome project area. We compared oil-water ratios through time at specified perforation intervals and well records showing recompletions higher in the section of the 120-foot oil column. Elevations of the oil-water contact were evaluated in 3D (Figure 5-16) and 2D cross sections (Figure 5-17). Oil-water contacts appear to have moved vertically in a relatively consistent, horizontal fashion. An exception is along the edges, which is consistent with Keg River CO₂ gravity-stable floods in Canada. This is consistent with the history-matched simulation model over the same period (Figure 5-18). In the simulation the oil/water contact was relatively uniform and exhibited no coning effects.

Figure 5-16. Oil-water contact changes through time in 3D.

Figure 5-17. Oil-water contact changes through time in 2D in the South Dome.

Figure 5-18. Water saturation (S_w) in Geneseo-Edwards simulation model from initial to present. Cooler colors are higher S_w (blue = 100%)

5.2.6 Operations Plan Based on Keg River Analogues

In Alberta, Canada alone, there have been 68 miscible floods as of 2005. 54 of these pools are on production and the majority of these floods are in carbonate rock and are vertical floods. In a typical hydrocarbon miscible flood, slug size proportions include 10-15 % solvent followed by 100% chase gas. Generally, the reservoir is designed with a 30-45 ft solvent bank. In the Geneseo-Edwards field, nearly pure CO_2 is to be injected into the reservoir with no chase gas, establishing a ~15-25 ft oil bank, with a ~100 ft solvent bank. Later in the Alberta miscible floods, water is injected into the bottom aquifer to control the voidage replacement ratio (VRR), water oil contact (WOC), and the pressure. As well, later in the miscible flood, horizontal and multilateral wells are considered for economic optimization in offset vertical wells to limit the “sandwich” losses.

In the Keg River A pool, an analogue vertical flood which started solvent injection in 1969, a uniform pressure was maintained. This gas injection continued without significant breakthrough until 1985, a period of approximately 15 years. The miscible flood continued for another 18 years, until 2003, when the flood was abandoned. During this time the oil decline showed a harmonic and rapid decline as the oil sandwich became thinner. In the Keg River B pool, the hydrocarbon miscible flood started and broke-through in 1986, much faster than the A pool. The differences in heterogeneity play the

most important role. The Keg River pools have a $RF_{CO_2} = 10\text{-}20\%$, while the Nisku pools have a $RF_{CO_2} = 20\text{-}30\%$.

Based on the analysis of the Arbuckle reservoir, material balance, correlations with empirically derived relationships, and with Canadian analogs, the projected CO_2 EOR target oil is shown in Table 5-3. North and South Domes are projected to recover 6.1 mmbo from oil displaced by a gas cap to subsea datum of -1486, assuming a coning factor of 60%.

Table 5-3. Estimated oil recovery for three domes analyzed.

CO_2 will be injected in a supercritical state at approximate BHP of 1100 psi (19).

Critical Pressure = 72.9 atm
Critical Temperature = 31.1 celcius

Current Reservoir Pressure = 74.8 atm
Current Reservoir Temperature = 47.2 celcius

Figure 5-19. Phase diagram showing anticipated conditions in target reservoir.

Figure 5-20 provides a 3D view of the project area.

Figure 5-20. 3-D view of three domes South Genesee-Edwards field. North and South domes are main targets in project. Domes are zoned into 5 layers, each 24 ft thick, for volumetric analysis.

- 1.25 years at 7.5mmcf/d
- 100-foot gas cap and 25-ft oil column at base of gas cap
- 2. Produce North Dome from perforations below oil column
 - Approx. 10-yr to economic limit
 - Recycle CO₂ back into gas cap
- 3. Fill South Dome to approximately -1486 subsea with CO₂
 - Begin after North Dome is filled
 - 2.25 years at 7.5mmcf/d
 - 100-foot gas cap and 25-ft oil column at base of gas cap
- 4. Produce from perforations below oil column
 - Approx. 11-yr to economic limit
 - Recycle CO₂ back into gas cap

Project life-cycle is illustrated in Figures 5-22 and 5-23. CO₂ utilization, recycle, and oil recovered are based on EPIC's study.

Figure 5-22. Well counts by well class during Geneseo-Edwards project life.

Figure 5-23. Forecast flowstreams for Geneseo-Edwards project life.

5.3 Characterization and Simulation Overview

5.3.1 Characterization-Simulation Team and Workflow

Reservoir characterization and simulation was a team effort with the co-authors of this report and technical aspects of the project. The basic workflow is provided in Figure 5-24. IMCCS researcher Dubois managed the data compilation, acquisition gap-filling data, much of the data analysis and processing and analysis, developed initial 2-D geologic framework in PetraTM, built the property data set at the well scale, and coordinated the overall characterization-simulation process. IMCCS researcher Belobraydic built the 3-D geologic and property static model (grid) in PetrelTM. IMCCS researchers Wang and Waggoner developed input parameters, calibrated the static model through history matching production, and performed reservoir simulations with EclipseTM.

Figure 5-24. Basic workflow for Geneseo-Edwards reservoir characterization and simulation.

5.3.2 Data Gathering and Processing

It is a challenge to accurately characterize mature oil and gas reservoirs due to paucity of data. That is the case for the southern Geneseo-Edwards field discovered in the mid-1930's and with most wells drilled prior to the mid 1950's. The timing of drilling, pre-modern well logs, the type of completions, mainly openhole, and the vintage of the development contribute to the lack of high quality reservoir data. Because the leases have changed hands multiple times since initial development by Conoco, there has been a substantial loss of production and other data that would be useful in documenting reservoir dynamics. The fact that the production data available through public records includes only oil at the lease scale on a monthly basis, exacerbates the problem. We have worked with existing data from public and private sources, operator files, and limited published work, and then filled in data gaps. Not all data gaps, most notably engineering data for developing an Equation of State, were able to be filled in the short, 7-month time frame for the project. Despite the circumstances, we feel that the static model (grid) is a reasonable representation of the target reservoir. Periodic well production tests provided by the operators, Daystar and Scheck, enabled us to estimate fluid production through time. A reasonable history match to present day was attained by numerical 3D reservoir

simulation and reservoir response to CO₂ injection predicted by simulations also appear to be within the expected range.

5.3.2.1 Production Data

Monthly oil production data was compiled from public digital and hard-copy sources under contract by IMCCS researcher Doug Beene, a production data specialist. Post-1966 data is from online public records at the Kansas Geological Survey (<http://www.kgs.ku.edu/Magellan/Field/index.html>). Pre-1967 data is from various hard-copy and microfiche sources. Oil Production is reported on a lease-scale with multiple wells going into the same tanks and the combined monthly production is reported. Water production is not required and water production data are not available from public databases.

Although individual well production data for oil and water are not publicly available, sporadic well tests for 41 individual wells were captured from operator well files (Figure 5-25). On average, 10 tests were available per well, giving snapshots of production rates and oil-water ratios through time at a given location and depth, providing sufficient data to map the oil-water contact in three dimensions through time. Figure 5-26 illustrates the movement of the oil-water contact through time in a crossplot. Typically, wells in the 1940's were completed for water-free oil production in open hole completions from the top of the Arbuckle, say at -1420 subsea) to as deep as -1490. Through time, as watercuts increased, the wells were plugged back to shallower and shallower depths when water production became an issue.

Figure 5-26. Approximate oil-water contact through time based on water cuts and perforation interval in project area.

5.3.2.2 Geologic and Petrophysical Data

Basic well header information, including location, operator name, lease name, well number, and datum elevation is from the online public database at the Kansas Geological Survey (<http://www.kgs.ku.edu/Magellan/Qualified/index.html>). All wells are vertical wells. Operator formation tops are from completion cards at the Kansas Geological Society library, Wichita, Kansas. A consulting geologist, Robert O'Dell of Wichita, Kansas, joined the IMCCS team and gathered well data, picked formation tops, reviewed operator files, and completed other basic data-gathering tasks. An electric-log based formation tops set was developed including more than half of the 321 wells in the 12-section area and surrounding the two-domed project (Figure 5-27). The 600-foot-thick Arbuckle was subdivided into up to six zones in 53 wells having the deepest penetration into the Arbuckle. Three databases and private operator files were searched for wireline logs, the Kansas Geological Survey, Kansas Geological Society Library, and MJ Systems. Wireline logs from fifteen wells were digitized for more detailed analysis. Logs were selected on the basis of depth of penetration into the Arbuckle and quality of the curves. One is a density-neutron porosity and dual induction log and the rest were uncalibrated gamma ray-neutron logs. Cores and conventional core analysis data was available for two wells (Figure 5-27).

Figure 5-27. Wells and data coverage in the project area. Log or sample tops were available for 95% of the 321 wells. Fifty-three had wireline logs and were deep enough penetrations to subdivide the Arbuckle (circled wells). Logs were digitized in 15 wells (brown dots). Two cored wells are highlighted in green.

5.3.2.3 Reservoir Data and Fluid Analysis

At the start of the project many fundamental reservoir and fluid properties were not known. Many of these data gaps were filled by field and lab measurements, although significant gaps remain. BHT and BHP data were gathered on three wells in the Geneseo-Edwards project area by Trilobite Testing, Inc. Three wells were selected (Figure 5-28) by the following criteria: open in the Arbuckle only, inactive or shut-in for more than 30-days, static fluid level, open casing with no casing leaks. BHP-BHT pressure bomb was

lowered into the wells as deep as possible. The intent was to get the tool to actual TD of the wells, but obstructions in the bottom of each well prevented reaching actual TD, but close.

Figure 5-28. Wells selected for BHT and BHP measurements in Geneseo-Edwards area.

Sufficient depth was reached to establish temperature and pressures and gradients to extrapolate to the Arbuckle interval:

BHT = 117 degrees F at 3200 ft with gradient of 0.02 degrees per foot.

BHP = 1080 psi @ 3200 ft with gradient of 0.43 psi per foot.

Table 5-4 summarizes the three tests. Post analysis discovered that the Lansing B2 was open in the Simpson, a zone that has been produced in the well and others around it and the pressure likely reflects the lower pressured Simpson sandstone.

Well	Arbuckle Depth	Well TD	Sample Depth	BHP (psig)	BHT (°F)
Gray 1 <i>API 1515901733</i>	3098	3176	3171	960	118
Lansing B2 <i>API 1515901921</i>	3163	3178 (OTD) >3210 (DDTD)	3210	656	117
Lansing B5 <i>API 1515919031</i>	3160	3970 (OTD) 4029 (DDTD)	2866	952	109
	Top of Arbuckle		3160	1078*	116*
	Base of Arbuckle		3706	1311*	128*

Table 5-4. Summary of BHP and BHT tests in Geneseo-Edwards

Crude oil samples were collected from two wells in the Geneseo-Edwards for compositional and MMP analysis (Figure 5-29). Wells were selected by the following criteria: producing from the Arbuckle only and no casing leaks. Oil was sampled at the wellhead by Daystar Petroleum field personnel from the bleeder valve into clean, sealable plastic containers, transported to JACAM Chemicals where samples were transferred to airtight containers suitable for shipping hazardous materials. Oils were shipped to SCAL, Inc. lab in Midland Texas. MMP analysis was performed by SCAL, Inc. using sand packed slim tube and industry-accepted practices. MMP for the two samples was 1356 and 1421 psi at 117 degrees (Figures 5-30 and 5-31).

Figure 5-29. Crude oil analysis performed on oils from two wells in Geneseo-Edwards field.

Figure 5-30. MMP for Gray #2 well is 1,356 psi @ 117 F

Figure 5-31. MMP for Kimble #3 well is 1,421 psi @ 117 F

Basic crude oil properties are summarized in Table 5-5.

	Gray #2		Kimple #3	
	70	117	70	117
Temperature (F)				
Min. Misc. Pres. (psi)		1,356		1,421
Density - SI (gm/cc)	0.835	0.819	0.84142	0.8304
Spec Grav - MA (ideal) (gm/cc)	0.7808		0.8161	
Vapor Pressure	7.2		4.73	
API gravity	37.9	41.3	36.7	38.9
Viscosity (cp)	6.7	3.3	8.87	3.08
Paraffin (%)	1.4		3.86	
Asphaltenes (%)	0.52		0.52	

SI - SCAL, Inc.

MA - Mitchell Analytical

Table 5-5. Summary of crude oil properties, South Geneseo-Edwards field.

5.3.3 Estimating Properties with Minimal Data

Building a basic property model was hindered by shallow Arbuckle penetrations, a paucity of modern open-hole logs, and core analysis data. Only on wells in the project area with relatively deep penetration into the Arbuckle have neutron-density porosity and induction electric logs, forcing the need to utilize uncalibrated neutron-gamma ray logs run in both the open hole and cased hole portions of the wells in the project area. Neutron curves were painstakingly calibrated to the single well with neutron-density porosity and to wells with core porosity to obtain digital porosity profiles at half-foot intervals in 15 wells. Figure 5-32 shows the core plug porosity compared to calibrated neutron curves. Much of the difference between core porosity and calibrated neutron porosity are due to the scale at which the measurements are made, inches (cm's) a few feet (0.5 m). Permeabilities were estimated using porosity-permeability transforms more fully described in Section 5.4.4.

Figure 5-32 Wireline log calibrated neutron porosity and core analysis data from Ainsworth A-10 (South Dome) and Pickerill A-10 (North Dome). Formation tops include the top of the Arbuckle and layer 31, an informal correlation point within the Arbuckle, and the approximate original oil-water contact (O/W).

Initial water saturation is problematic because of the age of the production, established in the mid-1930's. A search of literature and private operator files did not yield any clues. The initial water saturation is estimated as 30% on the basis of material balance analysis using a formation volume factor (FVF) of 1.1, average porosity of 11.5%, and oil-water contact subsea depth -1500. Neither original gas-oil-ratio nor FVF have been found in literature nor in operator files. It is highly unlikely that the FVF is any higher than 1.1 because there is no record of casing head gas production and current production is accompanied by minimal amount of gas that is too small to measure. Average porosity is derived from core and very limited wireline logs. The original oil-water contact is based on production tests. Because of the high permeability, the transition zone is very likely to be very narrow, thus using a single saturation value is probably satisfactory until capillary pressure data can be acquired and better estimates made.

5.4 Arbuckle Property Model Grid

The southern part of the Genesee-Edwards structure was selected for a potential EOR and CO₂ sequestration project by IMCCS. The property model for the Genesee-Edwards

was created to provide the initial conditions in *Petrel 2009.1.1*⁴ for the start of the dynamic simulation model and to give basic volumetrics of initial oil in place. Using well data for structure and physical properties the resulting model calculates 88 MMbbl ($14.0 \times 10^6 \text{ m}^3$) of oil initially in place for the dynamic model area.

5.4.1 Study Area

The study area for the property model was extended well past the EOR injection site in the Geneseo Edwards. The boundary for the property model was selected to encompass the entirety of the Geneseo-Edwards structural high (Figure 5-33). This size model allowed any size dynamic model to be selected out of the completed property model as need dictated. The property model covers most of T17S-R8W, T18S-R8W, and T19S-R8W; and partially covers T16S-R8W, T17S-R7W, T18S-R7W, and T19S-R7W.

Figure 5-33. Geneseo-Edwards location map. Black dots are the well locations. Orange dots are wells with data. The purple boundary is the property model boundary and the orange boundary is the dynamic model boundary.

5.4.2 Data Processing

Data for the model was exported from the Petra database provided by CAP CO2 and other industry partners, and all well locations, well tops, cultural polygons, and structural grids were imported to *Petrel*. The well logs received were porosity logs based on

⁴mark of Schlumberger

neutron curves calibrated to core data. All well locations and tops were verified by IMCCS researchers and erroneous data points were eliminated from the data set.

5.4.3 Structural Grid

The structural grid is based on the Arbuckle top surface (Figure 5-34) is based on tops in approximately 1100 wells in the area covered by the color-filled contours. The well top control for the area of interest suggests that a normal fault with about 300ft (91.44m) of displacement exists on the west side of the structure. This fault located in the model by identifying the inflection on the Arbuckle and Arbuckle 19 surfaces and extrapolated though the entire Arbuckle Formation.

The final stratigraphic horizons used in the model were the result of several iterations due to data inconsistency. Both the Arbuckle and Precambrian tops are erosional surfaces and have the most control across the region. The top of the Arbuckle was created first from Petra grids and well tops (Figure 5-34). The Arbuckle-19 horizon was created by isochore from the Arbuckle top; however, because the data were only in the area of interest, all areas outside the well control were heavily smoothed to remove artifact highs and lows inherited from the Arbuckle top surface (Figure 5-35). This method isochore and smoothing ensures that the data is honored and reduces structural errors for the other horizons that were built from the Arbuckle isochore. The Arbuckle-31 structural surface was built by isochore up from Arbuckle-19 (Figure 5-36). The Arbuckle-10, 4, 1 surfaces and the Precambrian surface were built by isochore down (Figures 5-37, 5-38, 5-39 and 5-40 respectively).

Figure 5-34. Arbuckle top surface for the Geneseo-Edwards model. Black dots are well top control points used in the model. Contour interval 25ft (7.62m).

Figure 5-35. Arbuckle-19 surface for the Geneseo-Edwards model. Black dots are well top control points used in the model. Contour interval 25ft (7.62m).

Figure 36. Arbuckle-31 surface for the Geneseo-Edwards model. Black dots are well top control points used in the model. Contour interval 25ft (7.62m).

Figure 5-37. Arbuckle-10 surface for the Geneseo-Edwards model. Black dots are well top control points used in the model. Contour interval 25ft (7.62m).

Figure 5-38. Arbuckle-4 surface for the Geneseo-Edwards model. Black dots are well top control points used in the model. Contour interval 25ft (7.62m).

Figure 5-39. Arbuckle-1 surface for the Geneseo-Edwards model. Black dots are well top control points used in the model. Contour interval 25ft (7.62m).

Figure 5-40. Precambrian surface for the Geneseo-Edwards model. Black dots are well top control points used in the model. Contour interval 25ft (7.62m).

Two significant unconformities exist in the stratigraphic column. First, there is a disconformity at the top of the Arbuckle that erodes into the top of the Arbuckle-31 zone.

Second, there is a nonconformity at the top of the Precambrian basement that has resulted in an absence of the Arbuckle 1 zone to the north. Figures 5-41 and 5-42 show East-West and North-South cross sections of the zones through the southern structural high of the Genesee-Edwards, the location of the dynamic model.

Figure 5-41. East-West cross section through the zones for the southern structure and the dynamic model area. Note fault cut in the middle of the section.

Figure 5-42. North-South cross section through the zones for the southern structure and the dynamic model area.

The size of the study area dictated that a 300ft by 300ft (91.44m by 91.44m) cell horizontal cell size was the smallest possible for the structural model, creating 49,494 2D cells for the model area. Layering of the zones was tied to the distribution of data. Above the Arbuckle-19 there were more well logs and a 5ft cell height was selected. Below the Arbuckle-19, a 10ft cell size was selected. For the entire modeled area a total of 6,335,232 cells were created with 146 in the i-direction, 339 in the j-direction, and 128 in the k-direction.

5.4.4 Property Model

The porosity curves calculated from neutron logs were upscaled to the structural grid using the arithmetic averaging method. The location of the data wells were rather far apart and geostatistical methods to analyze the data was found to be questionable. To better fit the geological conceptual model, the default *Petrel* settings for distribution were used; 5000ft (1524m) for the major range, 5000ft (1524m) for the minor range, and 10ft (3.05m) for the vertical range. Figures 5-43 and 5-44 show east-west and north-south cross sections of the porosity through the southern structural high of the Genesee-Edwards, the location of the dynamic model. Figure 5-45 is the histogram comparing the distribution of well log (red), upscaled (green), and 3D grid (blue).

Figure 5-43. East-West cross section of porosity through the dynamic model area. Note fault cut in the middle of the section.

Figure 5-44. North-South cross section of porosity through the dynamic model area.

Figure 5-45. Histogram comparing the distribution of porosity on different scales; well log (red), upscaled (green), and 3D grid (blue).

The porosity and permeability core data from two wells were used to make correlations to input to permeability into the property model. Four porosity/permeability trend lines were created from the data by modifying the range of data (Figure 5-46). The blue trend line used all the data provided from CAP CO2. The blank permeabilities were estimated by CAP-CO2 and the trend line equation:

$$K_{\text{blue}} = 1778154.23 * \text{porosity}^{5.66}$$

$$R^2 = 0.65$$

Where K is permeability and Φ is porosity. Removing the estimated permeability values (green) the trend line equation is:

$$K_{\text{green}} = 275904.63 * \text{porosity}^{4.31}$$

$$R^2 = 0.47$$

Figure 5-46. Cross-plot of porosity and permeability core data for the Geneseo-Edwards. Blue dots are for all core data and estimated data. Green dots are all core data with no estimated data. Red dots are the binned porosity and permeability averages for all core data and estimated data. Yellow dots are the binned porosity and permeability averages for all core data with no estimated data. Trend lines are in corresponding colors to the data.

To achieve a better fit to the upper cloud of data, porosity bins were established to average the porosity and permeability for all data. Using all of the data, including the permeability estimates, the bins were 0.02 porosity units (red). The data without the

estimates were binned in 0.03 porosity units (yellow). In both cases the averaged data for the bins better fits a power function with an R^2 value greater than 90. The trend line equations are:

$$K_{\text{red}} = 16788910.48 * \text{porosity}^{4.59}$$
$$R^2 = 0.909$$

$$K_{\text{yellow}} = 173272.82 * \text{porosity}^{3.29}$$
$$R^2 = 0.91$$

The sets with no estimated values were propagated in the model to eliminate potential estimation error. The binned set is used as a high permeability case, while the correlation for the raw data is the low permeability case. Using the previously mentioned power function, the distributed porosity was used to create the high and low permeability properties. The distributed permeabilities are shown in cross sections in Figures 5-47a-d. Figure 5-48 and 5-49 are the histograms for the low and high permeability distributions.

Figure 5-47a. East-West cross section of low permeability through the dynamic model area. Note fault cut in the middle of the section.

Figure 5-47b. North-South cross section of low permeability through the dynamic model area.

Figure 5-47c. East-West cross section of high permeability through the dynamic model area. Note fault cut in the middle of the section.

Figure 5-47d. North-South cross section of high permeability through the dynamic model area.

Figure 5-48. Histogram of low permeability distribution for 3D grid.

Figure 5-49. Histogram of high permeability distribution for 3D grid.

Water saturation was created by using the oil water contact (OWC) of -1500 ft TVDSS provided by CAP-CO2. An estimated water saturation of 30% was used above the OWC. This value was used to initialize the dynamic model. Table 5-6 contains the maximum, minimum, and mean values for each of the properties.

Property	Minimum	Maximum	Mean
Porosity	0.000	0.260	0.098
Low Permeability (md)	0*	830	25
High Permeability (md)	0*	2059	121
Water Saturation	0.3	1.0	---

*Note: values are significantly close to zero and are products of the porosity-permeability transform.

Table 5-6. Minimum, maximum, and mean values for porosity, low permeability, high permeability, and water saturation.

Volumetric calculations

Using the distributed porosity, water saturation, and an oil formation volume factor of 1.06 RB/STB ($0.169 \text{ m}^3/\text{m}^3$), a volume calculation was created for the property model. For the area of the dynamic model the pore volume is 130 MMbbl ($20.7 \times 10^6 \text{ m}^3$) with a hydrocarbon pore volume of 88 MMbbl ($14.0 \times 10^6 \text{ m}^3$) and about 40 MMbbl ($6.4 \times 10^6 \text{ m}^3$) of recoverable oil is present. The Arbuckle and Arbuckle-31 zones contain the entire hydrocarbon amount. These numbers will require validation through dynamic modeling. Table 5-7 contains a listing of the volumetrics by zone.

Zone	Bulk volume (MMbbl)	Net volume (MMbbl)	Pore volume (MMbbl)	HCPV oil (MMbbl)	STOIIP (MMbbl)	Recoverable oil (MMbbl)
Arbuckle	776	776	95	65	61	29
Arbuckle 31	322	322	35	23	22	10
Arbuckle 19*	0	0	0	0	0	0
Arbuckle 10*	0	0	0	0	0	0
Arbuckle 4*	0	0	0	0	0	0
Arbuckle 1*	0	0	0	0	0	0
Total	1098	1098	130	88	83	40

*Note: zone below oil water contact and no calculation for hydrocarbon was conducted.

Table 5-7. Volumetric calculation of STOIIP and Recoverable oil for the dynamic model area.

5.4.5 Summary

Using well tops, surface grids, core data, and well log data provided by CAP-CO2, structural and property models were created for dynamic simulation of the Geneseo-Edwards Field. The distribution of porosity was used to calculate permeability based upon power function transforms for the two different cases. The final model results in a hydrocarbon pore volume of 88 MMbbl ($14.0 \times 10^6 \text{ m}^3$) and approximately 40 MMbbl ($6.4 \times 10^6 \text{ m}^3$) of recoverable hydrocarbons.

5.5 Simulation of Gravity-Stable CO₂ Injection for EOR and Sequestration

5.5.1 Scope of Simulation Study

The CO₂ Injection Simulation task sought to model the injection of CO₂ into a mature oil reservoir for the dual purpose of CO₂ storage and mobilization of remain oil. This exercise was a preliminary simulation of the development and injection scenario outlined in Section 5.5.3. Optimization of well placement, trajectory, injection rates that could improve CO₂ storage and oil sweep were not applied in this initial simulation. The primary objective is to fill the two domes with CO₂ using a fixed maximum rate of 7,500 Mscf/d, and then observe the volume of oil displaced and where the displaced oil bank forms.

5.5.2 Simulation Model Parameters and History Match

The reservoir consists of two structurally high domes with closure on all sides. The North Dome is smaller and simpler, while the South Dome is more laterally extensive. The southern Geneseo-Edwards has been in production since 1935 with a total of 5.4 million m³ (33.7 million barrels) of oil recovered to date from the modeled area (Figure 5-50). A strong bottom drive aquifer has maintained the average reservoir pressure very well over the life of the field, even in the absence of active water injection.

Figure 5-50. Geneseo-Edwards model area with operator and lease names.

The simulation model area in this study covers a 12-section area most of which operated by Daystar Oil and Scheck Oil (see Figure 5-50). A total of 152 wells can be found in this area with 3.9 million m³ (24.8 million barrels) of oil recovered in the 75-year history. The following are the data available for the dynamic simulation work:

- Static model grid providing reservoir structural and property information
- PVT data of an oil sample collected in a neighboring field
- Annual oil production rates by lease areas
- Barrel test data of some individual wells provided by Daystar Oil and Scheck Oil

5.5.2.1 Static Model Grid

The dynamic simulation model (see Figure 5-51) was extracted from the static model grid with 91m x 91m (300ft x 300ft) grid cells and 87 layers each averaging 3m (10ft) in thickness. With the initial oil-water contact estimated to be at 458 m (1,503 ft) subsea, most of these layers cover the underlying saline aquifer. The CO₂ injected into the saline aquifer is expected to rise and eventually enters the swept oil zone from below. This phenomenon is included in the simulation with this integrated model.

Figure 5-51. The simulation model

5.5.2.2 Equation of State

An EOS (equation-of-state) for the Eclipse300 model was provided by University of Kansas and is based on a 33.3 API surface oil sample from a neighboring field, the Ogallah Unit (http://www.torp.ku.edu/research/Tsau_2a.pdf). On the other hand, the oil produced in the Geneseo-Edwards Field is closer to 37 API and this was achieved by slightly adjusting the EOS. The EOS was incorporated into the simulation model after mixing in a small amount of gas ($21.4 \text{ m}^3/\text{m}^3$ or 120 scf/stb). This gave the numerical fluid a saturation pressure of 4.2 MPa (610 psia) at the average reservoir temperature of 47°C (117°F) as shown in Figure 5-52. With this, the model was initialized with initial water saturation shown in Figure 5-53 and estimates a total of 13.57 million cubic meters (85.4 million barrels) of oil initially in place.

Figure 5-52. Model fluid phase diagram

Figure 5-53. Initial water distribution

5.5.2.3 History Match

As previously mentioned, the field had been in operation for the past 75 years and only sketchy production data are available. These include annual oil production figures by lease area and barrel tests of individual wells provided by Daystar Oil and Scheck Oil. It is evidenced that the reservoir is subject to a strong aquifer support during the substantial amount of primary oil recovery with a relatively stable reservoir pressure. With these in mind, analytical aquifers have been attached to the side and to the bottom of the model as extensions to the water body within the model.

Well completion and production information (annual oil production rates by lease) was incorporated (see Figure 5-4) once the initial model setup was complete. This was then followed by adjustments of certain model parameters in order to calibrate it to the historical production data. This process is commonly known as history matching. In this case, the model was made to match the general historical trends in water cut measurements during the barrel tests of the wells in the Daystar and Scheck leases. Model parameters (oil-water contact depth, residual oil saturation and analytical aquifer volumes) were adjusted within reasonable ranges.

Figure 5-54. Production and pressure profiles

Once a satisfactory match (see Figure 5-55) was achieved, the model could be used for simulating the effects of CO₂ injection in both the sweep oil zone (EOR) and the underlying saline aquifer (sequestration). It should be noted that the model calibration process is generally a non-unique one particularly when sparse field observations are sparse such as in this case. This typically necessitates an uncertainty analysis to evaluate the range of possible outcomes given the lack of data.

Figure 5-55. Barrel test water and calibrated model water cut profiles.

Figure 5-55 shows water breakthrough occurred rapidly and consistently throughout the field in the fifties and the sixties. This was caused by the encroaching water from the saline aquifer that allowed the production to take place without significant observable reservoir pressure declines. Production in recent years has been associated with approximately 99% water cut levels indicating that vast majority of the oil produced came exclusively from the swept oil zone. The model is able to mimic these trends with the strong analytical aquifers attached. Once the simulation of the historical production

has been completed, the model the present day fluid (oil and water) distributions and 56 shows three-dimensional water saturation distributions determined by the model at various points during the 75-year recovery process.

Figure 5-56. Aquifer encroachment progress shown with model generated water saturation distributions.

5.5.3 CO₂ Injection Plan

CO₂ injection processes simulated with the calibrated model involves CO₂ injected into the two domes, one at a time, at a fixed maximum rate of 7,500 Mscf/d, the output from the Kansas Ethanol facility at Lyons, Kansas. A group of six wells in the North Dome and six wells in the South Dome receive the CO₂, with the North Dome injection starting on 1 Jan 2012 and the South Dome injection starting after the North Dome is filled (Figure 5-57). Injection stops when the South Dome is filled. In both cases, filled is defined as injecting CO₂ from the top of the reservoir down to a subsea depth of -1,486 ft TVD, although in neither case is the fill uniform or necessarily complete. Further study is needed to optimize the injection by adjusting well locations and configurations, perforation zones, and injection rate for each well.

Figure 5-57. Arbuckle structure map showing location of 12 simulated injection wells, six injectors for each dome structure.

5.5.3.1 Wells

The wells used in this study occupy the same location as existing oil production wells. These simulation runs are a restart of the 74-year history match simulation run that ended 1 Jan 2010. Wells continue their group production rates with a BHP limit of 200 psia from 1 Jan 2010 until all production wells are shut on 1 Jan 2012. At this point, the six CO₂ injection wells in the North Dome start injecting with a target rate of 7,500 Mscf/d for the whole group and a BHP limit of 1,700 psia. A guide rate was used to inject more of this group rate to the wells toward the east side of the North Dome, and perforations were limited to about the top 3 layers, or about 20 ft, below the top of the reservoir. Simulated injection continued in the North Dome until 1 July 2014, for an injection period of 2.5 years. At this point, CO₂ has pushed below the subsea depth -1,486 ft depth in several parts of the dome, but has not reached it in others. There was not time in this brief study to optimize the injected CO₂ volume, so it is likely that a longer CO₂ injection period would be permissible.

At simulation timestep 1 July 2014, the six CO₂ injection wells in the South Dome start injecting with a target rate of 7,500 Mscf/d for the whole group and a BHP limit of 1,700 psia. Again, a guide rate and selective perforating were used to balance the injection, but the South Dome was considered to be filled after 2.5 years of injection.

The simulation stopped on 1 Jan 2017. Oil production from the "oil leg" beneath the CO₂ gas cap was not modeled in this simulation.

5.5.3.2 Well Pressures

While all injection wells were given a BHP limit of 1,700 psia, the maximum BHP observed is on the order of about 1,400 psia (Figure 5-58). This suggests that there is sufficient injectivity to increase the injection rate in the future, or even to reduce the perforation lengths further to achieve a more uniform filling. Additionally, it also suggests that this rate of CO₂ can be injected in fewer wells to reduce well conversion costs, although this would be detrimental to the uniformity of fill. Further study should investigate this balance between cost and fill.

Figure 5-58. Pressure through time at each injection well. Black is average model pressure. Colored are two sets of six injection wells, one set per dome. South dome pressure profile extended for the 2.5 years where injection was switched to South Dome.

5.5.4 Simulation Results

5.5.4.1 Discussion of North Dome Results

Figure 5-59 shows the predicted size of the CO₂ plume after each dome has received 0.4 million tons of CO₂ (7,500 Mscf/d for 2.5 years $\approx$ 0.4 million tons). The upper left panel shows cross sections through the North Dome, the upper right panel shows cross sections through the South Dome, and the lower panel shows the complete plume in both the North and South Domes. In all these figures, only cells with CO₂ saturation greater than zero are shown, and the color scale indicates the CO₂ saturation from 0.0 to about

0.45. Also shown on the top two panels is the reddish-brown semi-transparent surface at subsea -1,486 ft TVD. Since these views are from above that surface, cells below subsea -1,486 ft TVDSS are shaded. This gives a visual indication of where the injected CO₂ has filled the dome and where additional volume could be stored.

Figure 5-59. Predicted plume size (CO₂ injection case).

Figures 5-60 and 5-61 show the growth of the CO₂ plume in the North Dome and South Dome, respectively, in 0.5 year steps. The plume grows both laterally and vertically, with more vertical growth in the cells below the injection wells and fairly consistent lateral growth in all directions.

Figure 5-60. Predicted plume growth in the North Dome (CO₂ injection case).

Figure 5-61. Predicted plume growth in the South Dome (CO₂ injection case).

Figures 5-62 and 5-63 show the oil saturation and water saturation, respectively, in the North Dome in 0.5 year steps, starting with the initial state before CO₂ is injected. As expected, initially high oil saturations at the crest are reduced significantly, and this oil displacement can be seen to extend laterally with time. Vertical oil displacement can also be seen by the downward movement of yellow regions. This is interpreted as an oil bank that consists of both the initial mobile oil at the top (attic oil) and the initially residual oil that is mobilized after swelling. This ‘yellow’ oil bank accumulates at the base as an ‘orange’ oil leg between the fill depth and the oil water contact. The ‘orange’ coloration actually comes from viewing what are ‘yellow’ cells through the semi-transparent reddish surface. The water saturation figures in Figure 5-63 show similar displacement characteristics generally leading to a lower water saturation in the CO₂ filled dome.

Figure 5-62. Predicted oil saturation in the North Dome (CO₂ injection case).

Figure 5-63. Predicted water saturation in the North Dome (CO₂ injection case)

Figure 5-64 shows the oil and water saturation sections in the North Dome before injection, at the end of injection, and then after a 2.5 year quiet period. The top two sets of figures come directly from Figures 5-62 and 5-63, so the focus here is on the continued redistribution of fluids after CO₂ injection stops. During this 2.5 year period, there is no injection or production in this North Dome, although there may be some pressure influence from the CO₂ injection going on in the adjacent South Dome. So, while there is not a barrier between the domes, Fig. 5-59 shows that the CO₂ plumes do not overlap, so the continued movement of fluid in the North Dome can be interpreted as gravity-driven equilibration.

Figure 5-64. Predicted oil (left) and water (right) saturation in the North Dome (CO₂ injection case).

Movement of oil was seen in Figure 5-62 as the downward movement of ‘yellow’ cells. This is seen here in Figure 5-64 most clearly on the lower right arm of the oil saturation figures. It can also be seen that a thin ‘yellow’ layer appears on top of the ‘orange’ cells, indicating that some of the oil is coming back up above the fill depth. Given time and complete gravity stabilization (perhaps 50 to 100 years), a sharp interface between the CO₂, oil, and water phases will develop, and with the amount of CO₂ injected in this simulation, that stabilized CO₂ and oil interface would certainly be above the subsea -1,486 ft TVD surface.

5.5.4.2 Discussion of South Dome Results

Figures 5-65 and 5-66 show the oil saturation and water saturation, respectively, in the South Dome at 0.5 year steps. These figures show the same movement of displaced oil as

seen in the North Dome, although there doesn't appear to be as much mobile attic oil in the model initially. At the end of this 2.5 year CO₂ injection period, oil is still moving downward, but in this case there is not an observation period after injection stops that allow gravity stabilization to be observed.

Figure 5-65. Predicted oil saturation in the South Dome (CO₂ injection case).

Figure 5-66. Predicted water saturation in the South Dome (CO₂ injection case)

5.5.4.3 Quantification of Displaced Oil

Figure 5-67 shows the change in oil volume for each cell in the model, between the start and end of CO₂ injection in the North Dome (top left) and the South Dome (bottom right). The color scale indicates that red colors are a net gain in oil volume (as seen in the oil leg below subsea -1,486 ft TVD surface and purple and blue colors are a net loss in oil volume (as seen at the crest of the structure). Again, the North and South Domes show much the same behavior, although in the cross sections shown, there appears to be more oil displaced in the North Dome than the South Dome.

Figure 5-67. Predicted change in oil volume in the North Dome (top) and South Dome (bottom) (CO₂ injection case). Volume is in barrels of oil per cell.

Table 5-8 provides a summary of oil volumes and changes in the model. The North Dome and South Dome areas are confined to the intersection of the top reservoir horizon with the subsea -1,486 ft TVD surface. There is certainly oil in the model outside these dome areas, but the intent here is to focus on oil displaced by CO₂ as the direct result of CO₂ injection.

	North Dome	South Dome
Before CO ₂		
OIP (MMSTB) Above 1486 ' TVDSS	8.02	13.49
OIP (MMSTB) Below 1486 ' TVDSS	2.82	5.02
After CO ₂		
OIP (MMSTB) Above 1486 ' TVDSS	6.58	12.72
OIP (MMSTB) Below 1486 ' TVDSS	4.02	5.56

Table 5-8. Summary of oil in place before and after CO₂ injection.

The volume of oil in the North Dome before CO₂ injection was 10.84 MM STB. After CO₂ injection, there was 10.60 MM STB, indicating a loss of 0.24 MM STB. This oil is not 'lost', but is in fact just displaced out of the tightly defined North Dome area. Strictly speaking, this 'lost' volume can be considered part of the oil volume below subsea - 1,486 ft TVD surface since most of the area outside the North and South Domes are below this depth.

Before CO₂ injection, there were 8.02 MM STB above the fill depth and 2.82 MM STB below. After CO₂ injection, the oil volume above decreases by 1.44 MM STB to 6.58 MM STB, and the oil volume below increases by 1.2 MM STB to 4.02 MM STB. Again, the important number is the 1.44 MM STB that has been displaced out of the North Dome above subsea -1,486 ft TVD surface, and realize that the actual volume of oil mobilized by the CO₂ is greater than this. As the oil saturation results illustrated, not all of the oil bank made it to the fill depth, so should not be counted as displaced out of the dome.

The situation in the South Dome is similar, but with only 0.77 MM STB displaced out of the dome, even though there is initially more oil in the dome. This supports the observations that the displacement in the South Dome is not as efficient as in the North Dome. This may simply be a lack of initially mobile attic oil (as observed), or indicate that not enough CO₂ was injected to displace the oil fully out of the dome. With the laterally larger area, the South Dome is a bigger challenge, and may require more injection wells with a larger footprint.

5.5.5 Summary of Simulation Results

Results of this study should be considered a 'quick look,' figuratively speaking, and as such the conclusions must be taken cautiously. However, some specific salient conclusions may help direct the future direction of CO₂ injection in this and other Midwestern reservoirs:

1. The two domed structures are capable of storing significant quantities of CO₂. At the specified rate, the reservoir can be a CO₂ storage site for at least 5 years, and probably longer, although additional study is needed to quantify this extension.
2. During the CO₂ injection process, oil is displaced out of the crest of the dome and accumulated above the water. Oil production wells completed in this zone should be able to produce some of this oil, but the proximity of the thin oil leg to both the water below and CO₂ above will make it a challenge to avoid coning problems. If oil production is an objective, gravity stabilization following CO₂ injection will form a more well defined oil leg, but further study will be needed to determine whether that would occur effectively within a reasonable period of time.
3. The modeling of this CO₂ injection process has taken a conservative view of oil property changes in response to the CO₂, primarily because there isn't data available to directly quantify the changes. In some cases, the oil will become considerably leaner on contact with CO₂, and there could be a reduction in residual oil saturation. Without the means to quantify these effects, the decision was made to err on the side of caution instead of overstating the recovery potential. With the model indicating almost 22 MM STB of oil in both domes combined, there is the possibility that with proper characterization of the CO₂/oil interaction, a significant volume of oil could be mobilized and made available for production.

5.6 Capacity Verification

In the hypothetical gravity-stable CO₂ EOR project, CO₂ is injected into two domes until they are filled to a subsea depth of -1486. Two studies completed, a preliminary engineering study by EPIC and a "first look" simulation study by Schlumberger have differing volumetric results (Table 5-9). The EPIC study is based on correlations with empirical data while the Schlumberger simulates the base-case hypothetical plan using a static model grid developed from well information. Combined, they project 0.5 to 0.8 million metric tons of CO₂ would be stored over a 3.5 to 5 year injection period, utilizing the entire volume of CO₂ available from the Lyons ethanol plant. If the balance of the Geneseo-Edwards field was flooded in a similar fashion, the volume stored would nearly triple. Schlumberger's simulation projects the same amount of CO₂ will be stored by the project in both domes, despite the North Dome having only 56% of the pore space that the South Dome has. According to their observations the South Dome does not fill nearly

as efficiently as the North Dome because of reservoir heterogeneity and irregularities in the dome shape with respect to the injectors.

		North Dome	South Dome
Analogues	Billion ft ³	3.42	6.16
	Billion m ³	0.096	0.174
	Million Tons	0.20	0.36
	Million Metric Tons	0.18	0.32
	Months Supply	15	27
Simulation	Billion ft ³	6.82	6.82
	Billion m ³	0.194	0.194
	Million Tons	0.40	0.40
	Million Metric Tons	0.36	0.36
	Months Supply	30	30

Table 5-9. Estimated CO₂ stored in hypothetical gravity-stable CO₂ EOR project

The simulation study projects more CO₂ stored than the EPIC study in both domes. Some, but not all can be explained by 1) variations in pore volume - the Schlumberger model has slightly higher porosity, and 2) some CO₂ is stored below the subsea datum of -1486 in the Schlumberger model. Projected CO₂ saturations above -1486 in both domes would average 28% according to the EPIC study (Table 5-10), while they vary between domes in the Schlumberger study. Average CO₂ saturation was not harvested from the Schlumberger simulation, however, a discernable difference in saturation profiles is notable in Figure 5-59. North dome saturations appear to average around 35% while in the less efficient south dome they appear to average closer to 25%

Million STB	North Dome	South Dome
Pore Volume (STB)	19.0	33.8
CO ₂ Stored (STB)	5.27	9.49
CO ₂ Saturation %	0.28	0.28

Table 5-10. Volumetric CO₂ statistics for hypothetical flood based on Canadian analogues and empirical correlations. Abbreviation STB = Stock Tank Barrels. One STB = 0.16 m³.

5.7 Conclusions

The body of work summarized in this chapter and report should be considered an initial feasibility study to be followed by additional data gathering, field testing, more rigorous modeling and simulation study. Results of the studies are encouraging and suggest a gravity-stable immiscible CO₂ EOR flood in the Arbuckle would mobilize oil, form a horizontal oil bank, and could be commercially feasible. However, substantial

additional work is needed on three fronts: 1) fill critical fluid property gaps, 2) improve the static model grid geometry and petrophysical properties including residual oil saturation, and 3) gain a better understanding of the reservoir "plumbing system" to insure that a gravity-stable approach could be effective.

5.7.1 Key Findings

The objective of the study detailed in this chapter was to evaluate the potential for a gravity-stable EOR project in the Arbuckle given that the reservoir has a relatively thick oil column, the producing mechanism is a strong bottom-water drive, and evidence that the oil-water contact moved vertically in a fairly uniform manner, leaving behind sufficient residual oil to be targeted for EOR. Key findings include the following:

1. Significant residual oil remains in the water-swept portion of the reservoir. Residual oil saturation (S_{orw}) is approximately 38.9% established by material balance, assuming original saturation is 70%, average porosity is 11.5%, and a FVF of 1.1. EPIC's estimated S_{orw} to be 38.9% based on reservoir and oil properties, and history-matched reservoir simulation by Schlumberger yielded an average $S_{orw} = 36\%$.
2. It appears likely that that a CO_2 gas cap can be built downward while maintaining a relatively flat gas/water-oil contact. A study of oil-water contacts in 32 wells suggests strongly that the oil-water contact stayed relatively flat as it moved upward during the 80-year production history. Reservoir simulations indicate that a CO_2 gas cap with a fairly uniform gas/oil contact can be built downward.
3. Successful Keg River gravity-stable miscible floods (Canada) may be analogs to the Arbuckle of the Central Kansas Uplift.
4. The EPIC preliminary feasibility study, based on correlations with empirically derived data and equations, and comparisons with analogs, suggests that 6.1 million barrels of oil could be recoverable by EOR in the two-dome project.
5. The Schlumberger reservoir simulation study demonstrates that oil is mobilized by CO_2 in a gravity-stable process. However, the amount of oil mobilized is a fraction of that predicted to be recoverable by the EPIC study. Significant improvements in the oil mobilized by optimizing the simulation for improved sweep efficiency.

The above results should be utilized with caution. Many caveats and shortcomings have been discussed throughout the report and are summarized below:

1. Residual oil saturation is based on an assumed initial oil saturation of 70% and FVF of 1.1. Neither of these variables are known.

2. A published paper (Mullins and Ireland, 1967) on the Arbuckle reservoir 5 miles (8 kilometers) northwest of the proposed project suggests the reservoir is layered. This would negatively impact the potential for gravity-stable EOR process if it is the case in the project area.

3. The simulation model is based on a static model grid built from a sparse petrophysical data set. Critical fluid properties and the equation of state (EOS) for the crude oil were estimated.

5.7.2 Additional Work

The current study achieved some progress towards answering fundamental questions and provides encouragement for further evaluation. The final answers will not be known until the concept is tested by large-scale CO₂ injection, but there are a number of data to yet be collected, analyzed and incorporated in the model, and field testing that could help to elucidate the fluid dynamics of the reservoir system and reduce major risk factors due to current uncertainties:

Fill critical fluid property for well-constrained EOS and other parameters:

- Laboratory flash liberation tests (CCE)
- Laboratory differential liberation tests (DL, CVD)
- Viscosity versus pressure at reservoir temperature
- Swelling tests
- Additional MMPs
- Oil composition from downhole samples above bubble point
- Gas sample and composition

Improve the static model grid geometry

- Make another search for wireline logs and incorporate
- Acquire initial 3-D seismic survey and incorporate
- Improve layering and identify potential barriers in core

Improve the static model grid petrophysical properties:

- Obtain additional conventional and special core analysis from existing cores, including in situ properties, capillary pressure data, rock mechanical data for fracture pressure of reservoir and seal
- Run modern openhole logs in existing wells with long open hole sections and wells re-entered and deepened for reservoir tests, and incorporate petrophysical data and layering
- Obtain current Sorw from open hole logs

Gain a better understanding of the reservoir "plumbing system" in particular continuity in vertical permeability:

- Further analysis for movement of oil-water contact including correlating well production tests to current layered reservoir model, particularly in areas where there are anomalies what otherwise appears to be a relatively uniform pattern of upward movement.

- Investigate the data behind the Mullins and Ireland (1967) paper and production records since the paper was written to validate or refute the paper's findings.
- Analyze several cores available at the Kansas Geological Survey core storage facility paying particular attention to potential vertical barriers and correlate to wireline logs.
- Design and perform multiple well tests, including pulse tests and tracer surveys, to measure vertical permeability at varying scales.
- Research and deploy other methods for characterizing reservoir-scale permeability in three dimensions.

Multiple iterations of reservoir characterization, modeling and simulation will be required before one can predict reservoir behavior with confidence. The current understanding of past reservoir behavior, comparison with successful analogs, and current reservoir models all suggest that gravity-stable immiscible CO₂ EOR could be successful. Additional work could bolster the case sufficiently to justify moving forward to a commercial-scale development project.

Chapter 6 – Risk Assessment

6.0 Methodology

A qualitative risk assessment was performed during Phase I of the IMCCS Project. To accomplish this, a risk assessment working group was formed. Table 6-1 shows the individuals making up the risk assessment working group and their areas of focus.

Table 6-1. Risk Assessment Working Group

Name	Area of Focus
Jim Lepinski	Co-lead, subsurface, surface and programmatic
Bruce Letellier	Co-lead, subsurface and HSE risks
Phil Stauffer	Subsurface risks and HSE risks
Brian McPherson	Subsurface risks (especially deep saline
Marty Dubois	Subsurface risk (especially EOR)
Chris D'Acosta	Financial and local legislation/regulation risks
Ray Hattenbach	Dehydration, compression and pipeline risks
Mahesh Gundappa	Verification risks
Mike Moore	Federal legislation/regulation risks
Jon Erickson	Programmatic risks
Bob Kolb	Programmatic risks
Andrew Duguid	Borehole and monitoring risks
Ken Hnottavange-	Subsurface and programmatic risks
Neal Drawas	Liability and insurance risks
Brandon Pavlish	CO ₂ capture risks
Gina Rau	Health, safety and environmental risks
Pete Fote	Project management and EPC risks
John Mavor	Surface and programmatic risks

Comprehensive lists of programmatic and technical risks, including descriptions and relevance, were prepared by the IMCCS team. These lists were reviewed by members of the risk assessment working group. Project specific information was added to the lists. Risks were then ranked on a scale of 1 to 5 according to probability of occurrence and severity of impact. Tentative risk prevention and mitigation steps were developed and listed.

The comprehensive lists of risks are divided into Geologic Sequestration Technical Risks (an expanded version of the Quintessa FEPs list) and Surface & Programmatic Risks. The risks are broken into the following categories:

Geologic Sequestration Technical Risks (see Appendix 6-A)

- 0.0 Assessment Basis
 - 1.0 External Factors
 - 2.0 CO₂ Storage
 - 3.0 CO₂ Properties, Interactions & Transport
 - 4.0 Geosphere
 - 5.0 Boreholes
 - 6.0 Near-Surface Environment
 - 7.0 Impacts

Surface and Programmatic Risks (see Appendix 6-B)

- 8.0 Economic Risks
- 9.0 Permitting Risks
- 10.0 External Risks
- 11.0 Project Management Risks
- 12.0 Engineering Risks
- 13.0 Procurement Risks
- 14.0 Construction Risks
- 15.0 Commissioning and Startup Risks
- 16.0 Field Safety Risks
- 17.0 Legal Risks
- 18.0 CO₂ Capture Risks
- 19.0 Dehydration Risks
- 20.0 Compression Risks
- 21.0 Pipeline Risks
- 22.0 On-Site Facilities Risks
- 23.0 Monitoring Risks

Each risk is assigned a risk factor of 1 to 5 for probability of failure (P) and severity of failure (S). The risk priority number is the product of P x S and therefore ranges from 1 to 25. The definition of risk factors for probability and severity are shown in Tables 6-2 and 6-3.

Table 6-2. Risk Factors for Probability of Failure

1	Improbable	<1% chance of occurring*
2	Unlikely	1-10% chance of occurring*
3	Possible	11-50% chance of occurring*
4	Likely	51-75% chance of occurring
5	Probable	>75% chance of occurring*

*From beginning of project to 50 years after injection stops.

Table 6-3. Risk Factors for Severity of Failure

		Health & Safety	Financial Liability (\$)	Environment	Industry Viability
1	Light	Minor injury or illness, first aid	<\$50k	Discharge < reporting thresholds. Hazmat spill<100liters. Produced water spill<50 barrels.	Project lost time > 1 day. Moving vehicle citation.
2	Moderate	Temporary disability, Hospital to 1 day. Lost days 1-100	\$50-500k	Discharge > reporting thresholds. Hazmat spill<1000liters. Produced water spill<100 barrels.	Project lost time >1 week. Regulatory notice without fine. Local allegations of unethical practice or mismanagement.
3	Serious	Permanent disability. Lost days >100. Intensive care >1 day.	\$500k-5M	Discharge causes area evacuation or wildlife loss. Hazmat spill<10k liters. Produced water spill<500 barrels.	Project lost time >1 month. Permit suspension. Majority local opposition or substantial negative local media coverage.
4	Major	Fatality	\$5M-50M	Uncontrolled release of radioactive material. Hazmat spill >10k. Produced water spill >500 barrels.	Project lost time >1 year. International media coverage of law violations, questionable ethical practices, or mismanagement
5	Catastrophic	Multi-fatality	>\$50M	Multi-Catastrophic	Negative public experience results in legal ban on similar projects.

Special attention was given to wellbore risks in the T-A field. A database of plugged and abandoned wells in the T-A was compiled by Dr. Martin Dubois of CAP CO2 and analyzed by Dr. Andrew Duguid of Schlumberger Carbon Services. The analysis was then reviewed by members of the risk assessment working group. The results of the analysis can be found in Appendix 6-C.

6.1 Technical Risk Results and Discussion

Some of the more significant technical risks that were identified based on project specific information and ranking of risks are as follows.

Thrall-Aagard (T-A) Field

- Narrow operating pressure range between MMP and fracture pressure
- CO₂ leakage through 457 existing boreholes
- Potential broken seal/reservoir damage from explosive fracturing and hydraulic fracturing
- Potential leakage making it difficult to pressurize the reservoir
- Low pressure (3.4 MPa [500 psi]) thief zone (Douglas Sandstone) above reservoir
- Long time for equilibration of pressurized reservoir
- Up-dip migration of CO₂ in DSA monocline

Geneseo-Edwards (G-E) Field

- CO₂ leakage through 117 existing boreholes
- Non-uniform gravity stable CO₂ flood in G-E
- Bottom hole pressure closeness to CO₂ supercritical pressure in G-E
- High minimum miscible pressure (MMP) in G-E
- H₂S in Arbuckle water in G-E
- Difficulty of monitoring stacked plumes (EOR and DSA) in G-E field

Deep Bartlesville (DB) Fields

- CO₂ leakage through existing boreholes
- Located below or near sensitive groundwater area
- Located adjacent to or near the Humboldt fault zone
- Located in more populated area

Wellington Field

- CO₂ leakage through 134+ existing boreholes
- Located below or near sensitive groundwater area

Kansas Ethanol LLC (KE) Plant

- Flow rate fluctuation and inconsistent oxygen content CO₂ flow stream due to batch-type fermentation.
- Performance of the first-of-a-kind oxygen removal unit for KE CO₂ stream

Ash Grove Cement (AGC) Plant

- Performance of the first-of-a-kind CO₂ capture unit for the Ash Grove Cement (AGC) plant

6.1.1 CO₂ Capture

Coffeyville Resources Nitrogen Fertilizer LLC (CVR)

CVR generates a concentrated stream of CO₂ as a by-product in the production of ammonia. A Selexol system is used to recover the CO₂ from syngas. The Selexol system started up in July 2000 and has demonstrated high reliability. High plant availability is achieved because CVR has a spare gasifier. CO₂ quality is very consistent and is guaranteed by CVR. Therefore risks are relatively low.

Kansas Ethanol LLC (KE)

KE generates a concentrated CO₂ stream in the fermenting process of ethanol production. Overall plant availability is high, but CO₂ flow rate fluctuates and quality may be inconsistent due to the batch-type process of fermentation. It may be necessary for KE to perform a demonstration test to prove that it can consistently meet the CO₂

specification for the IMCCS project. Fluctuation in flow rate may impact dehydration and compressor performance.

Analyses of the KE CO₂ stream indicate the oxygen content is in the range of 0.4 to 1.3%. The pipeline specification requires oxygen to be less than 30 ppm. A catalytic combustion system has been proposed to remove the oxygen by combusting it with natural gas (injected at twice the stoichiometric amount of oxygen to be combusted) in the presence of a platinum catalyst. An electric heater is used for startup and when oxygen content is insufficient to provide sufficient heat for the catalytic reactor. As a first-of-a-kind application, there could be scale-up, operational and maintenance problems with this unit which may be intensified due to fluctuating flow rate and inconsistent oxygen content of the CO₂ stream coming from the batch type fermentation process.

Ash Grove Cement (AGC) CO₂ Capture

CO₂ capture for cement plants has not been commercially demonstrated yet. Some cement plants are looking at capturing the CO₂ in the form of solid carbonates or bicarbonates. For this project, the group initially evaluated recovering the CO₂ from cement plant flue gas using a skid-mounted amine-based acid gas removal unit with conventional adsorption tower and stripper. However, the economics didn't look favorable. As an alternative, the group looked at a skid-mounted, high-surface-area-contact unit that offered a potential 40-50% savings in capital cost. This unit has been used for SO_x removal at a power plant on a 20 MW scale but the CO₂ capture version has not been demonstrated beyond a bench scale. Again, the economics did not come out favorable due to the small scale. In addition, technical risks associated with first-of-a-kind and scale-up can be significant. After thorough study, it was concluded that these CO₂ capture units were not financeable or commercially viable at this time. This could change if legislation provided greater economic incentives for CO₂ capture.

6.1.2 CO₂ Dehydration

CVR Dehydration Unit

A tri-ethylene glycol (TEG) dehydration unit will be installed at CVR to remove moisture from the CO₂ stream. These units are used regularly in industry and generally operate well. The most common problems are: upset conditions; foaming in the contactor; buildup of liquid or solid contaminants in recycled glycol; contactor plugging due to fouling; reboiler tube, heat exchanger or pump seal failure due to fouling; corrosion; and thermal or oxidation degradation of the glycol. The unit at CVR should operate well.

KE Dehydration Unit

A tri-ethylene glycol (TEG) dehydration unit will also be installed at KE to remove moisture from the CO₂ steam. However due to the batch-type CO₂ generation at KE, the dehydration unit could be subjected to fluctuating CO₂ flow rates, and oxygen and organic contaminants in the CO₂ stream. This could lead to some of the problems listed in the paragraph above.

6.1.3 CO₂ Compression

CVR Compression Unit

The CO₂ at CVR will be compressed from 0.01 to 0.5 MPa (2 to 75 psig) in a stainless steel blower. It is then dehydrated to less than 508 kg H₂O/million Nm³ (30 lbs H₂O per million standard cubic feet) using a conventional glycol unit. The dry CO₂ is then compressed from (0.5 to 9.7 MPa (75 to 1400 psig) in a centrifugal compressor and from 9.7 to 18.3 MPa (1400 to 2650 psig) in a centrifugal pump at 49°C (120°F). These units are well proven in industry.

KE Compression Unit

The CO₂ stream at KE will be compressed from -0.005 to 10.9 MPa (-0.7 psig to 1587 psig) using three multi-stage reciprocating compressors. A major concern is the fluctuating flow rate of CO₂ coming from the batch-type fermentation process. Reciprocating compressors have a high turndown ration but overall efficiency will be lost due to fluctuating flow rates rather than steady state operation.

6.1.4 CO₂ Pipeline Transport

Two pipelines are planned for this project. A 0.2 m (8-inch) diameter pipeline will transport CO₂ from the CVR site to the Deep Bartlesville fields in Cowley or Wellington field in Sumner County, KS, and a 0.1 m (4-inch) diameter, pipeline will transport CO₂ from the KE site to the Geneseo-Edwards field in Rice County, KS.

The pipelines will use existing pipeline corridors (private land). Blue Source will oversee permitting. Experienced contractors will be used to design, construct and operate the pipelines. The pipelines will be designed, constructed and operated in compliance with Title 49 CFR Part 195, "Transportation of Hazardous Liquids by Pipeline" – Department of Transportation, rules and regulations.

The pipelines will be buried 1.2 m (4 ft) underground (1.8 m [6 ft] under river, road and railroad crossings). River, road and railroad crossings will be bored under rather than trenched.

Sensitive receptor areas (schools, prisons, hospitals, etc.) will be avoided. Sensitive environmental areas will be avoided or bored under. All surface facilities outside of the plant sites will be fenced off to prevent unauthorized access.

The pipelines will be constructed of new ERW pipe. Seamless pipe will be used in all sensitive areas such as crossings. All valves and fittings will be inspected for defects and checked for proper use. Block valves will be located at appropriate locations along the pipelines for emergency shut off. Appropriate access points will be available for maintenance. Room for booster pump stations will be reserved along the pipeline to allow for future expansion.

Cathodic protection and external coating will be employed to protect against external corrosion. Very-dry, H₂S-free CO₂ will be used to protect against internal corrosion.

Supervisory control and data collection (SCADA) will be installed. Plant and field operations will have both SCADA and telephone communication links. Computational pipeline monitoring leak detection system will be installed. Nominations (agreement on CO₂ supply and demand) will occur on a daily basis to maintain constant line and delivery pressure.

Crack arrestors will be installed to minimize propagating cracks. Certified welders will be used on pipe welding. All welds will be x-rayed and replaced if necessary. Pipelines will pass visual inspection for defects and hydrostatic testing. Appropriate back fill will be used to avoid damaging the pipelines during burial.

The top 0.15 m of top soil will be saved during construction and spread back over the area from which it was taken after the final grading. Before seeding any disturbed areas, the ROW will be restored to its original form, slope, contour, and soil density to the extent practicable.

The pipelines will operate at least 2 MPa (300 psig) above CO₂ supercritical pressure to prevent two-phase flow. Pressure will not exceed 80% of design operating pressure. Standardized operating procedures will be used for pressuring/depressuring the pipelines.

Regular ROW inspection/maintenance, markings, one-call system and field supervision will be used to prevent third-party excavation damage to the pipelines. As-built drawings and maps will be retained for the entire pipelines.

Appropriate field safety guidelines (OSHA) will be followed during construction and operation. All construction and operating personnel will receive training prior to working on the pipelines. DOT pipeline safety regulations will be followed in operation and maintenance of the pipelines. The pipelines will use inline inspection systems (smart pigs) and will be repaired as necessary. The frequency of pipeline inspections will be monitored and increased if any issues arise that require attention. A pipeline integrity management system will be implemented for high consequence areas (if any).

KE to G-E Pipeline

The KE to G-E pipeline is 102 mm (4 inches) in inside diameter, 26 km (16 miles) long and follows existing pipeline corridors. The capacity of the pipeline is 214,000 Nm³/d (8 million scfd) of CO₂. It will operate between (9.7- 10.9 MPa (1400-1587 psig), which is above the supercritical pressure of CO₂. Four block valves will divide the pipeline into five sections. Over 85% of the pipeline right-of-way is on agricultural/cultivated crop land, about 5% is on wooded land and 10% is on rangeland. Over 88% of the pipeline right-of-way is flat land. The pipeline crosses: 1 highway, 2 paved roads, 19 dirt road, 2 railroads, 1 river and 1 creek. There is no designated critical habitat or occurrence within 5 miles (8 kilometers) of the pipeline for any special status wildlife species. Based on information gathered in the pipeline feasibility study and Environmental Information Volume, there does not appear to be any significant risk associated with this pipeline.

CVR to T-A Pipeline

A feasibility study was completed for a pipeline from CVR to T-A. This proposed pipeline is 203 mm (8 inches) in inside diameter, 177 km (110 miles) long and follows existing pipeline corridors. The capacity of the pipeline is 1.07 million Nm³/d (40 million scfd) of CO₂. It is designed to operate between 9.7-18.3 MPa (1400-2650 psig), which is above the supercritical pressure of CO₂. Eighteen block valves divide the pipeline into 19 sections. Approximately 78% of the pipeline right-of-way is on rangeland, 10% is on wooded land, 10% is on agricultural/cultivated crop land, 1% is on residential land and 1% is on industrial/commercial land. Approximately 42% of the pipeline right-of-way is on flat land, 40% is gently sloping, 15% is moderately sloping, 4% is strongly sloping and 2% is steep to very steep. The pipeline crosses 5 highways, 17 paved roads, 64 dirt roads, 6 railroads, 4 rivers and 37 creeks. The pipeline intersects with, or comes close to,

several critical habitats, including five mussel species, the Eastern spotted skunk, the greater prairie chicken, the American burying beetle, the Topeka shiner. Based on the information gathered in the pipeline feasibility study and Environmental Information Volume, the CVR to T-A Pipeline has greater risks than the KE to G-E pipeline, but none of these risks appear insurmountable.

CVR to DB Pipeline

The proposed CVR to DB pipeline would be similar in size, length and capacity to the CVR to T-A pipeline. The pipeline route would follow existing pipeline corridors as much as possible.

CVR to Wellington Pipeline

The CVR to Wellington pipeline would be the same size and capacity as the CVR to T-A pipeline, but the length would be approximately 193 km (120 miles) instead of 177 km (110 miles). The pipeline route would follow existing pipeline corridors as much as possible.

6.1.5 CO₂ Enhanced Oil Recovery (EOR)

CO₂ EOR injection is proposed to take place in the Deep Bartlesville (DB) fields or Wellington field and Geneseo-Edwards (G-E) field respectively. The EOR injection sites will be designed, constructed and operated, in compliance with Kansas Corporation Commission rules and regulations for enhanced oil recovery (82-3-100 through 82-3-908). OSHA safety guidelines will be followed. All construction and operating personnel will receive training prior to working on site.

In the design phase, the EOR sites will be fully characterized and the following plans will be prepared:

- Existing well replugging plan
- Drilling and injection plan
- Closure plan
- EOR facility safety plan
- CO₂ storage verification plan

Geneseo-Edwards (G-E) Field EOR

The G-E field is a mature oil field with approximately 247 existing wells (117 wells in the two domes covered by the project). Prior to operation, the three wells penetrating into the Arbuckle reservoir will be replugged. These wells and others will be monitored for CO₂ leakage and remedial action will be taken if necessary. Several wells will be reconditioned or reactivated for use in EOR.

A gravity-stable, near miscible CO₂ flood will be used for EOR in the G-E field. Supercritical or dense-phase CO₂ will be injected into the top of an oil-filled dome with 37 m (120 ft) of closure. The CO₂ cap will push the residual oil downward. Oil production wells will collect the mobilized oil through perforations lower in the reservoir and recycle the associated CO₂. If the gravity stable flood becomes non-uniform, it may be necessary to decrease the CO₂ injection rate per well and/or add more vertical or horizontal injection wells.

The existing bottom-hole pressure in the top of the dome(s) in the G-E field is close to the CO₂ supercritical pressure. It will not be possible to increase the pressure of the Arbuckle formation. The CO₂ will be injected as a supercritical fluid, but it may revert to

a dense-phase gas in the top of the dome. This is not expected to create a problem for the gravity stable flood nor the long term retention of CO₂ within the dome.

The minimum miscible pressure for the residual oil in the G-E field is significantly higher than the existing bottom-hole pressure in the top of the dome. The CO₂ will be injected at near the minimum miscible pressure. This has been taken into account in calculating the expected oil yield.

The Arbuckle water produced with oil has been reported to be highly corrosive and containing H₂S. Water samples will be taken from the Arbuckle and analyzed for corrosiveness and appropriate materials of construction will be selected for systems that will handle the water and gases produced with the Arbuckle oil. Produced water will be reinjected back into the Arbuckle formation. It will be important to maintain tight seals and monitor for H₂S as well as CO₂.

There is a fault on the west side of the G-E field with approximately 91 m (300 feet) of vertical displacement. It is believed that this fault is not active and does not penetrate the caprock. It will be further characterized and included in simulation modeling.

Deep Bartlesville Fields (Rainbow Bend Field and others) EOR

The Deep Bartlesville Fields, in Cowley County, KS, are mature oil fields with some existing wells. The integrity of the seals has been proven over time. CO₂ leakage from existing wells represents a potential risk, however, prior to operation, a detailed borehole and replugging plan will be prepared. Wells that are at risk for leaking will be replugged. Prior to CO₂ injection, the field will be pressured in stages over 3-6 months by injecting water. This should help in detecting any leaks. The replugged wells and other wells will be monitored for leakage and remedial action will be taken as necessary. Some wells will be reconditioned or reactivated for use in EOR.

The Deep Bartlesville oil reservoirs are discontinuous fluvial channel sandstone up to 15 m thick. They are totally surrounded by shale overlain by multiple additional seals and sinks. Thus they are essentially “bottles”. The injection depths range from 914 to 1006 m (3,000 to 3,300 ft). The minimum miscible pressure (MMP) is approximately 11 MPa. The maximum injection pressure, (or fracture pressure minus 0.34 MPa) is approximately 15 MPa. This gives a working pressure range of approximately 4 MPa. Over pressuring the reservoirs will be prevented by producing oil, water and gas to compensate for the volume of CO₂ injected.

The reservoirs are in a of sensitive groundwater area along the Arkansas River. Monitoring or observation wells will be used to monitor CO₂ levels in sinks located above the primary seal to detect any CO₂ leakage before it comes in contact with groundwater. Procedures will be in place to prevent/mitigate any CO₂ contamination of groundwater or surface water, including extraction of CO₂ from a leaky reservoir and injecting it into another sealed reservoir if necessary. There are multiple small isolated reservoirs in the area for combined enhanced oil recovery and CO₂ sequestration. This should be a lower risk compared to one large reservoir.

The Humboldt fault zone is located adjacent to some of the Deep Bartlesville oil reservoirs. The fault zone is relatively stable in this area. 3-D seismic will be used to characterize the fault zone and the oil reservoirs. CO₂ injection will be kept away from the fault zone and will be controlled to prevent over pressuring. Monitoring and modeling will be used to track CO₂ migration.

Wellington Field EOR

The Wellington Filed is located two miles (3.2 kilometers) Northwest of Wellington, KS in Sumner County. The oil reservoir is in Mississippian Chat (chert and dolomite). It is 1113 m (3650 ft) deep, 20.7 km² (8 mi²) in lateral area, 6 m (20 ft) thick, and has 30% porosity, 6 MPa (1750 psi) pressure and 49°C (120°F) temperature. The caprock (primary seal) is Pennsylvanian shale with a thickness of around 18 m (60) feet. A secondary seal consists of a 61-91 m (200-300 ft) evaporite formation located below the shallow fresh water aquifer. The Arbuckle deep saline aquifer is located at a depth of 1250 to 1554 m (4100 to 5100 ft). It is separated from the Mississippian Chat oil reservoir by Chattanooga shale.

Wellington is a mature oil field that has been in existence over 80 years. Cumulative oil production has been 20.5 million barrels with over half coming from secondary water flooding. The field is unitized and owned by BEREXCO. It has over 134 existing wells. 44 are active wells. The field currently produces 138 bpd of 42° API gravity oil along with 10,000 bpd of water.

The Wellington field appears to be a very good candidate for CO₂ EOR. The formation pressure is sufficiently above the CO₂ supercritical pressure. The high API gravity of the crude oil indicates that the minimum miscible pressure should be lower than the Thrall-Aagard or Geneseo-Edwards fields. The greater depth should allow a higher maximum pressure. Thus the range of working pressure should be sufficient. The fact that more oil was produced with secondary water flooding than with primary oil production suggests that the tertiary CO₂ flooding will also be successful.

A current DOE program is underway at the Wellington Field. A 3-D seismic survey was completed in April 2010. High resolution gravity/magnetic survey and a 2-D seismic survey are scheduled for June 2010. Field data will be inputted into computer simulation to optimize CO₂ EOR operation. A typical 5-spot pattern is planned for the piston-type CO₂ EOR operation. A risk assessment of existing wells will be performed to determine how many are likely to fail (leak) over time. The effects of any sealing or transmitting faults will also be addressed. Characterization and risk assessment of potential CO₂ leakage pathways (wells, faults and fractures) located within 16 km (10 miles) of the field will be performed. It is estimated that the Mississippian Chat oil reservoir can hold approximately 25 million tonnes of CO₂. Additional CO₂ could be sequestered in the Arbuckle deep saline aquifer below the oil reservoir.

The primary risk that exists for environmental, health and safety issues related to the Wellington EOR site is wellbore leakage through degraded casings. Secondary risks include potential leakage through faults or fractures.

The proposed site is a mature oil field operated for over 80 years with many existing wells throughout the field. Depending upon the condition of the casings at the time of drilling, these wells could serve as fast migration pathways from the reservoir to the surface. Many of the existing wells have been plugged and abandoned and the procedures used may have varied over the years due to a range of regulations imposed on the cap/abandonment procedure occurring over the 80 years of operation. Therefore, these wells serve as potential conduits for free-phase CO₂ movement from the reservoir to the surface.

In addition to known wells located near the proposed injection site, there are possibly unknown wells located within the area that were not properly recorded. Such wells must be considered in any analysis to show what impact they might have on the overall risks of the project. If risks from unknown wells are small, they can be ignored. However, if these risks are high, some effort must be made to use monitoring or exploration to reduce uncertainty in these risk drivers. Risk associated with existing wells can be managed by selectively replugging and sealing those wells that are determined to be of concern after completing a quantitative risk analysis such as presented by Pawar et al. (2009).

Risks from leaking wells include (1) environmental impact to overlying groundwater systems (acidification of these systems), (2) CO₂ asphyxiation hazard close to the well, and (3) local plant, and soil bacterial stress in the overlying environment.

Induced seismicity could be an issue if the reservoir were to be over pressured. However, in an EOR operation, increased pressure from injection of CO₂ is partially or fully compensated for by production of oil, water and gas. The relatively small volume of CO₂ injection is not expected to cause anything more than microseismicity.

The Pennsylvanian shale caprock or primary seal is 18+ m thick. If the caprock is fractured, CO₂ could leak to overlying formations. However a 61-91 m thick evaporite formation is located between the primary seal and the shallow fresh water aquifer and should pose a formidable barrier to CO₂, keeping it away from the fresh water aquifer.

Slate Creek flows across the Southwestern edge of the Wellington Field. This creek feeds into the Arkansas River and is therefore included as part of the sensitive receptor vulnerable to CO₂ intrusion. Appropriate safeguards and monitoring would be needed to assure that CO₂ does not contaminate the water in Slate Creek.

Preliminary review of population density data suggests that the Wellington field are is sparsely populated with a population density of approximately 1 person per square mile (1 person per 2.6 square kilometers).

Additional concerns that may be resolved with a more detailed information survey include the following:

- Proximity to nearest seismic fault fracture and migration potential of the injected CO₂ plume. The Humboldt fault zone is located approximately 8 miles (13 kilometers) east of the injection site. There are some closer minor faults located on either side of the injection site.
- Previous water floods may have activated microfaults/fissures and/or damaged caprock integrity. Management history unknown at this time.
- Seal integrity and uniformity of overburden throughout the Wellington region uncertain.
- Modeling of geomechanical attributes of the stress field. Induced stresses are present from historical depletion. Possible thermal gradients during injection may induce localized tensile stresses on a previously “exercised” field.

Thrall Aagard (T-A) Field EOR

The IMCCS Project originally planned to inject CO₂ into the T-A (and other adjacent fields) for enhanced oil recovery. However, after significant study it was concluded that the T-A field was too shallow for CO₂ EOR. This resulted in insufficient working pressure range (1.5 MPa [215 psi]). Working pressure range is equal to maximum bottom hole injection

pressure (10.8 MPa [1560 psi] or fracture pressure minus 0.34 MPa [50 psi] at T-A) minus minimum miscibility pressure (9.3 MPa [1345 psi] at 43°C [110°F] at T-A).

In addition, it was most likely that the T-A field could not operate at a high enough pressure to achieve miscible CO₂ EOR. The reservoir pressure would have to operate significantly higher than original bottom hole pressure. And finally, the field has over 457 existing wells that could eventually leak through degraded casings.

This section is included for purpose of completeness to document the work that was done on the T-A field. Special attention was given to wellbore risks in the T-A field. A database of plugged and abandoned wells in the T-A was compiled by Dr. Martin Dubois of CAP CO₂ and analyzed by Dr. Andrew Duguid of Schlumberger Carbon Services. The analysis was then reviewed by members of the risk assessment working group. This analysis can be found in Appendix 6-C.

The T-A field is a mature oil field with approximately 457 existing wells. Some of the early wells have been fractured with nitroglycerin while later wells were hydrofractured to improve permeability. CO₂ leakage from existing wells represents the most significant risk for the T-A field. Prior to operation, a detailed replugging plan would be prepared. Three plugs are standard: one at the Bartlesville Sandstone at 671 m (2200 ft) depth (bottom plug), one at the top of the Douglas Sandstone at 366 m (1200 ft) depth (middle plug) and from 67 m (220 ft) to the surface (top plug). Wells which didn't meet this standard would be replugged. Prior to CO₂ injection, the field would be pressured in stages up to 8.3-9.7 MPa (1200-1400 psig) over 3-6 months by injecting water. This would help in detecting any leaks. The replugged wells and other wells would be monitored for leakage and remedial action would be taken as necessary. Several wells would be reconditioned or reactivated for use in EOR.

The Bartlesville oil reservoir, in the T-A field, is discontinuous fluvial channel sandstone up to 30 m thick x 6.4 km long x 1.3 km wide (100 ft thick x 4 miles (6.4 kilometers) long and 0.8 miles (1.3 kilometers) wide). It is totally surrounded (top, bottom and sides) by a Middle Pennsylvanian Cherokee shale (61 m [200 ft] above and 30 m [100 ft] below). Multiple additional seals and sinks occur above the Cherokee shale.

Water flooding indicates the Bartlesville oil reservoir is essentially a "bottle" surrounded by shale. Well records indicate the reservoir has been pressured up to 11.7 MPa (1700 psig). The current bottom-hole pressure is 5.9 MPa (850 psig). The minimum miscible pressure for the residual oil is 9.3 MPa (1345 psig). The plan was to pressurize the reservoir to 9.7 MPa (1400 psig) in order to maintain the CO₂ in supercritical form, make it miscible with the residual oil and stay below the formation fracture gradient. Any leaks through existing wells or lateral leaks would make it difficult to pressurize the reservoir, therefore special attention would be given in the drilling and injection plan to prevent or minimize leakage.

The Douglas Sandstone is a 15-24 m (50-80 ft) thick, highly-permeable, saline-aquifer, low pressure (3.4 MPa [500 psig]) thief zone located 152-183 m (500-600 ft) above the Bartlesville oil reservoir in the T-A field. Any leaky borehole would act as a conduit for passing CO₂ from the oil reservoir to the thief zone. Observation wells would be used to monitor CO₂ content in the thief zone and remedial action would be taken to locate and stop any CO₂ leakage that may occur.

After discontinuing CO₂ injection into the Bartlesville oil reservoir, it would be necessary to decrease the pressure from 9.7 MPa (1400 psig) back to the pre-injection pressure of 5.9 MPa (850 psig). This could be accelerated by recovering CO₂ from the

reservoir for use in EOR operations in other nearby oil fields, injecting the CO₂ into the Douglas Sandstone, or injecting the CO₂ into the Arbuckle formation. A closure plan would be prepared and implemented to select the best alternative.

6.1.6 CO₂ Deep Saline Aquifer (DSA) Sequestration

It was originally planned that CO₂ DSA sequestration would be included in Phase 2 of the IMCCS project. However, it was determined that under current market conditions, there is insufficient economic incentive to justify CO₂ DSA sequestration and this portion of the project was dropped from Phase 2. CO₂ DSA sequestration could become feasible in the future if appropriate legislation is enacted to incentivize CO₂ sequestration and the IMCCS project could add this portion back into the project if this happens. This section is included for completeness to indicate the work done on DSA risk assessment.

The original plan was to inject CO₂ into the Arbuckle DSA below the G-E and/or T-A fields. These are mature oil fields and the footprints of the deep saline CO₂ plumes was not expected to exceed the boundaries of the leased EOR surface area above them. In both cases, CO₂ would be injected into the bottom of the Arbuckle formation – a 183 m (600 ft) thick, porous-dolomite, with multiple stacked seals and sinks above it. The integrity of the vertical seals have been demonstrated by the presence of hydrocarbons in and above the Arbuckle formation.

Sufficient CO₂ would be injected into the DSA to enable 3-D seismic monitoring of the plumes (Up to 50,000 tonnes per year or 150,000 tonnes total over a 3-year period for G-E and up to 100,000 tonnes per year or 300,000 tonnes total over a 3-year period for T-A).

In the Design sub phase, the operators were to complete a full characterization of the site(s) including:

- Generalized stratigraphic column of the geologic formations encountered, supported with geophysical logs
- Geologic, geomechanic, geochemical, hydrogeologic and reservoir evaluation
- Assessment of regional and local faults and other structural or stratigraphic features
- Estimate of CO₂ storage capacity based on modeling
- Estimate of plume footprint over time based on modeling
- Identification of any petroleum or water resources that may be impacted
- Assessment of existing wells, and other man-made surface structures and activities within one-mile (1.6 kilometers) outside of the storage facility boundary
- Isopach maps of the CO₂ storage reservoir and adjacent confining layers
- Structural and stratigraphic cross sections of the reservoir at the site(s)
- Detailed monitoring plan for soil, useable water, and the first porous zone immediately above the CO₂ reservoir's confining layer
- Saline fluid flow map of the storage reservoir showing local and regional fluid flow directions

In addition, the following plans were to be prepared:

- Replugging plan for existing wells that penetrate the DSA
- Drilling and injection plan (number and type of wells, maximum injection rate, pressure, etc.)
 - Closure plan (including: pressure existing before and expected at the end of CO₂ injection, predicted time for equilibration, estimated ultimate extent of the CO₂ plume, and procedure for monitoring the plume)
 - CO₂ storage facility safety plan (facilities security, public safety, public notification procedures, emergency response and contingency plans for leaks or loss of containment, contact information for emergency response contractors, interface with county emergency management, monitoring plan to ensure containment of CO₂ vertically and horizontally, safety plan updating schedule).
 - CO₂ storage verification plan (monitoring and documentation procedures)

The DSA injection sites were to be designed, constructed, operated, and closed in compliance with Kansas Corporation Commission regulations for carbon dioxide storage facilities (82-3-1100 through 82-3-1120 effective as of February 26, 2010). OSHA safety guidelines will be followed. All construction and operating personnel will receive training prior to working on site.

The risks associated with CO₂ DSA sequestration included:

Leakage of CO₂ through existing boreholes - This is not as severe a problem compared to EOR operation the T-A field because there are only about 4 wells in the area that penetrate through the caprock to the Arbuckle. The risks for DSA and EOR in the G-E field are comparable because the oil reservoir is in the Arbuckle formation.

Up-dip migration of CO₂ in the T-A – The top of the Arbuckle under the T-A field is a gently

dipping monocline. There was not sufficient characterization work completed to determine if there were up-dip traps to secure the CO₂ long-term. However, after simulation modeling, it was determined that due to the low volume of CO₂ to be injected and the very gentle dip, the CO₂ migration would gradually stop after about 60 years.

H₂S stripping in the Arbuckle – Preliminary information indicates that the Arbuckle fluids contain H₂S. Free CO₂ could strip the H₂S and causing it to flow with the CO₂ if a leak developed. Therefore it would be necessary to monitor for H₂S as well as CO₂.

Transformation of CO₂ from supercritical to gas phase – The Arbuckle formation below the T-A field is sufficiently shallow that injected CO₂ would transform from supercritical phase to gas phase as it migrated away from the injection well. This could cool the surrounding area, significantly increase the volume of CO₂ stored, accelerate migration of the CO₂ and increase stripping of any H₂S.

6.1.7 Post Closure

At the end of CO₂ EOR injection, the operator will follow Kansas Corporation Commission regulations for plugging and abandonment of wells, removal of surface equipment, site remediation and safety.

All necessary records, including those needed for verification of long-term storage of CO₂, will be maintained for the duration of time required by law.

It is anticipated that the owner/operator of the EOR field(s), will take on all liabilities associated with the CO₂ storage until legislation establishes an appropriate mechanism for transferring long-term liability.

6.2 Programmatic Risk Results and Discussion

Based on ranking and project specific information, the following significant programmatic risks/issues have been identified. Under each issue, we have summarized the proposed strategies to prevent the occurrence or minimize the impact of the risk.

6.2.1 Securing strategic partners for EOR operation and cost share funding

Strategic partner agreements should be in place prior to finalizing the Phase 2 Agreement. A backup list of potential strategic partners has been developed in case any current partners should bail out. Note that the strategic partner(s) selected for the enhanced oil recovery may determine the final EOR site selected.

6.2.2 Acquiring contiguous leasehold interests for injection sites

Leaseholds should be in place prior to finalizing the Phase 2 Agreement. Compulsory unitization rules allow the operator to receive a Kansas Corporation Commission order with at least 63% interest. The process takes approximately 6 months. There are multiple oilfields in Cowley, Sumner and Rice Counties suitable for EOR. Lease acquisition is tied to current (declining) production levels; therefore there is motivation to sell to avoid lease termination.

6.2.3 Securing DOE funding support

We intend to comply with all of DOE requirements for obtaining and maintaining funding for this project.

6.2.4 Potential construction delays due to the need for an EIS rather than an EA

With the possibility that an EIS may be required, we have taken the conservative approach to include a 12 month Design sub-phase and sufficient funds in the budget to cover an EIS. If an EIS is required, we may also begin the EIS process as soon as possible after selection notification to gain three additional months (assuming an EIS may take 15 months to complete). While we have allocated 12 months for the Construction sub-phase beginning in October 2011, it is possible that construction can be compressed into six months with work beginning in April 2012 if necessary due to permitting delays or long-lead times on equipment.

2.5 Managing/coordinating multiple partners in the project

The project partners have been successfully working together throughout Phase 1. Phase 2 will use a similar organization structure consisting of a cross-functional management group, multiple working groups, well defined scopes of work and budgets, secure website, regular conference calls and meetings, and reporting system to keep the project on schedule, within budget and on target.

6.2.6 Cost escalation

Efforts have been made to get quotes and proposals covering major scopes of work for the project. Vendor quotes will be negotiated and subject to competitive bidding. Suitable escalation factors have been included and identified within the budget. Most of the capital budget will be expended in the first half of the project, thus escalation should be less than if the spending occurred in the last half. Long lead items, such as compressors, will be committed early.

6.2.7 Oil Price Fluctuation

Crude oil prices are unpredictable and subject to periods of high volatility. The price of CO₂ will be tied to crude oil price to allow the supplier and user to share in the risks and rewards associated with fluctuating oil prices. The project is commercially viable with average WTI crude oil prices above \$75/barrel over the 5-year term.

6.2.8 CO₂ quality

The project will require that Kansas Ethanol conduct a sufficiently long performance test to prove that it can consistently produce on-spec CO₂. The project will require Kansas Ethanol to guarantee CO₂ quality. Coffeyville Resources Nitrogen Fertilizer has already demonstrated it can consistently meet the CO₂ specification and is willing to guarantee it.

6.2.9 CO₂ supply interruption

Coffeyville Resource Nitrogen Fertilizer has a backup gasifier on site to maintain high plant availability. CO₂ is paid based upon 75% of available supply, no supply: no liability to pay. If suppliers are unable to provide reliable CO₂ supply, they forfeit reliability incentives that would otherwise be paid in year four. After initial four years of CO₂ injection, water-alternating-gas (WAG) techniques can minimize affects of CO₂ downtime. Eventually, CO₂ recycling will exceed fresh CO₂, this will minimize the impact of a temporary interruption in fresh CO₂ supply. There are several other ethanol plants in the area of the Geneseo-Edwards field that could ultimately replace or supplement Kansas Ethanol CO₂ supply.

6.2.10 Borehole replugging and remediation

We plan to replug any wells that have a risk of leaking before injecting CO₂. By switching the injection site away from the Thrall-Aagard field, the amount of borehole replugging and remediation will be significantly less. We will increase the pressure of the Bartlesville oil reservoirs with water and check for leakage before injecting any CO₂. Kansas Corporation Commission may offer assistance for locating and plugging abandoned wells. Lease purchases are conditioned on plugging details (with claw back for new discoveries of poorly plugged wells).

6.2.11 Oil recovery

Strong empirical results from water flooding during the past 50 years indicate that recovery of 12.5% of original oil in place (OOIP) with CO₂ EOR is achievable. Oil reservoirs will be thoroughly modeled and engineered to optimize well pattern, well spacing and oil recovery. Injection and production performance will be monitored and modeled and well pattern and spacing will be modified if necessary to optimize oil recovery.

6.2.12 Long-term liability for sequestered CO₂

CO₂ injection sites will be fully characterized and modeled to identify trapping mechanisms to hold CO₂ in place long-term. Site closure plans will be submitted to Kansas Corporation Commission as part of the permitting process for CO₂ sequestration. Verification of CO₂ sequestration will be done by an independent third party.

6.2.13 Deep saline aquifer (DSA) sequestration

Without new legislation, DSA sequestration is uneconomic. Regulations for DSA permitting, operation and closure are more onerous and less defined than those for EOR, resulting in higher costs and greater liabilities. The current plan is to operate under the

EOR umbrella during the 5-year term of the project with the option to expand into DSA sequestration in the future if the economic hurdles can be overcome.

6.2.14 Insurance coverage

Insurance coverage may be available for EOR operation but may not be available for DSA sequestration. Insurance coverage would address short-term liability including physical damage, machinery breakdown, business interruption (advanced loss of profits), third-party liability and environmental liabilities.

6.2.15 Engineering, Procurement and Construction

The project will work with competent, experienced firms to provide engineering, procurement and construction services. Design review meetings will be conducted by a cross-functional team of experts. As-built drawings will be reviewed for accuracy and completeness. Equipment and infrastructure will be inspected and tested before being placed into service. Budgets and schedules will be closely tracked and managed by experienced project managers.

6.2.16 Field Safety

A Health, Safety, Environment and Security (HSES) Plan and an Emergency Response Plan will be developed and implemented during the Design sub-phase. Personnel will receive HSES training before working in the field. The project will maintain compliance with all OSHA and State safety regulations including regular HSES training meetings, emergency response drills and safety audits. The project will mark and regularly inspect pipelines, use a one-call system, and supervise third-party excavation activities to prevent excavation damage to pipelines. Surface facilities will be fenced in and protected from public access. HSES incidents will be appropriately tracked and documented. The Emergency Response Plan will be regularly updated and integrated with the local community emergency response plan and public outreach and education program.

6.2.17 Public Outreach

The public outreach program will follow the NETL/DOE best practices manual. By focusing on EOR, it is believed that less public concern will be generated than with DSA sequestration. The oil industry and local residents have a long-term successful working relationship at the potential injection sites.

6.2.18 Pore Space Ownership

Pore space ownership is a significant issue in CO₂ deep saline aquifer sequestration but has not been an issue in CO₂ EOR. One of the reasons IMCCS has focused on EOR for Phase 2 is that regulations on pore space ownership have not been adopted in the State of Kansas. IMCCS will monitor developments in pore space ownership regulations and will need to comply with State of Kansas regulations when and if they are adopted.

6.3 Conclusions

The qualitative risk assessment on Phase I of the IMCCS project identified a comprehensive list of technical and programmatic risks associated with CO₂ capture, dehydration, compression, pipeline transportation, enhanced oil recovery and deep saline aquifer injection. The risks have been analyzed and ranked relative to site-specific conditions. Tentative risk prevention and mitigation steps have been developed for each risk.

The two suppliers of CO₂ for the project already generate concentrated CO₂ as a by-product of ammonia and ethanol production. The CO₂ capture at CVR is well proven and performing well on a continuous basis. The CO₂ capture at Kansas Ethanol tends to be variable in quality and flowrate due to the batch-type nature of fermentation. This may have a negative impact on CO₂ dehydration and compression performance. It may be necessary to install a surge tank at Kansas Ethanol to steady out CO₂ quality and flowrate and a performance test should be conducted to confirm that Kansas Ethanol can consistently meet CO₂ quality specification.

The two pipelines in the project will be installed along existing pipeline corridors. There does not appear to be any site-specific conditions that would result in above normal risks compared to other existing CO₂ pipelines. As long as the pipelines are installed and operated in accordance with US Department of Transportation regulations (Title 49 CFR Part 195), the pipelines should be able to operate safely.

Several mature oil fields were evaluated for enhanced oil recovery. The Thrall-Aagard Field appeared to have the highest technical risks due to shallow depth and high concentration of existing wells. The Deep Bartlesville Fields have better reservoir conditions due to depth and fewer well penetrations, but are located in a sensitive groundwater area of the Arkansas River and near the Humboldt fault zone, requiring greater precautions and more intensive monitoring. The Geneseo-Edwards Field requires gravity-stable CO₂ flooding which is more difficult to control. It reportedly has hydrogen sulfide in the Arbuckle formation that may require additional corrosion control in production wells and recycling systems. And there is a small fault on the west side of the field that will need to be characterized and monitored. The Wellington Field in Southern KS appears to be well suited for CO₂ EOR and may have the lowest risks. There are existing wells in the field, but significantly fewer than the Thrall-Aagard field. The field is near a sensitive groundwater area and eight miles (13 kilometers) away from the Humboldt fault zone.

Chapter 7 – Conclusions

Results of this project should be considered an initial feasibility study to be followed by additional data gathering, field testing, and more rigorous modeling and simulation study. Analyses suggest that deep saline sequestration is impractical and uneconomic, without additional (new) financial incentives. However, EOR analysis results of this project are encouraging and suggest a gravity-stable immiscible CO₂ EOR flood in select Midwestern oilfields would mobilize oil, form a horizontal oil bank, and could be commercially feasible. However, substantial additional work is needed on three fronts: 1) fill critical fluid property gaps, 2) improve assessments of geophysical and petrophysical properties including residual oil saturation, and 3) gain a better understanding of reservoir "plumbing systems" to insure that a gravity-stable approach could be effective in these reservoirs.

Key Findings

The objective of the study detailed in this chapter was to evaluate the potential for a gravity-stable EOR project in the Arbuckle given that the reservoir has a relatively thick oil column, the producing mechanism is a strong bottom-water drive, and evidence that the oil-water contact moved vertically in a fairly uniform manner, leaving behind sufficient residual oil to be targeted for EOR. Key findings include the following:

1. Significant residual oil remains in the water-swept portion of the reservoir. Residual oil saturation (Sorw) is approximately 38.9% established by material balance, assuming original saturation is 70%, average porosity is 11.5%, and a FVF of 1.1. EPIC's estimated Sorw to be 38.9% based on reservoir and oil properties, and history-matched reservoir simulation by Schlumberger yielded an average Sorw = 36%.
2. It appears likely that that a CO₂ gas cap can be built downward while maintaining a relatively flat gas/water-oil contact. A study of oil-water contacts in 32 wells suggests strongly that the oil-water contact stayed relatively flat as it moved upward during the 80-year production history. Reservoir simulations indicate that a CO₂ gas cap with a fairly uniform gas/oil contact can be built downward.
3. Successful Keg River gravity-stable miscible floods (Canada) may be analogs to the Arbuckle of the Central Kansas Uplift.
4. The EPIC preliminary feasibility study, based on correlations with empirically derived data and equations, and comparisons with analogs, suggests that 6.1 million barrels of oil could be recoverable by EOR in the two-dome project.

5. The Schlumberger reservoir simulation study demonstrates that oil is mobilized by CO₂ in a gravity-stable process. However, the amount of oil mobilized is a fraction of that predicted to be recoverable by the EPIC study. Significant improvements in the oil mobilized by optimizing the simulation for improved sweep efficiency.

The above results should be utilized with caution. Many caveats and shortcomings have been discussed throughout the report and are summarized below:

1. Residual oil saturation is based on an assumed initial oil saturation of 70% and FVF of 1.1. Neither of these variables are known.
2. A published paper (Mullins and Ireland, 1967) on the Arbuckle reservoir 5 miles (8 kilometers) northwest of the proposed project suggests the reservoir is layered. This would negatively impact the potential for gravity-stable EOR process if it is the case in the project area.
3. The simulation model is based on a static model grid built from a sparse petrophysical data set. Critical fluid properties and the equation of state (EOS) for the crude oil were estimated.

Recommended Additional Work

The current study achieved some progress towards answering fundamental questions and provides encouragement for further evaluation. The final answers will not be known until the concept is tested by large-scale CO₂ injection, but there are a number of data to yet be collected, analyzed and incorporated in the model, and field testing that could help to elucidate the fluid dynamics of the reservoir system and reduce major risk factors due to current uncertainties:

Fill critical fluid property for well-constrained EOS and other parameters:

- Laboratory flash liberation tests (CCE)
- Laboratory differential liberation tests (DL, CVD)
- Viscosity versus pressure at reservoir temperature
- Swelling tests
- Additional MMPs
- Oil composition from downhole samples above bubble point
- Gas sample and composition

Improve the static model grid geometry

- Make another search for wireline logs and incorporate
- Acquire initial 3-D seismic survey and incorporate
- Improve layering and identify potential barriers in core

Improve the static model grid petrophysical properties:

- Obtain additional conventional and special core analysis from existing cores, including in situ properties, capillary pressure data, rock mechanical data for fracture pressure of reservoir and seal
- Run modern openhole logs in existing wells with long open hole sections and wells re-entered and deepened for reservoir tests, and incorporate petrophysical data and layering
- Obtain current Sorw from open hole logs

Gain a better understanding of the reservoir "plumbing system" in particular continuity in vertical permeability:

- Further analysis for movement of oil-water contact including correlating well production tests to current layered reservoir model, particularly in areas where there are anomalies what otherwise appears to be a relatively uniform pattern of upward movement.
- Investigate the data behind the Mullins and Ireland (1967) paper and production records since the paper was written to validate or refute the paper's findings.
- Analyze several cores available at the Kansas Geological Survey core storage facility paying particular attention to potential vertical barriers and correlate to wireline logs.
- Design and perform multiple well tests, including pulse tests and tracer surveys, to measure vertical permeability at varying scales.
- Research and deploy other methods for characterizing reservoir-scale permeability in three dimensions.

Multiple iterations of reservoir characterization, modeling and simulation will be required before one can predict reservoir behavior with confidence. The current understanding of past reservoir behavior, comparison with successful analogs, and current reservoir models all suggest that gravity-stable immiscible CO₂ EOR could be successful. Additional work could bolster the case sufficiently to justify moving forward to a commercial-scale development project.

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Appendix 2A Process Flow Diagrams

Appendix 2-B Equipment List

Tag Number	Service	Qty	Type	Size		Electrical		Mech. Design		Material	Notes
				Parameter 1	Parameter 2	Oper. (HP)	Conn. (HP)	Pres [psig]	Temp (F)		
FURNACES, FIRED HEATERS AND STACK											
40-F-0101	Regeneration Gas Heater	1		3.742 MMBtu/h				50	1850	CS	Fuel Fired Burner heated Exchanger
40-S-0101	Heater Gas Stack	1		327,406 ft3/h				50	750	CS	
EXCHANGERS											
10-E-0101	Quench Water Cooler	1	Air Cooler	71.580 MMBtu/h	33,370 ft2 (Bare Tube Area)	475	560	130	190	CS	7 Bays (15'-10" x 40'-0" each) 14 Fans total with 40 hp Motors
20-E-0101	Amine Cooler	1	Air Cooler	337.021 MMBtu/h	94,717 ft2 (Bare Tube Area)	1,344	1,600	130	240	CS-HC	20 Bays (15'-7" x 40'-0" each) 40 Fans total with 40 hp Motors
20-E-0102	Lean/Rich Exchanger	1	Plate & Frame	368.287 MMBtu/h	68,564 ft2			90 130	260 310	CS-HC 316LSS	
20-E-0103	Amine Reclaimer	1	Shell side Tube side	224.650 MMBtu/h	52,611 ft2			130 175	240 420	CS-HC 316LSS	
20-E-0104	Condenser	1	Air Cooler	154.626 MMBtu/h	37,907 ft2 (Bare Tube Area)	539	640	50	255	316LSS	8 Bays (15'-7" x 40'-0" each) 16 Fans total with 40 hp Motors
20-E-0105	Amine Reboilers	1	Shell side Tube side	666.402 MMBtu/h	168,385 ft2			50 75	310 350	CS-HC 316LSS	
20-E-0106	Wash Water Cooler	1	Air Cooler	121.287 MMBtu/h	59,154 ft2 (Bare Tube Area)	775	960	75	200	CS	13 Bays (15'-0" x 40'-0" each) 24 Fans total with 40 hp Motors
20-E-0107	Wash Water Trim Cooler	1	Shell side Tube side	126.515 MMBtu/h	44,374 ft2			75 125	175 175	CS CS-HC	
30-E-0101	1st Stage Cooler	1	Air Cooler	25.330 MMBtu/h	21,895 ft2 (Bare Tube Area)	311	400	75	350	304SS	5 Bays (14'-6" x 40'-0" each) 10 Fans total with 40 hp Motors
30-E-0102	2nd Stage Cooler	1	Air Cooler	21.278 MMBtu/h	15,901 ft2 (Bare Tube Area)	229	240	140	350	304SS	4 Bays (13'-2" x 40'-0" each) 8 Fans total with 30 hp Motors
30-E-0103	3rd Stage Cooler	1	Air Cooler	19.481 MMBtu/h	11,518 ft2 (Bare Tube Area)	166	180	285	350	304SS	3 Bays (12'-7" x 40'-0" each) 6 Fans total with 30 hp Motors
30-E-0104	4th Stage Cooler	1	Air Cooler	20.743 MMBtu/h	10,205 ft2 (Bare Tube Area)	142	150	680	350	304SS	3 Bays (11'-4" x 40'-0" each) 6 Fans total with 25 hp Motors
30-E-0105	5th Stage Cooler	1	Air Cooler	12.874 MMBtu/h	7,158 ft2 (Bare Tube Area)	103	120	1085	265	304SS	2 Bays (12'-0" x 40'-0" each) 4 Fans total with 30 hp Motors

Tag Number	Service	Qty	Type	Size		Electrical		Mech. Design		Material	Notes
				Parameter 1	Parameter 2	Oper. (HP)	Conn. (HP)	Pres [psig]	Temp (F)		
30-E-0106	6th Stage Cooler	1	Air Cooler	37.196 MMBtu/h	8,564 ft2 (Bare Tube Area)	122	160	2435	330	304SS	2 Bays (14'-2" x 40'-0" each) 4 Fans total with 40 hp Motors
40-E-0101	Regeneration Gas Cooler	1	Air Cooler	1.802 MMBtu/h	491 ft2 (Bare Tube Area)	7.4	10	1070	300	304SS	1 Bay (4'-6" x 15'-0" each) 2 Fans total with 5 hp Motors
50-W-0101	Cooling Water Tower	1		126.005 MMBtu/h	8,436 gpm					CS	Cooling water supply temperature = 90F Cooling water return temperature = 120F Air wet bulb temperature = 76F
60-E-0101	Steam Condenser	1	Shell side Tube side	107.558 MMBtu/h	14,412 ft2	205	240	50	265	CS	3 Bays (15'-11" x 40'-0" each) 6 Fans total with 40 hp Motors
TOWERS											
10-T-0101	Quench Column	1	Vertical	372 in ID	50'-0" T/T			50	195	CS	
10-T-0101-P	Quench Column Packing	1	Structured	288 in depth	3Y Packing size			50	195	316LSS	
20-T-0101	Amine Absorber	1	Vertical	414 in ID	84'-6" T/T			50	220	CS-HIC	
20-T-0101-P	Amine Absorber Packing	1	Structured	504 in depth	3Y Packing size			50	220	316LSS	Water wash packing: 3Y structured packing, 144 in depth
20-T-0102	Stripper	1	Vertical	312 in ID	74'-0" T/T			50	310	CS-HIC	
20-T-0102-T	Stripper Trays	1	Valve	20 Trays	4-Pass Trays			50	310	316LSS	
VESSELS, DRUMS AND TANKS											
20-V-0101	Reflux Drum	1	Vertical	132 in ID	20'-6" T/T			50	180	304SS	
20-V-0102	Condensate KO Drum	1	Vertical	54 in ID	13'-6" T/T			175	420	CS	
30-V-0101	1st Stage Drum	1	Vertical	114 in ID	16'-6" T/T			75	175	304SS	
30-V-0102	2nd Stage Drum	1	Vertical	90 in ID	14'-6" T/T			140	175	304SS	
30-V-0103	3rd Stage Drum	1	Vertical	78 in ID	13'-0" T/T			285	175	304SS	
30-V-0104	4th Stage Drum	1	Vertical	78 in ID	12'-6" T/T			680	175	304SS	
30-V-0105	5th Stage Drum	1	Vertical	78 in ID	12'-6" T/T			1085	175	304SS	
40-V-0101/0102/0103	CO2 Dehydrators	1	Vertical	84 in ID	31'-0" T/T			1100	500	CS	Molecular Sieve Dehydration Beds
40-V-0104	Regeneration Gas KO Drum	1	Vertical	24 in ID	8'-6" T/T			1070	175	304SS	
50-TK-0101	Amine Storage Tank	1	Vertical	456 in ID	38'-0" T/T			50		CS-HC	
50-V-0101	Amine Sump	1	Horizontal	156 in ID	52'-0" T/T			100	400	CS-HC	
60-V-0101	Condensate Drum	1	Vertical	108 in ID	27'-9" T/T			175	420	CS	

Tag Number	Service	Qty	Type	Size		Electrical		Mech. Design		Material	Notes
				Parameter 1	Parameter 2	Oper. (HP)	Conn. (HP)	Pres [psig]	Temp (F)		
PUMPS, COMPRESSORS, BLOWERS AND DRIVERS											
10-B-0101A/B	Flue Gas Blowers	2	Centrifugal	538.650 MMSCFD	2.04 psi dP		5,500	50	195	CS	
30-C-0101A-D	CO2 Compressor Stage 1	4	Centrifugal	24.038 MMSCFD	Suction: 12 psig Discharge: 48 psig	1,609		75	350	CS	6-Stage Compressor - Motor Size 8,000 HP 4 CO2 Compressors are operating in parallel
30-C-0101A-D	CO2 Compressor Stage 2	4	Centrifugal	23.099 MMSCFD	Suction: 38 psig Discharge: 114 psig	1,614		140	350	CS	6-Stage Compressor - Motor Size 8,000 HP 4 CO2 Compressors are operating in parallel
30-C-0101A-D	CO2 Compressor Stage 3	4	Centrifugal	22.623 MMSCFD	Suction: 104 psig Discharge: 256 psig	1,444		285	350	CS	6-Stage Compressor - Motor Size 8,000 HP 4 CO2 Compressors are operating in parallel
30-C-0101A-D	CO2 Compressor Stage 4	4	Centrifugal	22.419 MMSCFD	Suction: 246 psig Discharge: 619 psig	1,494		680	350	CS	6-Stage Compressor - Motor Size 8,000 HP 4 CO2 Compressors are operating in parallel
30-C-0101A-D	CO2 Compressor Stage 5	4	Centrifugal	22.325 MMSCFD	Suction: 609 psig Discharge: 985 psig	663		1085	265	CS	6-Stage Compressor - Motor Size 8,000 HP 4 CO2 Compressors are operating in parallel
30-C-0101A-D	CO2 Compressor Stage 6	4	Centrifugal	22.230 MMSCFD	Suction: 955 psig Discharge: 2210 psig	1,094		2435	330	CS	6-Stage Compressor - Motor Size 8,000 HP 4 CO2 Compressors are operating in parallel
40-C-0101	Regeneration Gas Compressor	1	Centrifugal	8.918 MMSCFD	Suction: 955 psig Discharge: 996 psig	19.6	20	1100	185	CS	
10-P-0101A/B	Quench Water Pumps	2	Centrifugal	10,484 gpm	73 psi dP	598	600		190	A-8	
20-P-0101A/B	Rich Amine Pumps	2	Centrifugal	12,138 gpm	78 psi dP	735	800		190	A-8	
20-P-0102A/B	Lean Amine Pumps	2	Centrifugal	12,482 gpm	115 psi dP	1,118	1,250		310	A-8	
20-P-0103A/B	Reflux Pumps	2	Centrifugal	281 gpm	60 psi dP	21	25		180	A-8	
20-P-0104A/B	Wash Water Pumps	2	Centrifugal	10,367 gpm	63 psi dP	513	600		200	A-8	
50-P-0101	Amine Sump Pump	1	Centrifugal	125 gpm	27 psi dP	4	5		150	A-8	
50-P-0102	Amine Makeup Pump	1	Centrifugal	509 gpm	33 psi dP	16	20		150	S-8	
50-P-0103A/B	Cooling Water Circulation Pumps	2	Centrifugal	8,436 gpm	57 psi dP	377	400		170	S-5	
60-P-0101A/B	BFW Pumps	2	Centrifugal	2,246 gpm	171 psi dP	313	350		265	S-4	
SPECIAL EQUIPMENT											
10-U-0101	Quench Water Filter	1	Vertical	10,446 gpm	Cartridge Filter			130	190	304SS	
10-PK-0101	Wet FGD Unit	1	Packaged	430,000 ft3/h				50	270		
20-U-0102	Carbon Bed	1	Vertical	228 in ID	16'-0" T/T			130	240	CS-HC	
20-U-0103	Amine After Filter	1	Vertical	1,244 gpm	Cartridge Filter			130	240	CS-HC	
40-U-0101A/B	Dehydration After Filters	2	Vertical	88.920 MMSCFD	Cartridge Filter			1075	175	CS	
60-PK-0101	Boiler Package	1	Packaged	1,002.290 MMBTU/hr				175	420	CS	150# Steam, 1,012,314 lb/hr
60-PK-0102	Steam Condensate Chemical Feed Package	1	Packaged	17,323 ft3/h							
60-PK-0103	Raw Water Conditioning Package	1	Packaged	1,553 ft3/h							

Appendix 2-C
**Plot Plan of CO₂ Equipment Location Relative to Existing
Cement Plant**

Appendix 2-D One-Line Diagram

Appendix 2-E

Heat and Material Balance Data

UNIVERSITY OF UTAH
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Chanute, Kansas
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BLACK & VEATCH
Material Balance

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By: KWW
App: DAO

Material Balance														
Stream Name			Flue Gas from Cement Plant to Wet FGD Unit 10-PK-0101	Flue Gas to Flue Gas Blowers 10-B-0101A/B	Quench Overhead to Amine Absorber 20-T-0101	Quench Water from Quench Column 10-T-0101	Quench Water from Quench Water Cooler 10-E-0101	Quench Water to Quench Column 10-T-0101	Quench Water to Makeup Water Treatment	Sweet Gas from Amine Absorber 20-T-0101	Rich Amine from Amine Absorber 20-T-0101	Wash Water Recycle to Pump 20-P-0104A/B	Makeup Wash Water to Amine Absorber 20-T-0101	Wash Water to Cooler 20-E-0107
Stream Number	Mol Wt	Units	101	102	103	104	105	106	107	108	109	110	111	112
Liquid Properties	Vapor Fraction (Mole)		1.0000	1.0000	1.0000	0.0000	0.0000	0.0000	0.0000	1.0000	0.0000	0.0000	0.0000	0.0000
	Temperature	F	220	135	128	139	125	125	139	125	140	149	100	125
	Pressure	psia	14.7	14.6	16.1	16.6	106.6	16.1	96.6	15.0	16.1	15.1	85.0	55.0
	Mass Flow	lb/hr				4,755,470	4,692,385	4,692,385	63,198		6,213,317	4,838,997		4,838,997
	Molar Flow	lbmole/hr				263,940.8	260,439.4	260,439.4	3,507.6		252,632.4	266,970.2		266,970.2
	Volume Flow (actual)	USGPM				9,660.3	9,497.0	9,497.0	128.4		11,035.2	9,851.1		9,786.3
	Density	lb/ft3				61.4	61.6	61.6	61.4		70.2	61.2		61.6
	Viscosity	cP				0.48	0.54	0.54	0.48		1.46	0.44		0.55
	Thermal Conductivity	Btu/hr-ft-F				0.374	0.369	0.369	0.374		0.237	0.373		0.366
	Surface Tension	dyne/cm				66.1	67.6	67.6	66.1		88.2	64.8		67.4
	Molecular Weight					18.02	18.02	18.02	18.02		24.59	18.13		18.13
Vapor Properties	Mass Flow	lb/hr	1,552,520	1,584,094	1,521,009					1,104,161				
	Molar Flow	lbmole/hr	51,974.1	53,765.8	50,264.4					39,948.8				
	Volume Flow (standard)	MMSCFD	473.36	481.98	457.79					363.84				
	Density	lb/ft3	0.06	0.07	0.08					0.07				
	Compressibility		0.999	0.999	0.999					0.999				
	Viscosity	cP	0.020	0.018	0.018					0.019				
	Thermal Conductivity	Btu/hr-ft-F	0.017	0.015	0.015					0.016				
	Molecular Weight		29.87	29.65	30.26					27.64				
Compositions	O2	32.00	5,196.76	5,196.76	5,196.75	0.48	0.47	0.47	0.01	5,196.33	0.40	0.49	0.00	0.49
	N2	28.01	28,546.70	28,546.70	28,546.68	1.44	1.42	1.42	0.02	28,545.42	1.20	1.50	0.00	1.50
	H2O	18.02	8,315.16	10,122.19	6,621.08	263,920.98	260,419.87	260,419.87	3,507.37	5,193.11	208,084.92	266,178.20	0.00	266,178.20
	CO2	44.01	9,873.78	9,873.78	9,873.55	17.02	16.79	16.79	0.23	987.80	15,026.48	268.98	0.00	268.98
	SO2	64.06	15.61	0.31	0.30	0.84	0.83	0.83	0.01	0.00	40.82	0.00	0.00	0.00
	NO2	46.01	26.08	26.08	26.08	0.03	0.03	0.03	0.00	26.06	0.03	0.03	0.00	0.03
	MEA	61.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	29,478.52	521.03	0.00	521.03
	C1	16.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	C2	30.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	C3	44.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	nC4	58.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	nC5	72.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	nC6	86.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total			51,974.09	53,765.81	50,264.44	263,940.79	260,439.42	260,439.42	3,507.64	39,948.78	252,632.36	266,970.22		266,970.22
NOTES: 1. 2. 3.														

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BLACK & VEATCH
Material Balance

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Material Balance														
Stream Name			Wash Water to Amine Absorber 20- T-0101	Rich Amine to Stripper 20-T-0102	Lean Amine from Stripper 20-T-0102	Stripper Overhead to Condenser 20-E-0104	Stripper Overhead to Reflux Drum 20-V-0101	CO2 to Compression	Reflux to Stripper 20-T-0102	Amine to Reboiler 20-E-0105	Reboiler Return to Stripper 20-T-0102	Lean Amine to Amine Cooler 20-E-0101	Lean Amine to Absorber 20-T-0101	CO2 to 1st Stage Cooler 30-E-0101
Stream Number			113	114	115	116	117	118	119	120	121	122	123	124
Liquid Properties	Vapor Fraction (Mole)		0.0000	0.0000	0.0000	1.0000	0.5780	1.0000	0.0000	0.0000	1.0000	0.0000	0.0000	1.0000
	Temperature	F	100	210	259	205	125	125	125	257	259	184	125	300
	Pressure	psia	15.0	28.0	32.7	27.7	26.2	26.2	26.2	32.7	32.7	120.0	15.1	63.1
	Mass Flow	lb/hr	4,628,721	6,213,317	5,809,715		126,349		126,349	6,514,494	6,006,746	6,006,746	6,006,746	
	Molar Flow	lbmole/hr	255,369.0	252,632.4	243,034.8		7,007.7		7,007.7	279,954.8	253,917.9	253,917.9	253,917.9	
	Volume Flow (actual)	USGPM	9,307.3	11,171.3	11,348.1		255.7		255.7	12,762.4	11,485.8	11,485.8	11,315.2	
	Density	lb/ft3	62.0	69.3	63.8		61.6		61.6	63.6	65.2	65.2	66.2	
	Viscosity	cP	0.71	0.70	0.40		0.54		0.54	0.38	0.72	0.72	1.39	
	Thermal Conductivity	Btu/hr-ft-F	0.357	0.243	0.265		0.369		0.369	0.273	0.266	0.266	0.258	
	Surface Tension	dyne/cm	70.1	83.0	48.1		67.5		67.5	48.7	55.7	55.7	61.3	
Vapor Properties	Mass Flow	lb/hr	18.13	24.59	23.90		18.03		18.03	23.27	23.66	23.66	23.66	
	Molar Flow	lbmole/hr				529,951	403,602	403,602			704,779			403,602
	Volume Flow (standard)	MMSCFD				16,605.3	9,597.6	9,597.6			36,920.0			9,597.6
	Density	lb/ft3				151.23	87.41	87.41			336.25			87.41
	Compressibility					0.12	0.18	0.18			0.08			0.33
	Viscosity	cP				0.992	0.993	0.993			0.985			0.993
	Thermal Conductivity	Btu/hr-ft-F				0.017	0.016	0.016			0.014			0.020
	Molecular Weight					0.014	0.011	0.011			0.017			0.015
Compositions	O2	32.00	0.47	0.40	0.00	0.40	0.40	0.40	0.00	0.00	0.00	0.00	0.00	0.40
	N2	28.01	1.43	1.20	0.00	1.20	1.20	1.20	0.00	0.00	0.00	0.00	0.00	1.20
	H2O	18.02	254,611.36	208,084.92	207,363.27	7,725.37	7,725.37	721.67	7,003.70	0.00	218,223.78	218,223.78	218,223.78	721.67
	CO2	44.01	257.31	15,026.48	6,152.17	8,878.26	8,878.26	8,874.31	3.95	0.00	6,152.39	6,152.39	6,152.39	8,874.31
	SO2	64.06	0.00	40.82	40.82	0.00	0.00	0.00	0.00	0.00	40.53	40.53	40.53	0.00
	NO2	46.01	0.03	0.03	0.00	0.03	0.03	0.03	0.00	0.00	0.00	0.00	0.00	0.03
	MEA	61.08	498.42	29,478.52	29,478.52	0.02	0.02	0.00	0.02	0.00	29,501.20	29,501.20	29,501.20	0.00
	C1	16.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	C2	30.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	C3	44.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	nC4	58.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	nC5	72.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	nC6	86.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total			255,369.03	252,632.36	243,034.78	16,605.27	16,605.27	9,597.59	7,007.68	279,954.82	279,954.82	253,917.89	253,917.89	9,597.59
NOTES:														
1.														
2.														
3.														

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Material Balance

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Material Balance															
Stream Name			Recovered Water from 1st Stage KO Drum 30-V-0101	CO2 to 2nd Compressor Stage	CO2 to 2nd Stage Cooler 30-E-0102	CO2 to 2nd Stage KO Drum 30-V-0102	Recovered Water from 2nd Stage KO Drum	CO2 to 3rd Compressor Stage	CO2 to 3rd Stage Cooler 30-E-0103	CO2 to 3rd Stage KO Drum 30-V-0103	Recovered Water from 3rd Stage KO Drum	CO2 to 4th Compressor Stage	CO2 to 4th Stage Cooler 30-E-0104	CO2 to 4th Stage KO Drum 30-V-0104	Recovered Water from 4th Stage KO Drum
Stream Number	Mol Wt	Units	126	127	128	129	130	131	132	133	134	135	136	137	138
Liquid Properties	Vapor Fraction (Mole)		0.0000	1.0000	1.0000	0.9794	0.0000	1.0000	1.0000	0.9910	0.0000	1.0000	1.0000	0.9958	0.0000
	Temperature	F	125	125	300	125	125	125	300	125	125	125	300	125	125
	Pressure	psia	53.1	53.1	128.3	118.3	118.3	118.3	270.5	260.5	260.5	260.5	633.2	623.2	623.2
	Mass Flow	lb/hr	6,767			3,435	3,435			1,480	1,480			686	686
	Molar Flow	lbmole/hr	375.0			189.9	189.9			81.5	81.5			37.5	37.5
	Volume Flow (actual)	USGPM	13.7			6.9	6.9			3.0	3.0			1.4	1.4
	Density	lb/ft3	61.6			61.7	61.7			61.8	61.8			62.0	62.0
	Viscosity	cP	0.54			0.54	0.54			0.53	0.53			0.53	0.53
	Thermal Conductivity	Btu/hr-ft-F	0.368			0.366	0.366			0.362	0.362			0.354	0.354
	Surface Tension	dyne/cm	67.5			67.4	67.4			67.2	67.2			66.8	66.8
	Molecular Weight		18.05			18.08	18.08			18.16	18.16			18.32	18.32
Vapor Properties	Mass Flow	lb/hr		396,836	396,836	393,401		393,401	393,401	391,920		391,920	391,920	391,234	
	Molar Flow	lbmole/hr		9,222.6	9,222.6	9,032.7		9,032.7	9,032.7	8,951.1		8,951.1	8,951.1	8,913.7	
	Volume Flow (standard)	MMSCFD		84.00	84.00	82.27		82.27	82.27	81.52		81.52	81.52	81.18	
	Density	lb/ft3		0.37	0.69	0.85		0.85	1.48	1.95		1.95	3.62	5.30	
	Compressibility			0.986	0.987	0.969		0.969	0.974	0.930		0.930	0.941	0.823	
	Viscosity	cP		0.016	0.021	0.017		0.017	0.021	0.017		0.017	0.022	0.018	
	Thermal Conductivity	Btu/hr-ft-F		0.011	0.015	0.011		0.011	0.016	0.011		0.011	0.017	0.013	
	Molecular Weight			43.03	43.03	43.55		43.55	43.55	43.78		43.78	43.78	43.89	
Compositions	O2	32.00	lbmole/hr	0.00	0.40	0.40	0.40	0.00	0.40	0.40	0.40	0.00	0.40	0.40	0.00
	N2	28.01	lbmole/hr	0.00	1.20	1.20	1.20	0.00	1.20	1.20	1.20	0.00	1.20	1.20	0.00
	H2O	18.02	lbmole/hr	374.54	347.12	347.12	347.12	189.44	157.68	157.68	157.68	81.08	76.60	76.60	37.03
	CO2	44.01	lbmole/hr	0.44	8,873.87	8,873.87	8,873.87	0.49	8,873.38	8,873.38	8,873.38	0.45	8,872.93	8,872.93	8,872.93
	SO2	64.06	lbmole/hr	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	NO2	46.01	lbmole/hr	0.00	0.03	0.03	0.03	0.00	0.03	0.03	0.03	0.00	0.03	0.03	0.00
	MEA	61.08	lbmole/hr	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	C1	16.04	lbmole/hr	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	C2	30.07	lbmole/hr	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	C3	44.09	lbmole/hr	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	nC4	58.12	lbmole/hr	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	nC5	72.15	lbmole/hr	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	nC6	86.17	lbmole/hr	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total			lbmole/hr	374.98	9,222.61	9,222.61	189.93	9,032.68	9,032.68	9,032.68	81.53	8,951.15	8,951.15	8,951.15	37.47
NOTES: 1. CO2 flow at each stage is split between 4 compressors that are operating in parallel. 2. 3.															

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Material Balance													
Stream Name			CO2 to 5th Compressor Stage	CO2 to 5th Stage Cooler 30-E-0105	CO2 to 5th Stage KO Drum 30-V-0105	Recovered Water from 5th Stage KO Drum	CO2 to Dehydration	Dry CO2 to 8th Compressor Stage	HP CO2 to Pipeline				
Stream Number	Mol Wt	Units	139	140	141	142	143	144	145				
Liquid Properties	Vapor Fraction (Mole)		1.0000	1.0000	0.9992	0.0000	1.0000	1.0000	1.0000				
	Temperature	F	125	213	125	125	125	123	125				
	Pressure	psia	623.2	1,000.0	990.0	990.0	990.0	970.0	2,214.7				
	Mass Flow	lb/hr			132	132							
	Molar Flow	lbmole/hr			7.1	7.1							
	Volume Flow (actual)	USGPM			0.3	0.3							
	Density	lb/ft3			62.1	62.1							
	Viscosity	cP			0.52	0.52							
	Thermal Conductivity	Btu/hr-ft-F			0.349	0.349							
	Surface Tension	dyne/cm			66.5	66.5							
Vapor Properties	Molecular Weight				18.43	18.43							
	Mass Flow	lb/hr	391,234	391,234	391,102		391,102	390,549	390,549				
	Molar Flow	lbmole/hr	8,913.7	8,913.7	8,906.5		8,906.5	8,875.8	8,875.8				
	Volume Flow (standard)	MMSCFD	81.18	81.18	81.12		81.12	80.84	80.84				
	Density	lb/ft3	5.30	7.22	9.98		9.98	9.78	37.05				
	Compressibility		0.823	0.842	0.694		0.694	0.698	0.419				
	Viscosity	cP	0.018	0.021	0.020		0.020	0.020	0.046				
	Thermal Conductivity	Btu/hr-ft-F	0.013	0.016	0.015		0.015	0.015	0.037				
	Molecular Weight		43.89	43.89	43.91		43.91	44.00	44.00				
Compositions	O2	32.00	lbmole/hr	0.40	0.40	0.40	0.00	0.40	0.40				
	N2	28.01	lbmole/hr	1.20	1.20	1.20	0.00	1.20	1.20				
	H2O	18.02	lbmole/hr	39.57	39.57	39.57	7.04	32.53	1.80				
	CO2	44.01	lbmole/hr	8,872.49	8,872.49	8,872.49	0.11	8,872.38	8,872.38				
	SO2	64.06	lbmole/hr	0.00	0.00	0.00	0.00	0.00	0.00				
	NO2	46.01	lbmole/hr	0.03	0.03	0.03	0.00	0.03	0.03				
	MEA	61.08	lbmole/hr	0.00	0.00	0.00	0.00	0.00	0.00				
	C1	16.04	lbmole/hr	0.00	0.00	0.00	0.00	0.00	0.00				
	C2	30.07	lbmole/hr	0.00	0.00	0.00	0.00	0.00	0.00				
	C3	44.09	lbmole/hr	0.00	0.00	0.00	0.00	0.00	0.00				
	nC4	58.12	lbmole/hr	0.00	0.00	0.00	0.00	0.00	0.00				
	nC5	72.15	lbmole/hr	0.00	0.00	0.00	0.00	0.00	0.00				
	nC6	86.17	lbmole/hr	0.00	0.00	0.00	0.00	0.00	0.00				
Total			255,369.03	8,913.68	8,913.68	7.15	8,906.53	8,875.80	8,875.80				
<div>NOTES:</div> <div>1. CO2 flow at each stage is split between 4 compressors that are operating in parallel.</div> <div>2.</div> <div>3.</div>													

APPENDIX 3-A
FEASIBILITY DRAWINGS
THRALL-AAGARD FIELD

Plot Date: 3/31/2010 4:09:04 PM Plot By: David Whorton File Name: W:\Blue Source LLC\02703 - CVR-TAF C02 Pipeline and Associated Facilities\CAD\PIPING\PF02703-F-001.dwg

REFERENCE DRAWINGS		REVISIONS								BLUE SOURCE, LLC.	
DWG. NO.	DESCRIPTION	NO.	DESCRIPTION	BY	DATE	CHK	DATE	APP	DATE	CVR-TAF C02 PIPELINE CAP C02 COMPRESSION FACILITY PROCESS FLOW DIAGRAM	
		B	ISSUED WITH FINAL FEED REPORT	DLW	2010/03/31	ALS	2010/03/31	ALS	2010/03/31	Rooney Engineering, Inc. 12201 E. Arapahoe Rd. C10 Centennial, CO 80112 (303) 792-5911	
		A	ISSUED FOR PRELIMINARY CLIENT REVIEW	DLW	2010/03/26	ALS	2010/03/26	ALS	2010/03/26		
										SCALE: NTS	DWG. NUMBER: 02703-F-001
											REV: B

Plot Date: 3/31/2010 4:33:25 PM Plot By: David Whorton File Name: W:\Blue Source LLC\02703 - CVR-TAF CO2 Pipeline and Associated Facilities\CAD\GENERAL\02703-G-0100.dwg

PLAN
SCALE 3/32"=1'-0"

REFERENCE DRAWINGS			REVISIONS									BLUW SOURCE, LLC.		
										CVR-TAF CO2 PIPELINE COFFEYVILLE REFINERY PLOT PLAN				
			B	ISSUED WITH FINAL FEED REPORT	DLW	2010/03/31	ALS	2010/03/31	ALS	2010/03/31	Rooney Engineering, Inc. 12201 E. Arapahoe Rd. C10 Centennial, CO 80112 (303) 792-5911	SCALE: AS SHOWN	DWG. NUMBER: 02703-G-0100	REV: B
			A	ISSUED FOR PRELIMINARY CLIENT REVIEW	DLW	2010/03/26	ALS	2010/03/26	ALS	2010/03/26				
DWG. NO.	DESCRIPTION		NO.	DESCRIPTION	BY	DATE	CHK	DATE	APP	DATE

Proposed CO2 Pipeline

Existing Pipelines

River

CVR-TAF

EOR Project Areas

Freshwater Emergent Wetland

Freshwater Forested/Shrub Wetland

Freshwater Pond

Lake

Other

MWW	ZB	HS	3/2/10	A	ISSUED FOR CLIENT REVIEW
DRAWN	CHECKED	APPROVED	DATE	REV NO.	DESCRIPTION

PREPARED BY:
ROONEY ENGINEERING, INC.
CENTENNIAL, COLORADO
303-792-8911

Integrated Mid-Centimeter Carbon Capture, Sequestration & Enhanced Oil Recovery Project

Coffeyville Resources Fertilizer Plant (CVR) to Thrall-Aagard Oil Field (TAF)

Overview Sheet 3 of 7

DRAWN: MWW

CHECKED: ZB

DATE: 3/2/2010

SCALE: AS SHOWN

2703-M-003

Legend					
	Proposed CO2 Pipeline		Existing Pipelines		River
	CVR-TAF		EOR Project Areas		Freshwater Emergent Wetland
			Freshwater Forested/Shrub Wetland		Freshwater Pond
			Lake		Other
MWW	ZB	HS	3/2/10	A	
DRAWN	CHECKED	APPROVED	DATE	REV NO.	DESCRIPTION

PREPARED BY:
ROONEY ENGINEERING, INC.
CENTENNIAL, COLORADO
303-792-8911

Integrated Mid-Centinel Carbon Capture, Sequestration & Enhanced Oil Recovery Project
Coffeyville Resources Fertilizer Plant (CVR) to Thrall-Aagard Oil Field (TAF)
Overview Sheet 6 of 7

DRAWN: MWW

CHECKED: ZB

DATE: 3/2/2010

SCALE: AS SHOWN

2703-M-006

[illegible]

LAND OWNERSHIP		PRIVATE																250+00	
WETLANDS AND FLOODPLAINS		RIPARIAN				RIPARIAN				RIPARIAN				RIPARIAN					
WILDLIFE, RARE SPECIES, CRITICAL HABITAT		EASTERN SPOTTED SKUNK CRITICAL HABITAT																	
LAND USE / VEGETATION		R		W	R		W	R		W	R		W	R	W	R			
OTHER RESTRICTIONS																			
SURVEY STATIONING		PI 23° LT STA. 737+44 N 1481383 E 2093363 PI 46° RT STA. 729+80 N 1480649 E 2093909 PI 11° LT STA. 724+64 N 1480863 E 2094425 PI 6° LT STA. 693+55 N 1480329 E 2097488 PI 68° LT STA. 673+70 N 1479793 E 2098400 PI 63° RT STA. 671+41 N 1479566 E 2098425 PI 4° LT STA. 651+77 N 1478865 E 2101280 WILLIAMS PIPELINE PI 4° RT STA. 631+20 N 1477992 E 2103122 PI 8° RT STA. 622+30 N 1477678 E 2103955 PI 50° LT STA. 620+31 N 1477834 E 2104150 PI 38° RT STA. 613+95 N 1477068 E 2104439 PI 23° RT STA. 602+63 N 1476609 E 2105474 PI 27° LT STA. 595+51 N 1476596 E 2106186 PI 29° RT STA. 582+26 N 1475979 E 2107358 PI 1° LT STA. 556+86 N 1476015 E 2108898 PI 1° RT STA. 542+38 N 1476008 E 2111345 PI 41° RT STA. 514+22 N 1476044 E 2114162 PI 89° LT STA. 498+10 STA. 500+59 N 1476958 E 2115173 (2) MAPCO PIPELINES																	
PLAN VIEW																			
COVER		4'		5'	4'		5'	4'		5'	4'	5'	4'		5'	4'	5'		
GROUND PROFILE																			
MATERIAL PIPE SPECIFICATION																			
GENERAL NOTES		1. ROONEY ENGINEERING, INC. AND/OR BLUE SOURCE, L.L.C. ARE NOT RESPONSIBLE FOR THE LOCATION OF THIRD-PARTY PIPELINES AND UTILITIES SHOWN ON THIS DRAWING. THIS INFORMATION IS PRESENTED ON A BEST-EFFORTS BASIS AND IS PROVIDED WITHOUT LIABILITY ON THE PART OF ROONEY ENGINEERING, INC. AND/OR BLUE SOURCE, L.L.C. FOR ANY DAMAGES RESULTING FROM ERRORS OR OMISSIONS IN THIS INFORMATION. 2. PRIOR TO COMMENCING ANY ACTIVITIES WHICH COULD IMPACT PIPELINES OR UTILITIES, CONTACT KANSAS ONE-CALL AT 1-800-DIG-SAFE. 3. THE LOCATION OF PIPELINES, UTILITIES, OVERHEAD ELECTRIC LINES AND OTHER BURIED OR ABOVE-GROUND FACILITIES ARE FOR REFERENCE ONLY. 4. COORDINATE SYSTEM: KANSAS STATE PLANE, NAD83, SOUTH ZONE, USFEET 5. AERIAL PHOTOGRAPHY: USDA 2008 NAIP																	
PIPE SPECIFICATIONS		TYPE DESCRIPTION LIN. FT. REV. NO. DESCRIPTION DWN CHKD DATE 1 8.625" x 0.500" W.T. API 5L X-65 ERW w/ 14-16 MILS FBE TBD A ISSUED FOR REVIEW MW ZB 3/3/10 2 8.625" X 0.500" W.T. API 5L X-65 SMLS w/ FBE & ARO TBD B ADDED ENVIRONMENTAL DATA MW ZB 3/23/10																	
REVISIONS		DWN CHKD DATE MW ZB 3/3/10 MW ZB 3/23/10																	
PREPARED BY ROONEY ENGINEERING CENTENNIAL, COLORADO		INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION & ENHANCED OIL RECOVERY PROJECT COFFEYVILLE RESOURCES FERTILIZER PLANT TO THRALL-AAGARD OIL FIELD STA. 500+00 TO STA. 750+00																	
SCALE: AS SHWN DATE PROJECT NO. DRAWING NO.		DWN BY: MW 3/3/10 CHKD BY: ZB 3/3/10 ENGR: HS 3/3/10																	
REVISION: B		2703-M-103

LAND OWNERSHIP	1250+00															PRIVATE															1000+00																		
	WETLANDS AND FLOODPLAINS															RIPARIAN										RIPARIAN										RIPARIAN													
	WILDLIFE, RARE SPECIES, CRITICAL HABITAT															EASTERN SPOTTED SKUNK CRITICAL HABITAT																																	
	LAND USE / VEGETATION															W		R			W		AG			R			W	R		W	AG			R			W	R	W	R		W		R			
	OTHER RESTRICTIONS																																																

SURVEY STATIONING	PI 30° LT STA. 1249+12 N 1492979 E 2045576	PI 22° RT STA. 1235+89 N 1492164 E 2046617	PI 18° RT STA. 1215+15 N 1491583 E 2046608	PI 13° RT STA. 1185+53 N 1491183 E 2051544	PI 7° LT STA. 1160+43 N 1490962 E 2054044	PI 4° LT STA. 1134+16 N 1490406 E 2056611	PI 66° LT STA. 1109+04 N 1489693 E 2059019	PI 55° RT STA. 1100+18 N 1488813 E 2059133	PI 22° RT STA. 1095+61 N 1488600 E 2059537	WILLIAMS PIPELINE STA. 1074+11 STA. 1070+76 STA. 1067+17 N 1488305 E 2062366	PI 10° LT STA. 1055+80 N 1487904 E 2063429	PI 29° RT STA. 1043+67 N 1487292 E 2064476	PI 12° LT STA. 1013+80 N 1487243 E 2067462
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GENERAL NOTES

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2. PRIOR TO COMMENCING ANY ACTIVITIES WHICH COULD IMPACT PIPELINES OR UTILITIES, CONTACT KANSAS ONE-CALL AT 1-800-DIG-SAFE.

3. THE LOCATION OF PIPELINES, UTILITIES, OVERHEAD ELECTRIC LINES AND OTHER BURIED OR ABOVE-GROUND FACILITIES ARE FOR REFERENCE ONLY.

4. COORDINATE SYSTEM: KANSAS STATE PLANE, NAD83, SOUTH ZONE, USFEET

5. AERIAL PHOTOGRAPHY: USDA 2008 NAIP

PIPE SPECIFICATIONS

TYPE	DESCRIPTION	LIN. FT.
1	8.625" x 0.500" W.T. API 5L X-65 ERW w/ 14-16 MILS FBE	TBD
2	8.625" X 0.500" W.T. API 5L X-65 SMLS w/ FBE & ARO	TBD

REVISIONS

REV. NO.	DESCRIPTION	DWN	CHKD	DATE
A	ISSUED FOR REVIEW	MW	ZB	3/3/10
B	ADDED ENVIRONMENTAL DATA	MW	ZB	3/23/10

PREPARED BY
ROONEY ENGINEERING
CENTENNIAL, COLORADO

Blue Source

INTEGRATED MID-CONTINENT CARBON CAPTURE,
SEQUESTRATION & ENHANCED OIL
RECOVERY PROJECT
COFFEYVILLE RESOURCES FERTILIZER PLANT TO
THRALL-AAGARD OIL FIELD
STA. 1000+00 TO STA. 1250+00

SCALE:	AS SHWN	DATE	PROJECT NO.	DRAWING NO.
DWN BY:	MW	3/3/10		2703-M-105
CHKD BY:	ZB	3/3/10		
ENGR:	HS	3/3/10		

Appendix 3-16

PREPARED BY ROONEY ENGINEERING, INC. PL017ED - 03092010 11:36:21 AM

F:\Projects\02703 - Blue Source CTR-TAP\Mapping\Alignments\2703-M-105.dgn

LAND OWNERSHIP		PRIVATE												1500+00																			
WETLANDS AND FLOODPLAINS		RIPARIAN			RIPARIAN			RIPARIAN			RIPARIAN																						
WILDLIFE, RARE SPECIES, CRITICAL HABITAT		EASTERN SPOTTED SKUNK CRITICAL HABITAT																															
LAND USE / VEGETATION		W	R	W	R	AG	W	AG	W	AG	R	W	R																				
OTHER RESTRICTIONS																																	
SURVEY STATIONING		PI 151° RT STA. 1739+53 N 1501588 E 2000007 PI 4° RT STA. 1722+40 N 1502378 E 2001528 PI 31° LT STA. 1715+47 N 1502742 E 2002117 PI 19° LT STA. 1707+82 N 1502754 E 2002882 STA. 1704+60 N 1502652 E 2003188 PI 19° LT STA. 1691+90 N 1502763 E 2004452 PI 14° LT STA. 1673+14 N 1502313 E 2006274 PI 17° RT STA. 1659+38 N 1501670 E 2007491 PI 2° RT STA. 1646+51 N 1501432 E 2008755 PI 7° LT STA. 1617+91 N 1501023 E 2011586 PI 10° RT STA. 1605+32 N 1500892 E 2012801 PI 10° LT STA. 1598+51 N 1500630 E 2013479 PI 29° LT STA. 1589+16 N 1500378 E 2014380 STA. 1584+47 N 1500050 E 2014715 PI 11° RT STA. 1576+76 N 1499851 E 2015459 PI 50° LT STA. 1543+63 N 1499599 E 2018763 STA. 1539+43 N 1499257 E 2019005 PI 65° RT																															
PLAN VIEW																																	
GROUND PROFILE																																	
MATERIAL PIPE SPECIFICATION																																	
GENERAL NOTES		<p>1. ROONEY ENGINEERING, INC. AND/OR BLUE SOURCE, L.L.C. ARE NOT RESPONSIBLE FOR THE LOCATION OF THIRD-PARTY PIPELINES AND UTILITIES SHOWN ON THIS DRAWING. THIS INFORMATION IS PRESENTED ON A BEST-EFFORTS BASIS AND IS PROVIDED WITHOUT LIABILITY ON THE PART OF ROONEY ENGINEERING, INC. AND/OR BLUE SOURCE, L.L.C. FOR ANY DAMAGES RESULTING FROM ERRORS OR OMISSIONS IN THIS INFORMATION.</p> <p>2. PRIOR TO COMMENCING ANY ACTIVITIES WHICH COULD IMPACT PIPELINES OR UTILITIES, CONTACT KANSAS ONE-CALL AT 1-800-DIG-SAFE.</p> <p>3. THE LOCATION OF PIPELINES, UTILITIES, OVERHEAD ELECTRIC LINES AND OTHER BURIED OR ABOVE-GROUND FACILITIES ARE FOR REFERENCE ONLY.</p> <p>4. COORDINATE SYSTEM: KANSAS STATE PLANE, NAD83, SOUTH ZONE, USFEET</p> <p>5. AERIAL PHOTOGRAPHY: USDA 2008 NAIP</p>																															
PIPE SPECIFICATIONS		<table><tr><th>TYPE</th><th>DESCRIPTION</th><th>LIN. FT.</th></tr><tr><td>1</td><td>8.625" x 0.500" W.T. API 5L X-65 ERW w/ 14-16 MILS FBE</td><td>TBD</td></tr><tr><td>2</td><td>8.625" X 0.500" W.T. API 5L X-65 SMLS w/ FBE & ARO</td><td>TBD</td></tr></table>												TYPE	DESCRIPTION	LIN. FT.	1	8.625" x 0.500" W.T. API 5L X-65 ERW w/ 14-16 MILS FBE	TBD	2	8.625" X 0.500" W.T. API 5L X-65 SMLS w/ FBE & ARO	TBD											
TYPE	DESCRIPTION	LIN. FT.																															
1	8.625" x 0.500" W.T. API 5L X-65 ERW w/ 14-16 MILS FBE	TBD																															
2	8.625" X 0.500" W.T. API 5L X-65 SMLS w/ FBE & ARO	TBD																															
REVISIONS		<table><tr><th>REV. NO.</th><th>DESCRIPTION</th><th>DWN</th><th>CHKD</th><th>DATE</th></tr><tr><td>A</td><td>ISSUED FOR REVIEW</td><td>MW</td><td>ZB</td><td>3/3/10</td></tr><tr><td>B</td><td>ADDED ENVIRONMENTAL DATA</td><td>MW</td><td>AB</td><td>3/23/10</td></tr></table>												REV. NO.	DESCRIPTION	DWN	CHKD	DATE	A	ISSUED FOR REVIEW	MW	ZB	3/3/10	B	ADDED ENVIRONMENTAL DATA	MW	AB	3/23/10					
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Blue Source		<p>INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION & ENHANCED OIL RECOVERY PROJECT</p> <p>COFFEYVILLE RESOURCES FERTILIZER PLANT TO THRALL-AAGARD OIL FIELD</p> <p>STA. 1500+00 TO STA. 1750+00</p>																															
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SCALE:	AS SHWN	DATE	PROJECT NO.	DRAWING NO.																													
DWN BY:	MW	3/3/10		2703-M-107																													
CHKD BY:	ZB	3/3/10																															
ENGR:	HS	3/3/10

LAND OWNERSHIP		2250+00		PRIVATE		2000+00	
WETLANDS AND FLOODPLAINS							
WILDLIFE, RARE SPECIES, CRITICAL HABITAT				GREATER PRAIRIE CHICKEN RANGE, EASTERN SPOTTED SKUNK CRITICAL HABITAT			
LAND USE / VEGETATION				R			
OTHER RESTRICTIONS							

SURVEY STATIONING		PI 15° RT STA. 2233+02 N 1524300 E 1959974	PI 14° RT STA. 2176+72 N 1521940 E 1964085	PI 13° LT STA. 2144+94 N 1520805 E 1967054	PI 17° LT STA. 2132+07 N 1520273 E 1969226	PI 22° LT STA. 2095+65 N 1518401 E 1971350	PI 1° RT STA. 2076+08 N 1516836 E 1972525	PI 46° RT STA. 2053+20 N 1515039 E 1973941	PI 40° LT STA. 2046+67 N 1514976 E 1974591
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	<div>GENERAL NOTES</div> <div>1. ROONEY ENGINEERING, INC. AND/OR BLUE SOURCE, L.L.C. ARE NOT RESPONSIBLE FOR THE LOCATION OF THIRD-PARTY PIPELINES AND UTILITIES SHOWN ON THIS DRAWING. THIS INFORMATION IS PRESENTED ON A BEST-EFFORTS BASIS AND IS PROVIDED WITHOUT LIABILITY ON THE PART OF ROONEY ENGINEERING, INC. AND/OR BLUE SOURCE, L.L.C. FOR ANY DAMAGES RESULTING FROM ERRORS OR OMISSIONS IN THIS INFORMATION. 2. PRIOR TO COMMENCING ANY ACTIVITIES WHICH COULD IMPACT PIPELINES OR UTILITIES, CONTACT KANSAS ONE-CALL AT 1-800-DIG-SAFE. 3. THE LOCATION OF PIPELINES, UTILITIES, OVERHEAD ELECTRIC LINES AND OTHER BURIED OR ABOVE-GROUND FACILITIES ARE FOR REFERENCE ONLY. 4. COORDINATE SYSTEM: KANSAS STATE PLANE, NAD83, SOUTH ZONE, USFEET 5. AERIAL PHOTOGRAPHY: USDA 2008 NAIP</div> <div> </div>	<div>PIPE SPECIFICATIONS</div> <table><thead><tr><th>TYPE</th><th>DESCRIPTION</th><th>LIN. FT.</th></tr></thead><tbody><tr><td>1</td><td>8.625" x 0.500" W.T. API 5L X-65 ERW w/ 14-16 MILS FBE</td><td>TBD</td></tr><tr><td>2</td><td>8.625" X 0.500" W.T. API 5L X-65 SMLS w/ FBE & ARO</td><td>TBD</td></tr><tr><td></td><td></td><td></td></tr><tr><td></td><td></td><td></td></tr><tr><td></td><td></td><td></td></tr><tr><td></td><td></td><td></td></tr><tr><td></td><td></td><td></td></tr><tr><td></td><td></td><td></td></tr><tr><td></td><td></td><td></td></tr></tbody></table>	TYPE	DESCRIPTION	LIN. FT.	1	8.625" x 0.500" W.T. API 5L X-65 ERW w/ 14-16 MILS FBE	TBD	2	8.625" X 0.500" W.T. API 5L X-65 SMLS w/ FBE & ARO	TBD																						<div>REVISIONS</div> <table><thead><tr><th>REV. NO.</th><th>DESCRIPTION</th><th>DWN</th><th>CHKD</th><th>DATE</th></tr></thead><tbody><tr><td>A</td><td>ISSUED FOR REVIEW</td><td>MW</td><td>ZB</td><td>3/3/10</td></tr><tr><td>B</td><td>ADDED ENVIRONMENTAL DATA</td><td>MW</td><td>ZB</td><td>3/23/10</td></tr><tr><td></td><td></td><td></td><td></td><td></td></tr><tr><td></td><td></td><td></td><td></td><td></td></tr><tr><td></td><td></td><td></td><td></td><td></td></tr><tr><td></td><td></td><td></td><td></td><td></td></tr><tr><td></td><td></td><td></td><td></td><td></td></tr></tbody></table>	REV. NO.	DESCRIPTION	DWN	CHKD	DATE	A	ISSUED FOR REVIEW	MW	ZB	3/3/10	B	ADDED ENVIRONMENTAL DATA	MW	ZB	3/23/10																										<div>PREPARED BY ROONEY ENGINEERING CENTENNIAL, COLORADO</div> <div> Blue Source</div> <div>INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION & ENHANCED OIL RECOVERY PROJECT COFFEYVILLE RESOURCES FERTILIZER PLANT TO THRALL-AAGARD OIL FIELD STA. 2000+00 TO STA. 2250+00</div> <div><table><tr><td>SCALE:</td><td>AS SHWN</td><td>DATE</td><td>PROJECT NO.</td><td>DRAWING NO.</td></tr><tr><td>DWN BY:</td><td>MW</td><td>3/3/10</td><td rowspan="2"></td><td rowspan="2">2703-M-109</td></tr><tr><td>CHKD BY:</td><td>ZB</td><td>3/3/10</td></tr><tr><td>ENGR:</td><td>HS</td><td>3/3/10</td><td>REVISION:</td><td>B</td></tr></table></div>	SCALE:	AS SHWN	DATE	PROJECT NO.	DRAWING NO.	DWN BY:	MW	3/3/10		2703-M-109	CHKD BY:	ZB	3/3/10	ENGR:	HS	3/3/10	REVISION:	B
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CHKD BY:	ZB	3/3/10																																																																																										
ENGR:	HS	3/3/10	REVISION:	B																																																																																								

LAND OWNERSHIP		PRIVATE										3000+00		2750+00	
WETLANDS AND FLOODPLAINS		RIPARIAN										RIPARIAN		RIPARIAN	
WILDLIFE, RARE SPECIES, CRITICAL HABITAT		GREATER PRAIRIE CHICKEN RANGE										GREATER PRAIRIE CHICKEN RANGE EASTERN SPOTTED SKUNK CRITICAL HABITAT			
LAND USE / VEGETATION		W		R		W		R		W		R		W	
OTHER RESTRICTIONS															
SURVEY STATIONING		PI 2" LT STA. 2966+98 N 1559139 E 1892783 PI 4" LT STA. 2956+34 N 1557584 E 1895424 PI 8" RT STA. 2950+77 N 1557265 E 1895880 PI 2" LT STA. 2926+43 N 1556164 E 1898052 PI 4" RT STA. 2916+00 N 1555861 E 1898965 PI 24" RT STA. 2871+92 N 1553800 E 1902961 PI 21" LT STA. 2870+45 N 1553797 E 1903108 PI 5" LT STA. 2859+56 N 1553384 E 1904115 PI 5" RT STA. 2846+86 N 1552811 E 1905249 PI 5" LT STA. 2839+57 N 1552537 E 1905924 PI 2" RT STA. 2833+68 N 1552269 E 1906449 WILLIAMS PIPELINE STA. 2793+12 PI 4" LT STA. 2785+62 N 1550247 E 1910808 PI 1" LT STA. 2767+73 N 1549370 E 1912368													
PLAN VIEW															
COVER		4' 5' 4' 5' 4' 5' 4' 5' 4' 5' 4' 5' 4' 5'													
GROUND PROFILE															
MATERIAL PIPE SPECIFICATION															
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PIPE SPECIFICATIONS		TYPE DESCRIPTION LIN. FT. REV. NO. DESCRIPTION DWN CHKD DATE 1 8.625\"/>													
REVISIONS		REV. NO. DESCRIPTION DWN CHKD DATE A ISSUED FOR REVIEW MW ZB 3/3/10 B ADDED NWI DATA MW ZB 3/8/10 C ADDED ENVIRONMENTAL DATA MW ZB 3/23/10													
PREPARED BY ROONEY ENGINEERING CENTENNIAL, COLORADO		INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION & ENHANCED OIL RECOVERY PROJECT COFFEYVILLE RESOURCES FERTILIZER PLANT TO THRALL-AAGARD OIL FIELD STA. 2750+00 TO STA. 3000+00 SCALE: AS SHWN DATE PROJECT NO. DRAWING NO. DWN BY: MW 3/3/10 2703-M-112 CHKD BY: ZB 3/3/10 REVISION: ENGR: HS 3/3/10													

LAND OWNERSHIP		3100+00	PRIVATE	3000+00	
WETLANDS AND FLOODPLAINS				RIPARIAN	
WILDLIFE, RARE SPECIES, CRITICAL HABITAT			GREATER PRAIRIE CHICKEN RANGE		
LAND USE / VEGETATION			R	W	
OTHER RESTRICTIONS					

SURVEY STATIONING		PI 85° RT	PI 14° LT	PI 2° RT	PI 6° LT
		STA. 3094+46 N 1563670 E 1883050	STA. 3086+21 N 1563382 E 1883823	STA. 3040+85 N 1561496 E 1887948	STA. 3018+24 N 1560627 E 1890035

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LAND OWNERSHIP		3250+00	PRIVATE	3100+00
WETLANDS AND FLOODPLAINS	RIPARIAN		GREATER PRAIRIE CHICKEN RANGE	
WILDLIFE, RARE SPECIES, CRITICAL HABITAT				
LAND USE / VEGETATION			R	
OTHER RESTRICTIONS				

SURVEY STATIONING		PI 6° RT STA. 3247+39 N 1576411 E 1886699	PI 6° LT STA. 3224+24 N 1576127 E 1886319	PI 1° RT STA. 3190+41 N 1572659 E 1886447	PI 2° LT STA. 3165+07 N 1570399 E 1884838	QUEST (KPC) PIPELINE PI 90° LT STA. 3163+23 STA. 3162+73 N 1570243 E 1884898
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LAND OWNERSHIP		3500+00	PRIVATE	3250+00
WETLANDS AND FLOODPLAINS				
WILDLIFE, RARE SPECIES, CRITICAL HABITAT			GREATER PRAIRIE CHICKEN RANGE	
LAND USE / VEGETATION			R	
OTHER RESTRICTIONS				

SURVEY STATIONING		PI 1° RT STA. 3463+49 N 1599405 E 1891791	PI 2° RT STA. 3413+21 N 1594511 E 1890639	PI 3° LT STA. 3372+71 N 1590536 E 1889862	PI 2° LT STA. 3299+16 N 1583395 E 1889097
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COVER	4'
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MATERIAL PIPE SPECIFICATION	8.625" X 0.500" W.T. API 5L X-65 ERW w/ 14-16 MILS FBE
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LAND OWNERSHIP		3750+00	PRIVATE	3500+00
WETLANDS AND FLOODPLAINS				
WILDLIFE, RARE SPECIES, CRITICAL HABITAT			GREATER PRAIRIE CHICKEN RANGE	FRESHWATER EMERGENT WETLAND
LAND USE / VEGETATION			R	
OTHER RESTRICTIONS				

SURVEY STATIONING				PI 2° LT STA. 3559+20 N 160805 E 1894082
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COVER		4'
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LAND OWNERSHIP		4250+00	PRIVATE	4000+00
WETLANDS AND FLOODPLAINS			RIPARIAN	
WILDLIFE, RARE SPECIES, CRITICAL HABITAT			GREATER PRAIRIE CHICKEN RANGE	
LAND USE / VEGETATION				
OTHER RESTRICTIONS				

SURVEY STATIONING		PI 1° LT STA. 4239+84 N 1674897 E 1908875	PI 6° RT STA. 4159+33 N 1667354 E 1906060	PI 3° RT STA. 4060+13 N 1657667 E 1903832	PI 11° LT STA. 4040+92 N 1655797 E 1903490	PI 7° RT STA. 4001+78 N 1652138 E 1902101
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COVER	4'	5'	4'	5'	4'	5'	4'
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			GENERAL NOTES			PIPE SPECIFICATIONS			REVISIONS				PREPARED BY ROONEY ENGINEERING CENTENNIAL, COLORADO	Blue Source INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION & ENHANCED OIL RECOVERY PROJECT COFFEYVILLE RESOURCES FERTILIZER PLANT TO THRALL-AAGARD OIL FIELD STA. 4000+00 TO STA. 4250+00			
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											REVISION:	B

PREPARED BY ROONEY ENGINEERING, INC. PLOTTED: 2/28/2010 11:46:17 AM
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LAND OWNERSHIP		5250+00	PRIVATE												5000+00			
WETLANDS AND FLOODPLAINS			FRESHWATER POND	GREATER PRAIRIE CHICKEN RANGE						RIVERINE, RIPARIAN		RIVERINE, RIPARIAN		RIPARIAN				
WILDLIFE, RARE SPECIES, CRITICAL HABITAT																		
LAND USE / VEGETATION			R						AG	W	R		W	R		W	R	
OTHER RESTRICTIONS																		

SURVEY STATIONING	
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		GENERAL NOTES		PIPE SPECIFICATIONS		REVISIONS				<div>PREPARED BY ROONEY ENGINEERING CENTENNIAL, COLORADO</div> <div> Blue Source</div> <div>INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION & ENHANCED OIL RECOVERY PROJECT COFFEYVILLE RESOURCES FERTILIZER PLANT TO THRALL-AAGARD OIL FIELD STA. 5000+00 TO STA. 5250+00</div> <table><tr><td>SCALE:</td><td>AS SHWN</td><td>DATE</td><td>PROJECT NO.</td><td>DRAWING NO.</td></tr><tr><td>DWN BY:</td><td>MW</td><td>3/3/10</td><td rowspan="3"></td><td>2703-M-122</td></tr><tr><td>CHKD BY:</td><td>ZB</td><td>3/3/10</td></tr><tr><td>ENGR:</td><td>HS</td><td>3/3/10</td><td>REVISION:</td><td>C</td></tr></table>	SCALE:	AS SHWN	DATE	PROJECT NO.	DRAWING NO.	DWN BY:	MW	3/3/10		2703-M-122	CHKD BY:	ZB	3/3/10	ENGR:	HS	3/3/10	REVISION:	C
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LAND OWNERSHIP		5590+00	PRIVATE	5500+00	
WETLANDS AND FLOODPLAINS			RIPARIAN		
WILDLIFE, RARE SPECIES, CRITICAL HABITAT			GREATER PRAIRIE CHICKEN RANGE		
LAND USE / VEGETATION			R		
OTHER RESTRICTIONS					

SURVEY STATIONING			P13° RT	P16° LT	
			STA. 5544+32 N 1801669 E 1939265	STA. 5521+88 N 1799465 E 1937847

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LAND OWNERSHIP		5712+32		PRIVATE		5590+00
WETLANDS AND FLOODPLAINS					FRESHWATER EMERGENT WETLAND	
WILDLIFE, RARE SPECIES, CRITICAL HABITAT				GRAND PRAIRIE CHICKEN RANGE		
LAND USE / VEGETATION				R		
OTHER RESTRICTIONS						

SURVEY STATIONING		FOREIGN PIPELINE PI 74° RT		PI 13° RT		PI 19° LT		PI 12° RT		PI 12° LT		PI 84° LT
		STA. 5711+84 STA. 5711+31 N 1809813 E 1928667		STA. 5673+07 N 1908873 E 1932374		STA. 5633+07 N 1903095 E 1936296		STA. 5618+17 N 1907564 E 1937691		STA. 5603+89 N 1907118 E 1939048		STA. 5598+50 N 1906932 E 1939554

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					C	ADDED ENVIRONMENTAL DATA	MW	ZB	3/23/10																						

APPENDIX 3-B

COFFEYVILLE RESOURCE FERTILIZER PLANT
CO₂ COMPOSITIONAL ANALYSIS

THRALL-AAGARD FIELD

① Proposed take off location for CAP CO₂, LLC.

Changes:

1. Modify current 5-E-103/5-E-105 Exchanger to allow room for 20 rich take off.

2. Install PIC valve to hold back pressure of 2 psig upstream of 5-E-105.

Stream ID	65	CO ₂ Recovery
Temp of	2	
Pressure psig	192,942	
Mass Flow, lbs/hr	43,96	
Avg. Mol. weight		
Component	Mol wt	#-mole/hr
CO ₂	44.01	4382.80
H ₂ S	34.08	
Methane	16.04	.13
Water	18.02	2.63
Nitrogen	28.01	
Carbon monoxide	28.01	.44
Hydrogen	2.02	3.07
Argon	39.95	.18
OXYGEN	32	
COS	60.07	.09
TOTAL		4389.34

APPENDIX 3-C
PIPELINE HYDRAULIC CHARTS
THRALL-AAGARD FIELD

CVR-TAF Pipeline
8" x 0.500" WT Grade X-65 Pipeline at 40 MMSCFD - No Booster Stations

CVR-TAF Pipeline
10" x 0.438" WT Grade X-65 Pipeline at 40 MMSCFD - No Booster Stations

CVR-TAF Pipeline

12" x 0.375" WT Grade X-65 Pipeline at 40 MMSCFD - No Booster Stations

APPENDIX 3-D
PIPELINE ESTIMATE
THRALL-AAGARD FIELD

**INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION &
ENHANCED OIL RECOVERY PROJECT**

**Coffeyville Resources Nitrogen Fertilizer Plant (CVR) to
Thrall-Aagard Oil Field (TAF)**

ESTIMATE BASIS MEMORANDUM

A	Issued for Client Review					
MARK	DESCRIPTION	BY	CHKD	APVD	CLIENT APVD	DATE
REVISIONS						
CLIENT:	Blue Source					
PROJECT:	Coffeyville Resources Nitrogen Fertilizer Plant (CVR) to Thrall-Aagard Oil Field (TAF) Carbon Dioxide Pipeline Desktop Study					
JOB NO.:	02703					
DOC. NO.:	02703-DESKTOP-002

Coffeyville Resources Nitrogen Fertilizer Plant to Thrall-Aagard Oil Field

Date:	3/26/2010	PIPELINE SYSTEMS ESTIMATE BASIS	Doc. No.: 02703-DESKTOP-002
Rev:	A		Page: 2 of 9

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Coffeyville Resources Nitrogen Fertilizer Plant to Thrall-Aagard Oil Field

Date:	3/26/2010	PIPELINE SYSTEMS ESTIMATE BASIS	Doc. No.: 02703-DESKTOP-002
Rev:	A		Page: 3 of 9

1. PURPOSE

This estimate was prepared to provide budgetary cost information to design and construct the Coffeyville Resources Fertilizer Plant (CVR) to the Thrall-Aagard Oil Field (TAF) pipeline.

The CVR-TAF pipeline is a 108.2 mile, 8.625 inch in diameter steel pipeline to transport CO₂ from the Coffeyville Resources Fertilizer Plant (CVR) to the Thrall-Aagard Oil Field (TAF). A 15,000 BHP compression facility is proposed at the pipeline origination. A fiber optic communication system is proposed to facilitate the Supervisory Control and Data Acquisition (SCADA) system.

This estimate is comparable to an Association for the Advancement of Cost Engineering (AACE) Class 2 Estimate, with an expected accuracy range of +30%/-15%. A Class 2 estimate corresponds with 30% to 70% project definition, using primarily deterministic methodology. (See AACE Recommended Practice No. 17R-97 "Cost Estimate Classification Systems.")

The capital expenditure cost estimate addresses the pipeline systems, compression facility, and communication systems and includes material, engineering, procurement assistance, procurement inspection, right-of-way acquisition, right-of-way damages, cathodic protection, construction permitting, construction costs, construction management, survey, x-ray, construction inspection, commissioning, and start-up portions of the project.

2. SCOPE

The purpose of the CVR-TAF Pipeline is to transport compressed high-purity carbon dioxide via a 4" steel intra-state pipeline from the Coffeyville Resources Fertilizer Plant to the Thrall-Aagard Oil Field for both sequestration and enhanced oil recovery purposes.

The pipeline will be designed, constructed and operated in accordance to Title 49, Part 195, "Transportation of Hazardous Liquids by Pipeline," the Department Of Transportation rules and regulations.

The pipeline will be composed of approximately 108.2 miles of 8.625" O.D., 0.500" wall thickness, API5L, PSL2, Electric Resistance Welded (ERW) steel line pipe, coated with 14-16 mils of Fusion Bond Epoxy for corrosion protection. The pipeline will be designed to be operated at a Maximum Operating Pressure of 2,800 PSIG, with an ANSI 1500 flange rating.

All road, railroad and creek crossing pipes will be manufactured to Seamless line pipe specifications instead of ERW to further mitigate fracture propagation.

Carbon Dioxide must be compressed to approximately 2,548 PSIG at the Coffeyville Resources Fertilizer Plant in order to deliver it to the Thrall-Aagard Oil Field at 1,400 PSIG. These operating pressures were utilized to provide a reasonable margin between the operating pressures in the pipeline and the critical pressure of carbon dioxide, which is approximately 1,100 PSIA at 50 °F. Operating at pressures above the critical pressure ensures that the carbon dioxide is transported in the dense phase and that no phase changes occur in the pipeline system. Transporting carbon dioxide in dense-phase is the most efficient means of transportation since it allows for smaller pipeline sizes at high flow rates.

Eighteen (18) Isolation Block Valves will be strategically located in the pipeline system to isolate the pipeline and blow the Carbon Dioxide down in case of an emergency. Valve connections for two future pipeline booster stations will be located at Mile Post 36 and Mile Post 72.

Crack arrestor will be installed at every half mile on the 8.625" O.D. Steel Pipeline to mitigate fracture propagation. Clock Spring type crack arrestors were used in the cost estimate.

Coffeyville Resources Nitrogen Fertilizer Plant to Thrall-Aagard Oil Field

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The pipeline will be designed and constructed to accommodate intelligent pigs. Pig launcher and receiver will be installed into the system

The Engineering, procurement assistance, procurement inspection, right-of-way acquisition, right-of-way damages, cathodic protection, construction permitting, construction costs, construction management, survey, x-ray, construction inspection, commissioning, and start-up portions of the project involve the following work which was included in the estimate (see estimated quantities in the Capital Cost Estimate spreadsheet):

- ◆ Detailed Engineering for the project to include project calculations, P&ID Drawings, PFD Drawings, Piping Drawings, Alignment Sheet Drawings, Material Sheet Drawings, Road and Creek Crossing Detail Drawings, Ditch Detail Drawings, and project specifications.
- ◆ Procurement support for the project to include providing quotation packages, technical evaluation and recommendation, material inspection services, and material expediting.
- ◆ Construction Management, including progress tracking, contractor communication, construction inspection, survey, and x-ray.
- ◆ Surveyors to stake construction work areas and pipeline centerline. Surveyors shall gather required as-built information throughout the duration of construction.
- ◆ NDE (X-Ray) including material and labor to x-ray the entire circumference of 100% of all girth welds.
- ◆ Assemble Job Books and prepare As Built Drawings.

The construction of the above pipeline involves the following work which was included in the estimate (see estimated quantities in the Capital Cost Estimate spreadsheet):

- a) Mobilize to job site – located near Coffeyville, Kansas.
- b) Train all personnel in site safety and environmental requirements.
- c) Notify all underground utility and service providers, and abide by all their requirements.
- d) Company shall provide survey subcontractor. Surveyors will stake construction work areas and pipeline centerline. Surveyors shall gather the required as-built information throughout the duration of construction.
- e) Company will provide 75' wide construction work area for the construction of the pipeline and 300' x 300' work area on each side of each crossing.
- f) Company will provide one lay down yard for the project, strategically located for construction.
- g) Line pipe shall be delivered to the right-of-way by trucks – Contractor shall string pipe onto the right-of-way from the stringing trucks
- h) Access, clear and grade right-of-way to enable the crews to access and work on the right-of-way.
- i) Topsoil separation, storage and replacement of the ditch line and spoil in all construction areas.
- j) Install 8" buried (with risers) isolation block valves and valves for future booster stations.
- k) Perform field bending, align and weld pipe – Company will provide welding procedures.
- l) Install Company provided Clock Spring, Crack Arrestors (CS-130-04) which are 12" wide, 12 wraps each. Two Clock Springs will be installed next to each other. Clock Spring Crack Arrestors will be installed every ½ mile on the pipeline for a total of 30 locations (install two clock springs next to each other)

Coffeyville Resources Nitrogen Fertilizer Plant to Thrall-Aagard Oil Field

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- m) Company shall provide NDE (X-Ray) subcontractor - who will provide material and labor to x-ray the entire circumference of 100% of all girth welds.
- n) Apply Two (2) part Epoxy or Shrink Sleeves to the girth welds.
- o) Holiday test (Jeep) the FBE steel coated pipe. Contractor to supply patch sticks for the repair of the FBE.
- p) Ditch along the Right-of-way
- q) Contractor to provide equipment to pad and shade all pipe - Pad and shade with 6" (bottom of pipe) and 6" (above the pipe) of $\frac{3}{4}$ " minus material.
- r) Install fiber optic armored cable, hand-holes and pull boxes.
- s) Total pipe cover shall be 48" minimum. Cover at road crossings shall be 60" minimum.
- t) Install pipeline Company supplied markers.
- u) Install Company supplied cathodic protection test stations. Contractor to provide all wires and cad welds necessary for the installation of the test stations.
- v) Prepare hydrostatic test plan for the pipelines and submit to engineer for approval, run air swab, cleaning and gauging pigs (only soft pigs will be run in the HDPE lined pipelines), fill and dispose of test water, provide and fill the pipelines with clean water, successfully hydrostatically test the pipelines for a minimum of 8 hours and dispose of water. Contractor to provide all required pigs.
- w) Company will acquire permits for acquiring and disposing hydrostatic test water. Source and disposal site for the Hydro water will be within 50 miles of the job site.
- x) The 8" steel pipelines will be tested to 125% of MOP – minimum test pressure shall be 3500 PSIG
- y) Continuous clean up of right-of-way to the satisfaction of Company and landowner, make all necessary permanent repairs to gates and fences.
- z) Required re-seeding and re-vegetation will be by Company.
- aa) Demobilize from job site.

3. CONSTRUCTION APPROACH

It was assumed that the Right Of Way areas would be accessible to the contractor's equipment at all times during construction, and that the contractor would not have to compete for space to place spoils, pipeline materials or working crews.

4. QUANTITY BASIS

Pipe quantities were measured from preliminary routing from aerial photography, as shown on the preliminary Alignment Sheet Drawings.

Large diameter valve quantities were estimated based on the quantities shown on the preliminary Alignment Sheet Drawings.

Pig trap assembly quantities were estimated based on the quantities shown on the preliminary Alignment Sheet Drawings.

Quantity for all other material and construction quantities were estimated from Rooney Engineering's experience with similar pipeline systems, and from construction contractor input.

Coffeyville Resources Nitrogen Fertilizer Plant to Thrall-Aagard Oil Field

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A centrifugal compressor / pump package was selected from GE at 100% of the design flowrate. No redundancy was selected based on the high reliability and low expected maintenance of centrifugal compressors.

5. PRICING BASIS

The pricing for material in this estimate was derived from budgetary quotation pricing. Construction pricing is based on budgetary quotes provided by a contractor with experience in construction similar to that required for this project. The following items were priced based on budgetary quotations from vendors or were estimated based on a scale factor applied to quotations to adjust for the current scope of work. If multiple quotations were received, pricing was normalized and averaged.

Pipeline

- ◆ Steel Line Pipe and Fusion Bond Epoxy (FBE) Coating – Current budgetary quotations were received from Edgen Murray and McJunkin Red Man.
- ◆ Abrasive Resistant Outer (ARO) Line Pipe Coatings – Pricing from other recent projects was utilized.
- ◆ Valves and Actuators – Current budgetary quotations were received from Cameron.
- ◆ Pipeline Fittings and Flanges – Current budgetary quotations were received from Edgen Murray and McJunkin Red Man.
- ◆ Fabricated Assemblies (Pig Traps) – Current budgetary quotations were received from Sagebrush and PECO.
- ◆ Miscellaneous Materials (e.g. Clock Springs, Cathodic Test Stations, Shrink Sleeves, Pipeline Markers) – Current budgetary quotations were received from Hoff Company.
- ◆ Pipeline Construction and Site Construction (e.g. Road Bores, Cathodic Test Station Installation) and associated materials (e.g. Hay Bales, Silt Fence). – A site specific construction budgetary estimate was received from Jomax, who has completed many projects in and around Kansas.

Compression Facility

- ◆ Compressor Packages – Current budgetary quotations were received from Exterran, UE Compression, and GE Oil and Gas.
- ◆ Pump Packages – Current budgetary quotations were received from Sulzer and GE Oil and Gas.
- ◆ Dehydration Package – Current budgetary quotations were received from QB Johnson and Exterran.
- ◆ Scrubbers – Pricing from other recent projects was utilized.
- ◆ Orifice Meter – Pricing from other recent projects was utilized.
- ◆ Compressor Building – Recent cost per square foot pricing from Tri-State Insulation was utilized.
- ◆ Flow Control Valves – Pricing from other recent projects was utilized.
- ◆ Switchgear, Motor Control Center, Transformers, Control Switches and Lighting, Power and Control Building – Recent pricing from DM Consulting was utilized.
- ◆ Compressor Station Construction – Budgetary estimates for facility construction was received from Holloman Construction and LE Bell Construction.

SCADA and Fiber Optic

- ◆ SCADA Material, Licenses, and Vendor Services – Pricing from other recent projects was utilized.

Coffeyville Resources Nitrogen Fertilizer Plant to Thrall-Aagard Oil Field

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- ◆ Fiber Optic Installation – Pricing from other recent projects was utilized.
- ◆ Fiber Optic Material – Pricing from other recent projects was utilized.

6. MARKUPS and ESCALATION

Taxes – 5.98% sales tax included on all materials. No tax included on labor.

Material Escalation – No material escalation was included, vendors quoted for late summer 2010 delivery.

Construction Escalation – No construction escalation is included, assume late summer 2010 construction.

G&A – Included in cost estimate.

Construction Bond – 3% of total construction estimate

Contingency – 15% contingency included in each line item

7. CONSTRUCTION INDIRECTS

All construction indirect costs are included in construction labor unit prices.

8. ASSUMPTIONS AND QUALIFICATIONS

Pipeline

- ◆ Estimate includes construction permitting only. Costs for National Environmental Policy Act (NEPA) Review, Studies to Support the NEPA Process, COE Nationwide #12 Permit, Clean Water Act, Section 401 Consultations, U.S. Fish and Wildlife Service Consultations, Endangered Species Act are not included in this budget.
- ◆ Estimate includes (3) month license of PipePhase Hydraulic Modeling Software.
- ◆ Estimate assumes 75' wide construction work area and 300' x 300' temporary work areas at all crossings.
- ◆ Estimate assumes construction working six (6) days per week for ten (10) hours per day.
- ◆ Assumes source and disposal site for the Hydro water will be within 50 miles of the job site.
- ◆ 2.5% wastage assumed for pipe and piping components.
- ◆ Construction is in loose, dry soil.
- ◆ 45% Rock Ditch was included based on contractor input for the project area.
- ◆ Pricing reflects 3D fittings for a piggable system.
- ◆ Concrete foundation construction included in estimate.
- ◆ Silt fencing was included for the perimeter of all anticipated temporary work areas only.
- ◆ Contractor will be non-union.
- ◆ Mitigation measures and landowner requirements are unknown at this time.
- ◆ Estimate includes MFL /Caliper Tool - Smart Pig
- ◆ Estimate includes Cathodic Protection (Impressed Current).
- ◆ Estimate includes costs for Right of Way revegetation.
- ◆ Unforeseen conditions are not included in the estimate.

Coffeyville Resources Nitrogen Fertilizer Plant to Thrall-Aagard Oil Field

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- ◆ Capital Cost Estimate includes the units and quantities shown in the estimate.

Compression Facility

- ◆ Assume compressor station site is grass roots, relatively level field with minimal grading, grubbing and clearing required. No trees or existing infrastructure required to be removed.
- ◆ Assumes one centrifugal compressor train, consisting of a motor, gear box, a single stage Low Pressure Centrifugal Compressor (MCL753), a two stage Mid Pressure Centrifugal Compressor (2BCL456), a two stage High Pressure Centrifugal Compressor (2BCL454), and a single stage Centrifugal Pump. A separate Inter-cooler and scrubber skid package was not included in the base package, and has been added.
- ◆ Estimate includes 8% of the capital expenditure of the compressors/pumps for initial spares, as recommended by GE.
- ◆ Estimate includes one (1) compressor building for the compressors.
- ◆ Estimate includes one (1) 3.5 MMBTU/Hr TEG Dehydration Skid w/ 60" O.D. Contactor Tower.
- ◆ Estimate includes scrubber and orifice metering for dehydration re-boiler fuel gas

Fiber Optic and SCADA

- ◆ SCADA electrical construction contractor labor not included since wiring up the PLCs would be done by site contractor along with instruments.
- ◆ The PLC at each compressor and main line valve site will be a GE 90-30 or company approved equal and will be housed inside a small building to enable support personnel to program and maintain them in inclement weather.
- ◆ The SCADA software will have a primary system installed at the primary control center on one end of the pipeline and there will be a backup SCADA host at the facility at the other end of the pipeline. Costs for SCADA vendor services were also included. SCADA vendor services include project management, design specification documents, SCADA communications programming, SCADA screen programming, factory tests, installation onsite, onsite tuning of the software, commissioning tests, operations and the maintenance manual, training support for operators and technicians.
- ◆ The Leak Detection System will communicate with each station to analyze the pipeline for leaks and report to the SCADA software for operator notification. Leak Detection vendor services were also included. Leak Detection vendor services include project management, design specification documents, communications programming, graphical user interface screen programming, factory tests, installation onsite, tuning of the software, commissioning tests, operations and the maintenance manual, training support for operators and technicians.

Coffeyville Resources Nitrogen Fertilizer Plant to Thrall-Aagard Oil Field

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9. ATTACHED CONSTRUCTION CONTRACTOR BUDGETARY PROPOSAL

See attached contractor budgetary proposal that was utilized in preparing the capital cost estimate.

APPENDIX 3-E
ESTIMATE BASIS MEMORANDUM
THRALL-AAGARD FIELD

CVR-TAF Desktop FEED Capital Cost Estimate
Montgomery, Chautauqua, Elk, Cowley, and Greenwood Counties, Kansas
Date: March 26, 2010

CAPITAL COST ESTIMATE SUMMARY

Cost Description	Total Cost
Pipeline	
Materials	\$ 37,992,000
Construction	\$ 26,015,000
ROW Acquisition, Damages and Revegetation	\$ 7,120,000
Cathodic Protection	\$ 92,000
Construction Permitting	\$ 32,000
Property Plats	\$ 1,083,000
Engineering Survey and Procurement Inspection	\$ 634,000
Engineering & Procurement Assistance	\$ 1,453,000
Construction Administration	\$ 1,372,000
Construction Inspection, Surveying and X-Ray	\$ 6,841,000
Total Pipeline Cost	\$ 82,634,000
Fiber Optic and SCADA	
SCADA and Fiber Optic Materials	\$ 2,745,000
SCADA Engineering Hours/Expenses	\$ 249,000
SCADA Vendor Labor	\$ 466,000
Fiber Optic Construction Labor	\$ 1,314,000
Total Fiber Optic and SCADA Cost	\$ 4,774,000
Compressor / Pump Station	
Equipment and Materials	\$ 20,472,000
Construction	\$ 3,891,000
Land and ROW	\$ -
Environmental and Permitting	\$ 6,000
Engineering Design	\$ 985,000
Construction Administration	\$ 1,194,000
Total Compressor / Pump Cost	\$ 26,548,000
TOTAL ESTIMATED PROJECT COST	\$ 113,956,000

INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION & ENHANCED OIL RECOVERY PROJECT
Coffeyville Resources Fertilizer Plant (CVR) to the Thrall-Aagard Oil Field (TAF)
Capital Cost Estimate - 108.2 Miles of 8" Pipeline
Blue Source LLC
Date: March 26, 2010

	Qty.	Unit	Unit Cost	Total Cost	% of Total
LINE PIPE, COATING, & FREIGHT					
Steel					
8.625", 0.500" w.t., API 5L, X-65, PSL2, ERW Line Pipe, DRL, coated 14 -16 mils of FBE	574,967	ft.	\$ 50.23	\$ 28,880,600	
8.625", 0.500" w.t., API 5L, X-65, PSL2, SMLS Line Pipe, DRL, coated 14 -16 mils of FBE	8,143	ft.	\$ 47.48	\$ 386,600	
8.625" ARO Coating - Road Crossings	8,143	ft.	\$ 11.30	\$ 92,000	
FOB (Included in Unit Prices Above)	0	ea	\$ -	\$ -	
Line Pipe Contingency	15%			\$ 4,403,880	
Subtotal - Pipe & Coating				\$ 33,763,000	40.86%

PIPELINE - FITTINGS & APPURTENANCES					
Main-Line Valves					
8" 1500 RTJ GO CAMERON T31 TRIM 601 w/ 7" STEM EXTENSION & COAL TAR	18	ea	\$ 13,003.00	\$ 234,100	
6" 1500 RTJ GO CAMERON T31 TRIM 601	36	ea	\$ 9,300.00	\$ 334,800	
Miscellaneous Fittings	1	lot	\$ 256,000.00	\$ 256,000	
FOB	7	trk	\$ 3,000.00	\$ 20,300	
Two Future Booster Stations Valving					
8" 1500 RTJ GO CAMERON T31 TRIM 601 w/ 7" STEM EXTENSION & COAL TAR	6	ea	\$ 13,003.00	\$ 78,000	
6" 1500 RTJ GO CAMERON T31 TRIM 601	0	ea	\$ 9,300.00	\$ -	
Miscellaneous Fittings	1	lot	\$ 35,000.00	\$ 35,000	
FOB	1	trk	\$ 3,000.00	\$ 3,000	
Steel Fittings					
8.625", 0.500" w.t., 90°, 3D Segmentable, MSS SP-75, WPHY-65, with 14 -16 mils FBE	72	ea	\$ 1,781.50	\$ 128,500	
8.625", 0.500" w.t., 60°, 3D Segmentable, MSS SP-75, WPHY-65, with 14 -16 mils FBE	36	ea	\$ 1,756.50	\$ 63,400	
8.625", 0.500" w.t., 45°, 3D Segmentable, MSS SP-75, WPHY-65, with 14 -16 mils FBE	27	ea	\$ 1,110.50	\$ 30,000	
FOB (Included in Unit Prices Above)	0	load	\$ -	\$ -	
Shrink Sleeves					
For 8" Pipe	18,000	ea	\$ 8.17	\$ 147,100	
FOB	1	Truck	\$ 3,000.00	\$ 3,000	
Launcher/Receiver Assemblies					
ANSI 1500 8" x 12" Launcher/Receiver Barrel & Closure	2	ea	\$ 30,622.00	\$ 61,200	
ANSI 1500 8" x 12" Launcher Bill of Materials	1	ea	\$ 28,912.36	\$ 28,900	
ANSI 1500 8" x 12" Receiver Bill of Materials	1	ea	\$ 19,638.36	\$ 19,600	
FOB (Included in Unit Prices Above)	0	truck	\$ -	\$ -	
Miscellaneous					
Cathodic Protection Test Stations	182	ea	\$ 11.66	\$ 2,100	
Pipeline Markers	729	ea	\$ 12.45	\$ 9,100	
Crack Arrestor	325	ea	\$ 1,087.00	\$ 352,800	
FOB	2	lot	\$ 3,000.00	\$ 6,000	
Pipeline Fittings and Appurtenances Contingency	15%			\$ 271,935	
Subtotal - Fittings & Appurtenances				\$ 2,085,000	2.52%

INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION & ENHANCED OIL RECOVERY PROJECT
Coffeyville Resources Fertilizer Plant (CVR) to the Thrall-Aagard Oil Field (TAF)
Capital Cost Estimate - 108.2 Miles of 8" Pipeline
Blue Source LLC
Date: March 26, 2010

	Qty.	Unit	Unit Cost	Total Cost	% of Total
PIPELINE - CONSTRUCTION					
Pipeline Construction					
Mobilization / Demobilization to Construct 8" Carbon Dioxide Pipeline	1	LS	\$ 137,000.00	\$ 137,000	
Installation of pipe per lineal foot (Rural)	552,816	ft	\$ 20.00	\$ 11,056,300	
Installation of pipe per lineal foot (Town)	18,480	ft	\$ 80.00	\$ 1,478,400	
8" Open Cut Crossing - No Casing	3,200	ft	\$ 90.00	\$ 288,000	
8" Bored Crossing - No Casing	3,755	ft	\$ 90.00	\$ 338,000	
8" HDD Crossing - No Casing	800	ft	\$ 110.00	\$ 88,000	
8" ANSI 1500 Pig Launchers/Receivers with supports	2	LS	\$ 28,000.00	\$ 56,000	
Install 8" Buried Valve - with Risers	18	ea	\$ 18,000.00	\$ 324,000	
Install 8" Valving for Future Booster Stations	2	ea	\$ 18,000.00	\$ 36,000	
Install Cathodic Test Station	182	ea	\$ 2,000.00	\$ 364,000	
Install Silt Fence	319,200	ft	\$ 7.50	\$ 2,394,000	
Install Hay Bale	1,200	ea	\$ 20.00	\$ 24,000	
16" Foreign Pipeline Crossing	108	ea	\$ 2,000.00	\$ 216,000	
Install Foam Ditch Breaker (Ditch Plugs)	200	ea	\$ 1,200.00	\$ 240,000	
Fences - Remove 75' existing fences, install temporary for construction and replace	433	ea	\$ 1,400.00	\$ 606,200	
Install Crack Arrestor	325	ea	\$ 200.00	\$ 64,900	
Rock Ditch (Assumed at 45% of Route)	257,083	ft	\$ 12.00	\$ 3,085,000	
ROW Clearing - Timber (Estimated from Aerial Photography)	42,470	ft	\$ 20.00	\$ 849,400	
Hot Bends Installed	135	ea	\$ 500.00	\$ 67,600	
8" MFL /Caliper Tool - Smart Pig	1	LS	\$ 250,000.00	\$ 250,000	
Pipeline Construction Contingency	15%			\$ 3,294,420	
Subtotal - Construction				\$ 25,257,000	30.56%

Subtotal Materials				\$ 35,848,000	
Sales Tax on Material	5.98%			\$ 2,144,000	
Subtotal Materials				\$ 37,992,000	45.98%
Subtotal Construction				\$ 25,257,000	
Sales Tax on Labor	0.00%			\$ -	
Construction Bond	3.00%			\$ 758,000	
Subtotal Construction				\$ 26,015,000	31.48%
ROW Acquisition - Consultants	34,624	Rods	\$ 35.00	\$ 1,212,000	
ROW Acquisition & Damages	34,624	Rods	\$ 70.00	\$ 2,424,000	
ROW Procurement, Legal and Environmental Costs	34,624	Rods	\$ 27.50	\$ 952,000	
ROW Revegetation	1,533	acres	\$ 1,000.00	\$ 1,533,000	
COE Wetlands Mitigation	1	LS	\$ 70,000.00	\$ 70,000	
ROW Contingency	15%			\$ 929,000	
Subtotal ROW Acquisition				\$ 7,120,000	8.62%
Cathodic Protection (Impressed Current)	1	LS	\$ 50,000.00	\$ 50,000	
AC Mitigation Study	1	LS	\$ 30,000.00	\$ 30,000	
AC Mitigation Contingency	15%			\$ 12,000	
Subtotal Cathodic Protection				\$ 92,000	0.11%
Construction General Permit	1	LS	\$ 10,000.00	\$ 10,000	
Surface Water Discharge Permit	1	LS	\$ 5,000.00	\$ 5,000	
National Historic Preservation Act	1	LS	\$ 10,000.00	\$ 10,000	
Nongame and Endangered Species Conservation Act	1	LS	\$ 3,000.00	\$ 3,000	
Permitting Contingency	15%			\$ 4,000	
Total Construction Permitting				\$ 32,000	0.04%
Surveying - Property Plats	433	ea	\$ 2,500.00	\$ 1,083,000	1.31%
Engineering & Procurement Assistance				\$ 1,453,000	1.76%
Engineering Survey and Procurement Inspection				\$ 634,000	0.77%
Construction Administration				\$ 1,372,000	1.66%
Construction Inspection, Surveying and X-Ray				\$ 6,841,000	8.28%
TOTAL ESTIMATED COST				\$ 82,634,000	100.00%

INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION &
ENHANCED OIL RECOVERY PROJECT
Coffeyville Resources Fertilizer Plant (CVR) to the Thrall-Aagard Oil Field (TAF)
Detailed Engineering and Procurement Assistanace
Blue Source LLC
Date: March 26, 2010

DETAILED ENGINEERING AND PROCUREMENT - Rooney Engineering Direct Labor

INDIVIDUAL	TITLE	Billing	Billing	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
		Rate 1/10	Rate 8/10	1-Jul-10	8-Jul-10	15-Jul-10	22-Jul-10	29-Jul-10	5-Aug-10	12-Aug-10	19-Aug-10	26-Aug-10	2-Sep-10	9-Sep-10	16-Sep-10	23-Sep-10	30-Sep-10	7-Oct-10	14-Oct-10	21-Oct-10	28-Oct-10	4-Nov-10	11-Nov-10	18-Nov-10	25-Nov-10
PROJECT MANAGEMENT			7.0%																						
Henrick Sarkissian	Principal	\$151.00	\$161.57	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Other	Principal	\$151.00	\$161.57	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Office Personnel	Office Personnel	\$44.00	\$47.08	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	40	40
Accounting Personnel	Cost Accountant	\$64.00	\$68.48	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Subtotal Man-Hours				64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	84	84
Subtotal \$				\$7,176	\$7,176	\$7,176	\$7,176	\$7,176	\$7,678	\$7,678	\$7,678	\$7,678	\$7,678	\$7,678	\$7,678	\$7,678	\$7,678	\$7,678	\$7,678	\$7,678	\$7,678	\$7,678	\$7,678	\$8,620	\$8,620
PROJECT ENGINEERING																									
Quinn Bailey	Senior Project Engineer	\$121.00	\$129.47	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Zachary Bauer	Project Engineer	\$116.00	\$124.12	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Brian Techau	Project Engineer	\$116.00	\$124.12	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Subtotal Man-Hours				120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120
Subtotal \$				\$14,120	\$14,120	\$14,120	\$14,120	\$14,120	\$15,108	\$15,108	\$15,108	\$15,108	\$15,108	\$15,108	\$15,108	\$15,108	\$15,108	\$15,108	\$15,108	\$15,108	\$15,108	\$15,108	\$15,108	\$15,108	\$15,108
PROJECT DESIGN																									
Mike Wager	Designer	\$91.00	\$97.37	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Roxanne Burridge	Designer	\$91.00	\$97.37	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Chuck Haas	Designer	\$91.00	\$97.37	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Subtotal Man-Hours				120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120
Subtotal \$				\$10,920	\$10,920	\$10,920	\$10,920	\$10,920	\$11,684	\$11,684	\$11,684	\$11,684	\$11,684	\$11,684	\$11,684	\$11,684	\$11,684	\$11,684	\$11,684	\$11,684	\$11,684	\$11,684	\$11,684	\$11,684	\$11,684
SUBTOTAL ROONEY ENGINEERING (HOURS)				304.0 hrs	304.0 hrs	304.0 hrs	304.0 hrs	304.0 hrs	304.0 hrs	304.0 hrs	304.0 hrs	304.0 hrs	304.0 hrs	304.0 hrs	304.0 hrs	304.0 hrs	304.0 hrs	304.0 hrs	304.0 hrs	304.0 hrs	304.0 hrs	304.0 hrs	304.0 hrs	324.0 hrs	324.0 hrs
SUBTOTAL ROONEY ENGINEERING (COST)				\$32,216	\$32,216	\$32,216	\$32,216	\$32,216	\$34,471	\$34,471	\$34,471	\$34,471	\$34,471	\$34,471	\$34,471	\$34,471	\$34,471	\$34,471	\$34,471	\$34,471	\$34,471	\$34,471	\$34,471	\$35,413	\$35,413

DETAILED ENGINEERING AND PROCUREMENT - Subcontractors and Expenses

INDIVIDUAL	TITLE	Billing	Billing	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
		Rate 1/10	Rate 8/10	1-Jul-10	8-Jul-10	15-Jul-10	22-Jul-10	29-Jul-10	5-Aug-10	12-Aug-10	19-Aug-10	26-Aug-10	2-Sep-10	9-Sep-10	16-Sep-10	23-Sep-10	30-Sep-10	7-Oct-10	14-Oct-10	21-Oct-10	28-Oct-10	4-Nov-10	11-Nov-10	18-Nov-10	25-Nov-10
SUBCONTRACT ENGINEERING																									
		Rates REI COST																							
Mark Madden	Senior Project Engineer	\$121.00	\$129.47	0	0	40	40	40	40	0	40	40	0	0	0	0	0	0	40	40	40	40	0	0	0
Bruce Craig / Metcorr	Cathodic Protection	\$200.00	\$214.00	0	0	40	40	0	0	0	0	0	40	40	40	0	0	40	40	40	40	0	0	0	0
				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal Man-Hours				0	0	80	80	40	40	0	40	40	40	40	40	0	0	0	80	80	80	80	0	0	0
Subtotal \$				\$0	\$0	\$12,840	\$12,840	\$4,840	\$5,179	\$0	\$5,179	\$5,179	\$8,560	\$8,560	\$8,560	\$0	\$0	\$0	\$13,739	\$13,739	\$13,739	\$13,739	\$0	\$0	\$0
EXPENSES																									
Denver Office Travel Expenses				\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$0	\$0	\$0	\$3,000	\$0	\$3,000	\$0	\$3,000	\$0	\$0	\$3,000	\$0	\$0	\$3,000
Denver Office Expenses				\$200	\$200	\$200	\$200	\$200	\$200	\$200	\$200	\$200	\$200	\$200	\$200	\$200	\$200	\$200	\$200	\$200	\$200	\$200	\$200	\$200	\$200
Misc.				\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Hydraulic Software				\$10,000	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Subtotal \$				\$13,200	\$3,200	\$3,200	\$3,200	\$3,200	\$3,200	\$3,200	\$3,200	\$200	\$200	\$200	\$3,200	\$200	\$3,200	\$200	\$3,200	\$200	\$200	\$3,200	\$200	\$200	\$3,200
SUBTOTAL SUBCONTRACTORS AND EXPENSES (HOURS)				0.0 hrs	0.0 hrs	80.0 hrs	80.0 hrs	40.0 hrs	40.0 hrs	0.0 hrs	40.0 hrs	40.0 hrs	40.0 hrs	40.0 hrs	40.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	80.0 hrs	80.0 hrs	80.0 hrs	80.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs
SUBTOTAL SUBCONTRACTORS AND EXPENSES (COST)				\$13,200	\$3,200	\$16,040	\$16,040	\$8,040	\$8,379	\$3,200	\$8,379	\$5,379	\$8,760	\$8,760	\$11,760	\$200	\$3,200	\$200	\$16,939	\$13,939	\$13,939	\$16,939	\$200	\$200	\$3,200

PROJECT TOTAL (HOURS)				304.0 hrs	304.0 hrs	384.0 hrs	384.0 hrs	344.0 hrs	344.0 hrs	304.0 hrs	344.0 hrs	344.0 hrs	344.0 hrs	344.0 hrs	344.0 hrs	304.0 hrs	304.0 hrs	304.0 hrs	384.0 hrs	384.0 hrs	384.0 hrs	384.0 hrs	304.0 hrs	324.0 hrs	324.0 hrs
PROJECT TOTAL (COST)				\$45,416	\$35,416	\$48,256	\$48,256	\$40,256	\$42,850	\$37,671	\$42,850	\$39,850	\$43,231	\$43,231	\$46,231	\$34,671	\$37,671	\$34,671	\$51,410	\$48,410	\$48,410	\$51,410	\$34,671	\$35,613	\$38,613

INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTERED
ENHANCED OIL RECOVERY PROJECT
Coffeyville Resources Fertilizer Plant (CVR) to the Thrall-Aagar
Detailed Engineering and Procurement Assistance
Blue Source LLC
Date: March 26, 2010

Procurement

DETAILED ENGINEERING AND PROCUREMENT - Rooney Engineering

INDIVIDUAL	TITLE	Billing	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38
		Rate 1/10	2-Dec-10	9-Dec-10	16-Dec-10	23-Dec-10	30-Dec-10	6-Jan-11	13-Jan-11	20-Jan-11	27-Jan-11	3-Feb-11	10-Feb-11	17-Feb-11	24-Feb-11	3-Mar-11	10-Mar-11	17-Mar-11
PROJECT MANAGEMENT																		
Henrick Sarkissian	Principal	\$151.00	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	0
Other	Principal	\$151.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Office Personnel	Office Personnel	\$44.00	40	40	20	20	20	20	20	20	20	20	20	20	20	20	20	0
Accounting Personnel	Cost Accountant	\$64.00	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	0
Subtotal Man-Hours			84	84	64	64	64	64	64	64	64	64	64	64	64	64	64	0
Subtotal \$			\$8,620	\$8,620	\$7,678	\$7,678	\$7,678	\$7,678	\$7,678	\$7,678	\$7,678	\$7,678	\$7,678	\$7,678	\$7,678	\$7,678	\$7,678	\$0
PROJECT ENGINEERING																		
Quinn Bailey	Senior Project Engineer	\$121.00	40	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Zachary Bauer	Project Engineer	\$116.00	40	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Brian Techau	Project Engineer	\$116.00	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	0
Subtotal Man-Hours			120	120	40	40	40	40	40	40	40	40	40	40	40	40	40	0
Subtotal \$			\$15,108	\$15,108	\$4,965	\$4,965	\$4,965	\$4,965	\$4,965	\$4,965	\$4,965	\$4,965	\$4,965	\$4,965	\$4,965	\$4,965	\$4,965	\$0
PROJECT DESIGN																		
Mike Wager	Designer	\$91.00	40	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Roxanne Burrige	Designer	\$91.00	40	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Chuck Haas	Designer	\$91.00	40	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal Man-Hours			120	120	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal \$			\$11,684	\$11,684	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
SUBTOTAL ROONEY ENGINEERING (HOURS)			324.0 hrs	324.0 hrs	104.0 hrs	104.0 hrs	104.0 hrs	104.0 hrs	104.0 hrs	104.0 hrs	104.0 hrs	104.0 hrs	104.0 hrs	104.0 hrs	104.0 hrs	104.0 hrs	104.0 hrs	0.0 hrs
SUBTOTAL ROONEY ENGINEERING (COST)			\$35,413	\$35,413	\$12,643	\$12,643	\$12,643	\$12,643	\$12,643	\$12,643	\$12,643	\$12,643	\$12,643	\$12,643	\$12,643	\$12,643	\$12,643	\$0

Total Rate 1/10	Total Rate 8/10	Billed (\$)	Overhead 0.000	Total
200	1280	\$237,010	\$0	\$237,010
0	0	\$0	\$0	\$0
100	720	\$38,298	\$0	\$38,298
20	128	\$10,045	\$0	\$10,045
320	2128			
(Check)	\$285,353	\$285,353	\$0	\$285,353
200	760	\$122,597	\$0	\$122,597
200	760	\$117,531	\$0	\$117,531
200	1280	\$182,074	\$0	\$182,074
600	2800			
(Check)	\$422,202	\$422,202	\$0	\$422,202
200	760	\$92,201	\$0	\$92,201
200	760	\$92,201	\$0	\$92,201
200	760	\$92,201	\$0	\$92,201
600	2280			
(Check)	\$276,604	\$276,604	\$0	\$276,604
1520.0 hrs	7208.0 hrs			8728.0 hrs
(Check)	\$984,158	\$984,158	\$0	\$984,150

DETAILED ENGINEERING AND PROCUREMENT - Subcontractors and Expenses

INDIVIDUAL	TITLE	Billing	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38
		Rate 1/10	2-Dec-10	9-Dec-10	16-Dec-10	23-Dec-10	30-Dec-10	6-Jan-11	13-Jan-11	20-Jan-11	27-Jan-11	3-Feb-11	10-Feb-11	17-Feb-11	24-Feb-11	3-Mar-11	10-Mar-11	17-Mar-11
SUBCONTRACT ENGINEERING																		
		Rate 1/10																
Mark Madden	Senior Project Engineer	\$121.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bruce Craig / Metcorr	Cathodic Protection	\$200.00	0	0	0	0	0	40	40	40	40	0	0	0	0	0	0	0
			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal Man-Hours			0	0	0	0	0	40	40	40	40	0	0	0	0	0	0	0
Subtotal \$			\$0	\$0	\$0	\$0	\$0	\$8,560	\$8,560	\$8,560	\$8,560	\$0	\$0	\$0	\$0	\$0	\$0	\$0
EXPENSES																		
Denver Office Travel Expenses			\$0	\$3,000	\$3,000	\$0	\$0	\$3,000	\$0	\$0	\$3,000	\$0	\$0	\$3,000	\$0	\$3,000	\$0	\$0
Denver Office Expenses			\$200	\$10,000	\$100	\$100	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Misc.			\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Hydraulic Software			\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Subtotal \$			\$200	\$13,000	\$3,100	\$100	\$0	\$3,000	\$0	\$0	\$3,000	\$0	\$0	\$3,000	\$0	\$3,000	\$0	\$0
SUBTOTAL SUBCONTRACTORS AND EXPENSES (HOURS)			0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	40.0 hrs	40.0 hrs	40.0 hrs	40.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs
SUBTOTAL SUBCONTRACTORS AND EXPENSES (COST)			\$200	\$13,000	\$3,100	\$100	\$0	\$11,560	\$8,560	\$8,560	\$11,560	\$0	\$0	\$3,000	\$0	\$3,000	\$0	\$0

Total Rate 1/10	Total Rate 8/10	Billed (\$)	Overhead 0.150	Total
120	280	\$50,772	\$7,616	\$58,387
80	440	\$110,160	\$16,524	\$126,684
200	720			
(Check)	\$160,932	\$160,932	\$24,140	\$185,071
		\$57,000	\$8,550	\$65,550
		\$14,800	\$2,220	\$17,020
		\$0	\$0	\$0
		\$10,000	\$1,500	\$11,500
(Check)	\$81,800	\$81,800	\$12,270	\$94,070
760.0 hrs	160.0 hrs			920.0 hrs
(Check)	\$242,732	\$242,732	\$36,410	\$279,140

PROJECT TOTAL (HOURS)		324.0 hrs	324.0 hrs	104.0 hrs	104.0 hrs	104.0 hrs	144.0 hrs	144.0 hrs	144.0 hrs	144.0 hrs	104.0 hrs	104.0 hrs	104.0 hrs	104.0 hrs	104.0 hrs	104.0 hrs	104.0 hrs	0.0 hrs
PROJECT TOTAL (COST)		\$35,613	\$48,413	\$15,743	\$12,743	\$12,643	\$24,203	\$21,203	\$21,203	\$24,203	\$12,643	\$12,643	\$15,643	\$12,643	\$15,643	\$12,643	\$12,643	\$0

7812.0 hrs	1836.0 hrs			9648.0 hrs
(Check)	\$1,226,890	\$1,226,890	\$36,410	\$1,263,290

INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION & ENHANCED OIL RECOVERY PROJECT
Coffeyville Resources Fertilizer Plant (CVR) to the Thrall-Aagard Oil Field (TAF)
Construction Administration and As-Built
Blue Source LLC
Date: March 26, 2010

*Contractor Mobilize

CONSTRUCTION ADMINISTRATION AND AS BUILT - Rooney Engineering Direct Labor

INDIVIDUAL	TITLE	Billing	Billing	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
		Rate 1/11	Rate 8/11	3-Jun-11	10-Jun-11	17-Jun-11	24-Jun-11	1-Jul-11	8-Jul-11	15-Jul-11	22-Jul-11	29-Jul-11	5-Aug-11	12-Aug-11	19-Aug-11	26-Aug-11	2-Sep-11	9-Sep-11	16-Sep-11	23-Sep-11	30-Sep-11	7-Oct-11	14-Oct-11
PROJECT MANAGEMENT		7.0%	7.0%																				
Henrick Sarkissian	Principal	\$172.88	\$184.98	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Other	Principal	\$172.88	\$184.98	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Office Personnel	Office Personnel	\$50.38	\$53.90	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Accounting Personnel	Cost Accountant	\$73.27	\$78.40	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Subtotal Man-Hours				120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120
Subtotal \$				\$13,853	\$13,853	\$13,853	\$13,853	\$13,853	\$13,853	\$13,853	\$13,853	\$13,853	\$14,823	\$14,823	\$14,823	\$14,823	\$14,823	\$14,823	\$14,823	\$14,823	\$14,823	\$14,823	\$14,823
PROJECT ENGINEERING																							
Quinn Bailey	Senior Project Engineer	\$138.53	\$148.23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Zachary Bauer	Project Engineer	\$132.81	\$142.10	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Brian Techau	Project Engineer	\$132.81	\$142.10	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Subtotal Man-Hours				100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Subtotal \$				\$13,281	\$13,281	\$13,281	\$13,281	\$13,281	\$13,281	\$13,281	\$13,281	\$13,281	\$14,210	\$14,210	\$14,210	\$14,210	\$14,210	\$14,210	\$14,210	\$14,210	\$14,210	\$14,210	\$14,210
PROJECT DESIGN																							
Mike Wager	Designer	\$104.19	\$111.48	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	40	40
Chuck Haas	Designer	\$104.19	\$111.48	0	0	0	0	0	0	0	0	0	0	20	20	20	20	0	0	0	0	40	40
Subtotal Man-Hours				20	20	20	20	20	20	20	20	20	20	40	40	40	40	20	20	20	20	80	80
Subtotal \$				\$2,084	\$2,084	\$2,084	\$2,084	\$2,084	\$2,084	\$2,084	\$2,084	\$2,084	\$2,230	\$4,459	\$4,459	\$4,459	\$4,459	\$2,230	\$2,230	\$2,230	\$2,230	\$8,918	\$8,918
SUBTOTAL ROONEY ENGINEERING (HOURS)				240.0 hrs	240.0 hrs	240.0 hrs	240.0 hrs	240.0 hrs	240.0 hrs	240.0 hrs	240.0 hrs	240.0 hrs	240.0 hrs	260.0 hrs	260.0 hrs	260.0 hrs	260.0 hrs	240.0 hrs	240.0 hrs	240.0 hrs	240.0 hrs	300.0 hrs	300.0 hrs
SUBTOTAL ROONEY ENGINEERING (COST)				\$29,218	\$29,218	\$29,218	\$29,218	\$29,218	\$29,218	\$29,218	\$29,218	\$29,218	\$31,263	\$33,493	\$33,493	\$33,493	\$33,493	\$31,263	\$31,263	\$31,263	\$31,263	\$37,952	\$37,952

CONSTRUCTION ADMINISTRATION AND AS BUILT - Subcontractors and Expenses

INDIVIDUAL	TITLE	Billing	Billing	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
		Rate 1/11	Rate 8/11	3-Jun-11	10-Jun-11	17-Jun-11	24-Jun-11	1-Jul-11	8-Jul-11	15-Jul-11	22-Jul-11	29-Jul-11	5-Aug-11	12-Aug-11	19-Aug-11	26-Aug-11	2-Sep-11	9-Sep-11	16-Sep-11	23-Sep-11	30-Sep-11	7-Oct-11	14-Oct-11
SUBCONTRACT ENGINEERING																							
		Rates																					
		REI COST																					
Mark Madden	Senior Project Engineer	\$138.53	\$148.23	0	0	0	0	0	0	40	40	40	40	40	0	0	0	0	0	0	0	0	0
Bruce Craig / Metcorr	Cathodic Protection	\$228.98	\$245.01	0	0	0	0	0	0	40	40	40	40	40	0	0	0	0	0	0	0	0	0
				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal Man-Hours				0	0	0	0	0	0	80	80	80	80	80	0	0	0	0	0	0	0	0	0
Subtotal \$				\$0	\$0	\$0	\$0	\$0	\$0	\$14,701	\$14,701	\$14,701	\$15,730	\$15,730	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
EXPENSES																							
Denver Office Travel Expenses				\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000
Denver Office Expenses				\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500
Misc.				\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Subtotal \$				\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500
SUBTOTAL SUBCONTRACTORS AND EXPENSES (HOURS)				0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	80.0 hrs	80.0 hrs	80.0 hrs	80.0 hrs	80.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs
SUBTOTAL SUBCONTRACTORS AND EXPENSES (COST)				\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$18,201	\$18,201	\$18,201	\$19,230	\$19,230	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500
PROJECT TOTAL (HOURS)				240.0 hrs	240.0 hrs	240.0 hrs	240.0 hrs	240.0 hrs	240.0 hrs	320.0 hrs	320.0 hrs	320.0 hrs	320.0 hrs	340.0 hrs	260.0 hrs	260.0 hrs	260.0 hrs	240.0 hrs	240.0 hrs	240.0 hrs	240.0 hrs	300.0 hrs	300.0 hrs
PROJECT TOTAL (COST)				\$32,718	\$32,718	\$32,718	\$32,718	\$32,718	\$32,718	\$47,418	\$47,418	\$47,418	\$50,493	\$52,722	\$36,993	\$36,993	\$36,993	\$34,763	\$34,763	\$34,763	\$34,763	\$41,452	\$41,452

INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTERED
ENHANCED OIL RECOVERY PROJECT
Coffeyville Resources Fertilizer Plant (CVR) to the Thrall-Aagard
Construction Administration and As-Built
Blue Source LLC
Date: March 26, 2010

CONSTRUCTION ADMINISTRATION AND AS BUILT - Rooney Engineering

INDIVIDUAL	TITLE	Billing	21	22	23	24	25	26	27	28	29	30
		Rate 1/11	21-Oct-11	28-Oct-11	4-Nov-11	11-Nov-11	18-Nov-11	25-Nov-11	2-Dec-11	9-Dec-11	16-Dec-11	23-Dec-11
PROJECT MANAGEMENT		7.0%										
Henrick Sarkissian	Principal	\$172.88	60	60	60	60	60	60	60	0	0	0
Other	Principal	\$172.88	0	0	0	0	0	0	0	0	0	0
Office Personnel	Office Personnel	\$50.38	40	40	40	40	40	40	40	0	0	0
Accounting Personnel	Cost Accountant	\$73.27	20	20	20	20	20	20	20	0	0	0
Subtotal Man-Hours			120	120	120	120	120	120	120	0	0	0
Subtotal \$			\$14,823	\$14,823	\$14,823	\$14,823	\$14,823	\$14,823	\$14,823	\$0	\$0	\$0
PROJECT ENGINEERING												
Quinn Bailey	Senior Project Engineer	\$138.53	0	0	0	0	0	0	0	0	0	0
Zachary Bauer	Project Engineer	\$132.81	60	60	60	60	60	60	60	0	0	0
Brian Techau	Project Engineer	\$132.81	40	40	40	40	40	40	40	0	0	0
Subtotal Man-Hours			100	100	100	100	100	100	100	0	0	0
Subtotal \$			\$14,210	\$14,210	\$14,210	\$14,210	\$14,210	\$14,210	\$14,210	\$0	\$0	\$0
PROJECT DESIGN												
Mike Wager	Designer	\$104.19	40	40	40	40	40	40	40	0	0	0
Chuck Haas	Designer	\$104.19	40	40	40	40	40	40	40	0	0	0
Subtotal Man-Hours			80	80	80	80	80	80	80	0	0	0
Subtotal \$			\$8,918	\$8,918	\$8,918	\$8,918	\$8,918	\$8,918	\$8,918	\$0	\$0	\$0
SUBTOTAL ROONEY ENGINEERING (HOURS)			300.0 hrs	300.0 hrs	300.0 hrs	300.0 hrs	300.0 hrs	300.0 hrs	300.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs
SUBTOTAL ROONEY ENGINEERING (COST)			\$37,952	\$37,952	\$37,952	\$37,952	\$37,952	\$37,952	\$37,952	\$0	\$0	\$0

CONSTRUCTION ADMINISTRATION AND AS BUILT - Subcontractors

INDIVIDUAL	TITLE	Billing 21		22	23	24	25	26	27	28	29	30
		Rate 1/11	21-Oct-11	28-Oct-11	4-Nov-11	11-Nov-11	18-Nov-11	25-Nov-11	2-Dec-11	9-Dec-11	16-Dec-11	23-Dec-11
SUBCONTRACT ENGINEERING												
Mark Madden	Senior Project Engineer	\$138.53	40	40	40	40	40	0	0	0	0	0
Bruce Craig / Metcorr	Cathodic Protection	\$228.98	40	40	40	40	40	0	0	0	0	0
			0	0	0	0	0	0	0	0	0	0
Subtotal Man-Hours			80	80	80	80	80	0	0	0	0	0
Subtotal \$			\$15,730	\$15,730	\$15,730	\$15,730	\$15,730	\$0	\$0	\$0	\$0	\$0
EXPENSES												
Denver Office Travel Expenses			\$0	\$3,000	\$3,000	\$0	\$3,000	\$0	\$3,000	\$0	\$0	\$0
Denver Office Expenses			\$500	\$500	\$500	\$500	\$500	\$500	\$20,000	\$0	\$0	\$0
Misc.			\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Subtotal \$			\$500	\$3,500	\$3,500	\$500	\$3,500	\$500	\$23,000	\$0	\$0	\$0
SUBTOTAL SUBCONTRACTORS AND EXPENSES (HOURS)			80.0 hrs	80.0 hrs	80.0 hrs	80.0 hrs	80.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs
SUBTOTAL SUBCONTRACTORS AND EXPENSES (COST)			\$16,230	\$19,230	\$19,230	\$16,230	\$19,230	\$500	\$23,000	\$0	\$0	\$0
PROJECT TOTAL (HOURS)			380.0 hrs	380.0 hrs	380.0 hrs	380.0 hrs	380.0 hrs	300.0 hrs	300.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs
PROJECT TOTAL (COST)			\$54,181	\$57,181	\$57,181	\$54,181	\$57,181	\$38,452	\$60,952	\$0	\$0	\$0

Total Rate 1/11	Total Rate 8/11	Billed (\$)	Overhead 0.000	Total
540	1080	\$293,135	\$0	\$293,135
0	0	\$0	\$0	\$0
360	720	\$56,945	\$0	\$56,945
180	360	\$41,414	\$0	\$41,414
1080	2160			
(Check)	\$391,494	\$391,494	\$0	\$391,494
0	0	\$0	\$0	\$0
540	1080	\$225,190	\$0	\$225,190
360	720	\$150,127	\$0	\$150,127
900	1800			
(Check)	\$375,317	\$375,317	\$0	\$375,317
180	540	\$78,952	\$0	\$78,952
0	440	\$49,051	\$0	\$49,051
180	980			
(Check)	\$128,003	\$128,003	\$0	\$128,003
2160.0 hrs	4940.0 hrs			7100.0 hrs
(Check)	\$894,813	\$894,813	\$0	\$894,810

Total Rate 1/11	Total Rate 8/11	Billed (\$)	Overhead 0.150	Total
120	280	\$58,128	\$8,719	\$66,848
120	280	\$96,080	\$14,412	\$110,492
240	560			
(Check)	\$154,208	\$154,208	\$23,131	\$177,340
		\$72,000	\$10,800	\$82,800
		\$33,000	\$4,950	\$37,950
		\$0	\$0	\$0
(Check)	\$105,000	\$105,000	\$15,750	\$120,750
400.0 hrs	400.0 hrs			800.0 hrs
(Check)	\$259,208	\$259,208	\$38,881	\$298,080
4560.0 hrs	3340.0 hrs			7900.0 hrs
(Check)	\$1,154,022	\$1,154,022	\$38,881	\$1,192,890

**INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION &
ENHANCED OIL RECOVERY PROJECT**
Coffeyville Resources Fertilizer Plant (CVR) to the Thrall-Aagard Oil Field (TAF)
Inspection, Survey and X-Ray
Blue Source LLC
Date: March 26, 2010

Procurement Inspection

Description	Rate	Quantity	Manufacture [Days]	Set Up/ Close Out Duration [Days]	Total Cost
Chief Inspector	\$ 2100.00		66	10	\$ 167,200.00
Utility Inspector	\$ 2050.00		66	10	\$ 159,600.00
Inspector Mileage	\$ 0.50	480	66	10	\$ 18,240.00
Total Procurement Inspection					\$ 345,040
Total with Rooney Engineering Overhead of 15%					\$ 396,796
Total with Estimate Contingency of 15%					\$ 456,315

Construction Inspection

Description	Rate	Quantity	Construction Duration [Days]	Set Up/ Close Out Duration [Days]	Total Cost
Chief Inspector	\$ 2100.00		123	20	\$ 314,600.00
Chief Welding Inspector	\$ 6050.00		123	15	\$ 869,400.00
Welding Inspector	\$ 6000.00		123	15	\$ 828,000.00
Environmental Inspector	\$ 950.00	2	123	15	\$ 262,200.00
Inspector Mileage	\$ 0.50	1920	123	15	\$ 132,480.00
Total Construction Inspection					\$ 2,406,680
Total with Rooney Engineering Overhead of 15%					\$ 2,767,682
Total with Estimate Contingency of 15%					\$ 3,182,834

Survey - Route Survey

Description	Rate [\$/day]	Quantity [ea]	Construction Duration [Days]	Set Up/ Close Out Duration [Days]	Total Cost
2 Man Survey Crew (#1)	\$ 991.67	1	55	3	\$ 57,516.67
2 Man Survey Crew (#2)	\$ 991.67	0	0	0	\$ -
GPS Survey Equipment (#1)	\$ 650.00	1	55	3	\$ 37,700.00
GPS Survey Equipment (#2)	\$ 650.00	0	0	0	\$ -
Survey Truck (#1)	\$ 450.00	1	55	3	\$ 26,100.00
Survey Truck (#2)	\$ 450.00	0	0	0	\$ -
Per Diem (#1)	\$ 110.00	2	55	3	\$ 12,760.00
Per Diem (#2)	\$ 110.00	0	0	0	\$ -
Total Route Survey					\$ 134,077
Total with Rooney Engineering Overhead of 15%					\$ 154,188
Total with Estimate Contingency of 15%					\$ 177,316

Survey - Construction & As-Built Survey

Description	Rate [\$/day]	Quantity [ea]	Construction Duration [Days]	Set Up/ Close Out Duration [Days]	Total Cost
2 Man Survey Crew (#1)	\$ 991.67	2.5	123	2	\$ 309,895.83
2 Man Survey Crew (#2)	\$ 991.67	2.5	123	2	\$ 309,895.83
GPS Survey Equipment (#1)	\$ 650.00	2.5	123	2	\$ 203,125.00
GPS Survey Equipment (#2)	\$ 650.00	2.5	123	2	\$ 203,125.00
Survey Truck (#1)	\$ 450.00	2.5	123	2	\$ 140,625.00
Survey Truck (#2)	\$ 450.00	2.5	123	2	\$ 140,625.00
Per Diem (#1)	\$ 110.00	5	123	2	\$ 68,750.00
Per Diem (#2)	\$ 110.00	5	123	2	\$ 68,750.00
Total Survey - Construction and As-Built					\$ 1,444,792
Total with Rooney Engineering Overhead of 15%					\$ 1,661,510
Total with Estimate Contingency of 15%					\$ 1,910,737

NDE (X-Ray) Inspection

Description	Rate [\$/day]	Quantity	Construction Duration [Days]	Set Up/ Close Out Duration [Days]	Total Cost
Two Man RT Crew (#1)	\$ 933.33	2.5	123	20	\$ 333,665.48
Two Man RT Crew (#2)	\$ 933.33	2.5	123	20	\$ 333,665.48
Mobile Darkroom (#1)	\$ 85.00	2.5	123	20	\$ 30,387.50
Mobile Darkroom (#2)	\$ 85.00	2.5	123	20	\$ 30,387.50
Pick Up Truck (#1)	\$ 70.00	2.5	123	20	\$ 25,025.00
Pick Up Truck (#2)	\$ 70.00	2.5	123	20	\$ 25,025.00
Source and Camera (#1)	\$ 475.00	2.5	123	20	\$ 169,812.50
Source and Camera (#2)	\$ 475.00	2.5	123	20	\$ 169,812.50
HS & BRC Security Fee (#1)	\$ 35.00	2.5	123	20	\$ 12,512.50
HS & BRC Security Fee (#2)	\$ 35.00	2.5	123	20	\$ 12,512.50
Per Diem (per 2 man crew) (#1)	\$ 125.00	5	123	20	\$ 89,375.00
Per Diem (per 2 man crew) (#2)	\$ 125.00	5	123	20	\$ 89,375.00
Total NDE (X-ray)					\$ 1,321,556
Total with Rooney Engineering Overhead of 15%					\$ 1,519,789
Total with Estimate Contingency of 15%					\$ 1,747,758
Engineering Survey and Procurement Inspection					\$ 633,632
Construction Inspection, Surveying and X-Ray					\$ 6,841,329

**INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION &
ENHANCED OIL RECOVERY PROJECT**
Coffeyville Resources Fertilizer Plant (CVR) to the Thrall-Aagard Oil Field (TAF)
Material Quote Summary
Blue Source LLC
Dated: March 26, 2010

Pipeline Material Bid Summary

Type	Analysis	Material Description	Cost
3D Bends	Average	8", 0.500" w.t., 90 Degree, 3D, MSS SP-75, WPHY-65, Segmentable Fitting, coated with 14-16 mils of FBE	\$1,781.50
	Average	8", 0.500" w.t., 60 Degree, 3D, MSS SP-75, WPHY-65, Segmentable Fitting, coated with 14-16 mils of FBE	\$1,756.50
	Average	8", 0.500" w.t., 90 Degree, 3D, MSS SP-75, WPHY-65, Segmentable Fitting, coated with 14-16 mils of FBE	\$1,110.50
Line Pipe	Average	8.625" OD, 0.500" w.t., ERW, API 5L, PSL2, Grade X-65, DRL, BEW, Coated with 14-16 mils of FBE	\$50.23
	Average	8.625" OD, 0.500" w.t., SMLS, API 5L, PSL2, Grade X-65, DRL, BEW, Coated with 14-16 mils of FBE	\$47.48
Launcher/Receiver	Average	8" x 12" - ANSI 1500 Launcher/Receiver, Barrel and Closure (Yale 500 or equivalent) Only, Traps to accommodate instrumented pigs, conventional pigs and typical pipeline inspection tools.	\$30,622.00
Pig Launcher - Bill of Material	Edgen - Murray	8" x 12" Pig Launcher Bill of Materials	\$28,912.36
Pig Launcher - Bill of Material	Edgen - Murray	8" x 12" Pig Receiver Bill of Materials	\$19,638.36
Valves	Cameron	8" 1500 RTJ GO CAMERON T31 TRIM 601 w/ 7" STEM EXTENSION & COAL TAR	\$13,003.00
		6" 1500 RTJ GO CAMERON T31 TRIM 601	\$9,300.00

**INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION &
 ENHANCED OIL RECOVERY PROJECT**
Coffeyville Resources Fertilizer Plant (CVR) to the Thrall-Aagard Oil Field (TAF)
Blue Source LLC
Date: March 26, 2010

Road, Railroad, and Waterway Crossing List

Approx Mile Post	Description / Name	Approximate Length	Interstate	Highway / State Rd	Other Paved Road	Dirt Road	Railroad	Lake / River	Creek	Comments	Valve Locations
MP 0.0	East Martin Street	75 ft			1					Slick Bore - Uncased	
MP 0.2	North Pine Street	50 ft				1				Open Cut	
MP 0.3	East Martin Street	75 ft			1					Slick Bore - Uncased	
MP 0.3	Missouri Kansas Texas Railroad	100 ft				1				Dorectional Drill - Uncased	
MP 0.7	Sycamore Street	50 ft			1					Open Cut	
MP 1.0	Private Drive	50 ft			1					Open Cut	
MP 1.7	North Central Ave	50 ft			1					Open Cut	
MP 1.9	Stark Street	50 ft			1					Open Cut	
MP 2.1	North River Road	50 ft			1					Open Cut	
MP 2.9	North Buckeye Street	75 ft		1						Slick Bore - Uncased	
MP 3.3	North Cline Road	75 ft		1						Slick Bore - Uncased	
MP 4.1	County Road 4500	75 ft		1						Slick Bore - Uncased	
MP 4.6	Sycamore Creek	50 ft						1		Slick Bore - Uncased	
MP 5.1	County Road 4300	75 ft		1						Slick Bore - Uncased	
MP 6.1	County Road 4100	75 ft		1						Slick Bore - Uncased	
MP 7.2	County Road 3900	75 ft		1						Slick Bore - Uncased	
MP 8.2	County Road 3700	75 ft		1						Slick Bore - Uncased	
MP 8.5	Creek	50 ft						1		Slick Bore - Uncased	
MP 8.9	Private Drive	50 ft			1					Open Cut	
MP 9.5	Missouri-Pacific Railroad	100 ft				1				Dorectional Drill - Uncased	
MP 9.8	Onion Creek	75 ft						1		Slick Bore - Uncased	
MP 10.5	County Road 3300	75 ft		1						Slick Bore - Uncased	
MP 11.5	County Road 3100	75 ft		1						Slick Bore - Uncased	
MP 11.8	Spring Creek	75 ft						1		Slick Bore - Uncased	
MP 12.7	2600 Road	50 ft			1					Open Cut	
MP 12.8	Private Drive	50 ft			1					Open Cut	
MP 13.2	Private Drive	50 ft			1					Open Cut	
MP 13.8	2700 Road	50 ft			1					Open Cut	
MP 14.8	2500 Road	50 ft			1					Open Cut	
MP 15.6	Creek	30 ft						1		Slick Bore - Uncased	
MP 15.9	2300 Road	50 ft			1					Open Cut	
MP 16.6	2800 Road	50 ft			1					Open Cut	
MP 17.0	County Road 2100	75 ft		1						Slick Bore - Uncased	
MP 18.0	County Road 1900	50 ft			1					Open Cut	
MP 18.2	Highway 75	100 ft	1							Dorectional Drill - Uncased	
MP 18.3	Atchison Topeka and Santa Fe Railroad	100 ft				1				Dorectional Drill - Uncased	
MP 19.7	Private Drive	50 ft			1					Open Cut	
MP 20.8	County Road 1350	75 ft		1						Slick Bore - Uncased	
MP 21.0	3000 Road	50 ft			1					Open Cut	
MP 22.4	East County Line Road	50 ft			1					Open Cut	
MP 23.6	Private Drive	50 ft			1					Open Cut	
MP 24.8	Kansas Road	50 ft			1					Open Cut	
MP 25.7	Road 30	50 ft			1					Open Cut	
MP 28.2	Independence Road	50 ft			1					Open Cut	
MP 29.2	Lariat Road	50 ft			1					Open Cut	
MP 30.1	Lariat Road	50 ft			1					Open Cut	
MP 30.6	Private Drive	50 ft			1					Open Cut	
MP 31.1	North Caney Creek	50 ft						1		Slick Bore - Uncased	
MP 31.4	Private Drive	50 ft			1					Open Cut	
MP 32.2	Road 23	50 ft			1					Open Cut	
MP 32.9	Lariat Road	50 ft			1					Open Cut	
MP 34.5	Road 22	50 ft			1					Open Cut	
MP 36.0	Road 19	50 ft			1					Open Cut	
MP 38.8	Kansas 99	100 ft	1							Dorectional Drill - Uncased	
MP 41.0	Creek	25 ft						1		Slick Bore - Uncased	
MP 42.3	Creek	25 ft						1		Slick Bore - Uncased	
MP 42.6	Spring Creek	75 ft						1		Slick Bore - Uncased	
MP 43.1	Road 14	50 ft			1					Open Cut	
MP 45.4	County Road 12	50 ft			1					Open Cut	
MP 45.9	Creek	25 ft						1		Slick Bore - Uncased	
MP 46.5	Saddle Road	50 ft			1					Open Cut	
MP 46.5	Road 11	50 ft			1					Open Cut	
MP 47.7	Road 10	50 ft			1					Open Cut	
MP 47.9	Caney Creek	50 ft						1		Slick Bore - Uncased	
MP 48.8	Road 9	50 ft			1					Open Cut	
MP 49.0	Well Pad Access Road	50 ft			1					Open Cut	
MP 49.3	Well Pad Access Road	50 ft			1					Open Cut	
MP 50.0	Road 8	50 ft			1					Open Cut	
MP 51.2	Road 7	50 ft			1					Open Cut	
MP 52.8	Valley Road	50 ft			1					Open Cut	
MP 52.9	163 Road	50 ft			1					Open Cut	
MP 53.8	Caney River	200 ft					1			Dorectional Drill - Uncased	
MP 54.5	61 Road	50 ft			1					Open Cut	
MP 55.1	15 1/2 Road	50 ft			1					Open Cut	
MP 56.6	Private Drive	50 ft			1					Open Cut	
MP 56.1	Spring Creek	75 ft						1		Slick Bore - Uncased	
MP 56.9	Creek	25 ft						1		Slick Bore - Uncased	
MP 59.5	Highway 160	100 ft	1							Dorectional Drill - Uncased	
MP 61.2	Well Pad Access Road	50 ft			1					Open Cut	
MP 61.3	Atchison Topeka and Santa Fe Railroad	100 ft				1				Dorectional Drill - Uncased	
MP 61.9	Creek	25 ft						1		Slick Bore - Uncased	

**INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION &
 ENHANCED OIL RECOVERY PROJECT**
Coffeyville Resources Fertilizer Plant (CVR) to the Thrall-Aagard Oil Field (TAF)
Blue Source LLC
Date: March 26, 2010

Road, Railroad, and Waterway Crossing List

Approx Mile Post	Description / Name	Approximate Length	Interstate	Highway / State Rd	Other Paved Road	Dirt Road	Railroad	Lake / River	Creek	Comments	Valve Locations
MP 62.7	Creek	25 ft						1		Slick Bore - Uncased	
MP 63.0	Creek	25 ft						1		Slick Bore - Uncased	
MP 63.4	Creek	25 ft						1		Slick Bore - Uncased	
MP 65.7	Creek	25 ft						1		Slick Bore - Uncased	
MP 67.3	Creek	25 ft						1		Slick Bore - Uncased	
MP 68.0	Creek	25 ft						1		Slick Bore - Uncased	
MP 69.3	Creek	25 ft						1		Slick Bore - Uncased	
MP 70.7	Creek	25 ft						1		Slick Bore - Uncased	
MP 71.9	Oxen Road	50 ft			1					Open Cut	
MP 72.2	Creek	25 ft						1		Slick Bore - Uncased	
MP 72.4	South Branch Creek	50 ft						1		Slick Bore - Uncased	
MP 74.1	Creek	25 ft						1		Slick Bore - Uncased	
MP 74.4	Creek	25 ft						1		Slick Bore - Uncased	
MP 74.5	Crisco Road	50 ft			1					Open Cut	
MP 75.0	Creek	25 ft						1		Slick Bore - Uncased	
MP 75.1	Elk River	200 ft					1			Dorectional Drill - Uncased	
MP 77.9	Township Road 515	50 ft			1					Open Cut	
MP 79.5	St Louis - San Francisco Railroad	100 ft				1				Dorectional Drill - Uncased	
MP 80.2	Blodgett Road	50 ft			1					Open Cut	
MP 80.3	Highway 400	100 ft	1							Dorectional Drill - Uncased	
MP 80.9	McMillian Road	50 ft			1					Open Cut	
MP 81.3	Township Road 436	50 ft			1					Open Cut	
MP 82.8	North Branch Otter Creek	75 ft						1		Slick Bore - Uncased	
MP 83.4	Creek	25 ft						1		Slick Bore - Uncased	
MP 83.9	Star Road	50 ft			1					Open Cut	
MP 84.3	Creek	25 ft						1		Slick Bore - Uncased	
MP 84.9	Creek	25 ft						1		Slick Bore - Uncased	
MP 85.4	Beedle Drive	50 ft			1					Open Cut	
MP 85.5	County Road 27	75 ft		1						Slick Bore - Uncased	
MP 85.8	Watson Branch Creek	50 ft						1		Slick Bore - Uncased	
MP 86.7	Creek	25 ft						1		Slick Bore - Uncased	
MP 87.1	County Road 27	50 ft			1					Open Cut	
MP 89.1	County Road 25	75 ft		1						Slick Bore - Uncased	
MP 89.9	Spring Creek	75 ft						1		Slick Bore - Uncased	
MP 90.2	Private Drive	50 ft			1					Open Cut	
MP 90.4	Township Road 706	50 ft			1					Open Cut	
MP 90.7	Missouri-Pacific Railroad	100 ft				1				Dorectional Drill - Uncased	
MP 92.2	Highway 54	100 ft	1							Dorectional Drill - Uncased	
MP 93.3	Township Road 42	50 ft			1					Open Cut	
MP 93.3	Township Road 43	50 ft			1					Open Cut	
MP 94.0	Private Drive	50 ft			1					Open Cut	
MP 95.0	Creek	25 ft						1		Slick Bore - Uncased	
MP 95.3	West Branch Fall River	200 ft					1			Dorectional Drill - Uncased	
MP 95.9	County Road 15	75 ft		1						Slick Bore - Uncased	
MP 95.9	East Branch Fall River	200 ft					1			Dorectional Drill - Uncased	
MP 97.2	Township Road 45	50 ft			1					Open Cut	
MP 98.5	Township Road 46	50 ft			1					Open Cut	
MP 100.5	County Road 8	75 ft		1						Slick Bore - Uncased	
MP 101.6	Township Road 326	50 ft			1					Open Cut	
MP 104.7	Creek	25 ft						1		Slick Bore - Uncased	
MP 105.7	Township Road 576	50 ft			1					Open Cut	
MP 106.4	Creek	25 ft						1		Slick Bore - Uncased	

Crossing Summary

TYPE	TOTAL NO. CROSSINGS	TOTAL LENGTH	W.A. Length	W.A. Width	W.A. Dimensions
Interstate	0	0 ft	300 ft	300 ft	0 sq.ft.
Highway / State Rd	5	500 ft	300 ft	300 ft	900,000 sq.ft.
Other Paved Road	17	1,275 ft	300 ft	300 ft	3,060,000 sq.ft.
Dirt Road	64	3,200 ft	300 ft	300 ft	11,520,000 sq.ft.
Railroad	6	600 ft	300 ft	300 ft	1,080,000 sq.ft.
Lake / River	4	800 ft	300 ft	300 ft	720,000 sq.ft.
Creek	37	1,380 ft	300 ft	300 ft	6,660,000 sq.ft.
TOTAL	133	7,755 ft	N/A	N/A	23,940,000 sq.ft.

Total Crossing Work Areas = 549.6 acres
 Pipeline ROW Disturbance = 983.6 acres
Total Disturbance = 1533.2 acres

**INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION &
ENHANCED OIL RECOVERY PROJECT**
Coffeyville Resources Fertilizer Plant (CVR) to the Thrall-Aagard Oil Field (TAF)
Blue Source LLC
Date: March 29, 2010

FEED ESTIMATE FOR SCADA SYSTEM

CLIENT: BLUE SOURCE
 PROJECT: CVR-TAF
 DESCRIPTION: 108.2 MILES OF CO2 PIPELINE FROM THE COFFEYVILLE TO THRALL-AAGARD OIL FIELD

DATE: 29-Mar-10

Estimate Overview:

This estimate is for a SCADA and Leak Detection system for a CO2 pipeline with main stations on either end of the pipeline and block valves sites along the pipeline as required. Each site would have a PLC and installed in a small building. The main control center site would house the primary SCADA and Leak Detection Computers which would communicate via fiber to the other sites. The other end of the pipeline would have a backup control center which would also contain the secondary SCADA and Leak Detection computers. A fiber optic cable would be installed along the pipeline and would be configured in a ring configuration for improved reliability.

SCADA Materials

	Quantity	Unit Price	Extension
Origination Station	1	\$ 196,500.00	\$ 196,500.00
Terminal Station	1	\$ 176,700.00	\$ 176,700.00
Block Valve Stations	1	\$ 927,000.00	\$ 927,000.00
Fiber Optic Cable	1	\$ 951,944.00	\$ 951,944.00
		Subtotal	\$ 2,252,144.00
		Sales Tax on Material (5.98%)	\$ 134,700.00
		Subtotal	\$ 2,745,000

SCADA Engineering Hours/Expenses

	Hours	Unit Price	Extension
Sr Project Engineer - SCADA	1604	\$ 121.00	\$ 194,084.00
Sr Designer	104	\$ 91.00	\$ 9,464.00
Travel Expenses	1	\$ 13,130.00	\$ 13,130.00
		Subtotal	\$ 249,000

SCADA Vendor Labor

	Quantity	Unit Price	Extension
SCADA, PLC, Leak Detection Services	1	\$ 405,000.00	\$ 405,000.00
		Subtotal	\$ 466,000

Fiber Optic Construction Labor

	Quantity	Unit Price	Extension
Fiber Optic Cable Construction Contractor	1	\$ 1,142,592.00	\$ 1,142,592.00
		Subtotal	\$ 1,314,000

Total \$ 4,774,000

Assumed Estimate Contingency 15.0%

Notes:

- 1) SCADA electrical construction contractor labor not included since wiring up the PLCs would be done by site contractor along with instruments
- 2) Fiber optic labor assumes moderately difficult ground conditions which raises cable installation cost moderately
- 3) PLC MCC building is included at the terminal station
- 4) Instrumentation not included here.

**INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION &
ENHANCED OIL RECOVERY PROJECT**
Coffeyville Resources Fertilizer Plant (CVR) to the Thrall-Aagard Oil Field (TAF)
Blue Source LLC
Date: March 29, 2010

STATIONS ON EITHER END OF PIPELINE

Materials

		Quantity	Unit Price	Extension
ORIGINATION STATION	PLC, w Cabinet	1	\$ 40,000.00	\$ 40,000.00
	SCADA Software Licenses	1	\$ 35,000.00	\$ 35,000.00
	Backup communications components	1	\$ 10,000.00	\$ 10,000.00
	SCADA Server, Rack, Printer, etc	1	\$ 20,000.00	\$ 20,000.00
	Leak Detection Server	1	\$ 5,000.00	\$ 5,000.00
	Leak Detection Software Licenses (note 2)	1	\$ 60,000.00	\$ 60,000.00
	UPS	1	\$ 5,000.00	\$ 5,000.00
	Fiber Media Converter	1	\$ 1,500.00	\$ 1,500.00
	Communications Equipment for backup communications	1	\$ 5,000.00	\$ 5,000.00
	Misc	1	\$ 15,000.00	\$ 15,000.00
			Subtotal	\$ 196,500.00

		Quantity	Unit Price	Extension
TERMINAL STATION	PLC, w Cabinet	1	\$ 40,000.00	\$ 40,000.00
	PLC-MCC Building	1	\$ 65,000.00	\$ 65,000.00
	SCADA Software Licenses	1	\$ 7,000.00	\$ 7,000.00
	Backup communications components	1	\$ 10,000.00	\$ 10,000.00
	SCADA Computer, Rack	1	\$ 10,000.00	\$ 10,000.00
	Leak Detection Computer	1	\$ 5,000.00	\$ 5,000.00
	Leak Detection Software Licenses	1	\$ 15,000.00	\$ 15,000.00
	UPS	1	\$ 5,000.00	\$ 5,000.00
	Fiber Media Converter	1	\$ 3,200.00	\$ 3,200.00
	Communications Equipment for backup communications	1	\$ 1,500.00	\$ 1,500.00
	Misc	1	\$ 15,000.00	\$ 15,000.00
			Subtotal	\$ 176,700.00

			Extension
VENDOR SERVICES	SCADA Vendor Services for Origination Station (note 6)	1	\$ 175,000.00
	SCADA Vendor services for Terminal Station	1	\$ 10,000.00
	SCADA Vendor Travel Expenses	1	\$ 30,000.00
	PLC Programming for two PLCs	2	\$ 50,000.00
	PLC Programmer Travel Expenses	1	\$ 15,000.00
	Leak Detection System services for Origination Station	1	\$ 60,000.00
	Leak Detection System services for Terminal Station	1	\$ 5,000.00
	Leak Detection Vendor Travel Expenses	1	\$ 10,000.00
			\$ -
			Subtotal
			\$ 405,000.00

Notes:

- 1) Assumes fiber optic communications.
- 3) PLC MCC building is included at the terminal station
- 3) Assumes Wonderware class SCADA software
- 4) Assuming 120 VAC is available at both stations.
- 5) Instrumentation not included here.
- 6) SCADA vendor services include project management, design specification documents, SCADA communications programming, SCADA screen programming, factory tests, installation onsite, onsite tuning of the software, commissioning tests, operations and the maintenance manual, training support for operators and technicians
- 7) Leak Detection vendor services include project management, design specification documents, communications programming, graphical user interface screen programming, factory tests, installation onsite, tuning of the software, commissioning tests, operations and the maintenance manual, training support for operators and technicians

**INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION &
ENHANCED OIL RECOVERY PROJECT
Coffeyville Resources Fertilizer Plant (CVR) to the Thrall-Aagard Oil Field (TAF)
Blue Source LLC
Date: March 29, 2010**

BLOCK VALVE STATIONS

Materials

	Quantity	Unit Price	Extension
PLC, w Cabinet	18	\$ 15,000.00	\$ 270,000.00
PLC Building	18	\$ 30,000.00	\$ 540,000.00
Fiber media converter	18	\$ 1,500.00	\$ 27,000.00
Misc	18	\$ 5,000.00	\$ 90,000.00
		Subtotal	\$ 927,000.00

Services

	Quantity	Unit Price	Extension
PLC Programming	18	\$ 3,000.00	\$ 54,000.00
PLC Programmer Travel Expenses	18	\$ 1,000.00	\$ 18,000.00
Misc	18	\$ 2,000.00	\$ 36,000.00
		Subtotal	\$ 108,000.00

Notes:

1 PLC building is recommended due to the difficulty of maintaining PLC in winter conditions.

**INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION &
 ENHANCED OIL RECOVERY PROJECT
 Coffeyville Resources Fertilizer Plant (CVR) to the Thrall-Aagard Oil Field (TAF)
 Blue Source LLC
 Date: March 29, 2010**

FIBER OPTICS

Materials

	Quantity	Units	Unit Price	Extension
12 Strand Single Mode Armored Outside Plant Cable	571,296	ft	\$ 1.50	\$ 856,944.00
Fiber troubleshooting instrument	1	LS	\$ 35,000.00	\$ 35,000.00
Misc Hand Holes, etc	3	LS	\$ 20,000.00	\$ 60,000.00
			Subtotal	\$ 951,944.00

Labor - Installation Contractor

	Quantity	Units	Unit Price	Extension
Contractor Labor for installation and testing	571,296	ft	\$ 2.00	\$ 1,142,592.00
				\$ -
			Subtotal	\$ 1,142,592.00

Notes:

INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION &
 ENHANCED OIL RECOVERY PROJECT
 Coffeyville Resources Fertilizer Plant (CVR) to the Thrall-Aagard Oil Field (TAF)
 Blue Source LLC
 Date: March 26, 2010

SCADA PROJECT - ESTIMATE OF I&E ENGINEERING TASKS

			Project Management					TRAVEL & MISC EXPENSES					Engineering							
			Note 1	Project Manager	Secretary & File Clerk	Subtotal Man-Hours	Subtotal \$	Travel	Denver Office Travel - Other	Denver Office Expenses	Misc.	Subtotal \$	Project Engineer (Controls)	Sr. Project Engineer (Electrical)	Electrical Designers	Designer	Subtotal Man-Hours	Subtotal \$	Grand Total Hours	Grand Total \$
TASK #	TASKS		Rates:		\$44.00								\$116.00	\$121.00	\$91.00	\$91.00				
1	Initial Site visit					0	\$0	1,920				\$1,920		30			30	3,630	30	5,550
2						0	\$0					\$0					0	0	0	0
3						0	\$0					\$0					0	0	0	0
4	Assist with Project Budget preparation					0	\$0					\$0		24			24	2,904	24	2,904
5						0	\$0					\$0					0	0	0	0
6	SCADA SPECIFICATION, RFQ, CONTRACT OVERSIGHT, DESIGN APPROVAL, FACTORY TEST, SITE TEST					0	\$0		300			\$300		400			400	48,400	350	48,700
7						0	\$0					\$0					0	0	0	0
	LEAK DETECTION SYSTEM SPECIFICATION, RFQ, CONTRACT OVERSIGHT, DESIGN APPROVAL, FACTORY TEST, SITE TEST					0	\$0		200			\$200		300			300	36,300	250	36,500
1						0	\$0					\$0					0	0	0	0
2	Fiber Optic Design, RFQ					0	\$0					\$0		120			120	14,520	120	14,520
3						0	\$0					\$0					0	0	0	0
4	Fiber Optic Construction Spec, RFQ, Contract Oversight					0	\$0					\$0		100			100	12,100	100	12,100
5						0	\$0					\$0					0	0	0	0
6						0	\$0					\$0					0	0	0	0
7						0	\$0					\$0					0	0	0	0
8						0	\$0					\$0					0	0	0	0
9						0	\$0					\$0					0	0	0	0
10						0	\$0					\$0					0	0	0	0
11						0	\$0					\$0					0	0	0	0
12	Weekly Conference Calls					0	\$0					\$0		30			30	3,630	30	3,630
13						0	\$0					\$0					0	0	0	0
14	Construction Inspection Trip (X 5)					0	\$0	5,950				\$5,950		200			200	24,200	200	30,150
15	Testing Trips (x 4)					0	\$0	4,760				\$4,760		160			160	19,360	160	24,120
16						0	\$0					\$0					0	0	0	0
17						0	\$0					\$0					0	0	0	0
18	As Built Electrical Drawings					0	\$0					\$0		80	100		180	18,780	180	18,780
19	I&E Job Book					0	\$0					\$0		40	4		44	5,204	44	5,204
20						0	\$0					\$0					0	0	0	0
21	Assist with SCADA & Leak Detection Tuning					0	\$0					\$0		120			120	14,520	120	14,520
22						0	\$0					\$0					0	0	0	0
23						0	\$0					\$0					0	0	0	0
24						0	\$0					\$0					0	0	0	0
25							\$0										24	0		
26					0	0	\$0	0	0			\$0	0		0	0	0	0	0	0
27					0	0	\$0	0	0	0		\$0	0	0	0	0	0	0	0	0
Hours				0	0	0	\$0	12,630	0	500	0	13,130	0	1,604	104	0	1,732	203,548	1,608	
Cost (\$)				0	0	\$0		12,630	0	500	0	13,130	0	194,084	9,464	0		203,548		216,678
Back check							\$0					13,130						203,548		\$216,678
																		0		\$216,678

**BLUE SOURCE, LLC.
CVR-TAF CO2 PIPELINE PROJECT
COFFEYVILLE COMPRESSION FACILITY
TIER III - CAPITAL COST ESTIMATE**

Client: Blue Source, LLC.

Project: CVR-TAF CO2 Pipeline Project

System: Coffeyville Compression Facility

Scope: Ref. Blue Source RFP for Kansas CO2 Pipeline Study, Doc. RPH-12-29-09.

Description: Engineering, Design & Construction of low pressure booster facilities to take waste gas off of the Coffeyville Refinery Amine Plant vent stack and transport it approximately 1,300 ft. via a new 24", SDR-32.5 high density polyethylene (HDPE) pipeline to a new BS/CVR compression facility located in the SW NE of Section 36, T34S, R16E, where the CO2 mix stream is processed for use in Enhanced Oil Recover and taken from the vapor phase to the supercritical phase and boosted to pipeline pressure for transportation to the Thrall Aagard Field delivery point located in NW NW of Section 31, T24S, R10E.

COMPRESSION FACILITIES

ENGINEERING & DESIGN	\$985,000
BS/CVR COMPRESSION FACILITIES	\$984,538
LAND & RIGHT-OF-WAY	\$0
BS/CVR COMPRESSION FACILITIES	\$0
ENVIRONMENTAL & PERMITTING	\$6,000
BS/CVR COMPRESSION FACILITIES	\$5,750
EQUIPMENT & MATERIALS	\$20,472,000
BS/CVR COMPRESSION FACILITIES	\$17,885,950
FREIGHT @ 8%	\$1,430,876
TAXES @ 5.98%	\$1,155,146
CONSTRUCTION SERVICES	\$1,194,000
BS/CVR COMPRESSION FACILITIES	\$1,194,321
CONSTRUCTION	\$3,891,000
BS/CVR COMPRESSION FACILITIES	\$3,792,130
BOND @ 3%	\$98,925
GRAND TOTAL COMPRESSION FACILITIES:	
	\$26,548,000

Notes & Assumptions:

BLUE SOURCE, LLC.
CVR-TAF CO2 PIPELINE PROJECT
COFFEYVILLE COMPRESSION FACILITY
TIER III - CAPITAL COST ESTIMATE

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BS/CVR COMPRESSION FACILITIES				Station Horsepower: 15,000 BHP		% Total	
LAND & RIGHT-OF-WAY (BY OTHERS)					\$0		0.0%
ENVIRONMENTAL & PERMITTING (BY OTHERS)					\$5,000		0.0%
MATERIALS & EQUIPMENT					\$15,553,000		58.6%
CONSTRUCTION					\$3,297,505		12.4%
Land, Permitting, Materials & Construction Sub-Total:					\$18,855,505		71.0%
Freight on Materials & Equipment @ 8%					\$1,244,240		
Taxes @ 5.98%					\$1,004,475		
Land, Permitting, Materials & Construction Total:					\$21,104,219		79.5%
ENGINEERING & DESIGN					\$836,120		3.1%
GEOTECHNICAL INVESTIGATIONS					\$20,000		0.1%
CONSTRUCTION MANAGEMENT					\$723,540		2.7%
SURVEY (INCL W/ CONSTRUCTION COSTS)				0.0%	\$0		0.0%
INSPECTION SERVICES	No. of Inspectors: 4	240 Man-Days @	\$1,100 per Day	100%	\$264,000		1.0%
NON-DESTRUCTIVE EXAMINATION	No. of Crews: 1	30 Crew-Days @	\$1,700 per Day	100%	\$51,000		0.2%
LEGAL (BY OTHERS)					\$0		0.0%
Engineering & Contract Services Sub-Total:					\$1,894,660		7.1%
Compression Facilities Sub-Total:					\$22,998,879		
Contingency @ 15%					\$3,449,832		13.0%
Construction Performance Bond @ 3%					\$98,925		0.4%
COMPRESSION FACILITIES TOTAL:					\$26,547,637		100.0%
\$ / BHP:					\$1,770		

LAND & RIGHT-OF-WAY

100. BS/CVR COMPRESSOR STATION	\$0
Sub-Total:	\$0
Contingency @ 15%	\$0
Grand Total - Land & Right-of-Way:	\$0

Project Estimate Worksheet

Description	Cost Code	Qty	Units	Unit Rate	Sub-Total Price	Estimate Supplier
100. BS/CVR COMPRESSOR STATION					Sub-Total: \$0	
101. Acquisition & Damages						
01 Land & Property Appraisals		0	Weeks	\$2,500	\$0	
02 Land Acquisition Costs		0	Weeks	\$2,500	\$0	
03 Property Expense		0	LS	\$50,000	\$0	

ENVIRIONMENTAL & PERMITTING SUPPORT

100. BS/CVR COMPRESSOR STATION	\$5,000
Sub-Total:	\$5,000
Contingency @ 15%	\$750

Project Estimate Worksheet

Grand Total - Environmental & Permitting Support: \$5,750

Description	Cost Code	Qty	Units	Unit Rate	Sub-Total Price	Estimate Supplier
100. BS/CVR COMPRESSOR STATION					Sub-Total: \$5,000	
101. Permitting Assistance						
01 Air Permitting Support & Acquisition Costs	101.01	1	LS	\$5,000	\$5,000	LWR Consultants
102. Storm Water Monitoring						
01 TBD	102.01	1	LS	\$0	\$0	

Blue Source, LLC.
CVR-TAF CO2 Pipeline Project
Coffeyville Compression Facility

MATERIALS & EQUIPMENT

100. MECHANICAL EQUIPMENT & MATERIALS	\$14,463,000
200. ELECTRICAL & INSTRUMENTATION EQUIPMENT & MATERIALS	\$1,090,000
Sub-Total:	\$15,553,000
Freight @ 8%	\$1,244,240
Taxes @ 6%	\$1,004,475
Contingency @ 15%	\$2,670,257

Project Estimate Worksheet

Grand Total - Materials & Equipment: \$20,471,972

Description	Cost Code	Qty	Units	Unit Rate	Sub-Total Price	Estimate Supplier
100. MECHANICAL EQUIPMENT & MATERIALS					Sub-Total: \$14,463,000	
101. Pipe, Fittings & Materials						
01 Pipe, Various Diameters & Coatings	101.01	Pipe_Lot2	2	LOT	\$20,000	REI - Estimated
02 24-Inch, SDR-11, High Density Polyethylene	101.02	24_HDPE_SDR11	1,386	LF	\$65	Ferguson
03 Fittings, Various Diameters	101.03	Fitting_Lot3	2	LOT	\$15,000	REI - Estimated
102. Scrubbers / Filters / Separators						
01 Scrubber, 2-Phase, Vertical, 8.625" O.D. x 4'-0" S/S, ASME Sect. VIII, Div. 1, 285 psi @ -20/1C	01	Scrubber_Vertical 8x48	1	EA	\$5,749	Midco Fabricators
103. Compression Equipment						
01 API Centrifugal Compressor / API Centrifugal Pump, Integrated Package, 15,000 bhp Total	103.01	Comp_Cent_15000HP	1	EA	\$11,000,000	GE - Est.
02 Compressor / Pump Integrated Package Spare Parts	103.02	Spares	1	LS	\$880,000	GE - Est.
03 Compressor, Blower, GD Suitoilbuild 8000 or Equal, 500 HP, 4160V Inv. Duty Electric Drive	103.03	Comp_Blower_500HP	3	EA	\$200,000	UE Compression - Est.
104. Processing Equipment						
01 TEG Dehydration Package, 3.5 MMBTU/ Hr Reboiler, 60" Contactor Column	104.01	Dehy_TEG3.5	1	EA	\$1,100,000	QB Johnson
105. Compressor Building						
01 Compressor Building, 75' W x 80' L x 15' Eve Hght, Ovhd Door, Fixed Louvers, 5 Ton Bridge C	105.01	Comp_Bldg 75x80x15	1	EA	\$361,444	REI - Estimated
106. Block Valves & SDV's						
01 Valves, Various Sizes & Type	106.01	Valve_Lot4	1	LOT	\$250,000	REI - Estimated
107. Metering						
01 Meter, Ultrasonic, Krohne Model UFM3030, 8" 150# ANSI, RFFE, w/ Local Indication & Signal	107.01	8ULT150	3	EA	\$6,311	Trailblazer Controls
02 Orifice Meter, 2" ANSI 150 RFFE, Simplex w/ Flow Cond. & Skid Mounted Metal Building	107.02	2ORF150_JR	3	EA	\$7,738	JW Measurement
108. Check Valves						
01 Valve, Check, 4" ANSI 600 RFFE, Swing, API-6D	108.01	4C60AS	4	EA	\$742	REI - Estimated
109. Sump Tank						
01 Sump Tank, 3,000 Gallon, Double Wall Fiberglass w/ Turbine Enclosure, Leak Monitor, Brine	109.01	Sump_3000	1	EA	\$17,808	Palmer Mfct - 11.17.09
110. Pipe Supports						
01 Pipe Support, 20" Pipe, EZ-Line Model CSB-20 w/Shim Blocks, Pipe Clamp & Baseplate	110.01	CSB-20	8	EA	\$1,516	EZ-Line - 2009
02 Pipe Support, 12" Pipe, EZ-Line Model CSB-12 w/Shim Blocks, Pipe Clamp & Baseplate	110.02	CSB-12	16	EA	\$1,208	EZ-Line - 2009
03 Pipe Support, 8" Pipe, EZ-Line Model CSB-8 w/Shim Blocks, Pipe Clamp & Baseplate	110.03	CSB-08	8	EA	\$890	REI - Estimated
04 Pipe Support, 4" Pipe, EZ-Line Model CSB-4 w/Shim Blocks, Pipe Clamp & Baseplate	110.04	CSB-04	6	EA	\$742	REI - Estimated
200. ELECTRICAL & INSTRUMENTATION EQUIPMENT & MATERIALS					Sub-Total: \$1,090,000	
201. Instrumentation						
01 Pressure Gauge, 5" Dial, 1/2" MNPT Process Connection, Range: Varies	201.01	PI	3	EA	\$119	Applied Control Equip.
02 Gauge, Temperature, Range: Varies, w/ Thermowell	201.02	TI	3	EA	\$185	Applied Control Equip.
03 Switch, Gage Pressure, Range: Varies	201.03	PSHH	1	EA	\$425	REI - Estimated
04 Switch, Level, 316 SS Media Contacts w/ Relay, 24VDC	201.04	LSHH_1	1	EA	\$1,180	Applied Control Equip.
05 Gauge, Level, 316 SS Chamber w/ Side Connect Valves, Center-to-Center Dim: Varies	201.05	LG	1	EA	\$1,963	Applied Control Equip.
06 Pressure Transmitter, Indicating, "Smart", Range: Varies, Includes 2-Valve Manifold	201.06	PIT	4	EA	\$3,271	Rosemount, Inc.
07 Transmitter, Temperature, "Smart", Range: Varies, w/ Thermowell	201.07	TT	4	EA	\$2,650	Davis & Davis - Est.
08 Transmitter, Level, SABB Radar, Range: Varies w/ RTD Inputs	201.08	LIT-1	1	EA	\$4,637	Applied Control Equip.
09 Switch, Level, Range / Length: Varies	201.09	LSHH_2	1	EA	\$3,848	Applied Control Equip.
10 Carbon Dioxide Detector	201.10	CO2_DET	2	EA	\$1,272	REI - Estimated
11 Fire Eye, Class 1 / Div 1 Rated	201.11	FIRE_EYE	2	EA	\$1,272	REI - Estimated
12 Vibration Transducer	201.12	VT	8	EA	\$300	REI - Estimated
202. Switchgear / Motor Starters & MCC's						
01 Switchgear, 4160V w/ Vacuum Circuit Breaker & 4160V Solid State Reduced Voltage Starter	202.01	4160_Switchgear	1	EA	\$106,000	DM Consulting - Est.
02 4160V, 500 HP Soft Start	202.02	Soft_Start 1	3	EA	\$18,000	REI Estimated
03 Motor Control Center, 480V	202.03	480_MCC	1	EA	\$47,700	DM Consulting - Est.
203. Transformers						
01 Transformer, 4160V / 480V, Padmount, Oil Filled, 500 KVA, Nema 3R , 65 deg. C Rise	203.01	500KVA_TRN4160.480	1	EA	\$18,020	DM Consulting - Est.
02 Transformer, 13.8KV / 4160V, Padmount, Oil Filled, 5000 KVA	203.02	5000KVA_TRN138.4160	1	EA	\$132,500	DM Consulting - Est.
204. UPS / Power Supply Equipment						
01 Unitized Distribution Substation	204.01	UDS	1	EA	\$10,600	DM Consulting - Est.
02 UPS, Rack Mounted, Bypass Switch, 7 KVA	204.02	UPS	1	EA	\$9,540	DM Consulting - Est.
205. Control Switches & Lighting						
01 Lighting Subpanel, 120V, 1Ph	205.01	LGHT_Sub Panel	1	EA	\$636	DM Consulting - Est.
02 Yard Lighting, 1000 Watt w/40' Aluminum Pole	205.02	LGHT1000	6	EA	\$4,240	DM Consulting - Est.
206. Power & Control Buildings						
01 Building, Pre-Fab Metal, 13'x60', HVAC, w/ Access Platforms & Stairs	206.01	PDC_13x60MED	1	EA	\$260,760	REI - Estimated
207. PLC Equipment & Controls						
01 PLC & DIO Panel & Equipment, Incl. Programming & Commissioning	207.01	PLC_Lot2	0	LS	\$74,200	Included w/ SCADA
208. Consumables						
01 Electrical & Instrumentation Consumables (Compressor Station)	208.01	E&I_Cons 1	2	EA	\$184,440	DM Consulting - Est.

Blue Source, LLC.
CVR-TAF CO2 Pipeline Project
Coffeyville Compression Facility

CONSTRUCTION

100. BS/CVR COMPRESSOR STATION	\$3,297,505
Sub-Total:	\$3,297,505
Contingency @ 15%	\$494,626
Grand Total - Construction:	\$3,792,130

Project Estimate Worksheet

Description	Cost Code	Qty	Units	Unit Rate	Sub-Total Price	Estimate Supplier
100. BS/CVR COMPRESSOR STATION					Sub-Total: \$3,297,505	
101. BS/CVR Blower Facilities						
01 Blower Facility Construction	101.01	1	LS	\$600,000	\$600,000	REI - Estimated
102. 24-Inch LP HDPE Pipeline Construction						
01 24-Inch HDPE Pipeline	102.01	1,300	FT	\$25	\$32,500	Ferguson
103. Compressor Station Construction (Civil / Mechanical / Electrical)						
01 Compressor Station Construction	103.01	1	LS	\$2,207,900	\$2,207,900	REI - Estimated
104. 13.8KV Line Extension						
01 13.8 KV Line Extension, Includes Breaker & High Side Termination	104.01	1	LS	\$19,205	\$19,205	ESC, Inc.
105. E&I Unit Price Adders						
01 Megar / High Pot Testing	105.01	2	LS	\$50,000	\$100,000	REI - Estimated
02 Switchgear Commissioning	105.02	2	LS	\$35,000	\$70,000	REI - Estimated
106. Station Rock						
01 Station Rock Materials	106.01	1	LS	\$10,100	\$10,100	REI - Estimated
107. Pre-Commission / Commissioning / Start-Up Services						
01 E&I Contractor Support	107.01	12	DAYS	\$8,000	\$96,000	REI - Estimated
02 Mechanical Contractor Support	107.02	12	DAYS	\$10,000	\$120,000	REI - Estimated
03 Solid State Reduced Voltage Starters Technician	107.03	8	DAYS	\$2,000	\$16,000	REI - Estimated
04 Compression - Controls Technician	107.04	6	DAYS	\$2,300	\$13,800	REI - Estimated
05 Compression - Service Specialist / Supervisor	107.05	6	DAYS	\$2,000	\$12,000	REI - Estimated

APPENDIX 3-F
PROJECT SCHEDULE
THRALL-AAGARD FIELD

Project: MSProj11
Date: Wed 3/31/10

```
graph LR; Task[Task] --> Progress[Progress]; Progress --> Milestone[Milestone]; Milestone --> Summary[Summary]; Summary --> ProjectSummary[Project Summary]
```

The diagram illustrates a project workflow starting with a task, followed by progress tracking, a milestone, a summary, and finally a project summary.

APPENDIX 3-G
FEASIBILITY DRAWINGS
GENESEO-EDWARDS FIELD

Plot Date: 3/31/2010 4:09:28 PM File Name: W:\Blue Source LLC\02702 - KE-GE C02 Pipeline and Associated Facilities\CAD\PIPING\FD\02702-F-001.dwg Plot By: David Whorton

REFERENCE DRAWINGS		REVISIONS									<div>Rooney Engineering, Inc. 12201 E. Arapahoe Rd. C10 Centennial, CO 80112 (303) 792-5911</div>	CAP CO2, LLC.		
												KE-GE CO2 PIPELINE CAP CO2 COMPRESSION FACILITY PROCESS FLOW DIAGRAM		
DWG. NO.	DESCRIPTION	NO.	DESCRIPTION	BY	DATE	CHK	DATE	APP	DATE	SCALE: NTS	DWG. NUMBER: 02702-F-001	REV: B		
		B	ISSUED WITH FINAL FEED REPORT	DLW	2010/03/31	ALS	2010/03/31	ALS	2010/03/31					
		A	ISSUED FOR PRELIMINARY CLIENT REVIEW	DLW	2010/03/26	ALS	2010/03/26	ALS	2010/03/26					

Plot Date: 3/29/2010 4:23:43 PM Plot By: David Whorton File Name: W:\Blue Source LLC\02702 - KE-GE C02 Pipeline and Associated Facilities\CAD\GENERAL\02702-G-0100.dwg

REFERENCE DRAWINGS			REVISIONS										Rooney Engineering, Inc. 12201 E. Arapahoe Rd. C10 Centennial, CO 80112 (303) 792-5911	CAP CO2, LLC.		
														KE-GE CO2 PIPELINE KANSAS ETHANOL PLOT PLAN		
			B	ISSUED WITH FINAL FEED REPORT				DLW	2010/03/31	ALS	2010/03/31	ALS	2010/03/31	SCALE: AS SHOWN	DWG. NUMBER: 02702-G-0100	REV: B
			A	ISSUED FOR PRELIMINARY CLIENT REVIEW				DLW	2010/03/26	ALS	2010/03/26	ALS	2010/03/26			
DWG. NO.	DESCRIPTION		NO.	DESCRIPTION				BY	DATE	CHK	DATE	APP	DATE

[illegible]

APPENDIX 3-H

KANSAS ETHANOL PLANT
CO₂ COMPOSITIONAL ANALYSIS

GENESEO-EDWARDS FIELD

APT Project: GEN9301
Test Report – Lyons, Kansas Ethanol Plant

Kansas Ethanol, LLC : Lyons, Kansas Ethanol Plant					
Test Results Summary – Fermentation Scrubber @ 60 gpm water, 0.8 gph chemical (10/24/2009)					
	Run #1	Run #2	Run #3	Average	Permit Limits
Start Time	20:20	21:50	23:10		
Stop Time	21:20	22:50	0:10		
Stack Temp (°F)	59	58	58	58	
Stack Flow (dscfm)	7,026	6,989	6,685	6,900	
O ₂ (%vd)	0.9	0.9	0.9	0.9	
CO ₂ (%vd)	88.9	88.9	88.9	88.9	
H ₂ O (%vw)	1.8	1.7	1.7	1.8	
Emission Data					
TVOC (ppmvd as C ₃ H ₈)	44.6	50.4	63.5	52.8	
TVOC (lb/hr as C ₃ H ₈)	3.9	4.3	5.2	4.5	
TVOC (tons/year as C ₃ H ₈)	16.9	19.0	23.0	19.6	
Acetaldehyde (lb/hr)	0.47	1.15	2.03	1.22	
Acetaldehyde (tons/year)	2.07	5.05	8.87	5.33	
Acrolein (lb/hr)	0.005	0.005	0.005	0.005	
Acrolein (tons/year)	0.02	0.02	0.02	0.02	
Methanol (lb/hr)	0.005	0.005	0.005	0.005	
Methanol (tons/year)	0.02	0.02	0.02	0.02	
Formaldehyde (lb/hr)	0.003	0.004	0.005	0.004	
Formaldehyde (tons/year)	0.01	0.02	0.02	0.02	
Ethanol (lb/hr)	0.004	0.004	0.004	0.004	
Ethanol (tons/year)	0.02	0.02	0.02	0.02	
Total HAPs (lb/hr)	0.49	1.17	2.04	1.23	
Total HAPs (tons/year)	2.13	5.11	8.93	5.39	
RTO, Package Boiler, Fermentation Scrubber* & DDGS Cyclone Combined					
TVOC (tons/year as C ₃ H ₈)	--	--	--	42.68	73.2
Total HAPs (tons/year)	--	--	--	8.0	11.5
* Condition 2 of Fermentation Scrubber used since it represents the highest emissions of the 2 conditions tested on the unit.					

Table 4.11: Test Results Summary – Fermentation Scrubber, Condition 2

APPENDIX 3-I
PIPELINE HYDRAULIC CHARTS
GENESEO-EDWARDS FIELD

KE-GE Pipeline

3" x 0.216" WT Grade X-60 Pipeline at 8 MMSCFD

KE-GE Pipeline
4" x 0.237" WT Grade X-52 Pipeline at 8 MMSCFD

KE-GE Pipeline

6" x 0.280" WT Grade X-52 Pipeline at 8 MMSCFD

APPENDIX 3-J
PIPELINE ESTIMATE
GENESEO-EDWARDS FIELD

**INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION &
ENHANCED OIL RECOVERY PROJECT**

Kansas Ethanol LLC Plant (KE) to Geneseo-Edwards (GE) Oil Field

RICE COUNTY, KANSAS

ESTIMATE BASIS MEMORANDUM

B	Revised per Client Comment					4/6/2010
A	Issued for Client Review					3/31/10
MARK	DESCRIPTION	BY	CHKD	APVD	CLIENT APVD	DATE
REVISIONS						
CLIENT:	Blue Source					
PROJECT:	Kansas Ethanol LLC Plant (KE) to Geneseo-Edwards (GE) Oil Field Carbon Dioxide Pipeline System Estimate Basis Memorandum					
JOB NO.:	02702					
DOC. NO.:	02702-DESKTOP-002					

Kansas Ethanol LLC Plant to Geneseo-Edwards Oil Field

ROONEY ENGINEERING, INC.
Engineering for the Energy Industry

Date:	4/6/2010	PIPELINE SYSTEMS ESTIMATE BASIS	Doc. No.: 02702-DESKTOP-002
Rev:	B		Page: 2 of 10

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Kansas Ethanol LLC Plant to Geneseo-Edwards Oil Field

ROONEY ENGINEERING, INC.
Engineering for the Energy Industry

Date:	4/6/2010	PIPELINE SYSTEMS ESTIMATE BASIS	Doc. No.:	02702-DESKTOP-002
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1. PURPOSE

This estimate was prepared to provide budgetary cost information to design and construct the Kansas Ethanol, LLC Plant (KE) to the Geneseo-Edwards Oil Field (GE) pipeline.

The KE-GE pipeline is a 15.8 mile, 4.5 inch in diameter steel pipeline to transport CO₂ from the Kansas Ethanol, LLC Plant (KE), located outside Lyons, Kansas to the Geneseo-Edwards Oil Field (GE). A 4,500 BHP compression facility is proposed at the pipeline origination. A fiber optic communication system is proposed to facilitate the Supervisory Control and Data Acquisition (SCADA) system.

This estimate is comparable to an Association for the Advancement of Cost Engineering (AACE) Class 2 Estimate, with an expected accuracy range of +30%/- 15%. A Class 2 estimate corresponds with 30% to 70% project definition, using primarily deterministic methodology. (See AACE Recommended Practice No. 17R-97 "Cost Estimate Classification Systems.")

The capital expenditure cost estimate addresses the pipeline systems, compression facility, and communication systems and includes material, engineering, procurement assistance, procurement inspection, right-of-way acquisition, right-of-way damages, cathodic protection, construction permitting, construction costs, construction management, survey, x-ray, construction inspection, commissioning, and start-up portions of the project.

2. SCOPE

The purpose of the KE-GE Pipeline is to transport compressed high-purity carbon dioxide via a 4" steel intra-state pipeline from the Kansas Ethanol LLC Plant to the Geneseo-Edwards Oil Field for both sequestration and enhanced oil recovery purposes.

The pipeline will be designed, constructed and operated in accordance to Title 49, Part 195, "Transportation of Hazardous Liquids by Pipeline," the Department Of Transportation rules and regulations.

The pipeline will be composed of approximately 15.8 miles of 4.5" O.D., 0.237" wall thickness, API5L, PSL2, Electric Resistance Welded (ERW) steel line pipe, coated with 14-16 mils of Fusion Bond Epoxy for corrosion protection. The pipeline will be designed to be operated at a Maximum Operating Pressure of 1,700 PSIG, with an ANSI 900 flange rating.

All road, railroad and creek crossing pipes will be manufactured to Seamless line pipe specifications instead of ERW to further mitigate fracture propagation.

Carbon Dioxide must be compressed to 1,587 PSIG at the Kansas Ethanol LLC Plant in order to deliver it to the Geneseo-Edwards Oil Field at 1,400 PSIG. This pressure was utilized for a reasonable margin between the operating pressures in the pipeline and the critical pressure of carbon dioxide, which is approximately 1,100 PSIA at 50 °F. Operating at pressures above the critical pressure ensures that the carbon dioxide is transported in the dense phase and that no phase changes occur in the pipeline system. Transporting carbon dioxide in dense-phase is the most efficient means of transportation since it allows for smaller pipeline sizes at high flow rates.

Four (4) Isolation Block Valves will be strategically located in the pipeline system to isolate the pipeline and blow the Carbon Dioxide down in case of an emergency.

Crack arrestor will be installed at every half mile on the 4.5" O.D. Steel Pipeline to mitigate fracture propagation. Clock Spring type crack arrestors were used in the cost estimate.

Kansas Ethanol LLC Plant to Geneseo-Edwards Oil Field

ROONEY ENGINEERING, INC.
Engineering for the Energy Industry

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The pipeline will be designed and constructed to accommodate intelligent pigs. Pig launcher and receiver will be installed into the system

The Engineering, procurement assistance, procurement inspection, right-of-way acquisition, right-of-way damages, cathodic protection, construction permitting, construction costs, construction management, survey, x-ray, construction inspection, commissioning, and start-up portions of the project involve the following work which was included in the estimate (see estimated quantities in the Capital Cost Estimate spreadsheet):

- ◆ Detailed Engineering for the project to include project calculations, P&ID Drawings, PFD Drawings, Piping Drawings, Alignment Sheet Drawings, Material Sheet Drawings, Road and Creek Crossing Detail Drawings, Ditch Detail Drawings, and project specifications.
- ◆ Procurement support for the project to include providing quotation packages, technical evaluation and recommendation, material inspection services, and material expediting.
- ◆ Construction Management, including progress tracking, contractor communication, construction inspection, survey, and x-ray.
- ◆ Surveyors to stake construction work areas and pipeline centerline. Surveyors shall gather required as-built information throughout the duration of construction.
- ◆ NDE (X-Ray) including material and labor to x-ray the entire circumference of 100% of all girth welds.
- ◆ Assemble Job Books and prepare As Built Drawings.

The construction of the above pipeline involves the following work which was included in the estimate (see estimated quantities in the Capital Cost Estimate spreadsheet):

- a) Mobilize to job site – located near Lyons, Kansas.
- b) Train all personnel in site safety and environmental requirements.
- c) Notify all underground utility and service providers, and abide by all their requirements.
- d) Company shall provide survey subcontractor. Surveyors will stake construction work areas and pipeline centerline. Surveyors shall gather the required as-built information throughout the duration of construction.
- e) Company will provide 75' wide construction work area for the construction of the pipeline and 300' x 300' work area on each side of each crossing.
- f) Company will provide one lay down yard for the project, strategically located for construction.
- g) Line pipe shall be delivered to the right-of-way by trucks – Contractor shall string pipe onto the right-of-way from the stringing trucks
- h) Access, clear and grade right-of-way to enable the crews to access and work on the right-of-way.
- i) Topsoil separation, storage and replacement of the ditch line and spoil in all construction areas.
- j) Install 4" buried (with risers) isolation block valves
- k) Perform field bending, align and weld pipe – Company will provide welding procedures.

Kansas Ethanol LLC Plant to Geneseo-Edwards Oil Field

ROONEY ENGINEERING, INC.
Engineering for the Energy Industry

Date:	4/6/2010	PIPELINE SYSTEMS ESTIMATE BASIS	Doc. No.:	02702-DESKTOP-002
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- l) Install Company provided Clock Spring, Crack Arrestors (CS-130-04) which are 12" wide, 12 wraps each. Two Clock Springs will be installed next to each other. Clock Spring Crack Arrestors will be installed every ½ mile on the pipe line for a total of 30 locations (install two clock springs next to each other)
- m) Company shall provide NDE (X-Ray) subcontractor - who will provide material and labor to x-ray the entire circumference of 100% of all girth welds.
- n) Apply Two (2) part Epoxy or Shrink Sleeves to the girth welds.
- o) Holiday test (Jeep) the FBE steel coated pipe. Contractor to supply patch sticks for the repair of the FBE.
- p) Ditch along the Right-of-way
- q) Contractor to provide equipment to pad and shade all pipe - Pad and shade with 6" (bottom of pipe) and 6" (above the pipe) of ¾" minus material.
- r) Install fiber optic armored cable, hand-holes and pull boxes.
- s) Total pipe cover shall be 48" minimum. Cover at road crossings shall be 60" minimum.
- t) Install pipeline Company supplied markers.
- u) Install Company supplied cathodic protection test stations. Contractor to provide all wires and cad welds necessary for the installation of the test stations.
- v) Prepare hydrostatic test plan for the pipelines and submit to engineer for approval, run air swab, cleaning and gauging pigs (only soft pigs will be run in the HDPE lined pipelines), fill and dispose of test water, provide and fill the pipelines with clean water, successfully hydrostatically test the pipelines for a minimum of 8 hours and dispose of water. Contractor to provide all required pigs.
- w) Company will acquire permits for acquiring and disposing hydrostatic test water. Source and disposal site for the Hydro water will be within 50 miles of the job site.
- x) The 4" steel pipelines will be tested to 125% of MOP – minimum test pressure shall be 2125 PSIG
- y) Continuous clean up of right-of-way to the satisfaction of Company and landowner, make all necessary permanent repairs to gates and fences.
- z) Required re-seeding and re-vegetation will be by Company.
- aa) Demobilize from job site.

3. CONSTRUCTION APPROACH

It was assumed that the Right Of Way areas would be accessible to the contractor's equipment at all times during construction, and that the contractor would not have to compete for space to place spoils, pipeline materials or working crews.

4. QUANTITY BASIS

Pipe quantities were measured from preliminary routing from aerial photography, as shown on the preliminary Alignment Sheet Drawings.

Kansas Ethanol LLC Plant to Geneseo-Edwards Oil Field

ROONEY ENGINEERING, INC.
Engineering for the Energy Industry

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Large diameter valve quantities were estimated based on the quantities shown on the preliminary Alignment Sheet Drawings.

Pig trap assembly quantities were estimated based on the quantities shown on the preliminary Alignment Sheet Drawings.

Quantity for all other material and construction quantities were estimated from Rooney Engineering's experience with similar pipeline systems, and from construction contractor input.

Three (3) reciprocating compressors were selected, each designed to 50% of the total design flowrate, therefore giving a total redundancy of 50%.

5. PRICING BASIS

The pricing for material in this estimate was derived from budgetary quotation pricing. Construction pricing is based on budgetary quotes provided by a contractor with experience in construction similar to that required for this project. The following items were priced based on budgetary quotations from vendors or were estimated based on a scale factor applied to quotations to adjust for the current scope of work. If multiple quotations were received, pricing was normalized and averaged.

Pipeline

- ◆ Steel Line Pipe and Fusion Bond Epoxy (FBE) Coating – Current budgetary quotations were received from Edgen Murray and McJunkin Red Man.
- ◆ Abrasive Resistant Outer (ARO) Line Pipe Coatings – Rooney Engineering Estimated.
- ◆ Valves and Actuators – Current budgetary quotations were received from Cameron.
- ◆ Pipeline Fittings and Flanges – Current budgetary quotations were received from Edgen Murray and McJunkin Red Man.
- ◆ Fabricated Assemblies (Pig Traps) – Current budgetary quotations were received from Sagebrush and PECO.
- ◆ Miscellaneous Materials (e.g. Clock Springs, Cathodic Test Stations, Shrink Sleeves, Pipeline Markers) – Current budgetary quotations were received from Hoff Company.
- ◆ Pipeline Construction and Site Construction (e.g. Road Bores, Cathodic Test Station Installation) and associated materials (e.g. Hay Bales, Silt Fence). – A site specific construction budgetary estimate was received from Jomax, who has completed many projects in and around Kansas.

Compression Facility

- ◆ Compressor Packages – Current budgetary quotations were received from Exterran, UE Compression, and GE Oil and Gas.
- ◆ Dehydration Package – Current budgetary quotations were received from QB Johnson and Exterran.
- ◆ Oxygen Removal Package – Current budgetary pricing was received from BCK Engineers and Newpoint Gas, LP..
- ◆ Scrubbers – Pricing from other recent projects was utilized. Orifice Meter – Pricing from other recent projects was utilized. Compressor Building – Recent pricing costs per square foot from Tri-State Insulating was utilized.

Kansas Ethanol LLC Plant to Geneseo-Edwards Oil Field

ROONEY ENGINEERING, INC.
Engineering for the Energy Industry

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- ◆ Flow Control Valves – Pricing from other recent projects was utilized. Switchgear, Motor Control Center, Transformers, Control Switches and Lighting, Power and Control Building – Pricing from other recent projects was utilized. Compressor Station Construction – Budgetary estimates for facility construction was received from Holloman Construction and LE Bell Construction.

SCADA and Fiber Optic

- ◆ SCADA Material, Licenses, and Vendor Services – Pricing from other recent projects was utilized.
- ◆ Fiber Optic Installation – Pricing from other recent projects was utilized.
- ◆ Fiber Optic Material – Pricing from other recent projects was utilized.

6. MARKUPS and ESCALATION

Taxes – 5.98% sales tax included on all materials. No tax included on labor.

Material Escalation – No material escalation was included, vendors quoted for late summer 2010 delivery.

Construction Escalation – No construction escalation is included, assume late summer 2010 construction.

G&A – Included in cost estimate.

Construction Bond – 3% of total construction estimate

Contingency – 15% contingency included in each line item

7. CONSTRUCTION INDIRECTS

All construction indirect costs are included in construction labor unit prices.

8. ASSUMPTIONS AND QUALIFICATIONS

Pipeline

- ◆ Estimate includes construction permitting only. Costs for National Environmental Policy Act (NEPA) Review, Studies to Support the NEPA Process, COE Nationwide #12 Permit, Clean Water Act, Section 401 Consultations, U.S. Fish and Wildlife Service Consultations, Endangered Species Act are not included in this budget.
- ◆ Estimate includes (3) month license of PipePhase Hydraulic Modeling Software.
- ◆ Estimate assumes 75' wide construction work area and 300' x 300' temporary work areas at all crossings.
- ◆ Estimate assumes construction working six (6) days per week for ten (10) hours per day.
- ◆ Assumes source and disposal site for the Hydro water will be within 50 miles of the job site.
- ◆ 2.5% wastage assumed for pipe and piping components.
- ◆ Construction is in loose, dry soil.
- ◆ 5% Rock Ditch was included based on contractor input for the project area.
- ◆ Pricing reflects 3D fittings for a piggyback system.
- ◆ Concrete foundation construction included in estimate.
- ◆ Silt fencing was included for the perimeter of all anticipated temporary work areas only.

Kansas Ethanol LLC Plant to Geneseo-Edwards Oil Field

ROONEY ENGINEERING, INC.
Engineering for the Energy Industry

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- ◆ Contractor will be non-union.
- ◆ Mitigation measures and landowner requirements are unknown at this time.
- ◆ Estimate includes MFL /Caliper Tool - Smart Pig
- ◆ Estimate includes Cathodic Protection (Impressed Current).
- ◆ Estimate includes costs for Right of Way revegetation.
- ◆ Unforeseen conditions are not included in the estimate.
- ◆ Capital Cost Estimate includes the units and quantities shown in the estimate.

Compression Facility

- ◆ Estimate excludes appraisal and acquisition of 180'x 200' property adjacent to Kansas Ethanol plant. Assumed to be provided by Others.
- ◆ Assume compressor station site is grass roots, relatively level field with minimal grading, grubbing and clearing required. No trees or existing infrastructure required to be removed.
- ◆ Assumes three reciprocating compressors, each sized at 50% of the total design flowrate. No centrifugal pumps are required or included at this location.
- ◆ Estimate includes 2.5% of the capital expenditure of the compressors for initial spares, as recommended by GE.
- ◆ Estimate includes one (1) compressor building for all three compressors.
- ◆ Estimate includes one (1) TEG Dehydration Package, 125,000 BTU/ Hr Reboiler, 24" x 25', 8-Tray Contactor Column.
- ◆ Estimate includes scrubber and orifice metering for dehydration re-boiler fuel gas

Fiber Optic and SCADA

- ◆ SCADA electrical construction contractor labor not included since wiring up the PLCs would be done by site contractor along with instruments.
- ◆ The PLC at each compressor and main line valve site will be a GE 90-30 or company approved equal and will be housed inside a small building to enable support personnel to program and maintain them in inclement weather.
- ◆ The SCADA software will have a primary system installed at the primary control center on one end of the pipeline and there will be a backup SCADA host at the facility at the other end of the pipeline. Costs for SCADA vendor services were also included. SCADA vendor services include project management, design specification documents, SCADA communications programming, SCADA screen programming, factory tests, installation onsite, onsite tuning of the software, commissioning tests, operations and the maintenance manual, training support for operators and technicians.
- ◆ The Leak Detection System will communicate with each station to analyze the pipeline for leaks and report to the SCADA software for operator notification. Leak Detection vendor services were also included. Leak Detection vendor services include project management, design specification documents, communications programming, graphical user interface screen programming, factory tests, installation onsite, tuning of the software, commissioning tests, operations and the maintenance manual, training support for operators and technicians.

Kansas Ethanol LLC Plant to Geneseo-Edwards Oil Field

ROONEY ENGINEERING, INC.
Engineering for the Energy Industry

Date:	4/6/2010	PIPELINE SYSTEMS ESTIMATE BASIS	Doc. No.: 02702-DESKTOP-002
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9. ATTACHED VENDOR BUDGETARY PROPOSALS

See attached vendor budgetary quotes that were utilized in preparing the capital cost estimate.

Kansas Ethanol LLC Plant to Geneseo-Edwards Oil Field

ROONEY ENGINEERING, INC.
Engineering for the Energy Industry

Date:	4/6/2010	PIPELINE SYSTEMS ESTIMATE BASIS	Doc. No.: 02702-DESKTOP-002
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10. ATTACHED CONSTRUCTION CONTRACTOR BUDGETARY PROPOSAL

See attached contractor budgetary proposal that was utilized in preparing the capital cost estimate.

APPENDIX 3-K
ESTIMATE BASIS MEMORANDUM
GENESEO-EDWARDS FIELD

KE-GE Desktop FEED Capital Cost Estimate

Rice County, Kansas

Date: March 31, 2010

CAPITAL COST ESTIMATE SUMMARY

Cost Description	Total Cost
Pipeline	
Materials	\$ 1,327,000
Construction	\$ 2,836,000
ROW Acquisition, Damages and Revegetation	\$ 1,070,000
Cathodic Protection	\$ 92,000
Construction Permitting	\$ 32,000
Property Plats	\$ 158,000
Engineering & Procurement Assistance	\$ 635,000
Engineering Survey and Procurement Inspection	\$ 235,000
Construction Administration	\$ 742,000
Construction Inspection, Surveying and X-Ray	\$ 1,682,000
Total Pipeline Cost	\$ 8,809,000
Fiber Optic and SCADA	
SCADA and Fiber Optic Materials	\$ 913,000
SCADA Engineering Hours/Expenses	\$ 162,000
SCADA Vendor Labor	\$ 380,000
Fiber Optic Construction Labor	\$ 192,000
Total Fiber Optic and SCADA Cost	\$ 1,647,000
Compressor / Pump Station	
Equipment and Materials	\$ 13,644,000
Construction	\$ 4,181,000
Land and ROW	\$ -
Environmental and Permitting	\$ 6,000
Engineering Design	\$ 799,000
Construction Administration	\$ 1,035,000
Total Compressor / Pump Cost	\$ 19,665,000
TOTAL ESTIMATED PROJECT COST	\$ 30,121,000

INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION & ENHANCED OIL RECOVERY PROJECT
Kansas Ethanol LLC Plant (KE) to Geneseo-Edwards (GE) Oil Field
Capital Cost Estimate - 15.8 Miles of 4" Pipeline
Blue Source LLC
Date: March 31, 2010

	Qty.	Unit	Unit Cost	Total Cost	% of Total
LINE PIPE, COATING, & FREIGHT					
Steel					
4.5", 0.237" w.t., API 5L, X-52, PSL2, ERW Line Pipe, DRL, coated 14 -16 mils of FBE	83,406	ft	\$ 9.61	\$ 801,500	
4.5", 0.337" w.t., API 5L, X-52, PSL2, SMLS Line Pipe, DRL, coated 14 -16 mils of FBE	1,645	ft	\$ 20.16	\$ 33,200	
4.5" ARO Coating - Road Crossings	1,645	ft	\$ 5.90	\$ 9,700	
FOB (Included in Unit Prices Above)	0	ea	\$ -	\$ -	
Line Pipe Contingency	15%			\$ 126,660	
Subtotal - Pipe & Coating				\$ 971,000	11.02%

PIPELINE - FITTINGS & APPURTENANCES					
Main-Line Valves					
4" 900 RTJ GO CAMERON T31 TRIM 601 w/ 7' STEM EXTENSION & COAL TAR	4	ea	\$ 7,600.00	\$ 30,400	
3" 900 RTJ GO CAMERON T31 TRIM 601	8	ea	\$ 4,000.00	\$ 32,000	
Miscellaneous Fittings	1	lot	\$ 28,000.00	\$ 28,000	
FOB	2	trk	\$ 3,000.00	\$ 4,500	
Steel Fittings					
4.5", 0.237" w.t., 90°, 3D Segmentable, MSS SP-75, WPHY-52, with 14 -16 mils FBE	14	ea	\$ 577.50	\$ 8,100	
4.5", 0.237" w.t., 60°, 3D Segmentable, MSS SP-75, WPHY-52, with 14 -16 mils FBE	10	ea	\$ 570.00	\$ 5,700	
FOB (Included in Unit Prices Above)	0	load	\$ -	\$ -	
Shrink Sleeves					
For 4" Pipe	2,600	ea	\$ 5.98	\$ 15,500	
FOB	1	Truck	\$ 3,000.00	\$ 3,000	
Launcher/Receiver Assemblies					
ANSI 900 8" x 4" Launcher/Receiver Barrel & Closure	2	ea	\$ 14,101.00	\$ 28,200	
ANSI 900 8" x 4" Launcher Bill of Materials	1	lot	\$ 20,930.81	\$ 20,900	
ANSI 900 8" x 4" Receiver Bill of Materials	1	lot	\$ 18,462.81	\$ 18,500	
FOB (Included in Unit Prices Above)	0	Truck	\$ -	\$ -	
Miscellaneous					
Cathodic Protection Test Stations	27	ea	\$ 11.66	\$ 300	
Pipeline Markers	106	ea	\$ 12.45	\$ 1,300	
Crack Arrestor	47	ea	\$ 889.00	\$ 42,100	
FOB	2	lot	\$ 3,000.00	\$ 6,000	
Pipeline Fittings and Appurtenances Contingency	15%			\$ 36,675	
Subtotal - Fittings & Appurtenances				\$ 281,000	3.19%

INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION & ENHANCED OIL RECOVERY PROJECT

Kansas Ethanol LLC Plant (KE) to Geneseo-Edwards (GE) Oil Field

Capital Cost Estimate - 15.8 Miles of 4" Pipeline

Blue Source LLC

Date: March 31, 2010

	Qty.	Unit	Unit Cost	Total Cost	% of Total
PIPELINE - CONSTRUCTION					
Pipeline Construction					
Mobilization / Demobilization to Construct 4" Carbon Dioxide Pipeline	1	LS	\$ 50,000.00	\$ 50,000	
Installation of pipe per lineal foot	83,266	ft	\$ 16.00	\$ 1,332,200	
4" Open Cut Crossing - No Casing	950	ft	\$ 75.00	\$ 71,300	
4" Bored Crossing - No Casing	475	ft	\$ 75.00	\$ 35,600	
4" HDD Crossing - No Casing	100	ft	\$ 95.00	\$ 9,500	
4" ANSI 900 Pig Launchers/Receivers with supports	2	LS	\$ 20,000.00	\$ 40,000	
Install 4" Buried Valve - with Risers	4	ea	\$ 12,000.00	\$ 48,000	
Install Cathodic Test Station	27	ea	\$ 200.00	\$ 5,400	
Install Silt Fence	62,400	ft	\$ 7.50	\$ 468,000	
Install Hay Bale	200	ea	\$ 20.00	\$ 4,000	
16" Foreign pipeline Crossing	16	ea	\$ 2,000.00	\$ 32,000	
Install Foam Ditch Breaker (Ditch Plugs)	10	ea	\$ 1,200.00	\$ 12,000	
Fences - Remove 75' existing fences, install temporary for construction and replace	63	ea	\$ 1,400.00	\$ 88,200	
Install Crack Arrestor	32	ea	\$ 150.00	\$ 4,700	
Rock Ditch (Assumed at 5% of Route)	4,163	ft	\$ 10.00	\$ 41,600	
ROW Clearing - Timber (Estimated from Aerial Photography)	1,130	ft	\$ 20.00	\$ 22,600	
Hot Bends Installed	24	ea	\$ 375.00	\$ 9,000	
4" MFL /Caliper Tool - Smart Pig	1	LS	\$ 120,000.00	\$ 120,000	
Pipeline Construction Contingency	15%			\$ 359,115	
Subtotal - Construction				\$ 2,753,000	31.25%
Subtotal Materials				\$ 1,252,000	
Sales Tax on Material	5.98%			\$ 75,000	
Subtotal Materials				\$ 1,327,000	15.06%
Subtotal Construction				\$ 2,753,000	
Sales Tax on Labor	0.00%			\$ -	
Construction Bond	3.00%			\$ 83,000	
Subtotal Construction				\$ 2,836,000	32.19%
ROW Acquisition - Consultants	5,046	Rods	\$ 35.00	\$ 177,000	
ROW Acquisition & Damages	5,046	Rods	\$ 70.00	\$ 353,000	
ROW Procurement, Legal and Environmental costs	5,046	Rods	\$ 27.50	\$ 139,000	
ROW Revegetation	251	acres	\$ 1,000.00	\$ 251,000	
COE Wetlands Mitigation	1	LS	\$ 10,000.00	\$ 10,000	
ROW Contingency	15%			\$ 140,000	
Subtotal ROW Acquisition				\$ 1,070,000	12.15%
Cathodic Protection (Impressed Current)	1	LS	\$ 50,000.00	\$ 50,000	
AC Mitigation Study	1	LS	\$ 30,000.00	\$ 30,000	
AC Mitigation Contingency	15%			\$ 12,000	
Subtotal Cathodic Protection				\$ 92,000	1.04%
Construction General Permit	1	LS	\$ 10,000.00	\$ 10,000	
Surface Water Discharge Permit	1	LS	\$ 5,000.00	\$ 5,000	
National Historic Preservation Act	1	LS	\$ 10,000.00	\$ 10,000	
Nongame and Endangered Species Conservation Act	1	LS	\$ 3,000.00	\$ 3,000	
Permitting Contingency	15%			\$ 4,000	
Total Construction Permitting				\$ 32,000	0.36%
Surveying - Property Plats	63	ea	\$ 2,500.00	\$ 158,000	1.79%
Engineering & Procurement Assistance				\$ 635,000	7.21%
Engineering Survey and Procurement Inspection				\$ 235,000	2.67%
Construction Administration				\$ 742,000	8.42%
Construction Inspection, Surveying and X-Ray				\$ 1,682,000	19.09%
TOTAL ESTIMATED COST				\$ 8,809,000	100.00%

INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION & ENHANCED OIL RECOVERY PROJECT
Kansas Ethanol LLC Plant (KE) to Geneseo-Edwards (GE) Oil Field
Detailed Engineering and Procurement Assistance
Blue Source LLC
Date: March 31, 2010

Procurement

DETAILED ENGINEERING AND PROCUREMENT - Rooney Engineering Direct Labor

INDIVIDUAL	TITLE	Billing	Billing	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
		Rate 1/10	Rate 8/10	1-Jul-10	8-Jul-10	15-Jul-10	22-Jul-10	29-Jul-10	5-Aug-10	12-Aug-10	19-Aug-10	26-Aug-10	2-Sep-10	9-Sep-10	16-Sep-10	23-Sep-10	30-Sep-10	7-Oct-10	14-Oct-10	21-Oct-10	28-Oct-10	4-Nov-10	11-Nov-10
PROJECT MANAGEMENT			7.0%																				
Henrick Sarkissian	Principal	\$151.00	\$161.57	40	40	40	40	40	40	40	40	40	40	40	40	40	40	20	20	20	20	20	20
Other	Principal	\$151.00	\$161.57	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Office Personnel	Office Personnel	\$44.00	\$47.08	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Accounting Personnel	Cost Accountant	\$64.00	\$68.48	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Subtotal Man-Hours				64	64	64	64	64	64	64	64	64	64	64	64	64	64	44	44	44	44	44	44
Subtotal \$				\$7,176	\$7,176	\$7,176	\$7,176	\$7,176	\$7,678	\$7,678	\$7,678	\$7,678	\$7,678	\$7,678	\$7,678	\$7,678	\$7,678	\$4,447	\$4,447	\$4,447	\$4,447	\$4,447	\$4,447
PROJECT ENGINEERING																							
Quinn Bailey	Senior Project Engineer	\$121.00	\$129.47	40	40	40	40	40	40	40	40	40	40	40	40	40	40	0	0	0	0	0	0
Zachary Bauer	Project Engineer	\$116.00	\$124.12	40	40	50	40	40	40	40	50	40	40	40	40	40	40	40	40	40	40	40	40
Brian Techau	Project Engineer	\$116.00	\$124.12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal Man-Hours				80	80	90	80	80	80	80	90	80	80	80	80	80	80	40	40	40	40	40	40
Subtotal \$				\$9,480	\$9,480	\$10,640	\$9,480	\$9,480	\$10,144	\$10,144	\$11,385	\$10,144	\$10,144	\$10,144	\$10,144	\$10,144	\$10,144	\$4,965	\$4,965	\$4,965	\$4,965	\$4,965	\$4,965
PROJECT DESIGN																							
Mike Wager	Designer	\$91.00	\$97.37	40	40	40	40	40	40	40	40	40	40	40	40	40	0	0	0	0	0	0	0
Roxanne Burridge	Designer	\$91.00	\$97.37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Chuck Haas	Designer	\$91.00	\$97.37	40	40	40	40	40	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal Man-Hours				80	80	80	80	80	80	40	40	40	40	40	40	40	0	0	0	0	0	0	0
Subtotal \$				\$7,280	\$7,280	\$7,280	\$7,280	\$7,280	\$7,790	\$3,895	\$3,895	\$3,895	\$3,895	\$3,895	\$3,895	\$3,895	\$0	\$0	\$0	\$0	\$0	\$0	\$0
SUBTOTAL ROONEY ENGINEERING (HOURS)				224.0 hrs	224.0 hrs	234.0 hrs	224.0 hrs	224.0 hrs	224.0 hrs	184.0 hrs	194.0 hrs	184.0 hrs	184.0 hrs	184.0 hrs	184.0 hrs	184.0 hrs	144.0 hrs	84.0 hrs	84.0 hrs	84.0 hrs	84.0 hrs	84.0 hrs	84.0 hrs
SUBTOTAL ROONEY ENGINEERING (COST)				\$23,936	\$23,936	\$25,096	\$23,936	\$23,936	\$25,612	\$21,717	\$22,958	\$21,717	\$21,717	\$21,717	\$21,717	\$21,717	\$17,822	\$9,412	\$9,412	\$9,412	\$9,412	\$9,412	\$9,412

DETAILED ENGINEERING AND PROCUREMENT - Subcontractors and Expenses

INDIVIDUAL	TITLE	Billing	Billing	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
		Rate 1/10	Rate 8/10	1-Jul-10	8-Jul-10	15-Jul-10	22-Jul-10	29-Jul-10	5-Aug-10	12-Aug-10	19-Aug-10	26-Aug-10	2-Sep-10	9-Sep-10	16-Sep-10	23-Sep-10	30-Sep-10	7-Oct-10	14-Oct-10	21-Oct-10	28-Oct-10	4-Nov-10	11-Nov-10
SUBCONTRACT ENGINEERING																							
		Rates																					
		REI COST																					
Mark Madden	Senior Project Engineer	\$121.00	\$129.47	0	0	40	40	40	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bruce Craig / Metcorr	Cathodic Protection	\$200.00	\$214.00	0	0	40	40	40	40	40	0	0	0	0	0	0	40	0	0	0	0	0	0
				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal Man-Hours				0	0	80	80	80	80	40	0	0	0	0	0	0	40	0	0	0	0	0	0
Subtotal \$				\$0	\$0	\$12,840	\$12,840	\$12,840	\$13,739	\$8,560	\$0	\$0	\$0	\$0	\$0	\$0	\$8,560	\$0	\$0	\$0	\$0	\$0	\$0
EXPENSES																							
Denver Office Travel Expenses				\$3,000	\$3,000	\$3,000	\$3,000	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$3,000	\$0	\$3,000	\$0	\$3,000	\$0	\$0	\$3,000	\$0
Denver Office Expenses				\$200	\$200	\$200	\$200	\$200	\$200	\$200	\$200	\$200	\$200	\$200	\$5,000	\$200	\$100	\$100	\$100	\$100	\$100	\$100	\$100
Misc.				\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Hydraulic Software				\$10,000	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Subtotal \$				\$13,200	\$3,200	\$3,200	\$3,200	\$200	\$200	\$200	\$200	\$200	\$200	\$200	\$8,000	\$200	\$3,100	\$100	\$3,100	\$100	\$100	\$3,100	\$100
SUBTOTAL SUBCONTRACTORS AND EXPENSES (HOURS)				0.0 hrs	0.0 hrs	80.0 hrs	80.0 hrs	80.0 hrs	80.0 hrs	40.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	40.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs
SUBTOTAL SUBCONTRACTORS AND EXPENSES (COST)				\$13,200	\$3,200	\$16,040	\$16,040	\$13,040	\$13,939	\$8,760	\$200	\$200	\$200	\$200	\$8,000	\$200	\$11,660	\$100	\$3,100	\$100	\$100	\$3,100	\$100

PROJECT TOTAL (HOURS)				224.0 hrs	224.0 hrs	314.0 hrs	304.0 hrs	304.0 hrs	304.0 hrs	224.0 hrs	194.0 hrs	184.0 hrs	184.0 hrs	184.0 hrs	184.0 hrs	184.0 hrs	184.0 hrs	84.0 hrs	84.0 hrs	84.0 hrs	84.0 hrs	84.0 hrs	84.0 hrs
PROJECT TOTAL (COST)				\$37,136	\$27,136	\$41,136	\$39,976	\$36,976	\$39,550	\$30,477	\$23,158	\$21,917	\$21,917	\$21,917	\$29,717	\$21,917	\$29,482	\$9,512	\$12,512	\$9,512	\$9,512	\$12,512	\$9,512

INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTI
ENHANCED OIL RECOVERY PROJECT
Kansas Ethanol LLC Plant (KE) to Geneseo-Edwards (GE) Oil Fi
Detailed Engineering and Procurement Assistanace
Blue Source LLC
Date: March 31, 2010

DETAILED ENGINEERING AND PROCUREMENT - Rooney Engineerin

INDIVIDUAL	TITLE	Billing	21	22	23	24	25	26	27
		Rate 1/10	18-Nov-10	25-Nov-10	2-Dec-10	9-Dec-10	16-Dec-10	23-Dec-10	30-Dec-10
PROJECT MANAGEMENT									
Henrick Sarkissian	Principal	\$151.00	20	20	20	20	20	20	0
Other	Principal	\$151.00	0	0	0	0	0	0	0
Office Personnel	Office Personnel	\$44.00	20	20	20	20	20	20	0
Accounting Personnel	Cost Accountant	\$64.00	4	4	4	4	4	4	0
Subtotal Man-Hours			44	44	44	44	44	44	0
Subtotal \$			\$4,447	\$4,447	\$4,447	\$4,447	\$4,447	\$4,447	\$0
PROJECT ENGINEERING									
Quinn Bailey	Senior Project Engineer	\$121.00	0	0	0	0	0	0	0
Zachary Bauer	Project Engineer	\$116.00	40	40	40	40	40	40	0
Brian Techau	Project Engineer	\$116.00	0	0	0	0	0	0	0
Subtotal Man-Hours			40	40	40	40	40	40	0
Subtotal \$			\$4,965	\$4,965	\$4,965	\$4,965	\$4,965	\$4,965	\$0
PROJECT DESIGN									
Mike Wager	Designer	\$91.00	0	0	0	0	0	0	0
Roxanne Burridge	Designer	\$91.00	0	0	0	0	0	0	0
Chuck Haas	Designer	\$91.00	0	0	0	0	0	0	0
Subtotal Man-Hours			0	0	0	0	0	0	0
Subtotal \$			\$0	\$0	\$0	\$0	\$0	\$0	\$0
SUBTOTAL ROONEY ENGINEERING (HOURS)			84.0 hrs	84.0 hrs	84.0 hrs	84.0 hrs	84.0 hrs	84.0 hrs	0.0 hrs
SUBTOTAL ROONEY ENGINEERING (COST)			\$9,412	\$9,412	\$9,412	\$9,412	\$9,412	\$9,412	\$0

Total Rate 1/10	Total Rate 8/10	Billed (\$)	Overhead 0.000	Total
200	600	\$127,142	\$0	\$127,142
0	0	\$0	\$0	\$0
100	420	\$24,174	\$0	\$24,174
20	84	\$7,032	\$0	\$7,032
320	1104			
(Check)	\$158,348	\$158,348	\$0	\$158,348
200	360	\$70,809	\$0	\$70,809
210	850	\$129,862	\$0	\$129,862
0	0	\$0	\$0	\$0
410	1210			
(Check)	\$200,671	\$200,671	\$0	\$200,671
200	320	\$49,358	\$0	\$49,358
0	0	\$0	\$0	\$0
200	40	\$22,095	\$0	\$22,095
400	360			
(Check)	\$71,453	\$71,453	\$0	\$71,453
1130.0 hrs	2674.0 hrs			3804.0 hrs
(Check)	\$430,472	\$430,472	\$0	\$430,470

DETAILED ENGINEERING AND PROCUREMENT - Subcontractors and

INDIVIDUAL	TITLE	Billing	21	22	23	24	25	26	27
		Rate 1/10	18-Nov-10	25-Nov-10	2-Dec-10	9-Dec-10	16-Dec-10	23-Dec-10	30-Dec-10
SUBCONTRACT ENGINEERING									
		Rate REI C							
Mark Madden	Senior Project Engineer	\$121.00	0	0	0	0	0	0	0
Bruce Craig / Metcorr	Cathodic Protection	\$200.00	0	0	0	0	0	0	0
			0	0	0	0	0	0	0
Subtotal Man-Hours			0	0	0	0	0	0	0
Subtotal \$			\$0	\$0	\$0	\$0	\$0	\$0	\$0
EXPENSES									
Denver Office Travel Expenses			\$0	\$0	\$0	\$0	\$3,000	\$0	\$0
Denver Office Expenses			\$100	\$100	\$100	\$100	\$100	\$100	\$0
Misc.			\$0	\$0	\$0	\$0	\$0	\$0	\$0
Hydraulic Software			\$0	\$0	\$0	\$0	\$0	\$0	\$0
Subtotal \$			\$100	\$100	\$100	\$100	\$3,100	\$100	\$0
SUBTOTAL SUBCONTRACTORS AND EXPENSES (HOURS)			0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs
SUBTOTAL SUBCONTRACTORS AND EXPENSES (COST)			\$100	\$100	\$100	\$100	\$3,100	\$100	\$0
PROJECT TOTAL (HOURS)			84.0 hrs	84.0 hrs	84.0 hrs	84.0 hrs	84.0 hrs	84.0 hrs	0.0 hrs
PROJECT TOTAL (COST)			\$9,512	\$9,512	\$9,512	\$9,512	\$12,512	\$9,512	\$0

Total Rate 1/10	Total Rate 6/10	Billed (\$)	Overhead 0.150	Total
120	40	\$19,699	\$0	\$19,699
120	120	\$49,680	\$0	\$49,680
240	160			
(Check)	\$69,379	\$69,379	\$0	\$69,379
		\$27,000	\$4,050	\$31,050
		\$8,700	\$1,305	\$10,005
		\$0	\$0	\$0
		\$10,000	\$1,500	\$11,500
(Check)	\$45,700	\$45,700	\$6,855	\$52,555
400.0 hrs	0.0 hrs			400.0 hrs
(Check)	\$115,079	\$115,079	\$6,855	\$121,930
3952.0 hrs	252.0 hrs			4204.0 hrs
(Check)	\$545,551	\$545,551	\$6,855	\$552,400

INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION & ENHANCED OIL RECOVERY PROJECT
Kansas Ethanol LLC Plant (KE) to Geneseo-Edwards (GE) Oil Field
Construction Administration and As-Built
Blue Source LLC
Date: March 31, 2010

CONSTRUCTION ADMINISTRATION AND AS BUILT - Rooney Engineering Direct Labor

INDIVIDUAL	TITLE	Billing	Billing	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
		Rate 1/11	Rate 8/11	18-Mar-11	25-Mar-11	1-Apr-11	8-Apr-11	15-Apr-11	22-Apr-11	29-Apr-11	6-May-11	13-May-11	20-May-11	27-May-11	3-Jun-11	10-Jun-11	17-Jun-11	24-Jun-11	1-Jul-11	8-Jul-11	15-Jul-11	22-Jul-11
PROJECT MANAGEMENT		7.0%	7.0%																			
Henrick Sarkissian	Principal	\$172.14	\$184.19	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	0
Other	Principal	\$172.14	\$184.19	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Office Personnel	Office Personnel	\$50.16	\$53.67	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	0
Accounting Personnel	Cost Accountant	\$72.96	\$78.07	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	4	4	0
Subtotal Man-Hours				110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	104	104	0
Subtotal \$				\$13,064	\$13,064	\$13,064	\$13,064	\$13,064	\$13,064	\$13,064	\$13,064	\$13,064	\$13,064	\$13,064	\$13,064	\$13,064	\$13,064	\$13,064	\$13,064	\$12,627	\$12,627	\$0
PROJECT ENGINEERING																						
Quinn Bailey	Senior Project Engineer	\$137.94	\$147.60	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Zachary Bauer	Project Engineer	\$132.24	\$141.50	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	0
Brian Techau	Project Engineer	\$132.24	\$141.50	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	0
Subtotal Man-Hours				100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	0
Subtotal \$				\$13,224	\$13,224	\$13,224	\$13,224	\$13,224	\$13,224	\$13,224	\$13,224	\$13,224	\$13,224	\$13,224	\$13,224	\$13,224	\$13,224	\$13,224	\$13,224	\$13,224	\$13,224	\$0
PROJECT DESIGN																						
Mike Wager	Designer	\$103.74	\$111.00	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	40	40	40	0
Chuck Haas	Designer	\$103.74	\$111.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	40	40	40	0
Subtotal Man-Hours				20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	80	80	80	0
Subtotal \$				\$2,075	\$2,075	\$2,075	\$2,075	\$2,075	\$2,075	\$2,075	\$2,075	\$2,075	\$2,075	\$2,075	\$2,075	\$2,075	\$2,075	\$2,075	\$8,299	\$8,299	\$8,299	\$0
SUBTOTAL ROONEY ENGINEERING (HOURS)				230.0 hrs	230.0 hrs	230.0 hrs	230.0 hrs	230.0 hrs	230.0 hrs	230.0 hrs	230.0 hrs	230.0 hrs	230.0 hrs	230.0 hrs	230.0 hrs	230.0 hrs	230.0 hrs	230.0 hrs	290.0 hrs	284.0 hrs	284.0 hrs	0.0 hrs
SUBTOTAL ROONEY ENGINEERING (COST)				\$28,363	\$28,363	\$28,363	\$28,363	\$28,363	\$28,364	\$28,365	\$28,366	\$28,363	\$28,363	\$28,363	\$28,363	\$28,363	\$28,363	\$28,363	\$34,588	\$34,150	\$34,150	\$0

CONSTRUCTION ADMINISTRATION AND AS BUILT - Subcontractors and Expenses

INDIVIDUAL	TITLE	Billing	Billing	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
		Rate 1/11	Rate 8/11	18-Mar-11	25-Mar-11	1-Apr-11	8-Apr-11	15-Apr-11	22-Apr-11	29-Apr-11	6-May-11	13-May-11	20-May-11	27-May-11	3-Jun-11	10-Jun-11	17-Jun-11	24-Jun-11	1-Jul-11	8-Jul-11	15-Jul-11	22-Jul-11
SUBCONTRACT ENGINEERING																						
		Rates REI COST																				
Mark Madden	Senior Project Engineer	\$137.94	\$147.60	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	40	40	0	0
Bruce Craig / Metcorr	Cathodic Protection	\$228.00	\$243.96	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	40	40	0	0
				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal Man-Hours				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	80	80	0	0
Subtotal \$				\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$14,638	\$14,638	\$0	\$0
EXPENSES																						
Denver Office Travel Expenses				\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$0
Denver Office Expenses				\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$500	\$10,000	\$0
Misc.				\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Subtotal \$				\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$13,000	\$0
SUBTOTAL SUBCONTRACTORS AND EXPENSES (HOURS)				0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	0.0 hrs	80.0 hrs	80.0 hrs	0.0 hrs	0.0 hrs
SUBTOTAL SUBCONTRACTORS AND EXPENSES (COST)				\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500	\$18,138	\$18,138	\$13,000	\$0

PROJECT TOTAL (HOURS)				230.0 hrs	230.0 hrs	230.0 hrs	230.0 hrs	230.0 hrs	230.0 hrs	230.0 hrs	230.0 hrs	230.0 hrs	230.0 hrs	230.0 hrs	230.0 hrs	230.0 hrs	230.0 hrs	230.0 hrs	370.0 hrs	364.0 hrs	284.0 hrs	0.0 hrs
PROJECT TOTAL (COST)				\$31,863	\$31,863	\$31,863	\$31,863	\$31,863	\$31,864	\$31,865	\$31,866	\$31,863	\$31,863	\$31,863	\$31,863	\$31,863	\$31,863	\$31,863	\$52,725	\$52,287	\$47,150	\$0

INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUEST
ENHANCED OIL RECOVERY PROJECT
Kansas Ethanol LLC Plant (KE) to Geneseo-Edwards (GE) Oil F
Construction Administration and As-Built
Blue Source LLC
Date: March 31, 2010

INDIVIDUAL	TITLE	Billing	20
		Rate 1/11	29-Jul-11
PROJECT MANAGEMENT		7.0%	
Henrick Sarkissian	Principal	\$172.14	0
Other	Principal	\$172.14	0
Office Personnel	Office Personnel	\$50.16	0
Accounting Personnel	Cost Accountant	\$72.96	0
	Subtotal Man-Hours		0
	Subtotal \$		\$0
PROJECT ENGINEERING			
Quinn Bailey	Senior Project Engineer	\$137.94	0
Zachary Bauer	Project Engineer	\$132.24	0
Brian Techau	Project Engineer	\$132.24	0
	Subtotal Man-Hours		0
	Subtotal \$		\$0
PROJECT DESIGN			
Mike Wager	Designer	\$103.74	0
Chuck Haas	Designer	\$103.74	0
	Subtotal Man-Hours		0
	Subtotal \$		\$0
SUBTOTAL ROONEY ENGINEERING (HOURS)			0.0 hrs
SUBTOTAL ROONEY ENGINEERING (COST)			\$0

Total Rate 1/11	Total Rate 8/11	Billed (\$)	Overhead 0.000	Total
1080	0	\$185,911	\$0	\$185,911
0	0	\$0	\$0	\$0
720	0	\$36,115	\$0	\$36,115
168	0	\$12,257	\$0	\$12,257
1968	0			
(Check)	\$234,284	\$234,284	\$0	\$234,284
0	0	\$0	\$0	\$0
1080	0	\$142,819	\$0	\$142,819
720	0	\$95,213	\$0	\$95,213
1800	0			
(Check)	\$238,032	\$238,032	\$0	\$238,032
420	0	\$43,571	\$0	\$43,571
120	0	\$12,449	\$0	\$12,449
540	0			
(Check)	\$56,020	\$56,020	\$0	\$56,020
4308.0 hrs	0.0 hrs			4308.0 hrs
(Check)	\$528,341	\$528,341	\$1	\$528,340

INDIVIDUAL	TITLE	Billing	20
		Rate 1/11	29-Jul-11
SUBCONTRACT ENGINEERING			
Mark Madden	Senior Project Engineer	\$137.94	0
Bruce Craig / Metcorr	Cathodic Protection	\$228.00	0
			0
	Subtotal Man-Hours		0
	Subtotal \$		\$0
EXPENSES			
Denver Office Travel Expenses			\$0
Denver Office Expenses			\$0
Misc.			\$0
	Subtotal \$		\$0
SUBTOTAL SUBCONTRACTORS AND EXPENSES (HOURS)			0.0 hrs
SUBTOTAL SUBCONTRACTORS AND EXPENSES (COST)			\$0

Total Rate 1/11	Total Rate 8/11	Billed (\$)	Overhead 0.150	Total
80	0	\$11,035	\$1,655	\$12,690
80	0	\$18,240	\$2,736	\$20,976
160	0			
(Check)	\$29,275	\$29,275	\$4,391	\$33,666
		\$54,000	\$8,100	\$62,100
		\$18,500	\$2,775	\$21,275
		\$0	\$0	\$0
(Check)	\$72,500	\$72,500	\$10,875	\$83,375
160.0 hrs	0.0 hrs			160.0 hrs
(Check)	\$101,775	\$101,775	\$15,266	\$117,040

PROJECT TOTAL (HOURS)		0.0 hrs
PROJECT TOTAL (COST)		\$0

4468.0 hrs	0.0 hrs			4468.0 hrs
(Check)	\$630,116	\$630,116	\$15,267	\$645,380

**INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION &
ENHANCED OIL RECOVERY PROJECT**
Kansas Ethanol LLC Plant (KE) to Geneseo-Edwards (GE) Oil Field
Inspection, Surveying and X-Ray
Blue Source LLC
Date: March 31, 2010

Procurement Inspection

Description	Rate	Quantity	Manufacture [Days]	Set Up/ Close Out Duration [Days]	Total
Chief Inspector	\$2100.00		20	10	\$ 66,000
Utility Inspector	\$2050.00		20	10	\$ 63,000
Inspector Mileage	\$ 0.50	480	20	10	\$ 7,200
Total Procurement Inspection					\$ 136,200
Total with Rooney Engineering Overhead of 15%					\$ 156,630
Total with Estimate Contingency of 15%					\$ 180,125

Construction Inspection

Description	Rate	Quantity	Construction Duration [Days]	Set Up/ Close Out Duration [Days]	Total
Chief Inspector	\$1100.00		67	20	\$ 95,700
Chief Welding Inspector	\$8050.00		67	15	\$ 258,300
Welding Inspector	\$8000.00		67	10	\$ 231,000
Environmental Inspector	\$ 950.00	1	67	10	\$ 73,150
Inspector Mileage	\$ 0.50	960	67	15	\$ 39,360
Total Construction Inspection					\$ 697,510
Total with Rooney Engineering Overhead of 15%					\$ 802,137
Total with Estimate Contingency of 15%					\$ 922,457

Note that above inspectors will be responsible for all aspects of contractor's activities from mobilization to

Survey - Route Survey

Description	Rate [\$/day]	Quantity [ea]	Construction Duration [Days]	Set Up/ Close Out Duration [Days]	Total
2 Man Survey Crew (#1)	\$ 991.67	1	15	3	\$ 17,850
2 Man Survey Crew (#2)	\$ 991.67	0	0	0	\$ -
GPS Survey Equipment (#1)	\$ 650.00	1	15	3	\$ 11,700
GPS Survey Equipment (#2)	\$ 650.00	0	0	0	\$ -
Survey Truck (#1)	\$ 450.00	1	15	3	\$ 8,100
Survey Truck (#2)	\$ 450.00	0	0	0	\$ -
Per Diem (#1)	\$ 110.00	2	15	3	\$ 3,960
Per Diem (#2)	\$ 110.00	0	0	0	\$ -
Total Route Survey					\$ 41,610
Total with Rooney Engineering Overhead of 15%					\$ 47,852
Total with Estimate Contingency of 15%					\$ 55,029

Survey - Construction and As-Built Survey

Description	Rate [\$/day]	Quantity [ea]	Construction Duration [Days]	Set Up/ Close Out Duration [Days]	Total
2 Man Survey Crew (#1)	\$ 991.67	1	67	2	\$ 68,425
2 Man Survey Crew (#2)	\$ 991.67	1	67	2	\$ 68,425
GPS Survey Equipment (#1)	\$ 650.00	1	67	2	\$ 44,850
GPS Survey Equipment (#2)	\$ 650.00	1	67	2	\$ 44,850
Survey Truck (#1)	\$ 450.00	1	67	2	\$ 31,050
Survey Truck (#2)	\$ 450.00	1	67	2	\$ 31,050
Per Diem (#1)	\$ 110.00	2	67	2	\$ 15,180
Per Diem (#2)	\$ 110.00	2	67	2	\$ 15,180
Total Survey - Construction and As-Built					\$ 319,010
Total with Rooney Engineering Overhead of 15%					\$ 366,862
Total with Estimate Contingency of 15%					\$ 421,891

NDE (X-Ray) Inspection

Description	Rate [\$/day]	Quantity	Construction Duration [Days]	Set Up/ Close Out Duration [Days]	Total
Two Man RT Crew (#1)	\$ 933.33	1	67	2	\$ 64,399.77
Two Man RT Crew (#2)	\$ 933.33	1	67	2	\$ 64,399.77
Mobile Darkroom (#1)	\$ 85.00	1	67	2	\$ 5,865.00
Mobile Darkroom (#2)	\$ 85.00	1	67	2	\$ 5,865.00
Pick Up Truck (#1)	\$ 70.00	1	67	2	\$ 4,830.00
Pick Up Truck (#2)	\$ 70.00	1	67	2	\$ 4,830.00
Source and Camera (#1)	\$ 475.00	1	67	2	\$ 32,775.00
Source and Camera (#2)	\$ 475.00	1	67	2	\$ 32,775.00
HS & BRC Security Fee (#1)	\$ 35.00	1	67	2	\$ 2,415.00
HS & BRC Security Fee (#2)	\$ 35.00	1	67	2	\$ 2,415.00
Per Diem (per 2 man crew) (#1)	\$ 125.00	2	67	2	\$ 17,250.00
Per Diem (per 2 man crew) (#2)	\$ 125.00	2	67	2	\$ 17,250.00
Total NDE (X-ray)					\$ 255,070
Total with Rooney Engineering Overhead of 15%					\$ 293,330
Total with Estimate Contingency of 15%					\$ 337,329

Engineering Survey and Procurement Inspection	\$ 235,154
Construction Inspection, Surveying and X-Ray	\$ 1,681,677

**INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION &
ENHANCED OIL RECOVERY PROJECT**

Kansas Ethanol LLC Plant (KE) to Geneseo-Edwards (GE) Oil Field

Material Quote Summary

Blue Source LLC

Date: March 31, 2010

Pipeline Material Bid Summary

Type	Analysis	Material Description	Cost
3D Bends	Average	4", 0.337" w.t., 90 Degree, 3D, MSS SP-75, WPHY-52, Segmentable Fitting, coated with 14-16 mils of FBE	\$577.50
	Average	4", 0.337" w.t., 60 Degree, 3D, MSS SP-75, WPHY-52, Segmentable Fitting, coated with 14-16 mils of FBE	\$570.00
Line Pipe	Average	4.5" OD, 0.237" w.t., ERW, API 5L, PSL2, Grade X-52, DRL, BEW, Coated with 14-16 mils of FBE	\$9.61
	Average	4.5" OD, 0.337" w.t., SMLS, API 5L, PSL2, Grade X-52, DRL, BEW, Coated with 14-16 mils of FBE	\$20.16
Launcher/Receiver	Average	4" - ANSI 900 Launcher/Receiver, Barrel and Closure (Yale 500 or equivalent) Only, Traps to accommodate instrumented pigs, conventional pigs and typical pipeline inspection tools.	\$14,101.00
Pig Launcher - Bill of Material	Edgen - Murray	4" Pig Launcher Bill of Materials	\$20,930.81
Pig Launcher - Bill of Material	Edgen - Murray	4" Pig Receiver Bill of Materials	\$18,462.81
Valves	Cameron	4" 900 RTJ GO CAMERON T31 TRIM 601 w/ 7' STEM EXTENSION & COAL TAR	\$7,600.00
		3" 900 RTJ GO CAMERON T31 TRIM 601	\$4,000.00

INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION &
ENHANCED OIL RECOVERY PROJECT
Kansas Ethanol LLC Plant (KE) to Geneseo-Edwards (GE) Oil Field
Blue Source LLC
Date: March 31, 2010

Road, Railroad, and Waterway Crossing List

Approx Mile Post	Description / Name	Approximate Length	Interstate	Highway / State Rd	Other Paved Road	Dirt Road	Railroad	Lake / River	Creek	Comments	Valve Locations
MP 0.2	Avenue Q	75 ft			1					Slick Bore - Uncased	
MP 0.4	Missouri-Pacific Railroad	100 ft					1			Directional Drill - Uncased	
MP 1.1	17th Road	50 ft				1				Open Cut	
MP 1.6	Cow Creek	100 ft						1		Directional Drill - Uncased	
MP 1.8	Avenue P	50 ft			1					Open Cut	
MP 2.4	Well Pad Access Road	50 ft			1					Open Cut	
MP 2.8	Avenue O	50 ft			1					Open Cut	
MP 3.3	Well Pad Access Road	50 ft			1					Open Cut	
MP 3.8	Avenue N	50 ft			1					Open Cut	
MP 4.8	Avenue M	75 ft			1					Slick Bore - Uncased	
MP 5.2	Well Pad Access Road	50 ft			1					Open Cut	
MP 5.6	Highway 56	100 ft		1						Directional Drill - Uncased	
MP 5.6	Atchison Topeka and Santa Fe Railroad	100 ft					1			Directional Drill - Uncased	
MP 5.9	Owl Creek	25 ft						1		Slick Bore - Uncased	
MP 5.9	Avenue L	50 ft			1					Open Cut	
MP 7.0	17th Road	50 ft			1					Open Cut	
MP 7.1	Avenue K	50 ft			1					Open Cut	
MP 8.0	Avenue J	50 ft			1					Open Cut	
MP 9.0	Avenue I	50 ft			1					Open Cut	
MP 10.0	Private Road	50 ft			1					Open Cut	
MP 10.1	Avenue H	50 ft			1					Open Cut	
MP 11.1	Avenue G	50 ft			1					Open Cut	
MP 12.1	Avenue F	50 ft			1					Open Cut	
MP 13.1	Avenue E	50 ft			1					Open Cut	
MP 14.1	17th Road	50 ft			1					Open Cut	
MP 15.1	18th Road	50 ft			1					Open Cut	

Crossing Summary

TYPE	TOTAL NO. CROSSINGS	TOTAL LENGTH	W.A. Length	W.A. Width	W.A. Dimensions
Interstate	0	0 ft	300 ft	300 ft	0 sq.ft.
Highway / State Rd	1	100 ft	300 ft	300 ft	180,000 sq.ft.
Other Paved Road	2	150 ft	300 ft	300 ft	360,000 sq.ft.
Dirt Road	19	950 ft	300 ft	300 ft	3,420,000 sq.ft.
Railroad	2	200 ft	300 ft	300 ft	360,000 sq.ft.
Lake / River	1	100 ft	300 ft	300 ft	180,000 sq.ft.
Creek	1	25 ft	300 ft	300 ft	180,000 sq.ft.
TOTAL	26	1,525 ft	N/A	N/A	4,680,000 sq.ft.

Total Crossing Work Areas = 107.4 acres
Pipeline ROW Disturbance = 143.6 acres
Total Disturbance = 251.1 acres

**INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION &
ENHANCED OIL RECOVERY PROJECT**

Kansas Ethanol LLC Plant (KE) to Geneseo-Edwards (GE) Oil Field

Blue Source LLC

Date: March 31, 2010

FEED ESTIMATE FOR SCADA SYSTEM

CLIENT: BLUE SOURCE

PROJECT KE-GE

DESCRIPTION: 15.8 MILES OF CO2 PIPELINE FROM THE KANSAS ETHANOL PLANT TO GENESEO-EDWARDS FIELD

DATE 29-Mar-10

Estimate Overview:

This estimate is for a SCADA and Leak Detection system for a CO2 pipeline with main stations on either end of the pipeline and block valves sites along the pipeline as required. Each site would have a PLC and installed in a small building. The main control center site would house the primary SCADA and Leak Detection Computers which would communicate via fiber to the other sites. The other end of the pipeline would have a backup control center which would also contain the secondary SCADA and Leak Detection computers. A fiber optic cable would be installed along the pipeline and would be configured in a ring configuration for improved reliability.

SCADA Materials

	Quantity	\$ 5,000.00	Extension
Origination Station	1	\$ 186,500.00	\$ 186,500.00
Terminal Station	1	\$ 176,700.00	\$ 176,700.00
Block Valve Stations	1	\$ 206,000.00	\$ 206,000.00
Fiber Optic Cable	1	\$ 180,136.00	\$ 180,136.00
		Subtotal	\$ 749,336.00
		Sales Tax on Material (5.98%)	\$ 44,800.00
		Subtotal	\$ 913,000

SCADA Engineering Hours/Expenses

	Hours	Unit Price	Extension
Sr Project Engineer - SCADA	1056	\$ 121.00	\$ 127,776.00
Sr Designer	54	\$ 91.00	\$ 4,914.00
Travel Expenses	1	\$ 8,370.00	\$ 8,370.00
		Subtotal	\$ 162,000

SCADA Vendor Labor

	Quantity	Unit Price	Extension
SCADA, PLC, Leak Detection Services	1	\$ 330,000.00	\$ 330,000.00
		Subtotal	\$ 380,000

Fiber Optic Construction Labor

	Quantity	Unit Price	Extension
Fiber Optic Cable Construction Contractor	1	\$ 166,848.00	\$ 166,848.00
		Subtotal	\$ 192,000

Total \$ 1,647,000

Assumed Estimate Contingency 15.0%

Notes:

- 1) SCADA electrical construction contractor labor not included since wiring up the PLCs would be done by site contractor along with instruments
- 2) Fiber optic labor assumes moderately difficult ground conditions which raises cable installation cost moderately
- 3) PLC MCC building is included at the terminal station
- 4) Instrumentation not included here.

**INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION &
ENHANCED OIL RECOVERY PROJECT**

Kansas Ethanol LLC Plant (KE) to Geneseo-Edwards (GE) Oil Field

Blue Source LLC

Date: March 31, 2010

STATIONS ON EITHER END OF PIPELINE

Materials

		Quantity	Unit Price	Extension
ORIGINATION STATION	PLC, w Cabinet	1	\$ 40,000.00	\$ 40,000.00
	SCADA Software Licenses	1	\$ 25,000.00	\$ 25,000.00
	Backup communications components	1	\$ 10,000.00	\$ 10,000.00
	SCADA Server, Rack, Printer, etc	1	\$ 20,000.00	\$ 20,000.00
	Leak Detection Server	1	\$ 5,000.00	\$ 5,000.00
	Leak Detection Software Licenses (note 2)	1	\$ 60,000.00	\$ 60,000.00
	UPS	1	\$ 5,000.00	\$ 5,000.00
	Fiber Media Converter	1	\$ 1,500.00	\$ 1,500.00
	Communications Equipment for backup communications	1	\$ 5,000.00	\$ 5,000.00
	Misc	1	\$ 15,000.00	\$ 15,000.00
			Subtotal	\$ 186,500.00

		Quantity	Unit Price	Extension
TERMINAL STATION	PLC, w Cabinet	1	\$ 40,000.00	\$ 40,000.00
	PLC-MCC Building	1	\$ 65,000.00	\$ 65,000.00
	SCADA Software Licenses	1	\$ 7,000.00	\$ 7,000.00
	Backup communications components	1	\$ 10,000.00	\$ 10,000.00
	SCADA Computer, Rack	1	\$ 10,000.00	\$ 10,000.00
	Leak Detection Computer	1	\$ 5,000.00	\$ 5,000.00
	Leak Detection Software Licenses	1	\$ 15,000.00	\$ 15,000.00
	UPS	1	\$ 5,000.00	\$ 5,000.00
	Fiber Media Converter	1	\$ 3,200.00	\$ 3,200.00
	Communications Equipment for backup communications	1	\$ 1,500.00	\$ 1,500.00
	Misc	1	\$ 15,000.00	\$ 15,000.00
			Subtotal	\$ 176,700.00

		Quantity	Unit Price	Extension
VENDOR SERVICES	SCADA Vendor Services for Origination Station (note 6)	1	\$ 100,000.00	\$ 100,000.00
	SCADA Vendor services for Terminal Station	1	\$ 10,000.00	\$ 10,000.00
	SCADA Vendor Travel Expenses	1	\$ 30,000.00	\$ 30,000.00
	PLC Programming for two PLCs	2	\$ 50,000.00	\$ 100,000.00
	PLC Programmer Travel Expenses	1	\$ 15,000.00	\$ 15,000.00
	Leak Detection System services for Origination Station	1	\$ 60,000.00	\$ 60,000.00
	Leak Detection System services for Terminal Station	1	\$ 5,000.00	\$ 5,000.00
	Leak Detection Vendor Travel Expenses	1	\$ 10,000.00	\$ 10,000.00
				\$ -
			Subtotal	\$ 330,000.00

Notes:

1) Assumes fiber optic communications.

3) PLC MCC building is included at the terminal station

3) Assumes Wonderware class SCADA software

4) Assuming 120 VAC is available at both stations.

5) Instrumentation not included here.

6) SCADA vendor services include project management, design specification documents, SCADA communications programming, SCADA screen programming, factory tests, installation onsite, onsite tuning of the software, commissioning tests, operations and the maintenance manual, training support for operators and technicians.

7) Leak Detection vendor services include project management, design specification documents, communications programming, graphical user interface screen programming, factory tests, installation onsite, tuning of the software, commissioning tests, operations and the maintenance manual, training support for operators and technicians.

**INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION &
ENHANCED OIL RECOVERY PROJECT**
Kansas Ethanol LLC Plant (KE) to Geneseo-Edwards (GE) Oil Field
Blue Source LLC
Date: March 31, 2010

BLOCK VALVE STATIONS

Materials

	Quantity	Unit Price	Extension
PLC, w Cabinet	4	\$ 15,000.00	\$ 60,000.00
PLC Building	4	\$ 30,000.00	\$ 120,000.00
Fiber Media Converter	4	\$ 1,500.00	\$ 6,000.00
Misc	4	\$ 5,000.00	\$ 20,000.00
		Subtotal	\$ 206,000.00

Services

	Quantity	Unit Price	Extension
PLC Programming	4	\$ 5,000.00	\$ 20,000.00
PLC Programmer Travel Expenses	4	\$ 2,000.00	\$ 8,000.00
Misc	4	\$ 2,000.00	\$ 8,000.00
		Subtotal	\$ 36,000.00

Notes:

1 PLC building is recommended due to the difficulty of maintaining PLC in winter conditions.

**INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION &
 ENHANCED OIL RECOVERY PROJECT**
Kansas Ethanol LLC Plant (KE) to Geneseo-Edwards (GE) Oil Field
Blue Source LLC
Date: March 31, 2010

FIBER OPTICS

Materials

	Quantity	Units	Unit Price	Extension
12 Strand Single Mode Armored Outside Plant Cable	83,424	ft	\$ 1.50	\$ 125,136.00
Fiber Troubleshooting instrument	1	LS	\$ 35,000.00	\$ 35,000.00
Misc Hand Holes, etc	1	LS	\$ 20,000.00	\$ 20,000.00
			Subtotal	\$ 180,136.00

Labor - Installation Contractor

	Quantity	Units	Unit Price	Extension
Contractor Labor for installation and testing	83,424	ft	\$ 2.00	\$ 166,848.00
				\$ -
			Subtotal	\$ 166,848.00

INTEGRATED MID-CONTINENT CARBON CAPTURE, SEQUESTRATION &
ENHANCED OIL RECOVERY PROJECT
Kansas Ethanol LLC Plant (KE) to Geneseo-Edwards (GE) Oil Field
Blue Source LLC
Date: March 31, 2010

SCADA PROJECT - ESTIMATE OF I&E ENGINEERING TASKS

			Project Management				TRAVEL & MISC EXPENSES						Engineering							
			Note 1	Project Manager	Secretary & File Clerk	Subtotal Man-Hours	Subtotal \$	Travel	Denver Office Travel - Other	Denver Office Expenses	Misc.	Subtotal \$	Project Engineer (Controls)	Sr. Project Engineer (Electrical)	Electrical Designers	Designer	Subtotal Man-Hours	Subtotal \$	Grand Total Hours	Grand Total \$
TASK #	TASKS																			
			Rates:		\$44.00								\$116.00	\$121.00	\$91.00	\$91.00				
1	Initial Site visit					0	\$0	1,920				\$1,920		30			30	3,630	30	5,550
2						0	\$0					\$0					0	0	0	0
3						0	\$0					\$0					0	0	0	0
4	Assist with Project Budget preparation					0	\$0					\$0		24			24	2,904	24	2,904
5						0	\$0					\$0					0	0	0	0
6	SCADA SPECIFICATION, RFQ, CONTRACT OVERSIGHT, DESIGN APPROVAL, FACTORY TEST, SITE TEST					0	\$0		300			\$300		300			300	36,300	350	36,600
7						0	\$0					\$0					0	0	0	0
	LEAK DETECTION SYSTEM SPECIFICATION, RFQ, CONTRACT OVERSIGHT, DESIGN APPROVAL, FACTORY TEST, SITE TEST					0	\$0		200			\$200		200			200	24,200	250	24,400
1						0	\$0					\$0					0	0	0	0
2	Fiber Optic Design, RFQ					0	\$0					\$0		60			60	7,260	60	7,260
3						0	\$0					\$0					0	0	0	0
4	Fiber Optic Construction Spec, RFQ, Contract Oversight					0	\$0					\$0		80			80	9,680	80	9,680
5						0	\$0					\$0					0	0	0	0
6						0	\$0					\$0					0	0	0	0
7						0	\$0					\$0					0	0	0	0
8						0	\$0					\$0					0	0	0	0
9						0	\$0					\$0					0	0	0	0
10						0	\$0					\$0					0	0	0	0
11						0	\$0					\$0					0	0	0	0
12	Weekly Conference Calls					0	\$0					\$0		30			30	3,630	30	3,630
13						0	\$0					\$0					0	0	0	0
14	Construction Inspection Trip (X 3)					0	\$0	3,570				\$3,570		120			120	14,520	120	18,090
15	Testing Trips (x 2)					0	\$0	2,380				\$2,380		80			80	9,680	80	12,060
16						0	\$0					\$0					0	0	0	0
17						0	\$0					\$0					0	0	0	0
18	As Built Electrical Drawings					0	\$0					\$0		40	50		90	9,390	90	9,390
19	I&E Job Book					0	\$0					\$0		32	4		36	4,236	36	4,236
20						0	\$0					\$0					0	0	0	0
21	Assist with SCADA & Leak Detection Tuning					0	\$0					\$0		60			60	7,260	60	7,260
22						0	\$0					\$0					0	0	0	0
23						0	\$0					\$0					0	0	0	0
24						0	\$0					\$0					0	0	0	0
25							\$0										24	0		
26					0	0	\$0	0	0			\$0	0	0	0	0	0	0	0	0
27				0	0	0	\$0	0	0	0	0	\$0	0	0	0	0	0	0	0	0
Hours				0	0	0	\$0	7,870	0	500	0	8,370	0	1,056	54	0	1,134	132,690	1,210	
Cost (\$)				0	0	\$0		7,870	0	500	0	8,370	0	127,776	4,914	0		132,690		141,060
Back check							\$0					8,370						132,690		\$141,060
																		0		\$141,060

Not Included:

Without Expenses = \$132,690

Expenses = \$8,370

**BLUE SOURCE, LLC.
KE - GE CO2 PIPELINE PROJECT
CAP CO2 KANSAS ETHANOL COMPRESSION FACILITY
TIER III - CAPITAL COST ESTIMATE**

Client: Blue Source, LLC.

Project: KE-GE CO2 Pipeline Project

System: Kansas Ethanol Compression Facility

Scope: Ref. Blue Source RFP for Kansas CO2 Pipeline Study, Doc. RPH-12-29-09.

Description: Engineering, Design, and Construction of a new CAP CO2 compression facility at the Kansas Ethanol, Lyons, KS plant located in the NE NW of Section 27, T20S, R8W, for the purpose of recovering waste gases off of the Ethanol Plant and processing the high concentration CO2 mix stream for use in Enhanced Oil Recover and boosting the purified stream pressure for transportation as a supercritical phase fluid via pipeline to the Geneseo Edwards Field delivery point located in the center of Section 24, T18S, R8W.

COMPRESSION FACILITIES

ENGINEERING & DESIGN	\$799,000
LAND & RIGHT-OF-WAY	\$0
ENVIRONMENTAL & PERMITTING	\$6,000
EQUIPMENT & MATERIALS	\$13,644,000
	\$11,920,900
FREIGHT @ 8%	\$953,672
TAXES @ 5.98%	\$769,899
CONSTRUCTION SERVICES	\$1,035,000
CONSTRUCTION	\$4,181,000
	\$4,074,220
BOND @ 3%	\$106,284
GRAND TOTAL COMPRESSION FACILITIES:	
	\$19,665,000

Notes & Assumptions:

BLUE SOURCE, LLC.
KE - GE CO2 PIPELINE PROJECT
CAP CO2 KANSAS ETHANOL COMPRESSION FACILITY
TIER III - CAPITAL COST ESTIMATE

Client: Blue Source, LLC.

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CAP CO2 COMPRESSION FACILITIES					Station Horsepower: 4,080 BHP	% Total
LAND & RIGHT-OF-WAY (BY OTHERS)					\$0	0.0%
ENVIRONMENTAL & PERMITTING (BY OTHERS)					\$5,000	0.0%
MATERIALS & EQUIPMENT					\$10,366,000	52.7%
CONSTRUCTION					\$3,542,800	18.0%
Land, Permitting, Materials & Construction Sub-Total:					\$13,913,800	70.8%
Freight on Materials & Equipment @ 8%					\$829,280	
Taxes @ 5.98%					\$669,478	
Land, Permitting, Materials & Construction Total:					\$15,412,558	78.4%
ENGINEERING & DESIGN					\$674,570	3.4%
GEOTECHNICAL INVESTIGATIONS					\$20,000	0.1%
CONSTRUCTION MANAGEMENT					\$593,120	3.0%
SURVEY (BY OTHERS)				0.0%	\$0	0.0%
INSPECTION SERVICES	No. of Inspectors: 4	240 Man-Days @	\$1,100 per Day	100%	\$264,000	1.3%
NON-DESTRUCTIVE EXAMINATION	No. of Crews: 1	25 Crew-Days @	\$1,700 per Day	100%	\$42,500	0.2%
LEGAL (BY OTHERS)					\$0	0.0%
Engineering & Contract Services Sub-Total:					\$1,594,190	8.1%
Compression Facilities Sub-Total:					\$17,006,748	
Contingency @ 15%					\$2,551,012	13.0%
Construction Performance Bond @ 3%					\$106,284	0.5%
COMPRESSION FACILITIES TOTAL:					\$19,664,044	100.0%
\$ / BHP: \$4,013 Excludes Costs for ORU						
\$ / BHP: \$4,820 Includes Costs for ORU						

LAND & RIGHT-OF-WAY

100. CAP CO2 KANSAS ETHANOL COMPRESSOR STATION	\$0
Sub-Total:	\$0
Contingency @ 15%	\$0
Grand Total - Land & Right-of-Way:	\$0

Project Estimate Worksheet

Description	Cost Code	Qty	Units	Unit Rate	Sub-Total Price	Estimate Supplier
100. CAP CO2 KANSAS ETHANOL COMPRESSOR STATION					Sub-Total:	\$0
101. Acquisition & Damages						
01 Land & Property Appraisals		0	Weeks	\$2,500	\$0	
02 Land Acquisition Costs		0	Weeks	\$2,500	\$0	
03 Property Expense		0	LS	\$15,000	\$0	

ENVIRONMENTAL & PERMITTING SUPPORT

100. CAP CO2 KANSAS ETHANOL COMPRESSOR STATION	\$5,000
Sub-Total:	\$5,000
Contingency @ 15%	\$750

Project Estimate Worksheet

Grand Total - Environmental & Permitting Support: \$5,750

Description	Cost Code	Qty	Units	Unit Rate	Sub-Total Price	Estimate Supplier
100. CAP CO2 KANSAS ETHANOL COMPRESSOR STATION	Sub-Total:					\$5,000
101. Permitting Assistance						
01 Air Permitting Support & Acquisition Costs	101.01	1	LS	\$5,000	\$5,000	LWR Consultants
102. Storm Water Monitoring						
01 TBD	102.01	1	LS	\$0	\$0	

Air Permit

Blue Source, LLC.
KE-GE CO2 Pipeline Project
Kansas Ethanol Compression Facility

MATERIALS & EQUIPMENT

100. MECHANICAL EQUIPMENT & MATERIALS	\$9,358,000
200. ELECTRICAL & INSTRUMENTATION EQUIPMENT & MATERIALS	\$1,008,000
Sub-Total:	\$10,366,000
Freight @ 8%	\$829,280
Taxes @ 6%	\$669,478
Contingency @ 15%	\$1,779,714

Project Estimate Worksheet

Grand Total - Materials & Equipment: \$13,644,471

Description	Cost Code	Qty	Units	Unit Rate	Sub-Total Price	Estimate Supplier
100. MECHANICAL EQUIPMENT & MATERIALS					Sub-Total: \$9,358,000	
101. Pipe, Fittings & Materials						
01 Pipe, Various Diameters & Coatings	101.01	Pipe_Lot2	0.75	LOT	\$20,000	REI - Estimated
02 Fittings, Various Diameters	101.02	Fitting_Lot3	0.75	LOT	\$15,000	REI - Estimated
102. Scrubbers / Filters / Separators						
01 Scrubber, 2-Phase, Vertical, 8.625" O.D. x 4'-0" S/S, ASME Sect. VIII, Div. 1, 285 psi @ -20/1C	102.01	Scrubber_Vertical 8x48	1	EA	\$5,749	Midco Fabricators
103. Compression Equipment						
01 Compressor, Reciprocating, GE FS-706, 6-Stage, 4160V Inv. Duty Electric Drive	103.01	Comp_Recip_1360HP	3	EA	\$1,750,000	General Electric - Est.
02 Compressor Package Spare Parts	103.02	Spare	3	LS	\$44,000	General Electric - Est.
104. Processing Equipment						
01 Oxygen Removal Unit, 8 MMscfd, 3% Maximum O2	104.01	ORU_8MM	1	EA	\$3,290,000	BCCK Engineers
02 TEG Dehydration Package, 125,000 BTU/ Hr Reboiler, 24" x 25', 8-Tray Contactor Column	104.02	Dehy_TEG125	1	EA	\$350,000	QB Johnson
105. Metering Equipment						
01 Orifice Meter, 2" ANSI 150 RFFE, Simplex w/ Flow Cond. & Skid Mounted Metal Building	105.01	2ORF150_JR	1	EA	\$7,738	JW Measurement
106. Compressor Building						
01 Compressor Building, 50' W x 65' L x 15' Eve Hght, Ovhd Door, Fixed Wall Louvers, 5 Ton Bric	106.01	Comp_Bldg 50x65x15	1	EA	\$195,782	Tri-State - 11.18.09
107. Block Valves & SDV's						
01 Valves, Various Sizes & Type	107.01	Valve_Lot2	0.75	LOT	\$60,000	REI - Estimated
108. Control Valves & Regulators						
01 Flow Control Valve, Fisher EZ or Comparable, 1" ANSI 150 RFFE	108.01	FCV_150	1	EA	\$2,924	Applied Control Equip.
109. Liquid Dump Valves & Controllers						
01 Liquid Dump Valve, 1" Kimray SMT 1400 or Similar, 0.5-Inch Inner Valve	109.01	1400SMT_0.5	1	EA	\$315	RMWH
02 Level Controller, Kimray Gen II or Similar, Float Operated, 2" MNPT	109.02	LC	1	EA	\$421	RMWH
110. Check Valves						
01 Valve, Check, 4" ANSI 900 RFFE, Piston Type, API-6D	110.01	4C90AP	2	EA	\$4,770	REI - Estimated
02 Valve, Check, 4" ANSI 300 RFFE, Piston Type, API-6D	110.02	4C30AP	2	EA	\$3,604	REI - Estimated
111. Relief Valves						
01 Pressure Relief Valve, 1" FNPT X 1" FNPT, For Gas Service	111.01	1x1PSV_Gas	1	EA	\$700	REI - Estimated
112. Sump Tank						
01 Sump Tank, 3,000 Gallon, Double Wall Fiberglass w/ Turbine Enclosure, Leak Monitor, Brine	112.01	Sump_3000	1	EA	\$17,808	Palmer Mfct - 11.17.09
113. Pipe Supports						
01 Pipe Support, 6" Pipe, EZ-Line Model CSB-6 w/Shim Blocks, Pipe Clamp & Baseplate	113.01	CSB-06	16	EA	\$827	REI - Estimated
02 Pipe Support, 4" Pipe, EZ-Line Model CSB-4 w/Shim Blocks, Pipe Clamp & Baseplate	113.02	CSB-04	4	EA	\$742	REI - Estimated
200. ELECTRICAL & INSTRUMENTATION EQUIPMENT & MATERIALS					Sub-Total: \$1,008,000	
201. Instrumentation						
01 Pressure Gauge, 5" Dial, 1/2" MNPT Process Connection, Range: Varies	201.01	PI	3	EA	\$119	Applied Control Equip.
02 Gauge, Temperature, Range: Varies, w/ Thermowell	201.02	TI	3	EA	\$185	Applied Control Equip.
03 Switch, Gage Pressure, Range: Varies	201.03	PSHH	1	EA	\$425	REI - Estimated
04 Switch, Level, 316 SS Media Contacts w/ Relay, 24VDC	201.04	LSHH_1	1	EA	\$1,180	Applied Control Equip.
05 Gauge, Level, 316 SS Chamber w/ Side Connect Valves, Center-to-Center Dim: Varies	201.05	LG	1	EA	\$1,963	Applied Control Equip.
06 Pressure Transmitter, Indicating, "Smart", Range: Varies, Includes 2-Valve Manifold	201.06	PIT	4	EA	\$3,271	\$13,082
07 Transmitter, Temperature, "Smart", Range: Varies, w/ Thermowell	201.07	TT	4	EA	\$2,650	\$10,600
08 Transmitter, Level, SABB Radar, Range: Varies w/ RTD Inputs	201.08	LIT-1	1	EA	\$4,637	\$10,637
09 Switch, Level, Range / Length: Varies	201.09	LSHH_2	1	EA	\$3,848	\$3,848
10 CO2 Detector, Class 1 / Div. 1 Rated	201.10	CO2_DET	3	EA	\$1,272	\$3,816
11 Fire Eye, Class 1 / Div 1 Rated	201.11	FIRE_EYE	3	EA	\$1,272	\$3,816
12 Vibration Transducer	201.12	VT	3	EA	\$300	\$900
202. Switchgear / Motor Starters & MCC's						
01 Switchgear, 4160V w/ Vacuum Circuit Breaker & (3) 4160V Solid State Reduced Voltage Start	202.01	4160_Switchgear w/ SSRV	1	EA	\$235,000	\$235,000
02 Motor Control Center, 480V	202.02	480_MCC	1	EA	\$45,000	\$45,000
203. Transformers						
01 Transformer, 4160V / 480V, Padmount, Oil Filled, 500 KVA, Nema 3R , 65 deg. C Rise	203.01	500KVA_TRN4160.480	1	EA	\$17,000	\$17,000
02 Transformer, 13.8KV / 4160V, Padmount, Oil Filled, 5000 KVA	203.02	5000KVA_TRN138.4160	1	EA	\$125,000	\$125,000
204. UPS / Power Supply Equipment						
01 Unitized Distribution Substation	204.01	UDS	1	EA	\$10,000	\$10,000
02 UPS, Rack Mounted, Bypass Switch, 7 KVA	204.02	UPS	1	EA	\$9,000	\$9,000
205. Control Switches & Lighting						
01 Lighting Subpanel, 120V, 1Ph	205.01	LGHT_Sub Panel	1	EA	\$600	\$600
02 Yard Lighting, 1000 Watt w/40' Aluminum Pole	205.02	LGHT1000	4	EA	\$4,000	\$16,000
206. Power & Control Buildings						
01 Building, Pre-Fab Metal, 13'x40', HVAC, w/ Access Platforms & Stairs	206.01	PDC_13X40MED	1	EA	\$162,000	\$162,000
207. PLC Equipment & Controls						
01 PLC & DIO Panel & Equipment, Incl. Programming & Commissioning	207.01	PLC_Lot2	0	LS	\$70,000	\$0
208. Consumables						
01 Electrical & Instrumentation Consumables (Compressor Station)	208.01	E&I_Consum 1	1.5	EA	\$229,000	\$343,500

Blue Source, LLC.
KE-GE CO2 Pipeline Project
Kansas Ethanol Compression Facility

CONSTRUCTION

100. CAP CO2 KANSAS ETHANOL COMPRESSOR STATION	\$3,542,800
Sub-Total:	\$3,542,800
Contingency @ 15%	\$531,420
Grand Total - Construction:	\$4,074,220

Project Estimate Worksheet

Description	Cost Code	Qty	Units	Unit Rate	Sub-Total Price	Estimate Supplier
100. CAP CO2 KANSAS ETHANOL COMPRESSOR STATION					Sub-Total: \$3,542,800	
101. Compressor Station Construction (Civil / Mechanical / Electrical)						
01 Compressor Station Construction	01	1	LS	\$3,312,000	\$3,312,000	REI - Estimated
102. E&I Unit Price Adders						
01 Megar / High Pot Testing	01	1	LS	\$50,000	\$50,000	REI - Estimated
02 Switchgear Commissioning	02	1	LS	\$25,000	\$25,000	REI - Estimated
103. Station Rock						
01 Station Rock Materials	01	1	LS	\$10,000	\$10,000	REI - Estimated
104. Pre-Commission / Commissioning / Start-Up Services						
01 E&I Contractor Support	01	6	DAYS	\$8,000	\$48,000	REI - Estimated
02 Mechanical Contractor Support	02	6	DAYS	\$10,000	\$60,000	REI - Estimated
03 Solid State Reduced Voltage Starters Technician	03	6	DAYS	\$2,000	\$12,000	REI - Estimated
04 Compression - Controls Technician	04	6	DAYS	\$2,300	\$13,800	REI - Estimated
05 Compression - Service Specialist / Supervisor	05	6	DAYS	\$2,000	\$12,000	REI - Estimated

APPENDIX 3-L
PROJECT SCHEDULE
GENESEO-EDWARDS FIELD

ID	Task Name	Duration	Start	Finish	2010												2011												2012					
					1st Quarter			2nd Quarter			3rd Quarter			4th Quarter			1st Quarter			2nd Quarter			3rd Quarter			4th Quarter			1st Quarter			2nd Quarter		
					Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	
52	Process Equip - Delivery	26 wks	Mon 1/24/11	Fri 7/22/11																														
53	Facility Construction - RFQ, Eval, Award	2 mons	Mon 5/9/11	Fri 7/1/11																														
54																																		
55	KE-GE Construction	100 days	Mon 6/27/11	Fri 11/11/11																														
56	Pipeline Construction	67 days	Sat 7/2/11	Fri 9/16/11																														
57	Mobilize	10 days	Sat 7/2/11	Wed 7/13/11																														
58	Test Welders	4 days	Tue 7/5/11	Sat 7/9/11																														
59	Base Lay	50 days	Wed 7/13/11	Thu 9/8/11																														
60	Clear & Grade ROW	20 days	Wed 7/13/11	Fri 8/5/11																														
61	Ditch	20 days	Mon 7/18/11	Wed 8/10/11																														
62	String Pipe	20 days	Fri 7/22/11	Mon 8/15/11																														
63	Lay & Weld Pipe	20 days	Wed 7/27/11	Fri 8/19/11																														
64	Coat field joints	20 days	Wed 7/27/11	Fri 8/19/11																														
65	Lower-in & Backfill	20 days	Mon 8/1/11	Tue 8/23/11																														
66	Tie Ins	6 days	Wed 8/24/11	Tue 8/30/11																														
67	Clean, Fill, & Test	8 days	Tue 8/30/11	Thu 9/8/11																														
68	Clean-up	15 days	Tue 8/23/11	Thu 9/8/11																														
69	Build and Test Fabricated Assemblies	25 days	Sat 7/30/11	Sat 8/27/11																														
70	Install Fabricated Assemblies	10 days	Sat 8/27/11	Thu 9/8/11																														
71	Final tie-ins	2 days	Thu 9/8/11	Sat 9/10/11																														
72	Demobilize	5 days	Sat 9/10/11	Fri 9/16/11																														
73	Facility Construction	100 days	Mon 6/27/11	Fri 11/11/11																														
74	Mobilize	10 days	Fri 7/1/11	Thu 7/14/11																														
75	Test Welders	4 days	Wed 7/6/11	Mon 7/11/11																														
76	Civil Site Work	1 wk	Mon 6/27/11	Mon 7/4/11																														
77	Foundations / Pipe Support Installation	5 wks	Mon 7/4/11	Mon 8/8/11																														
78	Process Piping	8 wks	Mon 7/18/11	Fri 9/9/11																														
79	Electrical Install	10 wks	Mon 7/18/11	Fri 9/23/11																														
80	Process Equip Install	2 wks	Mon 7/25/11	Mon 8/8/11																														
81	Compressor Install	2 wks	Mon 8/8/11	Fri 8/19/11																														
82	SCADA Install	4 wks	Mon 9/12/11	Fri 10/7/11																														
83	Fill and Test	10 days	Mon 10/10/11	Fri 10/21/11																														
84	Commissioning	3 wks	Mon 10/24/11	Fri 11/11/11																														

Project: MSProj11
Date: Wed 3/31/10

Appendix 6-A

Geologic Sequestration Technical Risks for the IMCCS Project

CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number P×S (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
1	0.0.00.00.	Assessment Basis	This category of FEPs determines the boundary conditions for any assessment, specifying the spatial and temporal domain of the system. The Assessment Basis determines what is being assessed and why, so that those FEPs that need to be considered in the analysis can be defined, and those which can be screened out as being outside the scope of the assessment can be identified.		Quintessa scope & assumptions				NA	NA	NA	NA	NA
2	0.1.00.00.	Purpose of the assessment	The purpose of the assessment of geological CO2 sequestration.	The general purpose of an assessment of geological CO2 sequestration is to determine the performance of the sequestration system. In any specific case, however, the purpose of conducting an assessment may vary from simple calculations to test initial ideas for sequestration concepts, to support for an application for regulatory approval requiring detailed, site-specific performance assessment against relevant criteria. The level of complexity and comprehensiveness will vary according to the use to which it will be put. Additionally, the assessment endpoints of interest may not only vary in type, depending on the assessment purpose, but also in the level of rigor required for compliance demonstration.	Quintessa scope & assumptions		Site specific qualitative assessment of programmatic and technical risks		NA	NA	NA	NA	NA
3	0.2.00.00.	Endpoints of interest	The assessment endpoints of interest.	The structure and composition of an assessment will tend to reflect the endpoints that are required to be assessed. These in turn, will reflect the criteria that are adopted to judge the overall performance of the sequestration system. Thus, for example, an assessment may be constrained to considering the degree of containment within a geological feature, alternatively, it may need to address potential near-surface impacts. Invariably, a combination of endpoints will be required.	Quintessa scope & assumptions		Near surface HSE impact		NA	NA	NA	NA	NA
4	0.3.00.00.	Spatial domain of interest	The spatial domain of interest in the assessment.	The spatial domain of interest will be dependent on the site context, which may vary from generic assessments to site specific assessments, the sequestration concept and the endpoints of interest. The spatial domain will contribute to determining the information requirements and modeling capabilities that may be required.	Quintessa scope & assumptions		Compressor sites Pipeline ROWs Injection sites		NA	NA	NA	NA	NA

Appendix 6-2

CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
5	0.4.00.00.	Timescales of interest	Timescale of interest for the assessment.	Timescales over which the assessment will be performed will constrain processes which must be considered in the assessment. In general terms, there are two timescales of interest for geological storage of carbon dioxide. Firstly, there is that over which isolation of carbon dioxide from the atmosphere is necessary to mitigate climate change. This timescale is likely to be in the order of a few hundred years at most. The second timescale of interest is potentially much longer and is that pertaining to the assessment of potential hazard to humans and the environment. This timescale could be in the order of thousands to tens of thousands of years.	Quintessa scope & assumptions		50 years after injection stops.		NA	NA	NA	NA	NA
6	0.5.00.00.	Sequestration assumptions	High level assumptions concerning the sequestration system(s) of relevance to the assessment. For example, the quantity of CO2 sequestered, the method of injection and information concerning the assumed performance of the sequestration system.	Provides a background to the sequestration technique adopted. Note that more detailed consideration of the CO2 sequestration system is provided in subsequent FEP categories.	Quintessa scope & assumptions		Enhanced oil recovery and deep saline aquifer		NA	NA	NA	NA	NA
7	0.6.00.00.	Future human action assumptions	The assumptions made in the assessment concerning general boundary conditions for assessing future human action.	For example, it can be expected that human technology and society will develop over the timescales of relevance for the assessment of CO2 sequestration systems, however, this development is unpredictable. Therefore it may be necessary to make some assumptions in order to constrain the range of future human actions that are considered, such as assuming that only present-day technologies, or technologies practiced in the past, will be considered.	Quintessa scope & assumptions		Assume little change in human impact or technology over the life of the project		NA	NA	NA	NA	NA
8	0.7.00.00.	Legal and regulatory framework	The legal and regulatory framework within which the assessment takes place.	In undertaking an assessment it is vital to consider the appropriate regulatory framework requirements. At one extreme these may be specific, prescriptive quantitative requirements, at the other they could be non-prescriptive or may not have been fully developed. The legal and regulatory framework can shape various aspects of an assessment, such as the required assessment endpoints, timescales of interest and assumptions concerning future human actions.	Quintessa scope & assumptions		Legal and regulatory framework not fully developed		NA	NA	NA	NA	NA
9	0.8.00.00.	Model and data issues	General methodological issues affecting the assessment modeling process and use of data	Examples of general model and data issues include the treatment of uncertainty; the method for handling site specific data; and the reduction/simplification of models and data.	Quintessa scope & assumptions		Qualitative risk assessment - no modeling		NA	NA	NA	NA	NA

Appendix 6-3

CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
10	1.0.00.00.	External Factors	This category of FEPs describes natural or human factors that are outside the system domain. These FEPs are most important in determining scenarios for the future evolution of the system, and are often referred to as EFEPs (External FEPs). Three classes of FEPs are considered. Geological Factors and Climatic Factors are concerned with natural processes and events, whilst Future Human Actions is concerned with those human activities that can directly affect the sequestration system.		Quintessa original FEP				NA	NA	NA	NA	NA
11	1.1.00.00.	Geological factors	Natural geological processes and events in the environment outside the system domain that are relevant to the evolution of the sequestration system.	Changes in the geological environment outside the system domain may directly affect the transport of carbon dioxide within the system.	Quintessa original FEP				NA	NA	NA	NA	NA
12	1.1.01.00.	Neotectonics	Neotectonics is the study of crustal movements that both occurred in the Earth's recent past and are continuing at the present day. These movements, which are driven directly or indirectly by global plate motions (tectonics), result in the vertical and horizontal warping, folding or faulting of the Earth's surface.	Neotectonic events have the potential to cause sudden changes in the physical properties of rocks due to stress changes and induced hydrogeological changes.	Quintessa original FEP	Neotectonics do not play a significant role in the region.			1	3	3	NA	NA
13	1.1.02.00.	Volcanic and magmatic activity	Magma is molten, mobile rock material, generated below and within the Earth's crust, which gives rise to igneous rocks when solidified. A volcano is a vent or fissure in the Earth's surface through which molten or part-molten materials (lava) may flow, and ash and hot gases be expelled.	The high temperatures associated with volcanic and magmatic activity may result in permanent changes in the surrounding rocks, either directly, or through circulating high temperature fluids. This FEP is relevant to CO2 disposal in areas of potential magmatic activity, e.g. Japan. Besides bedrock damage, pressure and temperature changes due to heating, stress, and displacement could affect CO2 density and solubility, creating the risk of uncontrolled, rapid migration and escape of stored CO2. CO2STORE page 69)	Quintessa original FEP	No volcanic or magmatic activity has been observed in the region.			1	3	3	NA	NA
14	1.1.03.00.	Seismicity	Events and processes related to seismic events and also the potential for seismic events. A seismic event is caused by rapid relative movements within the Earth's crust usually along existing faults. The accompanying release of energy may result in rock movement and/or rupture, e.g. earthquakes.	Seismic events may result in changes in the physical properties of rocks due to stress changes and induced hydrogeological changes. Seismic events are most common in tectonically active or volcanically active regions at crustal plate margins.	Quintessa original FEP	Seismic activity has been associated with the Humboldt fault zone located 25 mi west of the Thrall-Aagard field.	Humboldt fault zone is slightly active, mostly in the Northeastern part of Kansas.		1	5	5	NA	Have emergency procedures in place for dealing with earthquakes.

Appendix 6-4

CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
15	1.1.03.01.	Earthquake induced fractures	<p>Many people are convinced that we want to avoid seismically-active areas for CO2 storage. In reality there are very large natural gas fields associated with some of the planet's major fault zones. For instance Indonesia and Malaysia have nay examples, and so does California. Earthquakes in these areas have never been associated with sudden emissions of significant quantities of natural gas or oil from deep reservoirs. (CCP 2009)</p> <p>Major earthquakes (magnitude 6 and above) occur primarily in strong, brittle basement rock at depths on the order of 6 miles or more (although very small earthquakes occur at depths as shallow as 2 miles.</p>	Seismic disturbances might cause caprock failure (Damen 2006). Earthquakes could disrupt drilling, well operation, and monitoring activities, and damage surface facilities including the CO2 source. An earthquake on a fault through the CO2 plume could create or close an open pathway. Earthquakes may cause public concern about the project even if not project related.	Additional [new] FEP	Very unlikely to be an issue.	<p>Humboldt fault zone is 25 miles down dip from Thrall Aagard. It is a slightly active strike-slip fault zone trending N-NE with most seismic activity occurring over 100 miles north of Thrall-Aagard field.</p> <p>The Geneseo-Edwards field appears to have one or more deep 300 ft vertical fault on the West side of the field.</p>	Data on seismic activity for the Geneseo-Edwards fault(s).	1	5	5	NA	Have emergency procedures in place for dealing with earthquakes.
16	1.1.03.02.	Natural micro-seismicity	Micro-seismicity consists of very tiny seismic events often responding to subsurface fluid flow and relative pressure changes. All parts of the earth's crust are in continuous movement and generate micro-seismic events, and the analysis of micro-seismicity offers unique insights into subsurface properties(CCP 2009).	Microseismicity may cause public concern about the project even if not project related, may add noise interfering with microseismic monitoring.	Additional [new] FEP	Natural microseismicity already exists. Considering installing passive microseismic monitors to differentiate between natural and induced microseismicity.			3	2	6	NA	Install passive microseismic monitors to differentiate between natural and induced microseismicity.
17	1.1.04.00.	Hydrothermal activity	<p>Processes associated with high temperature groundwaters, and hydrothermal alteration of minerals in the rocks through which the high temperature groundwater flows.</p> <p>Hydrothermal activity may be directly associated with volcanic and magmatic activity.</p> <p>Hot springs, geysers and submarine hydrothermal vents provide evidence of hydrothermal activity.</p>	Can result in the hydrothermal alteration of rocks or minerals by the reaction of hot water (and other fluids) with pre-existing rocks.	Quintessa original FEP	Thermal gradient measured in the two fields do not indicate any significant hydrothermal activity.			1	1	1	NA	NA
18	1.1.05.00.	Hydrological and hydrogeological response to geological changes	Processes arising from large-scale geological changes and could include changes of fluid boundary conditions due to the effects of changes of fluid properties of geological units due to changes in rock stress or fault movements.	In and below low-permeability geological formations, hydrogeological conditions may evolve very slowly and often reflect past geological conditions, i.e. be in a state of disequilibrium	Quintessa original FEP	Very unlikely to be an issue.	These sites are mature oil fields that have been operated for 75 to 80 years. Disequilibrium has not been identified as a problem in these fields.		1	2	2	NA	NA

Appendix 6-5

CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
19	1.1.06.00.	Large scale erosion	Processes related to the large scale (geological) removal of rocks and sediments, with associated changes in topography and geological/hydrogeological conditions of the system.	Potential to modify the geological and hydrogeological environment.	Quintessa original FEP	The pipelines will follow existing pipeline corridors which have existing for decades. The injection sites are existing EOR sites which have not experienced large scale erosion.			1	1	1	NA	NA
20	1.1.07.00.	Bolide impact (meteorite impact)	An extraterrestrial body in the 1-10-km size range, which impacts the earth at high velocity, explodes upon impact, and creates a large crater.	A low probability, high consequence event that has the potential to substantially disrupt the CO2 storage system. Often screened out on the basis that the impact of the bolide will greatly exceed that of the disruption caused to the sequestration system.	Quintessa FEP with additional text	Very unlikely to occur.			1	5	5	NA	Prepare procedures to shut down and evacuate site if warned of imminent impact.
21	1.2.00.00.	Climatic factors	Natural processes and events in the atmospheric environment that are relevant to the evolution of the sequestration system.	Changes in climate may directly affect the nature of any impacts that are incurred if carbon dioxide returns to the near-surface environment.	Quintessa original FEP	Very unlikely to be an issue.			1	1	1	NA	NA
22	1.2.01.00.	Global climate change	The process of global climate change due to natural and/or anthropogenic causes. The last two million years of the Quaternary have been characterized by glacial/interglacial cycling. According to the Milankovitch Theory, the Quaternary glacial/interglacial cycles are caused by long-term changes in seasonal and latitudinal distribution of incoming solar radiation which are due to the periodic variations of the Earth's orbit about the Sun (Milankovitch cycles). Evidence suggests that the Earth is presently in a period of global warming (see the figure below). The anthropogenic release of gases into the atmosphere may be increasing the rate of global warming by enhancing the natural greenhouse effect, a process by which long wave radiation emitted from the Earth is trapped in the atmosphere by greenhouse gases such as CO2.	Changes in the global climate are likely to impact the CO2 sequestration system in a number of ways. For example, through its affect on sea levels and the local and regional climate.	Quintessa original FEP	Very unlikely to be an issue.			1	1	1	NA	NA

Appendix 6-6

CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
23	1.2.02.00.	Regional and local climate change	<p>Processes related to the possible future changes, and evidence for past changes, of climate at a storage site. This is likely to occur in response to global climate change, but the changes will be specific to situation, and may include short term fluctuations.</p> <p>Climate is characterized by a range of factors including temperature, precipitation and pressure as well as other components of the climate system such as oceans, ice and snow, biota and the land surface. Climatic changes lasting only a few decades may be referred to as climatic fluctuations. These are unpredictable at the current state of knowledge although historical evidence indicates the degree of past fluctuations.</p> <p>The response of regional and local scale climate to global climate change have been considered for its implication for the geological disposal of radioactive waste in the EC's BIOCLIM program.</p>	Changes in the regional and local climate could affect the CO2 sequestration system in a number of ways. For example, changes in groundwater recharge could affect regional hydrogeology and hence the transport of CO2 dissolved in groundwater. It may also alter the near-surface environment to which some of the disposed CO2 may migrate.	Quintessa original FEP	Very unlikely to be an issue.			1	1	1	NA	NA
24	1.2.03.00.	Sea level change	<p>Processes related to changes in sea level which may occur as a result of global (eustatic) change and/or regional geological change, e.g. isostatic movements.</p> <p>The component of sea-level change involving the interchange of water between land ice and the sea is referred to as eustatic change. As ice sheets melt so the ocean volume increases and sea levels rise. Sea level at a given location will also be affected by vertical movement of the land mass, e.g. depression and rebound due to glacial loading and unloading, referred to as isostatic change.</p>	Sea level change may affect the sequestration system through its impact on the near surface environment and the regional or local hydrogeological regime.	Quintessa original FEP	Very unlikely to be an issue.			1	1	1	NA	NA
25	1.2.04.00.	Periglacial effects	Related to the physical processes and associated landforms in cold but ice-sheet-free environments.	An important characteristic of periglacial environments is the seasonal change from winter freezing to summer thaw with large water movements and potential for erosion. Frozen sub-soils are referred to as permafrost. Melt water from seasonal thaw is unable to percolate downwards due to permafrost and saturates the surface materials. Permafrost layers may isolate the deep hydrogeological regime from surface hydrology, or flow may be focused at "taliks" (localized unfrozen zones, e.g. under lakes, large rivers or at regions of groundwater discharge).	Quintessa original FEP	Very unlikely to be an issue.			1	1	1	NA	NA

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
26	1.2.05.00.	Glacial and ice sheet effects	Processes related to the effects of glaciers and ice sheets within the region of a storage site. This is distinct from the effects of large ice masses on global and regional climate. The ice sheet and the permafrost beneath the ice sheet may constitute a barrier to groundwater flow and to heat loss. If the basal transmissivity of the till and bedrock below the ice is low, water pressures may rise to levels equaling the ice pressure inducing the formation of major conduits in the subglacial material. The central parts of the ice sheet are likely to be warm-based and could permit groundwater recharge to take place. Discharge of groundwater is likely to take place close to and beyond the frontal parts of the ice sheet. Excessive recharge at the margin of the ice sheet could provide direct recharge of oxidizing water to considerable depths in conductive fracture zones. If the permeability at and beyond the rim of the ice is low, the water pressures may again build up resulting in hydrofracturing of the ice or the rock mass. As the ice sheet advances, these induced fractures may increase their aperture and depth due to freezing of subglacial melt water.	Erosional processes (abrasion, over deepening) associated with glacial action, especially advancing glaciers and ice sheets, and with glacial melt waters beneath the ice mass and at the margins, can lead to morphological changes in the environment, e.g. U-shaped valleys, hanging valleys, fjords and drumlins. Depositional features associated with glaciers and ice sheets include moraines and eskers. The pressure of the ice mass on the landscape may result in significant hydrogeological effects and even depression of the regional crustal plate.	Quintessa original FEP	Very unlikely to be an issue.			1	1	1	NA	NA
27	1.2.06.00.	Warm climate effects	Processes related to warm tropical and desert climates, including seasonal effects, and meteorological and geomorphological effects special to these climates.	Regions with a tropical climate may experience extreme weather patterns (monsoons, hurricanes) that could result in flooding, storm surges, high winds etc. with implications for erosion and hydrogeology. The high temperatures and humidity associated with tropical climates result in rapid biological degradation and soils are generally thin. In arid climates, total rainfall, erosion and recharge may be dominated by infrequent storm events.	Quintessa original FEP	Very unlikely to be an issue.			1	1	1	NA	NA
28	1.2.07.00.	Hydrological and hydrogeological response to climate change	Processes related to changes in hydrology and hydrogeology, e.g. recharge, sediment load and seasonality, in response to climate change in a region.	The hydrology and hydrogeology of a region is closely coupled to climate. Climate controls the amount of precipitation and evaporation, seasonal ice cover, and thus the soil water balance, extent of soil saturation, surface runoff and groundwater recharge. Vegetation and human actions may modify these responses.	Quintessa original FEP	Very unlikely to be an issue.			1	1	1	NA	NA

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
29	1.2.08.00.	Responses to climate change	<p>The process of global climate change due to natural and/or anthropogenic causes. The last two million years of the Quaternary have been characterized by glacial/interglacial cycling. According to the Milankovitch Theory, the Quaternary glacial/interglacial cycles are caused by long-term changes in seasonal and latitudinal distribution of incoming solar radiation which are due to the periodic variations of the Earth's orbit about the Sun (Milankovitch cycles).</p> <p>Evidence suggests that the Earth is presently in a period of global warming. The anthropogenic release of gases into the atmosphere may be increasing the rate of global warming by enhancing the natural greenhouse effect, a process by which long wave radiation emitted from the Earth is trapped in the atmosphere by greenhouse gases such as CO2.</p>	Changes in ecology and human behavior in response to climate change will influence the relevant FEPs to be considered in the surface environment as an assessment extends into the future.	Quintessa original FEP	Very unlikely to be an issue.			1	1	1	NA	NA
30	1.3.00.00.	Future human actions	Human activities that are relevant to the evolution of the sequestration system.	Human activities may directly interfere with the sequestered fluid resulting in immediate or delayed impacts.	Quintessa original FEP	Very unlikely to be an issue.	The injection sites are very sparsely populated. There are no residences within 1 mile of the Thrall injection site.	Need to confirm population density in and near Geneseo-Edwards injection site.	1	1	1	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.
31	1.3.01.00.	Human influences on climate	Processes related to human activities that could affect the change of climate either globally or in a region.	<p>Anthropogenic emissions of 'greenhouse' gases such as CO2 and CH4 have been implicated as factors in global warming. One of the primary aims of CO2 sequestration is to reduce the quantity of CO2 that is discharged to the atmosphere.</p> <p>Regionally, climate can be modified by human activities such as de-forestation.</p>	Quintessa original FEP	Very unlikely to be an issue.			1	1	1	NA	NA
32	1.3.02.00.	Motivation and knowledge issues	<p>Events and processes related to the degree of knowledge of the existence, location and/or nature of the storage site. Also, reasons for deliberate interference with, or intrusion into, a CO2 storage site after closure with complete or incomplete knowledge.</p> <p>Knowledge of the sequestration site may be regained through post-closure airborne, geophysical or other surface-based non-intrusive investigation of a sequestration site. Such investigations might occur after information of the location of the sequestration system has been lost and therefore excludes monitoring of the disposal system, but includes activities such as prospecting for geological resources. The evidence of the sequestration, such as injection boreholes, may itself prompt investigation.</p>	<p>Some future human actions could directly impact upon performance of the storage system. The following could be distinguished:</p> <ul style="list-style-type: none"> - inadvertent actions, which are actions taken without knowledge or awareness of the storage site, and - deliberate actions, which are actions that are taken with knowledge of the storage systems existence and location, e.g. deliberate attempts to retrieve any hydrocarbons (e.g., EOR and ECBM) associated with the CO2, malicious intrusion and sabotage. <p>Intermediate cases, of intrusion with incomplete knowledge, could also occur.</p>	Quintessa original FEP	Very unlikely to be an issue.			1	3	3	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
33	1.3.02.01.	Inadvertent interference with or intrusion into the CO2 reservoir	Third party inadvertent intrusion or interference with CO2 reservoir after closure due to incomplete knowledge.	Leakage and damage issues.	Expansion of Q FEP	Covered by KCC CO2 storage regulations			1	3	3	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.
34	1.3.02.02.	Deliberate interference with or intrusion into the CO2 reservoir	Third party deliberate intrusion or interference with CO2 reservoir after closure to recover hydrocarbons (e.g. EOR and ECBM) or malicious intrusion and sabotage.	Leakage and damage issues.	Expansion of Q FEP	Covered by KCC CO2 storage regulations			1	3	3	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.
35	1.3.03.00.	Social and institutional developments	Events and processes related to changes in social patterns and degree of local government, planning and regulation. Potentially significant social and institutional developments include: – changes in planning controls and environmental legislation; – demographic change and urban development; – changes in land use; – loss of archives/records, loss/degradation of societal memory.	Social and institutional developments have the potential to affect motivation and knowledge issues, human use of the surface and sub-surface environments and the type of impacts that may be considered.	Quintessa original FEP	Very unlikely to be an issue.			1	1	1	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.
36	1.3.03.01.	Changes in planning controls			Expansion of Q FEP	Very unlikely to be an issue.			1	1	1	Monitoring zoning announcements. Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.
37	1.3.03.02.	Changes in environmental legislation			Expansion of Q FEP	Uncertain. Changes in legislation could impact the project.			3	1	3	Monitoring environmental legislation. Provide input to lawmakers.	Monitoring environmental legislation. Provide input to lawmakers.
38	1.3.03.03.	Demographic change and urban development			Expansion of Q FEP	Very unlikely to be an issue.	Neither Thrall-Aagard or Geneseo-Edwards fields are close to urban areas. Urbanization highly unlikely.		1	1	1	Monitor local demographic changes. Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.
39	1.3.03.04.	Changes in land use			Expansion of Q FEP	Very unlikely to be an issue.	Land currently used for farming and ranching.	Check zoning regulations for Greenwood and Rice counties	1	1	1	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.
40	1.3.03.05.	Loss of archives/records, loss/degradation of societal memory			Expansion of Q FEP	Unlikely to occur			1	1	1	Keep backup documentation at off-site locations. Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
41	1.3.04.00.	Technological developments	Events and processes related to future developments in human technology and changes in the capacity and motivation to implement technologies. This may include retrograde developments, e.g. loss of capacity to implement a technology.	Of interest are those technologies that might change the capacity of humans to intrude deliberately or otherwise into a storage site, to cause changes that would affect the movement of CO2 and associated contaminants, or that may otherwise affect the performance and safety of the sequestration system. Technological developments are likely but may not be predictable especially at longer times into the future.	Quintessa original FEP	Highly unlikely during the life of the project.			1	1	1	NA	NA
42	1.3.04.01.	New technology that would replace the need for CO2 geologic sequestration	Shift from fossil fuels toward nuclear, solar or wind power. Breakthrough in terrestrial sequestration. Alternative ways of cooling the earth's atmosphere.	Increased public/permitting resistance, threat to project cash flow, potential loss of infrastructure investment, halt in > failure of monitoring of already-injected CO2 ...	Additional [new] FEP	Highly unlikely during the life of the project.			1	1	1	NA	Keep abreast of new technology developments and analyze impact on project. Take corrective action if necessary.
43	1.3.04.02.	New lower-cost desalination technology	A low-cost desalination technology could increase the value of deep saline aquifers in desert regions and may limit the use of deep saline aquifers for CO2 geologic sequestration. However, it could also make treatment and disposal of saline water easier.	Possible regulatory proscription of aquifer use, but also possible benefit if project design incorporated saline water withdrawals for pressure management.	Additional [new] FEP	Very unlikely to be an issue.	Arbuckle is a Class 1 hazardous waste reservoir.		1	1	1	NA	Keep abreast of new technology developments and analyze impact on project. Take corrective action if necessary.
44	1.3.04.03.	Lack of CO2 capture technology improvements	Lack of significant improvements in CO2 capture technology could hinder retrofitting of existing coal-fired power plants and cement plants and thus limit availability or increase cost of CO2 for geologic sequestration.	Threat to project cash flow, potential loss of infrastructure investment, halt in > failure of monitoring of already-injected CO2 ...	Additional [new] FEP	Very unlikely to be an issue.	Fertilizer and ethanol plants already concentrate CO2		1	1	1	NA	Keep abreast of new technology developments and analyze impact on project. Take corrective action if necessary.
45	1.3.05.00.	Drilling activities	Events related to any type of drilling activity in the vicinity of the CO2 sequestration system. These may be taken with or without knowledge of the disposal and may include activities such as: - exploratory and/or exploitation drilling for natural resources; - attempted recovery of residual hydrocarbon resources (e.g., EOR and ECBM); - drilling for water resources; - drilling for site characterization or research; - drilling for further disposal; and - drilling for hydrothermal resources.	Has the potential to disrupt geological features that provide a barrier to CO2 migration and provide a relatively quick migration pathway to the near-surface.	Quintessa original FEP	Very unlikely to be an issue.			1	3	3	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.
46	1.3.05.01.	Drilling for water resources			Expansion of Q FEP	Very unlikely to be an issue.	Drinkable water aquifer extends down to 200ft at both sites but historically there hasn't been enough water for windmills to fill stock troughs. All drinkable water currently comes from surface water.		1	3	3	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
47	1.3.05.02.	Drilling for site characterization or research			Expansion of Q FEP	Very unlikely to be an issue.			1	2	2	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.
48	1.3.05.03.	Drilling for further disposal			Expansion of Q FEP	Unlikely to be an issue	Disposal would likely be in the Arbuckle formation, below any EOR activity.		2	2	4	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.
49	1.3.05.04.	Drilling for hydrothermal resources			Expansion of Q FEP	Very unlikely to be an issue.	Hydrothermal resources are not significant in the area.		1	3	3	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.
50	1.3.06.00.	Mining and other underground activities	Events related to any type of mining or excavation activity carried out in the vicinity of the storage site. These may be taken with or without knowledge of the site. Mining and other excavation activities include: - resource mining; - excavation for industry; - excavation for storage or disposal; - excavation for military purposes; - geothermal energy production; - injection of liquid wastes and other fluids; - scientific or archaeological investigation; - shaft construction, underground construction and tunneling; - underground nuclear testing; - malicious intrusion, sabotage or war; - recovery of materials associated with CO2 injection (e.g., EOR and ECBM)	Mining and other underground activities have the potential to disrupt the geosphere (storage reservoir, surrounding and overlying rock) and near-surface environment. They therefore have the potential to significantly affect the migration and distribution of sequestered CO2.	Quintessa original FEP	Very unlikely to be an issue.			1	3	3	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.
51	1.3.06.01.	Resource mining			Expansion of Q FEP	Very unlikely to be an issue.	No known mineral resources other than oil at sites.		1	3	3	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.
52	1.3.06.02.	Excavation for industry			Expansion of Q FEP	Very unlikely to be an issue.	No industries nearby.		1	3	3	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.
53	1.3.06.03.	Excavation for storage or disposal			Expansion of Q FEP	Very unlikely to be an issue.	No industries nearby.		1	3	3	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.
54	1.3.06.04.	Excavation for military purposes			Expansion of Q FEP	Very unlikely to be an issue.	No military bases nearby.		1	3	3	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
55	1.3.06.05.	Geothermal energy production			Expansion of Q FEP	Very unlikely to be an issue.	No geothermal properties identified.		1	3	3	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.
56	1.3.06.06.	Injection of liquid waste and other fluids			Expansion of Q FEP	Unlikely to be an issue	No liquid waste generators nearby except EOR water production		2	3	6	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.
57	1.3.06.07.	Scientific or archaeological investigation			Expansion of Q FEP	Very unlikely to be an issue.	Mature oil fields. No archeological sites identified.	Check Kansas historical society	1	3	3	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.
58	1.3.06.08.	Shaft construction, underground construction and tunneling;			Expansion of Q FEP	Very unlikely to be an issue.	Sparsely populated area. No underground construction work planned.		1	3	3	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.
59	1.3.06.09.	Underground nuclear testing			Expansion of Q FEP	Very unlikely to be an issue.	Site not suitable for nuclear testing.		1	3	3	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.
60	1.3.06.10.	Malicious intrusion, sabotage or war;			Expansion of Q FEP	Very unlikely to be an issue.	Site is sparsely populated and residents have long history of cooperating with oil companies.		1	3	3	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.
61	1.3.06.11.	Recovery of materials associated with CO2 injection (e.g., EOR and ECBM)			Expansion of Q FEP	EOR part of project. No coal seams.	Potential for additional EOR recovery if technology improves.		3	3	9	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.
62	1.3.07.00.	Human activities in the surface environment	Events and processes related to any type of human activities that may be carried out in the surface environment that can potentially affect the performance of the storage system, or leakage pathways, excepting those FEPs related to water management which are described elsewhere. Examples include: – quarrying, trenching; – excavation for construction; – residential, industrial, transport and road construction; – pollution of surface environment and groundwater.	Human activities in the surface environment have the potential to affect CO2 release processes, should leakage occur. They may also determine the types of impact to be considered.	Quintessa original FEP	Very unlikely to be an issue.			1	1	1	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.
63	1.3.07.01.	Quarrying, trenching			Expansion of Q FEP	Very unlikely to be an issue.	No industry near injection sites		1	1	1	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.

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CO2 Geologic Sequestration Risks for the IMCCS Project							Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Qunitessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number P x S (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)	
64	1.3.07.02.	Excavation and construction			Expansion of Q FEP	Very unlikely to be an issue.	No industry near injection sites		1	1	1	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.	
65	1.3.07.03.	Residential, industrial transport and road construction			Expansion of Q FEP	Very unlikely to be an issue.	No industry near injection sites		1	1	1	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.	
66	1.3.07.04.	Pollution of surface environment			Expansion of Q FEP	Very unlikely to be an issue.	No industry near injection sites		1	1	1	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.	
67	1.3.07.05.	Changes in groundwater geochemistry (not caused by project)	Apart from potential project impacts, waters in the project area formations above the reservoir formation could change chemically (including total dissolved solids) due to groundwater extraction, climate, contamination, or other non-project causes. This could change their susceptibility to impact or the requirement for monitoring or protection.		Additional [new] FEP	Very unlikely to be an issue.	Fresh water sources are very small volume - not enough for windmills and stock tanks at Thrall.		1	2	2	Characterize groundwater aquifer. Conduct baseline survey of groundwater geochemistry. Monitor third-party activity in the area.	Monitor groundwater geochemistry and determine root cause of any changes.	
68	1.3.07.06.	Human activities in the surface environment offsite	Above the CO2 plume, humans could incur risks related to specific activities that take place in low areas (e.g. farming, pruning, harvesting, irrigation maintenance) that may have limited air circulation.		Additional [new] FEP	Very unlikely to be an issue.	There appear to be few low lying areas in or near the injection sites and the sites are sparsely populated.		1	2	2	Identify any low lying areas in or near the injection sites. Mark sites with warnings. Educate local population on safety aspects.	Routine site inspection and/or monitoring.	
69	1.3.08.00.	Water management	Events and processes related to groundwater and surface water management including water extraction, reservoirs, dams, and river management. Water is a valuable resource and water extraction and management schemes provide increased control over its distribution and availability through construction of dams, barrages, canals, pumping stations and pipelines. Groundwater and surface water may be extracted for human domestic use (e.g. drinking water, washing), agricultural uses (e.g. irrigation, animal consumption) and industrial uses.	Extraction and management of water may affect the movement of CO2 or associated contaminants to and in the surface environment.	Quintessa original FEP	Unlikely to be an issue.	There is no significant surface water in or near the injection sites. Drinkable water aquifer extends down to 200ft at both sites but historically there hasn't been enough water for windmills to fill stock troughs.		2	3	6	Characterize surface water and groundwater aquifer. Monitor third-party activity in the area.	Routine site inspection and/or monitoring.	
70	1.3.08.01.	Water extraction			Expansion of Q FEP	Unlikely to be an issue.	There is no significant surface water in or near the injection sites. Drinkable water aquifer extends down to 200ft at both sites but historically there hasn't been enough water for windmills to fill stock troughs.		2	3	6	Characterize surface water. Monitor third-party activity in the area.	Routine site inspection and/or monitoring.	

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CO2 Geologic Sequestration Risks for the IMCCS Project					Project Specific Information				Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
71	1.3.08.02.	Reservoirs			Expansion of Q FEP	Very unlikely to be an issue.	There is no significant surface water in or near the injection sites.		1	3	3	Characterize surface water. Monitor third-party activity in the area.	Routine site inspection and/or monitoring.
72	1.3.08.03.	Dams			Expansion of Q FEP	Very unlikely to be an issue.	There is no significant surface water in or near the injection sites.		1	3	3	Characterize surface water. Monitor third-party activity in the area.	Routine site inspection and/or monitoring.
73	1.3.08.04.	River management			Expansion of Q FEP	Very unlikely to be an issue.	There is no significant surface water in or near the injection sites.		1	3	3	Characterize surface water. Monitor third-party activity in the area.	Routine site inspection and/or monitoring.
74	1.3.09.00.	CO2 presence influencing future operations	The presence of injected CO2 may hinder future extractive operations by obscuring seismic traces or by making the drilling process more difficult. Conversely, the presence of CO2 locally, might allow for more economic future enhanced oil recovery operations. This FEP assumes that future technical advances might identify useable resources in the vicinity of previous CO2 injection.	Drilling through a formation filled with supercritical CO2 might cause 'blowouts' or loss of CO2 along the wellbore. A CO2 'bubble' will change the velocity of seismic waves, distorting the 'image' of the underlying formations, and reducing confidence in the understanding of this structure.	Quintessa original FEP	Very unlikely to be an issue.	Covered by KCC CO2 storage regulations.		1	4	4	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.
75	1.3.10.00.	Explosions and crashes	Events related to deliberate or accidental explosions and crashes such as might have some impact on a closed storage site, e.g. underground nuclear testing, an aircraft crash on the site, acts of war, marine collisions or trawler damage to exposed seabed structures.	Explosions and crashes are likely to be low probability events that could have a significant impact on the performance of the sequestration system by disrupting the expected evolution of the system.	Quintessa original FEP	Very unlikely to be an issue.	Area is sparsely populated.		1	5	5	Avoid high activity areas in site selection.	Prepare procedures to handle emergencies in and near the sites.
76	1.3.10.01.	Accidental explosions and crashes			Expansion of Q FEP	Very unlikely to be an issue.	Area is sparsely populated.		1	5	5	Avoid high activity areas in site selection.	Prepare procedures to handle emergencies in and near the sites.
77	1.3.10.02.	Deliberate explosions and crashes			Expansion of Q FEP	Very unlikely to be an issue.	Area is sparsely populated.		1	5	5	Avoid high activity areas in site selection.	Prepare procedures to handle emergencies in and near the sites.
78	2.0.00.00.	CO2 Storage	This category of FEPs specifies details of the sequestration concept under consideration. It is split into two classes for the pre- and post-closure periods.		Quintessa original FEP		NA		NA	NA	NA	NA	NA
79	2.1.00.00.	Pre-closure	Details of the sequestration concept, the fluids injected, and factors for the design, construction, operation and decommissioning phases.	The details of the sequestration concept are fundamental to determining which FEPs in other categories need to be considered in a given assessment. Some details of sequestration operations may affect the post-closure performance.	Quintessa original FEP	Unlikely to be an issue.			2	3	6	Prepare a post closure plan early in the design process and update as needed over time.	Prepare a post closure plan early in the design process and update as needed over time.
80	2.1.01.00.	Storage concept	Features related to the concept of storage, such as whether a closure exists (sequestration in an abandoned oil or gas field) or whether isolation of CO2 is dependent upon slow diffusion rates through an areally extensive open structure (saline aquifer sequestration).	Different processes will be relevant to different storage concepts. For example, the rate of CO2 migration in an open aquifer will be relevant to safety assessment of saline aquifer storage, but less relevant to sequestration in a closed geological structure.	Quintessa original FEP	Unlikely to be an issue.			2	3	6	Fully characterize and model the sites early in the design phase.	Fully characterize and model the sites early in the design phase.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
81	2.1.02.00.	CO2 quantities, injection rate	Features related to the amounts of CO2 injected and their rate of injection into the storage aquifer/reservoir.	High rates of CO2 injection could have adverse affects, such as hydrofracturing. For fast injection rates, displacement of oil/water will not be efficient during enhanced oil recovery; instead one will recover CO2; premature break through is undesirable from an economic perspective.	Quintessa original FEP	Unlikely to be an issue.	Thrall will be pressured with water prior to CO2 injection. If Genesee-Edwards exhibits coning, the injection rate per well will be cut back and additional injection wells will be used.		2	3	6	Fully characterize and model the sites early in the design phase. Conduct injectivity tests and adjust injection plan appropriately. Avoid excessive injection pressures. If injection pressure is unacceptably high, cut back on individual well injection rate and use additional injection wells.	Fully characterize and model the sites early in the design phase. Conduct injectivity tests and adjust injection plan appropriately. Avoid excessive injection pressures. If injection pressure is unacceptably high, cut back on individual well injection rate and use additional injection wells.
82	2.1.03.00.	CO2 composition	The composition and physical state (liquid, supercritical fluid etc.) of injected CO2, with contents of impurities etc. Temperature and pressure of injected fluid are also relevant. During CO2 storage operations, the principal injected gas is CO2 captured and concentrated from human activity sources. However, the gas that is injected into a reservoir may not be 100 % CO2, especially if there is some recycling of gas (in the case of enhanced oil recovery). Impurities can include: H2S, CH4, N2, NOx, SO2 and mercaptans. These may be present either intentionally or because it could be particularly difficult or superfluous to separate them from CO2.	The presence of even small amounts of other gases has a strong effect on the phase behavior of CO2-dominated gases. High-pressure equations of state for CO2-dominated gas mixtures are required to take into account changes in critical pressures and temperatures caused by the presence of other gases. Impurities will reduce the critical temperature which, in turn, has effects on interfacial tension. Amongst the possible companion gases, NOx and SO2 are particularly relevant because: - NOx and SO2 are polluting gases that are generated by the same power plants that generate massive amounts of CO2 and attract emission taxes in certain countries (e.g. Italy). Their injection, in smaller amounts, with CO2 could therefore help the economics of sequestration. Impurities may affect pore water chemistry (pH and redox conditions, for example) depending on the impurities involved. Special care is needed when considering corrosive gases, such as H2S.	Quintessa original FEP	Unlikely to be an issue.	CVR CO2 stream composition is well documented and consistent. KE CO2 stream composition is poorly documented and is expected to fluctuate.	Confirm composition and consistency of KE CO2 stream.	2	2	4	Set target specifications for CO2 streams. Confirm CO2 stream composition through performance tests and guarantees. Monitor CO2 composition. Provide backup deep saline injection option if CO2 stream doesn't meet specification for EOR or ECBM. Or vent CO2 prior to compression if necessary.	Set target specifications for CO2 streams. Confirm CO2 stream composition through performance tests and guarantees. Monitor CO2 composition. Provide backup deep saline injection option if CO2 stream doesn't meet specification for EOR or ECBM. Or vent CO2 prior to compression if necessary.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Qunitessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
83	2.1.03.01.	CO2 containing H2S			Expansion of Q FEP	Very unlikely to be an issue.	H2S is very low in CVR or KE CO2 streams but may be present in recycled CO2 streams at EOR operations.	Confirm H2S levels in Arbuckle oil, water and gas at Genesee-Edwards.	1	3	3	Fully characterize site for subsurface H2S generation. Specify appropriate materials of construction for handling H2S in production wells, disposal wells and CO2 recycle systems. Include H2S in modeling. Monitor for H2S along with CO2 above and below ground. Train operators how to handle H2S safely.	Fully characterize site for subsurface H2S generation. Specify appropriate materials of construction for handling H2S in production wells, disposal wells and CO2 recycle systems. Include H2S in modeling. Monitor for H2S along with CO2 above and below ground. Train operators how to handle H2S safely.
84	2.1.03.02.	CO2 containing H2O		If the water vapor is not removed prior to compression, the CO2 product will be very corrosive and the pipeline well head and borehole would have to be built with much more expensive materials than carbon steel.	Expansion of Q FEP	Unlikely to be an issue.	CO2 will be dehydrated to specified levels prior to compression and transportation.		2	3	6	Install CO2 dehydration units. Operate appropriately. Monitor CO2 water content in and out of dehydration. Vent CO2 if dehydration is not working. Keep CO2 pipelines free of water. Specify appropriate materials of construction for production wells and CO2 recycling facilities to handle wet CO2.	Install CO2 dehydration units. Operate appropriately. Monitor CO2 water content in and out of dehydration. Vent CO2 if dehydration is not working. Keep CO2 pipelines free of water. Specify appropriate materials of construction for production wells and CO2 recycling facilities to handle wet CO2.
85	2.1.03.03.	CO2 containing O2	EOR and deep saline applications can tolerate some oxygen (air) in the CO2, but ECBM can't.		Expansion of Q FEP	Possible issue.	Oxygen is very low in CVR CO2 but may need to be removed from KE CO2 prior to compression and transport in order to meet target specifications.	Confirm O2 content and variability in KE CO2 stream.	3	2	6	Install O2 removal system at KE facility to achieve CO2 specification. Require CO2 suppliers to guarantee O2 content of CO2 stream. Monitor O2 content in CO2 streams. Take corrective action if O2 exceeds specification.	Monitor O2 content of CO2 stream. Take corrective action if O2 exceeds specification: vent CO2 prior to compression or inject off-spec CO2 into back up deep saline injection well.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
86	2.1.03.04.	CO2 containing N2		Nitrogen is undesirable for EOR because it raises the minimum miscibility pressure of the fluid and makes the injection process less efficient. Nitrogen is not a problem in ECBM as a minor component of CO2. It will lower the partial pressure of methane and allow more methane to be released and recovered.	Expansion of Q FEP	Likely to be an issue.	Nitrogen is very low in the CVR CO2 stream, but may fluctuate in the KE CO2 stream	Confirm N2 content and variability in KE CO2 stream. Need to model the impact of N2 on MMP at Geneseo-Edwards.	4	2	8	Request that KE adjust their operating practices to guarantee minimum N2 content and fluctuation in the CO2 stream. Monitor N2 content in the CO2 stream. Take corrective action if N2 exceeds specifications.	Monitor N2 content of CO2 stream. Take corrective action if N2 exceeds specification: vent CO2 prior to compression or inject off-spec CO2 into back up deep saline injection well.
87	2.1.03.05.	CO2 containing NOx			Expansion of Q FEP	Very unlikely to be an issue.	CVR and KE have very low NOx content in the CO2 streams.		1	2	2	NA	NA
88	2.1.03.06.	CO2 containing SOx			Expansion of Q FEP	Very unlikely to be an issue.	CVR and KE have very low SOx content in the CO2 streams.		1	2	2	NA	NA
89	2.1.03.07.	CO2 containing CH4			Expansion of Q FEP	Unlikely to be an issue.	CVR and KE have very low CH4 content in the CO2 streams. However, there could be high CH4 in the recycle CO2 stream.		2	2	4	Monitor for CH4 content in fresh and recycle CO2 streams.	Prepare operating procedures to deal with high CH4 in the CO2 stream.
90	2.1.03.08.	CO2 containing mercaptans		Mercaptans and other malodorous sulfur compounds are strong smelling and require additional sealing around the wellhead to capture fugitive emissions and minimize odors.	Expansion of Q FEP	Very unlikely to be an issue.	CVR and KE have very low mercaptan content in the CO2 streams. However, there could be mercaptans in the recycle CO2 stream.		1	3	3	Monitor for mercaptans in production wells.	Prepare operating procedures to deal with mercaptans if they are found in the CO2.
91	2.1.03.09.	CO2 containing CO			Expansion of Q FEP	Possible issue.	CVR and KE have very low CO content in the CO2 streams.		3	2	6	Monitor for CO content in CO2 streams.	Prepare operating procedures to deal with high CO content if found in the CO2.
92	2.1.03.10	CO2 containing H2		Hydrogen can leak through seals that other gases can't	Expansion of Q FEP	Unlikely to be an issue.	CVR and KE have very low H2 content in the CO2 streams.		2	2	4	Monitor for H2 content in CO2 streams.	Prepare operating procedures to deal with high H2 content if found in the CO2.
93	2.1.03.10.	CO2 containing particulates			Expansion of Q FEP	Very unlikely to be an issue.	CVR and KE have very low particulate content in the CO2 streams.		1	2	2	Monitor for particulate content in CO2 streams.	Prepare operating procedures to deal with high particulate content if found in the CO2.
94	2.1.04.00.	Microbiological contamination	Microbiological contamination of injected fluid. Contamination of supercritical CO2 is considered unlikely due to its being a very good solvent. However, other fluids may be injected into the storage site that may be contaminated with microbes.	The introduction of microbes into the sequestration system may affect both the performance of the storage system and the endpoints considered.	Quintessa original FEP	Very unlikely to be an issue.		Identify any significant subsurface microbial cultures at the injection sites.	1	1	1	Monitor for microbial activity if injection pressures increase unexpectedly. Avoid O2 content in the CO2 stream.	Use chemical treatment if necessary to control microbial growth.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
95	2.1.05.00.	Schedule and planning	Features related to the sequence of events and activities occurring during storage system design, CO2 injection and sealing. This could include enhanced oil recovery processes.	Relevant events may include phased drilling of wells and emplacement of CO2, sealing of boreholes, and monitoring activities to provide data on the transient behavior of the system or to provide input to the final assessment. The sequence of events and time between events may have implications for long term performance, e.g. chemical and hydraulic changes during a prolonged injection phase.	Quintessa original FEP	Possible issue.	Complex project with multiple parties and multiple parts.		3	2	6	Establish management committee and working groups. Detailed project schedule and work breakdown structure. Secure website. Weekly conference calls.	Establish management committee and working groups. Detailed project schedule and work breakdown structure. Secure website. Weekly conference calls.
96	2.1.06.00.	Pre-closure administrative control	Features related to measures to control events at or around the sequestration site during the design, construction, operation and decommissioning phases. The type of administrative control may vary depending on the stage in the storage system lifetime.	The pre-closure administrative control will influence the quantity and quality of information about the sequestration project that is available post-closure, therefore helping to determine societal memory. The better the amount and quality of information available, the lower the possibility of inadvertent intrusion.	Quintessa original FEP	Unlikely to be an issue.	Data management working group established.		2	2	4	Data management.	Data management.
97	2.1.07.00.	Pre-closure monitoring of storage	Processes related to any monitoring undertaken during the operational and closure phase. The extent and requirement for such monitoring activities may be determined by issues such as storage concept, geological setting, regulations, or public pressure. A number of monitoring techniques exist including seismic data, electrical resistance, soil gas and isotopic characteristics.	Monitoring during the operational phase contributes towards the amount and quality of information initially available after closure concerning the behavior and distribution of sequestered CO2.	Quintessa original FEP	Unlikely to be an issue.	Monitoring working group established to prepare and implement MVA plan.		2	2	4	Preparation and implementation of MVA plan.	Preparation and implementation of MVA plan.
98	2.1.08.00.	Quality control	Features related to quality control procedures and tests during the design, and operation of the storage system. It could be expected that a range of quality control measures would be applied during operation of the storage system and supply of CO2 to be sequestered. There may be specific regulations governing quality control procedures, objectives and criteria.	The degree of quality control during the design, construction, operation and decommissioning of a sequestration system can affect the post-closure performance by influencing the integrity of the engineered parts of the system (borehole seals, for example) and by influencing the quantity, quality and accuracy of records.	Quintessa original FEP	Unlikely to be an issue.	Risk management working group established		2	2	4	Risk management overseeing quality control.	Risk management overseeing quality control.
99	2.1.09.00.	Accidents and unplanned events	Events related to accidents and unplanned events during site investigation, CO2 emplacement and closure which might have an impact on long-term performance or safety. Accidents are events that are outside the range of normal operations although the possibility that certain types of accident may occur should be anticipated in operational planning. Unplanned events include accidents but could also include deliberate deviations from operational plans, e.g. in response to an accident, unexpected geological events or unexpected aspects of CO2 quality and injection arising during operations.	Accidents and unplanned events may affect the post-closure performance of the sequestration system. One example may be the incomplete sealing of an injection borehole that may subsequently provide a pathway for CO2 migration.	Quintessa original FEP	Possible issue.	Risk management working group established		3	4	12	Implement safety training and standard procedures. Analyze project changes. Document response to accidents and unplanned events.	Implement safety training and standard procedures. Analyze project changes. Document response to accidents and unplanned events.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
100	2.1.10.00.	Over pressuring	<p>The CO2 injection process is greatly influenced by the target reservoir formation pressure (pore pressure).</p> <p>The formation pressure is considered overpressure if it is above the normal hydrostatic pressure for the given depth. Over pressuring may occur at any depth, naturally or artificially. Man-made overpressure may be accidental or deliberate.</p> <p>An example of deliberate overpressure is injecting gaseous CO2 in an aquifer at a faster rate than water can drain from the reservoir zone. In such a case the overpressure is created intentionally. The maximum tolerable overpressure is calculated as a function of the desired storage volume and of a chosen safety factor below the critical fracturing gradient of the top seal rock.</p> <p>An example of accidental overpressure is given by the depressurization of a storage reservoir where the CO2 is in liquid form, below but near the critical phase change pressure. The change of phase to gas creates a gas column that could exercise an unforeseen overpressure at the top of the gas column.</p>	Deliberate or accidental over pressuring during the operational phase will affect the initial geosphere conditions for a post-closure assessment. It has the potential to cause fractures in the sealing formation and hence provide migration pathways for the sequestered CO2.	Quintessa original FEP	Possible issue with Bartlesville Sandstone.	<p>Bartlesville Sandstone integrity has been demonstrated up to 1700 psig with water injection without problems. Maintain injection pressure below 80% of fracture pressure.</p> <p>Can't overpressure the Arbuckle formation.</p>		3	4	12	<p>Determine fracture pressure. Monitor injection pressure. Maintain injection pressure below 80% of fracture pressure. Alarm system if injection pressure exceeds 80% of fracture pressure.</p>	<p>Develop procedures for handling an over pressuring situation. Operator training.</p>
101	2.1.10.01.	Deliberate over pressuring	<p>An example of deliberate overpressure is injecting gaseous CO2 in an aquifer at a faster rate than water can drain from the reservoir zone. In such a case the overpressure is created intentionally. The maximum tolerable overpressure is calculated as a function of the desired storage volume and of a chosen safety factor below the critical fracturing gradient of the top seal rock.</p>	Induced fractures in the caprock can be created by over pressuring the reservoir. Fractures could be sealed in time by precipitation of newly formed minerals, but could also be re-opened as a consequence of new changes in stresses during storage of CO2.	Expansion of Q FEP	Possible issue with Bartlesville Sandstone.	<p>Bartlesville Sandstone integrity has been demonstrated up to 1700 psig with water flood without problems. Maintain injection pressure below 80% of fracture pressure.</p> <p>Can't overpressure the Arbuckle formation.</p>		3	4	12	<p>Determine fracture pressure. Monitor injection pressure. Maintain injection pressure below 80% of fracture pressure. Alarm system if injection pressure exceeds 80% of fracture pressure.</p>	<p>Develop procedures for handling an over pressuring situation. Operator training.</p>
102	2.1.10.02.	Accidental over pressuring due to CO2 phase change	<p>An example of accidental overpressure is given by the depressurization of a storage reservoir where the CO2 is in liquid form, below but near the critical phase change pressure. The change of phase to gas creates a gas column that could exercise an unforeseen overpressure at the top of the gas column.</p>	Fractures in the caprock can be created by over pressuring the reservoir. Fractures could be sealed in time by precipitation of newly formed minerals, but could also be re-opened as a consequence of new changes in stresses during storage of CO2.	Expansion of Q FEP	Thrall has already seen this in water flood and survived quite well. Geneseo-Edwards will not exceed bottom hole pressure.	<p>Bartlesville Sandstone integrity has been demonstrated up to 1700 psig with water flood without problems. Maintain injection pressure below 80% of fracture pressure.</p>		3	4	12	<p>Bartlesville Sandstone integrity has been demonstrated up to 1700 psig with water flood without problems. Maintain injection pressure below 80% of fracture pressure.</p>	<p>Bartlesville Sandstone integrity has been demonstrated up to 1700 psig with water flood without problems. Maintain injection pressure below 80% of fracture pressure.</p>

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
103	2.1.10.03.	Regional-scale over pressuring			Additional [new] FEP	Very unlikely to be an issue.	Can't overpressure the Arbuckle. Bartlesville Sandstone is locally isolated.		1	4	4	NA	NA
104	2.1.10.04.	Local-scale over pressuring			Additional [new] FEP	Can't overpressure the Arbuckle	Bartlesville Sandstone integrity has been demonstrated up to 1700 psig with water flood without problems. Maintain injection pressure below 80% of fracture pressure.	Need more detail on the Thrall	2	4	8	Bartlesville Sandstone integrity has been demonstrated up to 1700 psig with water flood without problems. Maintain injection pressure below 80% of fracture pressure.	Bartlesville Sandstone integrity has been demonstrated up to 1700 psig with water flood without problems. Maintain injection pressure below 80% of fracture pressure.
105	2.1.10.05.	Caprock failure due to over pressuring	Over pressuring can generate new fractures or faults in the caprock. Catastrophic failure (bursting) of the caprock.	CO2 leakage through induced fractures or faults in caprock.	Additional [new] FEP	Possible issue.	Bartlesville Sandstone integrity has been demonstrated up to 1700 psig with water flood without problems. Maintain injection pressure below 80% of fracture pressure.		3	4	12	Bartlesville Sandstone integrity has been demonstrated up to 1700 psig with water flood without problems. Maintain injection pressure below 80% of fracture pressure.	Bartlesville Sandstone integrity has been demonstrated up to 1700 psig with water flood without problems. Maintain injection pressure below 80% of fracture pressure.
106	2.1.10.06.	Caprock failure due to dilatant shear	Significant fluctuations in reservoir pressure could cause dilatant shear formation and fracturing in the caprock.		Additional [new] FEP	Unlikely to be an issue at Geneseo-Edwards. Could be an issue in the Thrall.		Not sure of the physics - need to document	2	4	8	Avoid large up-and-down pressure swings	Monitor and control injection pressure.
107	2.1.10.07.	Reactivating existing faults and/or fractures in caprock	Over pressuring can reactivate existing faults and/or fractures in the caprock.	CO2 leakage through reactivated fault or fracture in caprock.	Additional [new] FEP	Very unlikely to be an issue.	No faults identified in the Thrall area. Faults in Geneseo-Edwards area are down dip and do not penetrate the seal. In addition, the Arbuckle can't be over pressured.	Confirm that all faults have been identified and properly characterized.	1	4	4	NA	NA
108	2.1.10.08.	Low injection pressure limit	An artificially low injection pressure limit may require drilling additional injection wells, resulting in the unintended consequence of creating additional artificial penetrations of the containment system. (CCP2009)		Additional [new] FEP	Possible issue.	High CO2 injection rate could lead to non-uniform gravity stable CO2 flooding (coning) in the Geneseo-Edwards domes.		3	2	6	Install multiple CO2 injection wells and/or horizontal injection wells.	If coning occurs, decrease CO2 injection rate per well, add new injection wells and/or switch from vertical to horizontal injection wells.
109	2.1.10.09.	Increase in pressure leading to changes in pathway migration			Additional [new] FEP	Thrall has already seen this in water flood and survived quite well. Geneseo-Edwards will not exceed bottom hole pressure.	Arbuckle in the Thrall field is a slightly dipping monocline.		3	3	9	Increase pressure in the Bartlesville Sandstone using water and identify and eliminate leaks before injecting CO2.	Monitor CO2 plume and adjust CO2 injection strategy if necessary to control CO2 migration. Could include recovery of CO2 and reinjection elsewhere.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
110	2.2.00.00.	Post-closure	Details of post-closure activities associated with sequestration.	Human activities post-closure may affect the likelihood of specific impacts being incurred.	Quintessa original FEP	Very unlikely to be an issue.	Injection areas are sparsely populated.		1	3	3	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring.
111	2.2.01.00.	Post-closure administrative control	Administrative control of the sequestration site after closure of the project. The administrative control of the post-closure site may differ from that of the pre-closure site with subsequent implications for the resources available for administrative control, the degree of access and availability of information etc.	There may be potential for loss of information in any transfer of administrative control. A lack of awareness about the details of a CO2 sequestration project could result in inadvertent disruption in the future.	Quintessa original FEP	Unlikely to be an issue.	Data management working group established.		2	3	6	Implement data management. Use multiple back up sites for data storage. Clearly mark site with warnings and register site as CO2 storage site with the State.	Data management. Routine site inspection and/or monitoring.
112	2.2.02.00.	Post-closure monitoring of storage	FEPs related to any monitoring undertaken during the post-closure phase. This includes monitoring of parameters related to the long-term safety and performance. The extent and requirement for such monitoring activities may be determined by issues such as storage concept, geological setting, regulations, or public pressure. A number of monitoring techniques exist including seismic data, electrical resistance, soil gas and isotopic characteristics.	Post-closure monitoring will provide information regarding the performance of the sequestration project and may trigger post-closure remedial actions, if necessary.	Quintessa original FEP	Unlikely to be an issue.			2	1	2	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring. Prepare procedures for potential remedial action.
113	2.2.03.00.	Records and markers (long-term knowledge retention)	Features related to the retention of records of the content and nature of a CO2 storage site after closure and also the placing of permanent markers at or near the site.	It is expected that records will be kept to allow future generations to recall the existence and nature of the storage reservoir/aquifer following closure.	Quintessa FEP with additional text	Unlikely to be an issue.			2	1	2	Clearly mark site with warnings and register site as CO2 storage site with the State.	Routine site inspection and/or monitoring. Prepare procedures for potential remedial action.
114	2.2.04.00.	Reversibility	The degree to which the sequestered CO2 could be deliberately removed, if required. Either as an extreme remedial action, because the CO2 is required as a resource, or because its presence is impeding access to other geological resources.	The degree to which reversibility is considered in the design of a sequestration system may influence its long-term performance, by leaving viable boreholes in-situ after closure, for example.	Quintessa original FEP	Some CO2 could be recovered from the Geneseo-Edwards domes and/or the Bartlesville Sandstone.	It is likely that CO2 would be removed for the Bartlesville Sandstone in order to achieve pressure equilibrium faster.		2	3	6	Maintain good records and models on CO2 injection. Use appropriate materials of construction.	Prepare procedures for removal of CO2.
115	2.2.05.00.	Remedial actions	Events and processes related to actions that might be taken following closure of a storage site to remedy problems that, either, are associated with its not performing to the standards required, result from disruption by some natural event or process, or result from inadvertent or deliberate damage by human actions.	The aim of possible future remedial actions will be to modify the performance and safety of the CO2 sequestration system.	Quintessa original FEP	Possible issue.			3	3	9	Maintain good records and models on CO2 injection. Use appropriate materials of construction.	Prepare procedures for remediating CO2 leakage. Monitor for CO2 leakage. Remediate any CO2 leakage quickly.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
116	3.0.00.00.	CO2 Properties, Interactions & Transport	This category of FEPs is concerned with those Features, Events and Processes that are relevant to the fate of the sequestered fluid. Carbon dioxides properties can vary greatly between conditions at depth and near surface, and a wide range of physical and chemical reactions can be important. The category is divided into three classes for the properties, interactions and transport of carbon dioxide.		Quintessa original FEP				NA	NA	NA	NA	NA
117	3.1.00.00.	CO2 properties	The fundamental physical and chemical properties of carbon dioxide, taking into account impurities.	Carbon dioxides properties can vary greatly with pressure, temperature and impurities, and an understanding of these properties is essential before the fate of sequestered fluid can be assessed.	Quintessa original FEP				NA	NA	NA	NA	NA
118	3.1.00.01.	CO2 properties changed by pressure			Expansion of Q FEP	Unlikely to be an issue.	Potential for CO2 phase change in the Thrall-Aagard field. EOR and DSA.		2	3	6	Characterize reservoir pressure and include in modeling. Pressurize the Bartlesville Sandstone above 1200 psig with water before injecting CO2.	Monitor CO2 plume and adjust CO2 injection strategy if necessary to control CO2 migration. Could include recovery of CO2 and reinjection elsewhere.
119	3.1.00.02.	CO2 properties changed by temperature			Expansion of Q FEP	Very unlikely to be an issue.	Phase change from supercritical to gas could lower CO2 temperature in the Thrall EOR and DSA.		1	2	2	Characterize reservoir temperature and include in model.	Monitor BHT. Identify any irregularities. Determine root cause. Modify injection strategy if necessary.
120	3.1.00.03.	CO2 properties changed by impurities			Expansion of Q FEP	Unlikely to be an issue.	KE CO2 may have O2 and N2 that could impact EOR operation. Recycled CO2 may pickup H2S in the Arbuckle.		2	3	6	Characterize CO2 composition and include in modeling. Monitor CO2 composition and maintain within spec.	Vent off-spec CO2 or inject off-spec CO2 into backup DSA.
121	3.1.00.04	CO2 properties changed by geochemistry	CO2 properties can change by encountering different reservoir geochemistry, e.g. migrating from quartz sand into calcite cemented sand.		Additional [new] FEP	Unlikely to be an issue.	Arbuckle is a dolomite and contains H2S.		2	3	6	Characterize reservoir geochemistry and include in modeling.	Take Arbuckle geochemistry into consideration in modeling.
122	3.1.01.00.	Physical properties of CO2	Physical properties of CO2 including density, viscosity, interfacial tension and thermal conductivity and their dependence on pressure and temperature.	The physical properties of CO2 determine the way in which it will behave in the environment once injected.	Quintessa original FEP				NA	NA	NA	Take CO2 physical properties into consideration in modeling.	Take CO2 physical properties into consideration in modeling.
123	3.1.01.01.	CO2 density			Expansion of Q FEP	Possible issue.	CO2 density will be low due to low injection pressures.		3	3	9	Increase pressure in the Bartlesville Sandstone using water before injecting CO2 for EOR. Inject CO2 deep in the Arbuckle for DSA.	Monitor CO2 plume and adjust CO2 injection strategy if necessary to control CO2 migration. Could include recovery of CO2 and reinjection elsewhere.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
124	3.1.01.02.	CO2 viscosity			Expansion of Q FEP	Unlikely to be an issue.		Insufficient information to determine impact.	2	3	6	Take CO2 viscosity into consideration in modeling.	Take CO2 viscosity into consideration in modeling.
125	3.1.01.03.	CO2 interfacial tension			Expansion of Q FEP	Unlikely to be an issue.		Insufficient information to determine impact.	2	3	6	Take CO2 interfacial tension into consideration in modeling.	Take CO2 interfacial tension into consideration in modeling.
126	3.1.01.04.	CO2 thermal conductivity			Expansion of Q FEP	Very unlikely to be an issue.		Insufficient information to determine impact.	1	3	3	Take CO2 thermal conductivity into consideration in modeling.	Take CO2 thermal conductivity into consideration in modeling.
127	3.1.02.00.	CO2 phase behavior	FEPs related to the phase behavior (gas, liquid, supercritical fluid) of CO2. The presence of contaminants in the injected CO2 (e.g. N2) and gas and hydrocarbons (e.g., in EOR and ECBM operations) in the reservoir will affect the phase behavior and partition of CO2 between different physical states. CO2 mixing with other fluids and gases, leads to modified flow behavior that is not fully understood (CCP 2009)	CO2 phase behavior is a primary consideration for modeling CO2 migration.	Quintessa FEP with additional text	Possible issue.	Potential for CO2 phase change in the Thrall-Aagard field. EOR and DSA.		3	3	9	Take CO2 phase change behavior into consideration in modeling.	Take CO2 phase change behavior into consideration in modeling.
128	3.1.03.00.	CO2 solubility and aqueous speciation	CO2 solubility is the amount of CO2 that can dissolve for given conditions in water. It can vary as a function of temperature, pressure and precise composition of the fluid (e.g. salinity, dissolved species/complexes, presence of hydrocarbons - e.g., EOR and ECBM). Changing temperature and pressure accompanying migration of CO2 can therefore influence CO2 solubility, potentially leading to gas exsolution. CO2 is present in the aqueous phase as: aqueous CO2; carbonic acid (H2CO3); bicarbonate (HCO3-); and carbonate (CO3--). Note that other dissolved ions (Na+, Mg++, Ca++, etc.) are also involved and provide an array of linked, reversible reactions.	CO2 solubility has an impact on the chemical composition of formation fluids, pressure distribution, 'sorption' processes, mineral-fluid reactions and the overall storage capacity of CO2. Dissolved CO2 may migrate in a different manner to 'free' supercritical CO2. CO2 solubility in water and its partition between aqueous, gaseous, and organic phases controls the efficiency of diffusive transport and successive mineral reactions. The aqueous speciation of dissolved CO2 will impact upon the mobility of sequestered CO2 and associated contaminants.	Quintessa original FEP	Unlikely to be an issue.			2	3	6	Take CO2 solubility and aqueous speciation into consideration in modeling.	Take CO2 solubility and aqueous speciation into consideration in modeling.
129	3.2.00.00.	CO2 interactions	Potential interactions of carbon dioxide with solid, liquid or gaseous media.	A wide range of physical and chemical reactions can be important, and an understanding of these interactions is essential for the assessment of potential impacts.	Quintessa original FEP	Unlikely to be an issue.			2	3	6	Take CO2 physical and chemical interactions into consideration in modeling.	Take CO2 physical and chemical interactions into consideration in modeling.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
130	3.2.01.00.	Effects of pressurization of reservoir on caprock	A storage reservoir will experience enhanced pressure due to injection of CO2. This may exceed original 'natural' pressurization due to hydrocarbon emplacement (EOR or ECBM, for example), or clay mineral transformations during diagenesis.	'Over pressuring' of the reservoir may involve leakage of CO2 through the caprock due to fracturing or enhanced interactions with CO2.	Quintessa original FEP	Unlikely to be an issue.			2	3	6	Determine fracture pressure. Monitor injection pressure. Maintain injection pressure below 80% of fracture pressure. Alarm system if injection pressure exceeds 80% of fracture pressure.	Develop procedures for handling an over pressuring situation. Operator training.
131	3.2.02.00.	Effects of pressurization on reservoir fluids	Increased pressurization caused by the injection of supercritical CO2 will affect the behavior of other fluids within the reservoir.	The potential importance of increased pressurization to enhanced oil and gas recovery indicates that it can modify the mobility of other fluids in the receiving reservoir.	Quintessa original FEP	Unlikely to be an issue.			2	3	6	Take effects of pressurization on reservoir fluids into consideration in modeling.	Take effects of pressurization on reservoir fluids into consideration in modeling.
132	3.2.03.00.	Interaction with hydrocarbons	In EOR or ECBM sites, for example, hydrocarbons could be mobilized by CO2, by miscible displacement for example, and transported to the near-surface. This is of particular relevance if enhanced oil recovery is an additional aim of the sequestration concept. Kolak and Burruss (2003) demonstrate that polyaromatic hydrocarbons (PAHs) can be mobilized by sequestration in deep coal beds. Sequestered CO2 can also precipitate asphaltenes from crude oil under certain conditions of composition, temperature and pressure. Such precipitation in the vicinity of injection wells can lead to loss of injectivity and even plugging of the wells.	Mobilized hydrocarbons may migrate to the near-surface environment. Precipitated asphaltenes can clog pores, reducing permeability and affecting fluid flow paths.	Quintessa original FEP	Unlikely to be an issue.			2	3	6	Take CO2 interactions with hydrocarbons into consideration in modeling.	Take CO2 interactions with hydrocarbons into consideration in modeling.
133	3.2.03.01.	EOR attributes	Technical screening guidelines for CO2 flooding: recommended (current projects range) Crude oil gravity, °API: >22 (27 to 44) Crude oil viscosity, cp: <10 (0.3 to 6) Crude oil composition: High percent of C5 to C12 Reservoir oil saturation: >40 (15 to 70) Type of formation: Relatively thin sandstone or carbonate unless dipping Permeability: Not critical if sufficient rates can be applied Depth/temperature: For miscible displacement, depth must be great enough to allow injection pressures greater than the MMP, which increase with temperature and for heavier oils (API 2007).		Additional [new] FEP	Thrall-Aagard and Geneseo-Edwards fields fall within preferred EOR attribute guidelines	Crude API : 37-38 Crude viscosity: 4- 8.9 cp Reservoir Oil Saturation: 34-40%	Fully characterize all fields for EOR attributes.	1	3	3	Fully characterize all fields for EOR attributes.	Monitor and model EOR performance. Identify irregularities. Determine root cause. Adjust injection strategy if necessary.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
134	3.2.03.02.	EOR reservoir depth	<p>Recommended depths of CO2 floods of typical Permian Basin oils</p> <p>CO2 Miscible <u>Gravity, °API</u> <u>Depth</u> >40 > 2500 ft 32 to 39.3 > 2800 ft 28 to 31.9 > 3300 ft 22 to 27.9 > 4000 ft <22 Fails CO2 screening</p> <p>CO2 Immiscible <u>Gravity, °API</u> <u>Depth</u> 13 to 21.9 > 1800 ft <13 Fails CO2 screening (API 2007)</p>		Additional [new] FEP	Thrall is shallower than 2800 ft but water floods injected at 1500 psi and our MMP is 1100 psi. We plan to inject at same pressure as water floods.	G-E Depth: 3200 ft T-A Depth: 2300 ft		3	3	9	Increase pressure of Bartlesville Sandstone with water prior to injecting CO2 to compensate for shallow depth.	Increase pressure of Bartlesville Sandstone with water prior to injecting CO2 to compensate for shallow depth.
135	3.2.03.03.	Oil recovery	<p>Typical oil recovery by recovery mechanism as a function of Original Oil in Place (OOIP) Primary: 6 to 15% OOIP Secondary: 6 to 30% OOIP Miscible CO2 EOR: 8 to 20% OOIP Remaining: 8 to 35% OOIP (API 2007)</p> <p>Miscible CO2 EOR: 7-23% OOIP Immiscible CO2 EOR: 9 to 19% OOIP (API 2007)</p>		Additional [new] FEP	We expect oil recovery to be in the economic range based on engineering studies		Confirm expected oil recovery from simulation modeling.	2	3	6	Model EOR operation and try to optimize oil recovery through reservoir engineering. Operate close to or above MMP if possible,	Adjust CO2 EOR strategy to improve oil recovery if necessary., such as injection beneath and above G-E reservoir or adjusting well spacing.
136	3.2.03.04.	CO2 demand per unit EOR	For field scale miscible CO2 EOR floods net (purchased) amount of CO2 required is estimated to be between 2.5 to 11 MCF/STB of incremental recovery with an average value of 6 to 7 MCF/STB. For immiscible floods, actual incremental oil recovery has been on the order of 5 to 12 MCF/STB (API 2007).		Additional [new] FEP	Our engineering studies suggest that we will be in the "normal" range.		Confirm expected CO2 demand per unit of EOR from simulation modeling.	2	3	6	Model EOR operation and try to optimize CO2 consumption per barrel of oil through reservoir engineering. Monitor CO2 consumption per barrel of oil.	Adjust CO2 EOR strategy to improve oil recovery if necessary., such as injection beneath and above G-E reservoir or adjusting well spacing.
137	3.2.03.05.	Viscosity relations	Because the viscosity of CO2 at reservoir conditions is much lower than that of most oils, viscous instability will limit the sweep efficiency of the displacement and, therefore, oil recovery (API 2007).	Can lead to adverse hydrodynamic instabilities, such as fingering, which lead to vertical fluid stratification and reduced oil recovery (API 2007).	Additional [new] FEP	Gravity override is working in our favor in the Thrall. Geneseo-Edwards is a gravity stable process and we will take advantage of the CO2 buoyancy.			2	3	6	Model EOR operation and try to optimize CO2 performance through reservoir engineering.	Adjust CO2 EOR strategy to improve oil recovery if necessary., such as injection beneath and above G-E reservoir or adjusting well spacing.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Qunitessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
138	3.2.03.06.	Oil reservoir heterogeneity	Oil reservoir rock is extremely heterogeneous, exhibiting zones of high permeability in close proximity to those of low permeability. These permeability differences may be innate, that is caused by differences in pore structure at the time of geological deposition, or a product of fractures, natural or man-made (API 2007)	Can decrease efficiency of oil recovery.	Additional [new] FEP	Thrall was a great water flood - supporting homogeneity. Geneseo-Edwards was a great bottom-water drive reservoir - heterogeneity not a problem.			2	3	6	Fully characterize oil reservoir. Take heterogeneity of oil reservoir into EOR modeling and reservoir engineering in order to optimize performance.	Adjust CO2 EOR strategy to improve oil recovery if necessary., such as injection beneath and above G-E reservoir or adjusting well spacing.
139	3.2.03.07.	Hydrocarbon precipitation	Precipitation of asphaltenes or paraffins. CO2 injection promotes asphaltene precipitation. Paraffins precipitate when temperatures are less than 25°C.	Precipitation of asphaltenes can clog pores, reducing permeability and affecting fluid flow paths. It can also cause plugging of boreholes.	Additional [new] FEP	Could be a problem, particularly in the Geneseo-Edwards. More study needed. Gravity stable means oil doesn't move very far. Therefore, may not be a problem.		More study needed	3	3	9	Monitor for asphaltene precipitation. Injection of hot water or steam every couple of months.	Injection of hot water, steam, hot oil, deasphalted oil, solvents or enzymes.
140	3.2.03.08.	Miscibility	Flooding a reservoir with CO2 can occur either miscibly or immiscibly. Miscible CO2 displacement is only achieved under a specific combination of conditions, which are set by four variables: reservoir temperature, reservoir pressure, injected gas composition, and oil chemical composition (API 2007). Miscible displacement is achieved at pressures above the minimum miscibility pressure (MMP). If the reservoir pressure is below the MMP, CO2 can still be injected, but the efficiency of the enhanced oil recovery process is adversely impacted. Typically this does not occur since, after primary depletion, water flooding operations commence which restore reservoir pressure to values above the MMP(API 2007).	Immiscible operation decreases efficiency of CO2 in recovering oil.	Additional [new] FEP	Will be miscible in the Thrall and near miscible in Geneseo-Edwards.			3	3	9	Try to maintain injection pressures in the miscible or near miscible range. Keep nitrogen content low.	Increase reservoir pressure.
141	3.2.03.09.	Residual oil saturation	Poor injectivity due to oil presence reduction of relative permeability to CO2. Unexpected bottom hole pressure increase.		Additional [new] FEP	Definitely not a problem based on injectivities in the Thrall water flood and withdrawal rate in Geneseo-Edwards.			1	3	3	NA	NA
142	3.2.03.10.	Breakthrough	The alternating water and CO2 gas (WAG) approach is typically applied in CO2 EOR to minimize CO2 use (as it is purchased) and to avoid early breakthrough of CO2.		Additional [new] FEP	Possible issue.			3	3	9	Optimize reservoir engineering.	Increase well spacing. Modify well pattern.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
143	3.2.03.11.	WAG ratio	The ratio of water to CO2 (WAG ratio) injection may need to be adjusted to optimize EOR performance. Typical WAG ratios range from 1:1 to 5:1.		Additional [new] FEP	Possible issue.	WAG will not be used in G-E but will be used in T-A.		3	3	9	Optimize WAG through reservoir engineering and modeling.	Evaluate WAG performance based on projected modeling and make adjustments in WAG ratio or well spacing/pattern as needed.
144	3.2.03.12.	Injection water quality / attributes / chemistry			Additional [new] FEP	Not a problem. Water will be treated.		Obtain water chemistry	1	2	2	Obtain water chemistry and compare with recommended specification for WAG. Set up water treatment facilities to meet specification.	Monitor water quality and treat as needed
145	3.2.03.13.	Injection water pressure	Water is denser than CO2. When changing from CO2 injection to water injection, a pressure differential needs to be overcome. To do so, the water supply header operates at a pressure in excess of the CO2 supply header pressure. This allows water to be throttled into the well, its pressure declining to the appropriate value once the CO2 is displaced from the wellbores (API 2007).		Additional [new] FEP	Unlikely to be an issue.	Will be managed.		2	2	4	Calculate water pressure needed based on modeling. Install sufficient pumping capacity to meet water pressure requirements.	Monitor water pressure and adjust pump pressure as needed.
146	3.2.03.14.	Injection and production well spacing and pattern	The layout of the injection and production wells will impact the efficiency of the sweep.		Additional [new] FEP	Yes			3	3	9	Optimize well spacing and pattern based on modeling and reservoir engineering.	Monitor well performance versus model prediction. Adjust model and well spacing and pattern as needed to optimize oil recovery.
147	3.2.03.15.	Oil attributes (Oil gravity)	Oil API gravity influences minimum miscibility pressure		Additional [new] FEP	This is high gravity oil	API: 37-38		2	3	6	Fully characterize crude oil API and MMP. Take API and MMP into account in modeling and reservoir engineering.	Monitor API and MMP during operation. Make adjustments to CO2 injection pressure as needed to maintain miscible operation.
148	3.2.03.16.	Intermittent CO2 supply	Intermittent CO2 supply can negatively impact sweep efficiency.		Additional [new] FEP	Should not be a problem.	Will have plans for short-term interruptions - switch to WAG for example.		3	2	6	Maintain daily, weekly and monthly nominations for CO2 supply and demand planning.	Use water injection as a backup for sweep if necessary.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
149	3.2.04.00.	Displacement of saline formation fluids	<p>Injection of CO2 into a geologic formation may result in displacement of saline formation fluids into potable water supplies. Limitations on the pressure in a formation (for seal integrity) will mean that existing fluids are displaced/replaced. Displaced fluids are highly likely to be saline. Because the pressure wave created by injection travels much further than the physical CO2 front, displacement of saline formation fluids can occur at locations outside the CO2 storage area. Inter-connection of aquifer systems may enable saline fluids to enter potable water formations.</p> <p>For significant storage to be possible, it is necessary for a significant amount of the native pore space fluid to be displaced from the reservoir over the injection period. This may occur either by production of fluids (oil or gas), by deliberate production of formation water, and/or by migration of fluids into adjacent formations, surface or oceans.</p>	Displaced saline formation fluids may contaminate near-surface aquifers with subsequent impacts, such as contamination of potable water supplies.	Quintessa FEP with additional text	Not an issue for EOR because of water and oil production. Only an issue for DSA. But the volume of CO2 to be used for DSA is so small compared to the Arbuckle capacity, it will not be an issue in this project.			2	3	6	Fully characterize and model reservoirs to understand likely displacement of saline formation fluids. Take into account fluid displacement in reservoir engineering.	Monitor near surface aquifers for increases in salinity. Determine root cause for any increase in salinity. Use tracers if necessary.
150	3.2.05.00.	Mechanical processes and conditions	<p>Features and processes related to the mechanical processes and conditions resulting from the injection of CO2 that affect the rock, boreholes and other engineered features, and the overall mechanical evolution with time. This includes the effects of hydraulic, mechanical and thermal loads imposed on the rock by the injected CO2. Injection of CO2 into a reservoir can cause (directly or indirectly) changes of the geomechanical properties of the reservoir rock. Direct changes can be due to change of reservoir pressure and temperature (PVT system). Indirect changes (of rock properties) might result from geochemical and mineralogical changes after storage of CO2.</p>	Mechanical changes of the reservoir resulting from CO2 injection (such as generation of fractures, reactivation of fractures/faults, changes of bulk elastic properties and effective reservoir) could lead to subsidence/uplift (at surface), induced seismicity, changes in migration pathways, even burst/leakage of the seal. Examples of other relevant processes are: borehole lining collapse; rock volume changes, leading to cracking	Quintessa original FEP	Unlikely to be an issue.	T-A Bartlesville Sandstone has demonstrated operation at 1700 psig with water flooding. The CO2 EOR will operate below that. The G-E can't be pressurized. Volume increase from CO2 injection will be compensated for by water/oil production in EOR.		2	3	6	Operate below 80% of fracture pressure.	Operate below 80% of fracture pressure. Monitor injection pressure, tiltmeter and micro-seismicity.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
151	3.2.06.00.	Induced seismicity	<p>Injection of CO2 may cause and trigger seismic events and earthquake hazards through processes such as reducing friction at existing faults. This may occur both in seismically active areas and in areas characterized by a low background seismicity (reactivation of ancient fault planes, changes in the orientation, fluid-pockets occurrence). This FEP includes microseismicity.</p> <p>Induced macro-seismicity activity is a function of existing regional and local stresses, of porosity structure, and of imposed injection stresses. Induced macro-seismicity is less likely if the injection formation is dominated by intergranular and not fracture porosity.</p> <p>The problem of seismicity might be more serious when CO2 is injected into a reservoir in tectonically active regions with high density of active faults (Damen 2006).</p>	<p>Seismicity can introduce sudden physical changes to the sequestration system and may expose any local population to earthquake hazards.</p> <p>Potential effects of reservoir-induced seismicity (RIS) are damage to the caprock and wells , which might cause CO2 leakage , and damage to building and infrastructure (Damen 2006).</p> <p>In a reservoir that is under high tectonic stresses, any significant reduction of pressure (pressure acting between individual rock particles) may trigger faults. This may lead to uplifting or down-faulting of the surface (Damen 2006).</p>	Quintessa FEP with additional text	Unlikely to be an issue.	T-A Bartlesville Sandstone has demonstrated operation at 1700 psig with water flooding. The CO2 EOR will operate below that. The G-E can't be pressurized. Volume increase from CO2 injection will be compensated for by water/oil production in EOR.		2	3	6	Operate below 80% of fracture pressure. Monitor injection pressure, tiltmeter and micro-seismicity. Volume increase from CO2 injection will be compensated for by water/oil production in EOR.	Operate below 80% of fracture pressure. Monitor injection pressure, tiltmeter and micro-seismicity. Volume increase from CO2 injection will be compensated for by water/oil production in EOR.
152	3.2.07.00.	Subsidence or uplift	<p>Injecting the CO2 may cause acidification of formation water, leading to mineral dissolution and subsidence. This is of particular relevance to shallow storage sites.</p> <p>Injection of large quantities of CO2 into a confined aquifer may increase pore pressure and lift the overlying rocks upwards.</p>	Deformation may affect geological processes and may result in impacts of concern at the surface.	Quintessa original FEP	Unlikely to be an issue.	T-A Bartlesville Sandstone has demonstrated operation at 1700 psig with water flooding. The CO2 EOR will operate below that. The G-E can't be pressurized. Volume increase from CO2 injection will be compensated for by water/oil production in EOR.		2	3	6	Operate below 80% of fracture pressure. Monitor injection pressure, tiltmeter and micro-seismicity. Volume increase from CO2 injection will be compensated for by water/oil production in EOR.	Operate below 80% of fracture pressure. Monitor injection pressure, tiltmeter and micro-seismicity. Volume increase from CO2 injection will be compensated for by water/oil production in EOR.
153	3.2.07.01.	Subsidence	<p>Injecting the CO2 may cause acidification of formation water, leading to mineral dissolution and subsidence. This is of particular relevance to shallow storage sites.</p> <p>Chemical compaction or dissolution of the reservoir rock will particularly be a matter of concern in carbonate rocks with high porosity (Damen 2006).</p>	<p>Dissolution of the reservoir rock (chemical compaction) can lead to the reservoir caving in under the weight of the overburden formation (Damen 2006)</p> <p>Vertical subsidence above large reservoirs could affect lake levels and shift streams in lowland areas with low topographic relief.</p> <p>Subsidence could damage buildings or farmland.</p>	Expansion of Q FEP	Unlikely to be an issue.	T-A Bartlesville Sandstone has demonstrated operation at 1700 psig with water flooding. The CO2 EOR will operate below that. The G-E can't be pressurized. Volume increase from CO2 injection will be compensated for by water/oil production in EOR.		2	3	6	Operate below 80% of fracture pressure. Monitor subsurface change with 3d seismic and/or VSP. Compare with model. Identify any irregularities and take corrective action if necessary.	Monitor surface change with tiltmeters. Monitor subsurface change with 3d seismic and/or VSP. Compare with model. Identify any irregularities and take corrective action if necessary.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number P x S (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
154	3.2.07.02.	Uplift	Injection of large quantities of CO2 into a confined aquifer may increase pore pressure and lift the overlying rocks upwards. It is not envisaged that uplift will take place in a CO2 reservoir as long as the maximum storage pressure is kept below the geostatic pressure (Damen 2006).	Vertical uplift above large reservoirs could affect lake levels and shift streams in lowland areas with low topographic relief. Uplift could damage buildings or farmland.	Expansion of Q FEP	Unlikely to be an issue.	T-A Bartlesville Sandstone has demonstrated operation at 1700 psig with water flooding. The CO2 EOR will operate below that. The G-E can't be pressurized. Volume increase from CO2 injection will be compensated for by water/oil production in EOR.		2	3	6	Operate below 80% of fracture pressure. Monitor injection pressure, tiltmeter and micro-seismicity. Volume increase from CO2 injection will be compensated for by water/oil production in EOR.	Operate below 80% of fracture pressure. Monitor injection pressure, tiltmeter and micro-seismicity. Volume increase from CO2 injection will be compensated for by water/oil production in EOR.
155	3.2.08.00.	Thermal effects on the injection point	Temperature of the injected fluid could result in geological modification of the region around the point of injection due to thermal gradients.	These thermal effects could influence the mobility of the injected CO2 and impurities.	Quintessa original FEP	The volume of CO2 to be injected is relatively small. The CO2 goes could have a localized cooling effect if it goes from supercritical state to a gas due to low pressure.	The CO2 will have a wellhead temperature of 18-20°C and the BHT is 47°C at G-E and 36°C at T-A.		2	2	4	Maintain CO2 injection pressure above the CO2 supercritical pressure.	Maintain CO2 injection pressure above the CO2 supercritical pressure.
156	3.2.09.00.	Water chemistry	Water phase geochemistry of sequestered CO2. This includes the solubility trapping of CO2 in water (H2O) to form carbonic acid (H2CO3). Subsequent ionic trapping of carbonic acid with hydroxide ions (OH-) forms bicarbonate ions (HCO3-), which can react in turn with further hydroxide ions to form carbonate (CO3).	Modification of the water phase geochemistry can disturb the equilibria between the water and solid phase of the reservoir and result in further geochemical (for example, solid phase geochemistry) and physical changes with resulting implications for the long-term performance of the sequestration system.	Quintessa original FEP	Reactions are likely to be slow.		Need more information of water chemistry in Arbuckle and Bartlesville.	2	2	4	Take geochemistry into account in modeling and reservoir engineering.	Monitor impact on boreholes and replug/remediate if necessary.
157	3.2.09.01.	Formation of carbonic acid (H2CO3)			Expansion of Q FEP	Reactions are likely to be slow.		Need modeling results	2	2	4	Take geochemistry into account in modeling and reservoir engineering.	Monitor impact on boreholes and replug/remediate if necessary.
158	3.2.09.02.	Formation of bicarbonate ions (HCO3-)			Expansion of Q FEP	Reactions are likely to be slow.		Need modeling results	2	2	4	Take geochemistry into account in modeling and reservoir engineering.	Monitor impact on boreholes and replug/remediate if necessary.
159	3.2.09.03.	Formation of carbonate (CO3)			Expansion of Q FEP	Reactions are likely to be slow.		Need modeling results	2	2	4	Take geochemistry into account in modeling and reservoir engineering.	Monitor impact on boreholes and replug/remediate if necessary.
160	3.2.10.00.	Interaction of CO2 with chemical barriers	Chemical barriers (pH, Eh-pH, ion exchange) may exist in aquifers to retard the migration of CO2 from depth. The precipitation of CO2 bearing solids may result from such interactions.	Such barriers will affect the rate of migration of CO2 from depth.	Quintessa original FEP	Very unlikely to be an issue.	No chemical barriers have been identified in the project area. CO2 containment is not dependent on chemical barriers.		1	3	3	NA	NA

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PIS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
161	3.2.11.00.	Sorption and desorption of CO2 (CO2 interaction with coal seams)	The sorption and desorption of CO2 on geological materials. Sorption onto coal and the displacement of methane (CH4) is the primary mechanism behind the enhanced coal bed methane recovery (ECBM) method for geological CO2 sequestration.	The rate of sorption and desorption of CO2 on geological materials affects its mobility and therefore the performance of the storage system.	Quintessa FEP with additional text	Very unlikely to be an issue in this project. Very small percentage of total CO2.			1	2	2	Take into account in modeling and reservoir engineering.	NA
162	3.2.11.01.	Sorption of CO2 on coal and release of methane	>2 mol CO2 adsorbed on coal for every mol of CH4 desorbed.		Expansion of Q FEP	Very unlikely to be an issue in this project. Very small percentage of total CO2.			1	2	2	Take into account in modeling and reservoir engineering.	NA
163	3.2.11.02.	Desorption of CO2 from coal or other solids			Expansion of Q FEP	Very unlikely to be an issue in this project. Very small percentage of total CO2.			1	3	3	Take into account in modeling and reservoir engineering.	NA
164	3.2.11.03.	Coal swelling	The chemical reactions and physical processes that occur during CO2 injection into coal seams and their impact on the integrity of the coal seams are not well understood. One of the reactions is swelling of the coal matrix when injecting CO2. (Damen 2006)	Coal seam swelling may cause a reduction in permeability. Swelling might also induce stresses on the overlying and underlying rock strata in non ideal coal seams (thin, low permeability and highly faulted), that could cause faulting and possible migration pathways out of the coal seam (Damen 2006).	Additional [new] FEP	Very unlikely to be an issue.	Not doing ECBM in Phase 2.		1	2	2	NA	NA
165	3.2.11.04.	Release of polyaromatic hydrocarbons from coal seams		Toxicity	Additional [new] FEP	Very unlikely to be an issue.	Not doing ECBM in Phase 2.		1	2	2	NA	NA
166	3.2.12.00.	Heavy metal release	Heavy metal ions may be dissolved in formation fluids or sorbed on rock/mineral surfaces. Complexation may occur between CO2 and heavy metals dissolved in formation fluids. The influence of dissolved CO2 on pore water chemistry can also reduce the pH and change the equilibrium between sorption/desorption of metals, thereby resulting in significant release of these metals.	This process has the potential to release heavy metals, which may then migrate to the near-surface environment with resulting impacts of interest. These heavy metals will also change pore water chemistry, which could impact on carbonate complexation.	Quintessa original FEP	Heavy metals likely to be an issue only if there is leakage. Leakage is most likely to occur through boreholes.	Need data on heavy metal content of Arbuckle, Bartlesville and Douglas and near surface waters.		3	3	9	Fully characterize Arbuckle, Bartlesville and Douglas and take heavy metals content into account in modeling and monitoring.	Monitor for appropriate heavy metals in near surface waters in the area.
167	3.2.13.00.	Mineral phase	Geochemistry of the mineral phase relevant to sequestered CO2, including ion exchange and mineral dissolution.	Geochemical reactions between sequestered CO2 and the mineral phase of the storage system will affect the evolution of the system and the sorption (and therefore mobility) of the CO2.	Quintessa original FEP	Not likely to be an issue in this project. Very small percentage of total CO2. Long time frame.			1	1	1	NA	NA
168	3.2.13.01.00	Mineral dissolution and precipitation	The dissolution of minerals due to the addition of CO2 (an acid gas) to the geochemistry and precipitation. For example, the dissolution of albite and precipitation of calcite modeled for the Sleipner site by Gaus et al. (2003).	CO2 reaction with the host rock will modify: the porosity and permeability of the reservoir; fluid flow (direction or velocity); mechanical properties (e.g. strength); and CO2 storage capacity.	Quintessa original FEP	There is likely to be some mineral dissolution and precipitation associated with CO2 and the Arbuckle dolomite but this is very long term and not likely to pose a risk.			2	1	2	Take mineral dissolution and precipitation into account in modeling.	Monitor impact on boreholes and replug/remediate if necessary.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
169	3.2.13.01.01	Mineral dissolution reservoir	Minerals in the reservoir formation (grains or cement) may dissolve. This may locally increase porosity and permeability along the borehole, and/or may lead to mineral reprecipitation that reduces local porosity and permeability.		Additional [new] FEP	Very little risk.			2	1	2	Take mineral dissolution and precipitation into account in modeling.	Monitor impact on boreholes and replug/remediate if necessary.
170	3.2.13.01.02	Mineral dissolution borehole	Minerals in borehole cement or in the reservoir formation next to the borehole (grains and cement) may dissolve. This may locally increase porosity and permeability along the borehole, and/or may lead to mineral reprecipitation that reduces local porosity and permeability.		Additional [new] FEP	Very little risk			2	1	2	Take mineral dissolution and precipitation into account in modeling.	Monitor impact on boreholes and replug/remediate if necessary.
171	3.2.13.01.03	Mineral dissolution caprock	Minerals in the caprock formation may dissolve. This may locally increase porosity and permeability in the caprock and or may lead to mineral reprecipitation that reduces local porosity and permeability. Especially in the caprock, this phenomenon might be localized along a microfracture.		Additional [new] FEP	Very little risk			2	1	2	Characterize caprock mineralogy. Take mineral dissolution and precipitation into account in modeling.	Monitor for CO2 leakage in sinks above seal. Plug leaks, if necessary, extract CO2 from leaky formation and reinject CO2 into a sealed formation.
172	3.2.13.01.04	Precipitation of carbonate minerals	Calcium carbonate and magnesium carbonate can be formed when HCO_3^- reacts with Ca^{2+} or Mg^{2+} .	Dry out and salt out may cause reduced porosity and permeability in the reservoir, especially near the borehole.	Additional [new] FEP	Very little risk			2	1	2	Take mineral precipitation into account in modeling.	Monitor impact near boreholes.
173	3.2.13.01.05	Salt precipitation	Dry CO2 can pick up moisture from high salinity brines in the reservoir. This increases the salinity of the brines. (CCP 2009)	Increased salinity of brines can lead to precipitation of salt in pore space, which can decrease reservoir permeability and impair injection rates of CO2. (CCP 2009)	Additional [new] FEP	Very little risk. Not likely to be an issue in the EOR operations.	No water in the top of the G-E domes where CO2 will be injected.		1	1	1	Include brine salinity and potential for salt precipitation in modeling. Control salinity of water injected into the Bartlesville Sandstone.	Monitor salinity in brine. Use fresh water injection to dissolve salt buildup.
174	3.2.13.01.06	Scale buildup	CO2 reacts with brine to form hard water which can lead to scaling in or near a production well	Scale buildup can cause reduced porosity and permeability in the reservoir, especially near the borehole.	Additional [new] FEP	Unlikely to be a issue.	Will deal with this using chemicals.		2	1	2	Monitor brine for common ions that cause scale. Periodically treat system with chemicals.	Treat system with chemicals.
175	3.2.13.02.	Ion exchange	The process of exchanging one ion in the liquid phase for another ion on a charged, solid substrate. Injected CO2 may perturb ion exchange equilibria between relevant minerals (such as sheet silicates) and the pore fluid. Some cations may be released to the pore fluid and others fixed as a consequence.	Disturbance of the rock-pore fluid equilibria may affect the capacity of the rock to store CO2.	Quintessa original FEP	Very unlikely to be an issue.			1	1	1	Take ion exchange into account in modeling	Monitor and model CO2 injection. Identify irregularities. Determine root cause. Modify injection strategy if necessary.
176	3.2.13.03.	Desiccation of clay	CO2 is likely to be dried to prevent corrosion during transport. Injection of dry CO2 will cause it to take up water from the pores of the host formation and overlying rocks. It has the potential to suck water out of an overlying clay. CO2 can also sorb in clay.	If clay dehydrates, it will shrink and crack. This might aid CO2 migration upwards.	Quintessa FEP with additional text	Very unlikely to be an issue.		Check clay content of seals,	1	2	2	Characterize seals to evaluate clay content and potential for desiccation. Include in modeling if it appears to be an issue.	Inject water to hydrate clay.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number P x S (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
177	3.2.14.00.	Gas chemistry	Gases such as CO2, methane and H2S, will occur naturally in the geosphere, either sorbed onto minerals, dissolved in formation fluids or as a free gas phase. Gas solubility will depend upon pressure, temperature and the salinity of the formation fluid.	Gases naturally present in the geosphere could affect the behavior of CO2 injected into a storage reservoir and could accompany CO2 along potential migration paths.	Quintessa original FEP	Very unlikely to be an issue.	G-E and T-A expected to have little gas based on historical production results. Arbuckle may contain H2S.	Check for gas in reservoirs (particularly H2S)	1	3	3	Check reservoirs for presence of gases (particularly H2S). Include results in systems design.	Monitor for H2S and train operators how to handle H2S appropriately.
178	3.2.14.01.	CO2 interaction with free gases in the reservoir			Additional [new] FEP	Very unlikely to be an issue.	G-E and T-A expected to have little gas based on historical production results. Arbuckle may contain H2S.	Check for gas in reservoirs (particularly H2S)	1	3	3	Check reservoirs for presence of gases (particularly H2S). Include results in systems design.	Monitor for H2S and train operators how to handle H2S appropriately.
179	3.2.14.02.	CO2 interaction with gases sorbed on minerals			Additional [new] FEP	Very unlikely to be an issue.	G-E and T-A expected to have little gas based on historical production results. Arbuckle may contain H2S.	Check for gas in reservoirs (particularly H2S)	1	3	3	Check reservoirs for presence of gases (particularly H2S). Include results in systems design.	Monitor for H2S and train operators how to handle H2S appropriately.
180	3.2.14.03.	CO2 interaction with gases dissolved in formation fluids			Additional [new] FEP	Very unlikely to be an issue.	G-E and T-A expected to have little gas based on historical production results. Arbuckle may contain H2S.	Check for gas in reservoirs (particularly H2S)	1	3	3	Check reservoirs for presence of gases (particularly H2S). Include results in systems design.	Monitor for H2S and train operators how to handle H2S appropriately.
181	3.2.14.04.	CO2 interaction with gaseous hydrocarbons in the reservoir			Additional [new] FEP	Very unlikely to be an issue.	G-E and T-A expected to have little or no hydrocarbon gas based on historical production results.	Check for hydrocarbon gases in the reservoirs.	1	3	3	Check reservoirs for presence of hydrocarbon gases. Include results in systems design.	Monitor for H2S and train operators how to handle H2S appropriately.
182	3.2.15.00.	Gas stripping	CO 2 migration through the reservoir and into the overlying barrier sequence could result in the CO2 stripping other gases entrained within the sediments. These gases could include radon, methane (CH4) and hydrogen sulphide (H2S).	The presence of other gases in a leaking CO2 gas stream is important in deciding the level of CO2 leakage that can be tolerated and may constitute an important hazard.	Quintessa original FEP	Unlikely to be a issue.	G-E and T-A expected to have little gas based on historical production results. Arbuckle may contain H2S.	Check for gas in reservoirs (particularly H2S)	2	3	6	Check reservoirs for presence of gases (particularly H2S). Include results in systems design.	Monitor for H2S and train operators how to handle H2S appropriately.
183	3.2.15.01.	Radon stripping			Expansion of Q FEP	Very unlikely to be an issue.		Check for radon in reservoirs.	1	3	3	Check for radon in reservoirs. Include results in modeling and system design if necessary.	Monitor for radon and train operators how to handle radon appropriately.
184	3.2.15.02.	Methane (CH4) stripping			Expansion of Q FEP	Very unlikely to be an issue.	G-E and T-A expected to have little or no methane based on historical production results.	Check for methane in reservoirs.	1	3	3	Check for methane in reservoirs. Include results in modeling and system design if necessary.	Monitor for methane and train operators how to handle methane appropriately.
185	3.2.15.03.	Hydrogen sulfide (H2S) stripping			Expansion of Q FEP	Very unlikely to be an issue.	H2S has been reported in the Arbuckle.	Check for H2S in the reservoirs.	1	3	3	Check for H2S in reservoirs. Include results in modeling and system design if necessary.	Monitor for H2S and train operators how to handle H2S appropriately.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
186	3.2.16.00.	Gas hydrates	Gas hydrates are 'ice-like' solids that form at low temperatures and high pressures. They are formed of 'cages' of water molecules surrounding a gas molecule. CO2 can form hydrates in the presence of water.	Cooling of the reservoir (e.g. by injecting cold CO2 or through adiabatic expansion) well below normal in-situ temperatures might stabilize gas hydrates. Their growth might seal fluid flow pathways (at least temporarily). If CO2 is injected below deep water or permafrost, then rising CO2 might hit the hydrate stability zone before escaping to the ocean or air, so hydrates could act as a secondary chemical barrier. Similarly, storage could be focused on actively forming CO2 hydrate as a stable, immobile phase to lock up the CO2 (Koide et al., 1997).	Quintessa original FEP	Very unlikely to be an issue.	G-E Arbuckle could be cooled locally by CO2 changing form subcritical to gas phase, but the CO2 volume is relatively small and not expected to form gas hydrates.	Evaluate potential of hydrate formation through modeling.	1	1	1	NA	NA
187	3.2.16.01.	Gas hydrates formed below deep water			Expansion of Q FEP	Very unlikely to be an issue.	No deep water		1	1	1	NA	NA
188	3.2.16.02.	Gas hydrates formed below permafrost			Expansion of Q FEP	Very unlikely to be an issue.	No permafrost		1	1	1	NA	N'
189	3.2.17.00.	Biogeochemistry	Features and processes related to the biological/biochemical processes that affect the CO2, borehole seals and rock/pore fluid, and the overall biological/biochemical evolution with time. This includes the effects of biological/biochemical influences on the CO2 and engineered components by the surrounding geology. Microbes exist in the subsurface and are used in hydrocarbon operations to improve hydrocarbon recovery (e.g., in EOR and ECBM operations). Microbes can also catalyze geochemical reactions, including methanogenesis, but the latter reaction is thermodynamically unfavorable and is unlikely.	Examples of relevant processes are: - microbial growth; - microbially/biologically mediated processes; and - microbial/biological effects of evolution of redox (Eh) and acidity/alkalinity (pH) , etc. This FEP has probably low relevance to the safety/fate of CO2. However, CO2 releases may affect/impact microbe populations being used in independent hydrocarbon-recovery enhancement projects.	Quintessa original FEP	Very unlikely to be an issue.		Identify any significant subsurface microbial cultures at the injection sites.	1	1	1	Monitor for microbial activity if injection pressures increase unexpectedly. Avoid O2 content in the CO2 stream.	Use chemical treatment if necessary to control microbial growth.
190	3.2.18.00.	Microbial processes	Microbes can metabolize CO2, for example, methanogenic microbes use H2 to reduce CO2 to methane (CH4), a process called methanogenesis. These microbes need anaerobic conditions.	Methanogenesis, if it occurs, could affect the pressure distribution of CO2. The fate and impact of the CH4 produced may be an endpoint of interest in itself.	Quintessa original FEP	Very unlikely to be an issue.		Identify any significant subsurface microbial cultures at the injection sites.	1	1	1	Monitor for microbial activity if injection pressures increase unexpectedly. Avoid O2 content in the CO2 stream.	Monitor for methane. Use chemical treatment if necessary to control microbial growth.
191	3.2.19.00.	Biomass uptake of CO2	If sequestered CO2 migrates to the biosphere, it can be taken up by microbes, plants and algae (including phytoplankton).	This mechanism may provide a sink for CO2 that has migrated from the sequestration system.	Quintessa original FEP	Very unlikely to be an issue.	Biomass in the injection site areas appear to be minimal.		1	1	1	NA	NA
192	3.3.00.00.	CO2 transport	Transport processes that may affect sequestered carbon dioxide and associated impurities.	An understanding of those processes that could transport carbon dioxide, and associated impurities, within the geosphere, near-surface and surface environments is fundamental to the assessment of long-term performance and safety.	Quintessa original FEP	Very unlikely to be an issue.			1	3	3	Fully characterize and model the sites and avoid or eliminate potential leaks.	Monitor for CO2 leakage. If necessary, extract CO2 from leaky formation and reinject CO2 into a sealed formation.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
193	3.3.01.00.	Advection of free CO2	<p>Advection of free CO2 occurs in response to differences in pressure. The pressure difference may be due to differences in the pressure of injected CO2 and formation pressures.</p> <p>The rate and direction of advection is affected by the physical properties of the rock, such as porosity and permeability.</p> <p>Advection may also occur through fractures. Fracture flow will be episodic with high transport efficiencies. Resealing of fractures (for example by cementation) will reduce and ultimately block fluid flow.</p>	Advective flow is a key transport process for migrating CO2, and associated contaminants, in the geosphere (reservoir, surrounding and overlying rock), near-surface and surface environments.	Quintessa original FEP	Unlikely to be a issue.	Oil reservoirs in G-E and T-A have top and lateral seals,		2	3	6	Inject CO2 into reservoirs that have top and lateral seals such as domes at G-E or "bottles" at T-A.	Monitor CO2 plumes to make sure they don't pass beyond spill points or enter leakage pathways. If necessary, extract CO2 from leaky formation and reinject CO2 into a sealed formation.
194	3.3.01.01.	Advection causing change in CO2 migration direction			Additional [new] FEP	Unlikely to be a issue.	Oil reservoirs in G-E and T-A have top and lateral seals,		2	3	6	Thoroughly characterize and model reservoirs and include results in reservoir engineering.	Monitor CO2 plumes to make sure they don't pass beyond spill points or enter leakage pathways. If necessary, extract CO2 from leaky formation and reinject CO2 into a sealed formation.
195	3.3.01.02.	Hydrodynamic gradients	CO2 migration path diverges from expected path. Significant CO2 volumes migrate off structure.		Additional [new] FEP	Unlikely to be a issue.	Oil reservoirs in G-E and T-A have top and lateral seals, CO2 injection for DSA in the Arbuckle could be impacted by hydrodynamic gradients but the injected volume will be very limited and will ultimately flow upward and spread out on top of the formation.		2	2	4	Thoroughly characterize and model reservoirs and include results in reservoir engineering.	Monitor CO2 plumes to make sure they don't pass beyond spill points or enter leakage pathways. If necessary, extract CO2 from leaky formation and reinject CO2 into a sealed formation.
196	3.3.01.01.	Fault valving	Fault valving is a process resulting from gradual build up of pore pressure due to fluid generation, causing the subsequent opening of a fault along with fluid escape towards surface. This mechanism has been recognized as causing earthquakes in many parts of the world, as a result of hydrocarbon generation (e.g., in EOR or ECBM operations) or infiltration of other fluids.	Large releases of pore fluids may occur during fault valving episodes.	Quintessa original FEP	Unlikely to be a issue.	Existing faults in G-E are stable, down dip and don't penetrate the caprock. The Arbuckle can't be pressurized in that area. Faults in T-A are 25 miles away and the Bartlesville Sandstone is isolated.		2	4	8	Don't inject CO2 near faults. Don't overpressure the reservoir near faults.	Monitor micro-seismicity and CO2 on surface of faults. If necessary, extract CO2 from leaky formation and reinject CO2 into a sealed formation.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
197	3.3.01.02.	CO2 leakage through an existing open fault	Existing open fault detected or undetected.	CO2 can leak through an open fault into shallower formations or the surface.	Additional [new] FEP	Unlikely to be a issue.	Existing faults in G-E are stable, down dip and don't penetrate the caprock. The Arbuckle can't be pressurized in that area. Faults in T-A are 25 miles away and the Bartlesville Sandstone is isolated.		2	4	8	Don't inject CO2 near faults. Don't overpressure the reservoir near faults.	Monitor micro-seismicity and CO2 on surface of faults. If necessary, extract CO2 from leaky formation and reinject CO2 into a sealed formation.
198	3.3.01.03.	CO2 leakage through a reactivated fault	Reactivation of an existing fault due to pressure buildup from CO2 injection.	CO2 can leak through a reactivated fault into shallower formations or the surface.	Additional [new] FEP	Unlikely to be a issue.	Existing faults in G-E are stable, down dip and don't penetrate the caprock. The Arbuckle can't be pressurized in that area. Faults in T-A are 25 miles away and the Bartlesville Sandstone is isolated.		2	4	8	Don't inject CO2 near faults. Don't overpressure the reservoir near faults.	Monitor micro-seismicity and CO2 on surface of faults. If necessary, extract CO2 from leaky formation and reinject CO2 into a sealed formation.
199	3.3.02.00.	Buoyancy-driven flow	Different relative densities of fluids in a geological system will result in buoyancy-driven flows as less dense fluids will have a tendency to flow upwards. The density of fluids will depend on its temperature and pressure.	Carbon dioxide can be less dense than water, which may cause injected CO2 to flow upwards and accumulate above the water phase below the caprock of a reservoir. Water with dissolved CO2 is more dense than water, which can result in stratification of water bodies into which CO2 may leak, if conditions are suitable.	Quintessa original FEP	Buoyancy driven flow not an issue with EOR in G-E and T-A except if tied to well bore leakage. May not be an issue in DSA due to the small amount of CO2 to be injected.	Buoyancy driven flow is helpful for gravity stable flooding in the G-E dome. In G-E DSA, buoyancy driven flow will push CO2 upward into oil reservoir. In T-A, Bartlesville Sandstone is isolated and CO2 will be conventional piston flood. In T-A DSA, buoyancy driven flow will cause CO2 to flow up to top of Arbuckle and spread out until plume is stabilized.		3	2	6	Ensure integrity of vertical and lateral seals.	Monitor and model CO2 plume. If necessary, extract CO2 from leaky formation and reinject CO2 into a sealed formation.
200	3.3.02.01.	CO2 exceeding reservoir spill point	CO2 migrates beyond the reservoir's structural spill points.		Additional [new] FEP	Possible issue.	Applicable to spill points in G-E domes.		3	3	9	Stop CO2 injection before exceeding spill point in domes. Switch injection to other domes.	Monitor and model CO2 plume and adjust CO2 injection strategy if necessary to control CO2 migration. Could include recovery of CO2 and reinjection elsewhere.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
201	3.3.02.02.	Lateral CO2 flow	CO2 migrates laterally across the reservoir formation into unintended areas.	May result in migration up a fault, groundwater contamination, civil suit for trespass, permit revocation, increased monitoring costs, etc.	Additional [new] FEP	Possible issue.	Applicable to T-A DSA. No lateral seals in Arbuckle below T-A.	Need 3-d seismic to identify potential traps in top of Arbuckle at T-A..	3	3	9	Characterize the site for lateral seals. Keep CO2 injection to a minimum if there are no lateral seals.	Monitor and model CO2 plume and adjust CO2 injection strategy if necessary to control CO2 migration. Could include recovery of CO2 and reinjection elsewhere.
202	3.3.03.00.	Displacement of formation fluids	<p>This depends on interfacial tension and capillary pressure.</p> <p>Capillary pressure is the pressure difference existing across the interface separating two immiscible fluids due to interfacial tension. The interfacial tension itself is caused by the imbalance in the molecular forces of attraction experienced by the molecules at the surface and is a function of temperature and pressure.</p> <p>At a given pressure, increased interfacial tension values between water and CO2 will make larger pores accessible to CO2 (this is only valid for water-wet systems). The change from a water-wet system to a CO2-wet system has an effect on capillary forces (i.e. displacement of water by enhanced pressure versus CO2 injection with less capillary pressure) and the displacement capacity (i.e. as a non-wetting fluid, CO2 will have less displacement capacity). If the injection velocity is high, effects of capillary forces are small.</p>	Interfacial tension and capillary pressure determine the location of CO2 within the pore spaces of the reservoir and the displacement capacity of the reservoir.	Quintessa original FEP	Not an issue with EOR because oil/water production compensate for CO2 injection. Not an issue for DSA in the Arbuckle due to limited amount of injection and under pressured reservoir.			1	3	3	Characterize and model the reservoirs. Keep CO2 injection for DSA to a minimum.	Monitor and model displacement of formation fluids. If necessary, extract brine and reinject elsewhere.
203	3.3.04.00.	Dissolution in formation fluids	The process of dissolution of CO2 in formation fluids. The rate of dissolution depends on factors such as the interfacial area between the CO2 and the formation fluids and temperature.	Dissolution in formation fluids can be an important process in determining the period that free CO2 remains in the reservoir.	Quintessa original FEP	Not likely to be an issue. Dissolution of CO2 takes thousands of years.			1	2	2	Include dissolution in model.	Include dissolution in model.
204	3.3.04.02.	CO2 exsolution from water	<p>Long-term risks might result from the gravitational sinking of dense CO2 saturated brines; if they come into contact with salt formations this could lead to a degassing of the formation water and the ascent of CO2 outside of the original closed storage structure. (CO2STORE, page 68)</p> <p>Exsolution can also occur under significant (large) changes in pressure or temperature. The risk of major changes in pressure or temperature in a deep reservoir is very low.</p>	Displaced brine containing dissolved CO2 flows to the surface and releases CO2 to the atmosphere or ocean.	Additional [new] FEP	Not likely to be an issue. The amount of CO2 available for exsolution is expected to be very low.			1	2	2	Characterize reservoir. Maintain integrity of vertical and lateral seals. Include CO2 exsolution in modeling.	Monitor ground water and surface water CO2 content. Extract contaminated water, remove contaminants and reinject treated water and CO2.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
205	3.3.05.00.	Water mediated transport	<p>Processes related to the transport of CO2, and associated contaminants, in groundwater and surface water, including advection, dispersion and molecular diffusion.</p> <p>Advection is the process by which contaminants are transported by the bulk movement of the water in which they are dissolved. Advective groundwater flow can occur along connected porous regions, such as fractures and faults.</p> <p>Dispersion is the collective name for the consequences of a number of processes that cause 'spreading-out' of CO2, and associated contaminants, dissolved in water in all directions, superimposed on the bulk movement predicted by a simple advection model. It results in a spatially distributed contaminant plume.</p> <p>Diffusion is the process whereby chemical species move under the influence of a chemical potential gradient (usually a concentration gradient).</p>	<p>The transport of CO2, and associated contaminants, within groundwater is likely to be a key migration process and therefore an important consideration in determining performance and safety.</p> <p>CO2 dissolves in brine at CO2/brine interface and brine transports CO2 out of closure.</p>	Quintessa original FEP	Not likely to be an issue. There is very little groundwater in the project areas.			2	2	4	Ensure integrity of vertical and lateral seals. Monitor wells for leakage and repair leaky wells.	Monitor ground water and surface water CO2 content. Extract contaminated water, remove contaminants and reinject treated water and CO2.
206	3.3.06.00.	CO2 release processes	<p>Processes by which CO2 is lost from the sequestration system. Once in the near-surface, changes in pressure and temperature result in the potential for phase changes and degassing, with resulting changes in the transport properties of sequestered CO2. Examples of CO2 release processes include:</p> <ul style="list-style-type: none"> - surface and undersea blowouts; - CO2 geysers such as Crystal Geyser in Utah; - submarine gas release. 	The potential for CO2 to be lost from a sequestration system will determine the performance of that system.	Quintessa original FEP	Possible issue.	Most likely to be tied to wellbore leakage.		3	4	12	Ensure integrity of vertical and lateral seals.	Monitor higher formations, surface and wells for CO2 leakage. Plug leaks. If necessary, extract CO2 from leaky formation and reinject CO2 into a sealed formation.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
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207	3.3.06.01.	Limnic eruption	<p>The rapid turnover and degassing of CO2 from a surface water body.</p> <p>Due to the high solubility of CO2 in water, a lake can dissolve a volume of CO2 that, in gaseous form, is more than five times its volume. CO2 rich water is denser than pure water which can result in an unstable stratification. A drop in temperature will reduce the solubility of CO2 in water. If the water reaches its solubility limit as a result, bubbles will nucleate. As the bubbles rise and grow, a chain reaction occurs where a sudden ex-solution of CO2 can result in a rapid degassing of the water body with an eruption of rising, expanding bubbles.</p> <p>Limnic eruptions can be triggered by events such as landslides that disturb the unstable stratification.</p>	<p>Limnic eruption provides a release mechanism for CO2, migrating from a storage system to the atmosphere.</p> <p>Natural limnic eruption events can be catastrophic. On the 29th of August 1986, a massive limnic eruption from Lake Nyos in Cameroon resulted in 1800 deaths as the CO2 smothered local villages. The CO2, which is volcanic in origin, seeps through the lake bed sediments and builds up in the lower strata of the water column.</p> <p>The Lake Nyos sudden release involved an estimated 240,000 tonnes of CO2 (Damen 2006)</p>	Quintessa original FEP	Very unlikely to be an issue.	No significant surface water bodies in the injection area		1	5	5	Avoid injection under deep lakes.	Monitor CO2 buildup in bottom of deep lakes and use convection to keep CO2 content under control.
208	3.3.06.02.	Surface blowout		Could occur as a well blowout. CO2 shooting into the atmosphere will rapid mixing with air. Injury more likely from flying object rather than CO2 asphyxiation.	Expansion of Q FEP	Very unlikely to be an issue.			1	3	3	Replug old wells. Maintain well integrity. Install automatic shut off protection.	Alert any people at risk. Shutdown and plug leak. Train operators and educate residence on what to do if a blowout occurs.
209	3.3.06.03.	Undersea blowout			Expansion of Q FEP	Very unlikely to be an issue.			1	3	3	NA	NA
210	3.3.06.04.	CO2 geyser			Expansion of Q FEP	Very unlikely to be an issue.			1	3	3	NA	NA
211	3.3.06.05.	Submarine gas release			Expansion of Q FEP	Very unlikely to be an issue.			1	3	3	NA	NA
212	3.3.06.06.	Diffusion through soil			Additional [new] FEP	Possible if tied to a leaky well.			3	2	6	Plug and seal old wells. Increase pressure Bartlesville reservoir with water, check for leaks and fix them prior to injecting CO2.	Monitor Soil and atmosphere for CO2. Plug leaks or depressurize leaky reservoir.
213	3.3.06.07.	Mud volcano or mud flow	<p>In fine-clastic unconsolidated rocks, suspensions could form and cause mud-volcanism and mud flows. (CO2STORE p.68)</p> <p>Mud diapir could be formed in unconsolidated (plastic, water-rich, under-compacted) reservoir and overburden strata possibly including the entire reservoir because of the buoyancy of store CO2. (CO2STORE, page 68)</p>	CO2 released to the surface in mud flow.	Additional [new] FEP	Very unlikely to be an issue.			1	3	3	NA	NA

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214	3.3.07.00.	Co-migration of other gases	Surface seepages of CO2 may contain significant amounts of other gases due to co-migration, such as hydrogen sulphide (H2S). This is especially the case where the CO2 reservoir is a reducing chemical environment. H2S is derived from the hydration of sulphide minerals (e.g. FeS) or from the chemical reduction of aqueous sulphate species. H2S is highly toxic and therefore potentially harmful to the biosphere. Even in low concentrations it is deleterious to long-term health (human/animal), in addition to being extremely unpleasant.	The co-migration of other gases to the surface environment may cause areas of leakage to become uninhabitable – at least temporarily. The detection of H2S provides a quick (non-analytical/aesthetic) test for CO2 escape and thus can be used as a “marker” gas.	Quintessa original FEP	Potential for CO2 to pick up H2S in the G-E Arbuckle.			3	3	9	Ensure the integrity of vertical and lateral seals.	Monitor for H2S and train operators how to handle H2S appropriately.
215	4.0.00.00.	Geosphere	This category of FEPs is concerned with the geology, hydrogeology and geochemistry of the geosphere. The category covers the reservoir, overburden and surrounding rock up to the near-surface which is considered in a separate FEP category. Taken together, the FEPs in this category describe what is known about the natural system prior to sequestration operations commencing. The category is divided into three classes: Geology, Fluids, and Geochemistry.		Quintessa original FEP				NA	NA	NA	NA	NA
216	4.1.00.00.	Geology	Geological features of the geosphere, which comprises of the reservoir, overburden and surrounding rock prior to injection of CO2.	An understanding of the natural system into which the carbon dioxide is injected is essential for the assessment of long-term performance and safety.	Quintessa original FEP	Very unlikely to be an issue.	G-E and T-A have isolated oil reservoirs with multiple seals and sinks above.		1	2	2	Fully characterize the EOR and DSA sites.	NA
217	4.1.01.00.	Geographical location	The geographic location of a CO2 storage reservoir will influence the type of impacts to consider, e.g. continental or sub-marine, in the vicinity of a volcano, or tectonic activity, etc. In addition, proximity to human populations will increase importance of any release to the surface.	Proximity to natural hazards will increase their importance in being considered in the assessment. Proximity to human populations place more emphasis on the significance of near-surface releases.	Quintessa original FEP	Very unlikely to be an issue.	G-E has 216 residences in or near the project area and T-A has none.		1	3	3	Avoid siting project near natural hazards and dense population areas.	Prepare emergency response plan and educate employees and neighbors on what to do in an emergency.
218	4.1.01.01.	Onshore reservoir		The potential impact on human beings of a sudden release of CO2 from an onshore reservoir will be higher than from an onshore reservoir (Damen 2006)	Additional [new] FEP	Unlikely to be an issue.	G-E and T-A are located onshore in sparsely populated areas.		2	3	6	Avoid siting project near dense populations. Ensure the integrity of vertical and lateral seals.	Prepare emergency response plan and educate employees and neighbors on what to do in an emergency.
219	4.1.01.02.	Offshore reservoir		The potential impact on human beings of a sudden release of CO2 from an offshore reservoir will be lower than from an onshore reservoir (Damen 2006). However CO2 storage costs are likely to be higher for offshore reservoirs.	Additional [new] FEP	NA	NA		1	2	2	NA	NA
220	4.1.02.00.	Natural resources	Natural resources within the geosphere including solid mineralogical resources, such as coal or minerals, fluid and gaseous resources, such as hydrocarbons (EOR and ECBM) or water, and other resources such as geothermal or microbial resources.	The presence of natural resources may mean that future human exploitation of the system cannot be ignored in assessing long-term performance since they may increase the possibility of future human intrusion.	Quintessa original FEP	Very unlikely to be an issue.	No known mineral resources other than oil at sites.		1	2	2	NA	NA

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
221	4.1.02.01.	Mineral resources		Owners of mineral rights could claim primacy over CO2 injection.	Additional [new] FEP	Very unlikely to be an issue.	No known mineral resources other than oil at sites.		1	2	2	NA	NA
222	4.1.02.02.	Coal seams		Unmineable coal seams could become mineable with robotic mining systems.	Additional [new] FEP	Very unlikely to be an issue.	No mineable coal seams in the area.		1	2	2	NA	NA
223	4.1.02.03.	Oil resources			Additional [new] FEP	Unlikely to be an issue.	G-E and T-A oil reservoirs are isolated from other oil reservoirs in the area.		2	2	4	Obtain leaseholds for the entire isolated reservoir for EOR. Avoid exceeding the spill point	Monitor and model CO2 plume. Adjust injection strategy if necessary.
224	4.1.02.04.	Natural gas resources			Additional [new] FEP	Very unlikely to be an issue.	Natural gas storage site located 15 miles south of G-E		1	2	2	NA	NA
225	4.1.02.05.	Underground drinking water sources			Additional [new] FEP	Unlikely to be an issue.	There is very little underground drinking water in the G-E and T-A. There are no public or private water wells in the areas.		2	2	4	Ensure the integrity of vertical and lateral seals and wells.	Monitor CO2 content in ground water before, during and after injection.
226	4.1.02.06.	Geothermal resources	Deep aquifers with high porosity suitable for CO2 storage would also be potentially suitable for geothermal energy production. (CO2STORE, page 70)		Additional [new] FEP	Very unlikely to be an issue.	There are no geothermal resources in the area.		1	2	2	NA	NA
227	4.1.02.07.	Pore space owned by others		CO2 from adjacent injection projects could infringe the project's pore space	Additional [new] FEP	Possible issue.	Kansas does not have any regulations on pore space ownership. Arbuckle has been widely used for disposal by others. EOR sites are isolated.		3	2	6	Maintain a buffer around the project area and CO2 plume.	Monitor legislation on pore space ownership.
228	4.1.02.08.	Saline water	Although saline water has few uses currently, these resources are protected by mining law in some EU states. And in some countries and states, brines legally are classified as groundwater and protected by law. (CO2STORE page 70).	Increased demand for water and improvement in desalination technologies could convert deep saline aquifers into valuable natural resources which could lead to restrictions on CO2 injection into deep saline aquifers in the future.	Additional [new] FEP	Very unlikely to be an issue.	Arbuckle is a Class 1 hazardous waste reservoir.		1	2	2	NA	NA
229	4.1.02.09.	Natural CO2	Depths for known natural major CO2 fields range from 200 m to 5,000 m. (CCP 2009)	Existing natural CO2 within the reservoir may complicate seismic data and make it difficult to model and verify CO2 storage.	Additional [new] FEP	Very unlikely to be an issue.	No natural CO2 in the area.		1	2	2	NA	NA
230	4.1.03.00.	Reservoir type	The generic type of reservoir being considered for storage of CO2. For example: - oil reservoir (such as the Weyburn project); - gas reservoir (such as the Coal-Seq project); - aquifer (such as at Sleipner); and - coal beds (such as the Coal-Seq and RECOPOL projects).	The generic reservoir type will provide a high-level indication of the geological characteristics of the storage location. It will also contribute towards the extent and type of historical exploitation of any geological resources.	Quintessa original FEP	Very unlikely to be an issue.	G-E and T-A are mature oil fields.		1	2	2	NA	NA
231	4.1.03.01.	Oil reservoir (EOR)			Expansion of Q FEP	Possible issue.	Yes		3	2	6	Ensure the integrity of vertical and lateral seals and wells.	Monitor and model the reservoir. If necessary, extract CO2 from a leaky reservoir and inject it into a sealed reservoir.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
232	4.1.03.02.	Gas reservoir			Expansion of Q FEP	Very unlikely to be an issue.	NA		1	2	2	NA	NA
233	4.1.03.03.	Deep saline aquifer			Expansion of Q FEP	Possible issue.	Yes		3	2	6	Ensure the integrity of vertical and lateral seals.	Monitor and model the reservoir. If necessary, extract CO2 from a leaky reservoir and inject it into a sealed reservoir.
234	4.1.03.04.	Coal seams (ECBM)			Expansion of Q FEP	Very unlikely to be an issue.	NA		1	2	2	NA	NA
235	4.1.03.05.	Brownfield site	Brownfield developments, for example in mature oil and gas fields, will offer the benefit of beginning with a well-characterized system and a significant amount of infrastructure. However, field redevelopments for CO2 storage will require a significant amount of work to assess the integrity and re-usability of existing well, flow lines and facilities. (CCP 2009)	Development in these fields can expect to include a significant number of well re-completions, abandonments and possibly re-abandonment of old wells, new drilling and upgrades to surface infrastructure. (CCP 2009)	Additional [new] FEP	Possible issue.	G-E and T-A are mature oil fields.		3	3	9	Ensure the integrity of vertical and lateral seals and wells.	Monitor and model the reservoir. If necessary, extract CO2 from a leaky reservoir and inject it into a sealed reservoir.
236	4.1.03.06.	Greenfield site	Greenfield developments, such as deep saline aquifers, require significant new infrastructure and additional initial characterization work and are associated with greater uncertainty. A steeper learning curve is to be expected and modifications to an initial development plan may occur as additional knowledge is gained during early development work. (CCP 2009)	More time and money to develop sufficient site characterization data but less likely to have leakage through existing wells due to the lack of existing wells.	Additional [new] FEP	Very unlikely to be an issue.	NA		1	3	3	NA	NA
237	4.1.04.00.	Reservoir geometry	Geometry of the CO2 storage reservoir including the spatial distribution, depth and the topography of the top.	The geometry of the storage reservoir helps to determine the capacity of the geosphere. The geometry of the top is particularly important because supercritical CO2 is buoyant and will therefore migrate to the top of a reservoir. Once at the top of the reservoir, it will migrate according to the precise topography of the top. Local "highs" could produce small-scale traps within the overall aquifer; bigger structures would produce bigger traps. Spill points are determined by the lowest point that can retain the sequestered CO2.	Quintessa original FEP	Very unlikely to be an issue.	G-E is a dome structure. The T-A Bartlesville oil reservoir is an isolated bottle structure. The T-A Arbuckle top is 1% dipping monocline.		1	3	3	Avoid exceeding the spill point in the G-E dome. Minimize the amount of CO2 injection into the Arbuckle at the T-A.	Monitor and model the reservoir. If necessary, extract CO2 from a leaky reservoir and inject it into a sealed reservoir.
238	4.1.04.01.	Insufficient reservoir depth	It is desirable to store CO2 at depths below approximately 800-1000 m where CO2 is compressed to a supercritical (dense) phase. (CCP 2009)	Insufficient reservoir depth may result in pressures that are too low for keeping CO2 in a supercritical state	Additional [new] FEP	Likely to be an issue.	The T-A has marginal depth and the CO2 may transfer from supercritical to gas phase after injection. There is also insufficient range for operating pressure between minimum miscible pressure and maximum operating pressure.		4	4	16	Increase pressure of Bartlesville Sandstone with water prior to injecting CO2 to compensate for shallow depth. Inject deep into the Arbuckle of DSA.	Monitor and model the reservoir. If necessary, extract CO2 from a leaky reservoir and inject it into a sealed reservoir.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
239	4.1.04.02.	Insufficient hydrostatic pressure	Pressure too low for keeping CO2 in a supercritical state.	At low pressure, CO2 could revert back to a gas state requiring greater pore volume for storage.	Additional [new] FEP	Possible issue.	The Bartlesville and Arbuckle formations are under pressured and the CO2 may transfer from supercritical to gas phase after injection.		3	3	9	Increase pressure of Bartlesville Sandstone with water prior to injecting CO2 to compensate for shallow depth. Inject deep into the Arbuckle of DSA.	Monitor and model the reservoir. If necessary, extract CO2 from a leaky reservoir and inject it into a sealed reservoir.
240	4.1.04.03.	Excessive reservoir depth		Excessive reservoir depth will significantly increase the cost of CO2 injection	Additional [new] FEP	Very unlikely to be an issue.	NA		1	3	3	NA	NA
241	4.1.04.04.	Excessive hydrostatic pressure		Increased cost for CO2 compression.	Additional [new] FEP	Very unlikely to be an issue.	NA		1	3	3	NA	NA
242	4.1.04.05.	Insufficient reservoir thickness	Normally, a formation thickness of around 20 meters would be considered as a minimum requirement, but this varies with injection volume requirements.	Insufficient reservoir thickness will result in an extended CO2 plume and limit the storage capacity of the reservoir	Additional [new] FEP	Very unlikely to be an issue.	Bartlesville is over 100 ft thick and Arbuckle is 600 ft thick,		1	3	3	NA	NA
243	4.1.04.06.	Insufficient reservoir lateral continuity (spacial distribution)		Insufficient lateral continuity (or spacial distribution) of a reservoir will limit its CO2 storage capacity	Additional [new] FEP	Very unlikely to be an issue.	CO2 storage capacity for G-E and T-A are sufficient for the project needs		1	3	3	Characterize and model the reservoirs and prepare an injection plan compatible with reservoir capacity.	NA
244	4.1.04.07.	Dipping top topography (monocline)	Reservoirs with dipping top topography (monocline) are susceptible to buoyancy-driven up dip CO2 migration. The migration up dip may enhance CO2/brine contact and CO2 dissolution in the brine.	Dipping top topography of the reservoir may make it difficult to trap buoyant CO2. Injected CO2 migrates up dip out of closure.	Additional [new] FEP	Unlikely to be an issue.	At T-A, the Arbuckle top dips from East to West by 1%. This dip is shallow enough and the amount of CO2 to be injected is small enough to allow the plume to stabilize in 60 years (based on modeling).	Need 3-d seismic to identify potential traps in top of Arbuckle at T-A..	2	3	6	Limit the amount of CO2 injected for DSA at T-A to approximately 50,000 tpy over 3 years.	Monitor and model the reservoir. If necessary, extract CO2 from a leaky reservoir and inject it into a sealed reservoir.
245	4.1.04.08.	Flat top topography	The preferred top topography is an anticline or dome structure to restrict the flow of injected CO2 on multiple sides.	Flat top topography of the reservoir may make it difficult to contain the CO2 plume	Additional [new] FEP	Very unlikely to be an issue.	At T-A, the top of the Arbuckle is almost flat (1% dip) with no lateral seals.		1	3	3	Limit the amount of CO2 injected for DSA at T-A to approximately 50,000 tpy over 3 years.	Monitor and model the reservoir. If necessary, extract CO2 from a leaky reservoir and inject it into a sealed reservoir.
246	4.1.04.09.	Shallow spill points	Spill point is the lowest point that can retain sequestered CO2	Shallow spill point may limit the amount of CO2 that can be locally contained in a reservoir	Additional [new] FEP	Very unlikely to be an issue.	The G-E spill points gives 100 ft of working space in the dome.		1	3	3	Avoid exceeding the spill point in the G-E dome. Switch to other dome if more capacity needed.	Monitor and model CO2 plume. Adjust injection strategy if necessary if spill point is exceeded.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
247	4.1.04.10.	Insufficient buffer zone for CO2 plume		Potential for CO2 plume to infringe on third party pore space.	Additional [new] FEP	Very unlikely to be an issue.	G-E and T-A EOR plumes are contained vertically and laterally. G-E and T-A DSA plumes are not expected to exceed the project area.	Need to verify through modeling	1	3	3	Model CO2 plume and provide sufficient buffer zone around site to accommodate the predicted plume area plus contingency. Or limit the amount of CO2 injection to keep the plume within the site boundaries.	Monitor and model CO2 plume. Adjust injection strategy, or increase the project area, if plume is likely to exceed the project boundary.
248	4.1.04.11.	Insufficient reservoir CO2 storage capacity	Reservoir CO2 storage capacity is primarily determined by pore volume.	Requirement for alternative storage site(s). Increased storage costs.	Additional [new] FEP	Very unlikely to be an issue.	G-E and T-A sites have been modeled and nearby back up reservoirs have been identified.		1	3	3	Characterize and model the storage reservoir prior to injection. Identify alternative reservoirs nearby that could be used as backup.	Monitor and model CO2 plume and reservoir pressure. Switch to backup reservoir if necessary.
249	4.1.04.12.	Lack of lateral sealing of reservoir	Lateral flow barriers can include unconformities or pinch-outs that erode the porous and permeable material and provide direct contact to a low permeability seal, faults and naturally over pressured zones.	Potential for CO2 plume to infringe on third party pore space or escape.	Additional [new] FEP	Possible issue.	The G-E and T-A EOR reservoirs are laterally sealed. The T-A DSA is not laterally sealed.	Need 3-d seismic to identify potential traps in top of Arbuckle at T-A..	3	3	9	Characterize the T-A DSA to identify traps on the top of the Arbuckle. Limit the amount of CO2 injected for DSA at T-A to approximately 50,000 tpy over 3 years.	Monitor and model the reservoir. If necessary, extract CO2 from a leaky reservoir and inject it into a sealed reservoir.
250	4.1.04.13.	Reservoir and caprock structural geology too complex	In tectonically complex areas, there are too many small structures to be identified, delineated and investigated individually.	Greater difficulty in modeling, monitoring and controlling CO2 storage.	Additional [new] FEP	Very unlikely to be an issue.	The structural geology at G-E and T-A is not complex.		1	3	3	NA	NA
251	4.1.04.14.	Reservoir compartmentalization	A once continuous reservoir can become compartmentalized. CO2 migration restricted to an isolated part of the formation. Unexpected bottom hole pressure increase. Pressure transient analysis suggests hydraulically isolated wells.	Greater difficulty in modeling, monitoring and controlling CO2 storage.	Additional [new] FEP	Unlikely to be an issue.	Variation in bottom hole pressure suggest that the Arbuckle is compartmentalized at G-E.	Determine if the G-E and T-A oil reservoirs are compartmentalized.	2	3	6	Characterize and model the EOR reservoir and provide input into reservoir engineering.	Adjust the injection strategy to take into account compartmentalizing if it exists.
252	4.1.04.15.	Reduced pore volume or distribution limiting CO2 injection	Rate of long-term pressure build-up greater than expected	Increased CO2 injection costs. Need for additional wells.	Additional [new] FEP	Very unlikely to be an issue.	Modeling suggests that salt buildup could be an issue in the Arbuckle.		1	3	3	Characterize and model the EOR and DSA reservoirs. Inject fresh water prior to CO2 injection to help avoid salt buildup due to water evaporation near the well.	Monitor BHP during injection. Adjust injection strategy if pressure begins building up. Determine root cause of pressure build up and take corrective action such as treating for asphaltene or paraffin buildup.
253	4.1.04.16.	Lack of stacked reservoirs	Stacked reservoirs consist of multiple alternating seals and reservoirs above the primary reservoir. The additional reservoirs	No fallback position if CO2 escapes from primary reservoir.	Additional [new] FEP	Very unlikely to be an issue.	Multiple stacked sinks and seals.		1	3	3	NA	NA

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
254	4.1.04.17.	Reservoir chemically reactive with CO2		Greater difficulty in modeling, monitoring and controlling CO2 storage.	Additional [new] FEP	Unlikely to be an issue.	Arbuckle dolomite reactive. Bartlesville Sandstone not as reactive.		2	3	6	Incorporate reservoir chemical reactions in modeling and take into account in reservoir engineering.	Monitor and model reservoir to determine impact on performance.
255	4.1.05.00.	Reservoir exploitation	Degree to which geological resources (such as oil and gas) have been exploited prior to the injection of CO2.	The extent of previous exploitation will help to determine the initial state of a storage reservoir. For example: - the existence and nature of boreholes; and - the presence of geological resources, such as oil and gas. Previous exploitation of the storage reservoir area will improve the amount of historical information available concerning the reservoir characteristics.	Quintessa original FEP	Very unlikely to be an issue.	Historical data has been reviewed for the G-E and T-A sites. Residual oil saturation has been estimated.		1	3	3	Thoroughly review and analyze historical production data and incorporate results into site characterization and modeling.	Thoroughly review and analyze historical production data and incorporate results into site characterization and modeling.
256	4.1.05.01.	Existing boreholes			Additional [new] FEP	Definite issue.	T-A has 370 existing wells. G-E has 247 existing wells.		5	4	20	Plug and seal old wells. Increase pressure Bartlesville reservoir with water, check for leaky wells and fix them prior to injecting CO2.	Monitor old wells and replug if necessary.
257	4.1.05.02.	Oil previously removed			Additional [new] FEP	Possible impact on oil recovery	Over 25 million barrels of oil removed from G-E south dome. 21 million barrels of oil removed from T-A.		3	3	9	Historical oil production used in modeling to determine residual oil saturation today and potential EOR yield with CO2 injection.	Historical oil production used in modeling to determine residual oil saturation today and potential EOR yield with CO2 injection.
258	4.1.05.03.	Gas previously removed			Additional [new] FEP	Not an issue	T-A initially had 600 scf/bbl associated gas. It produces none today. G-E has no historical data on gas production and none is produced today.		1	2	2	NA	NA
259	4.1.05.04.	Existing mine workings	This would be applicable to ECBM.		Additional [new] FEP	Very unlikely to be an issue.	None		1	1	1	NA	NA
260	4.1.05.05.	In-situ coal gasification	This would be applicable to ECBM.		Additional [new] FEP	Very unlikely to be an issue.	None		1	1	1	NA	NA
261	4.1.05.06.	Natural gas storage			Additional [new] FEP	Very unlikely to be an issue.	Natural gas storage site located 15 miles south of G-E		1	1	1	NA	NA
262	4.1.05.07.	Compressed air storage			Additional [new] FEP	Very unlikely to be an issue.	None		1	1	1	NA	NA
263	4.1.05.08.	Radioactive waste disposal			Additional [new] FEP	Very unlikely to be an issue.	None		1	1	1	NA	NA
264	4.1.05.09.	Ground water extraction			Additional [new] FEP	Unlikely to be an issue.	No public or private water wells in the area. Groundwater not sufficient for use. Limited to top 200 feet below ground.		2	2	4	NA	NA

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number P x S (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
265	4.1.06.00.	Caprock or sealing formation	The nature of the relatively impermeable layer of rock overlying the storage reservoir that forms a barrier to the upward migration of buoyant fluids, such as sequestered CO2.	The caprock or sealing formation plays a key roll in preventing the sequestered CO2 from migrating to the surface environment.	Quintessa original FEP	Unlikely to be an issue.	Multiple seals and sinks above primary reservoir and caprock.		2	3	6	Keep injection pressure below fracture pressure.	Monitor and model the reservoir. If necessary, extract CO2 from a leaky reservoir and inject it into a sealed reservoir.
266	4.1.06.01.	Caprock geometry	Geometry of the caprock including the spatial distribution, depth and the topography of the bottom.	CO2 migration diverges from expected path. Significant CO2 volumes migrate off structure. Insufficient capacity for planned injection volume of CO2. Unexpected pressure increase during injection.	Additional [new] FEP	Unlikely to be an issue.	The G-E caprock is a dome structure. The T-A caprock encloses the oil reservoir. The T-A Simpson Shale caprock is a slightly dipping monocline above the Arbuckle.		2	3	6	Keep injection pressure below fracture pressure.	Monitor and model the caprock and sinks above it. If necessary, extract CO2 from a leaky reservoir and inject it into a sealed reservoir.
267	4.1.06.02.	Caprock thickness		Insufficient caprock thickness could lead to caprock failure and/or release of CO2 from the reservoir.	Additional [new] FEP	Unlikely to be an issue.	Primary caprock above Arbuckle is the Simpson shale which is very thin (11 ft). However, this is backed up by the Kinderhook shale which is 72 feet thick.		2	3	6	Keep injection pressure below fracture pressure.	Monitor and model the caprock and sinks above it. If necessary, extract CO2 from a leaky reservoir and inject it into a sealed reservoir.
268	4.1.06.03.	Caprock discontinuous		CO2 escapes through gap in caprock into higher formation or aquifer	Additional [new] FEP	Unlikely to be an issue.	Caprock in G-E and T-A appears to be continuous.	Use 3d seismic survey to verify that caprock is continuous.	2	3	6	Input results of 3d seismic survey into site characterization and models. Avoid sites where caprock is discontinuous.	Monitor and model the caprock and sinks above it. If necessary, extract CO2 from a leaky reservoir and inject it into a sealed reservoir.
269	4.1.06.04.	Caprock geochemical properties	CO2 chemical reaction with caprock can weaken the physical strength of the caprock. High permeability zones might exist or be formed by reaction of CO2 with the caprock, causing the caprock to dissolve. CO2 can dehydrate clay shales in the caprock, thereby increasing its permeability. (Damen 2006)	Unintended migration of CO2 by chemical reaction induced breaching of the caprock.	Additional [new] FEP	Unlikely to be an issue.	Caprock in G-E and T-A is a shale backed up by multiple seals and sinks above.	Characterize caprock mineralogy.	2	3	6	Characterize and model caprock mineralogy and geochemical properties.	Monitor and model the caprock and sinks above it. If necessary, extract CO2 from a leaky reservoir and inject it into a sealed reservoir.
270	4.1.06.05.	Caprock geomechanical properties	Low fracturing pressure	Could limit CO2 injection rate. Increased CO2 injection cost.	Additional [new] FEP	Unlikely to be an issue.	Caprock above T-A Bartlesville Sandstone has withstood pressures up to 1700 psig. G-E reservoir can't be pressurized.	Obtain caprock geomechanical properties through testing of core samples.	2	3	6	Keep injection pressure below fracture pressure.	Monitor and model the caprock and sinks above it. If necessary, extract CO2 from a leaky reservoir and inject it into a sealed reservoir.
271	4.1.06.06.	Permeable zones in caprock	Mudstone caprock permeability is typically less than 0.001 milli-darcies (mD).	Permeable zones in the caprock could form CO2 pathways of escape.	Additional [new] FEP	Unlikely to be an issue.	Caprock integrity has been demonstrated at G-E and T-A through 75 to 80 years of oil production.	Characterize caprock permeability.	2	3	6	Characterize and model caprock permeability. Avoid sites where caprock permeability is high.	Monitor and model the caprock and sinks above it. If necessary, extract CO2 from a leaky reservoir and inject it into a sealed reservoir.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
272	4.1.06.07.	Caprock capillary entry pressure	No rocks have zero porosity, but the sealing layer provides a seal because the pore throats are too small to permit CO2 to enter the water-filled pores. (CCP 2009)	If the CO2 injection pressure exceeds the capillary pressure of the caprock, CO2 can penetrate or pass through the caprock	Additional [new] FEP	Unlikely to be an issue.	Caprock above T-A Bartlesville Sandstone has withstood pressures up to 1700 psig. G-E reservoir can't be pressurized.	Confirm caprock capillary pressure	2	3	6	Keep injection pressure below caprock capillary pressure.	Monitor and model the caprock and sinks above it. If necessary, extract CO2 from a leaky reservoir and inject it into a sealed reservoir.
273	4.1.06.08.	Caprock fracture pressure	The critical pressure to avoid exceeding is the fracture pressure of the confining interval (caprock) above the reservoir, which is normally higher than the fracture pressure in the injection interval. (CCP 2009)	If the CO2 injection pressure exceeds the fracture pressure of the caprock, the caprock could fracture and allow CO2 to pass through the caprock.	Additional [new] FEP	Unlikely to be an issue.	Caprock above T-A Bartlesville Sandstone has withstood pressures up to 1700 psig. G-E reservoir can't be pressurized.	Confirm caprock fracture pressure	2	3	6	Keep injection pressure below fracture pressure.	Monitor and model the caprock and sinks above it. If necessary, extract CO2 from a leaky reservoir and inject it into a sealed reservoir.
274	4.1.07.00.	Additional seals (Caprock - secondary)	This concerns the concept of successive lithological, hydraulic and/or chemical barriers acting successively to prevent fluid escape to surface environments. From a geological point of view the permeability barrier is probably the most important, in comparison with other types of traps. However, it may be necessary to consider a sequence of traps in CO2 migration models in addition to the conventional low permeability barriers. For example, within the Weyburn sequestration project, the primary caprock is the Watrous formation, however, low permeability formations at higher stratigraphical layers provide potential additional seals, preventing upward migration of sequestered CO2.		Quintessa FEP with additional text	Very unlikely to be an issue.	Multiple seals and sinks above primary reservoir and caprock.	Characterize multiple seals and sinks above reservoirs.	1	4	4	Characterize and model multiple seals and sinks above reservoir.	Monitor and model the caprock and sinks above it. If necessary, extract CO2 from a leaky reservoir and inject it into a sealed reservoir.
275	4.1.08.00.	Lithology	The systematic description of rocks in terms of their mineral assemblage and texture. The lithology of the geosphere (including both the reservoir and the caprock) determines the reservoir physical and transport properties (including porosity and permeability). It concerns the mineralogical composition, texture (grain size, sorting) and fabric (sedimentary structures, vertical and horizontal heterogeneities). Potential reservoir lithologies include sandstones and limestones.	The physical and chemical and mineralogical properties of the reservoir rocks affect: the capacity to store CO2; fluid flow and CO2 migration; determine which water-rock reactions can take place; and influence the rock strength and elastic properties (such as compressibility, shear strength, Poisson's ratio etc).	Quintessa original FEP	Very unlikely to be an issue.			1	3	3	Characterize the reservoir and incorporate lithology into the model. Use results to optimize reservoir engineering.	Monitor and model the reservoir. If necessary, extract CO2 from a leaky reservoir and inject it into a sealed reservoir.
276	4.1.08.01.	Reservoir lithology	Reservoirs are typical composed of porous limestone, dolomite, sandstone, or in the case of ECBM, coal.		Additional [new] FEP	Unlikely to be an issue.	Arbuckle dolomite and Bartlesville sandstone		2	3	6	Characterize the reservoir and incorporate lithology into the model. Use results to optimize reservoir engineering.	Monitor and model the reservoir. If necessary, extract CO2 from a leaky reservoir and inject it into a sealed reservoir.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
277	4.1.08.02.	Caprock lithology	Caprock or sealing formations are typically composed of mudstone, claystone, shale, and/or evaporites such as anhydrites and halites.	Mudstone sequences can vary significantly and generally require more detailed investigation. (CCP 2009)	Additional [new] FEP	Unlikely to be an issue.	Simpson Shale and Kinderhook Shale		2	3	6	Characterize the caprock and incorporate lithology into the model. Use results to optimize reservoir engineering.	Monitor and model the caprock and sinks above it. If necessary, extract CO2 from a leaky reservoir and inject it into a sealed reservoir.
278	4.1.08.01.	Lithification / diagenesis	The slow physical, chemical and/or biological processes by which unconsolidated sediments become sedimentary rock. These processes can result in changes to the original mineralogy.	The state of lithification/diagenesis contributes to determining the physical and chemical characteristics of sedimentary rock. For example, porosity usually decreases during diagenesis, except in rare cases such as dissolution of minerals and dolomitization.	Quintessa original FEP	Very unlikely to be an issue.	Reaction time on the order of thousands of years.		1	3	3	Include lithification reactions in model.	Include lithification reactions in model.
279	4.1.08.02.	Pore architecture	Structure and density of discrete voids within the rock (pores).	The pore architecture determines the porosity and permeability of the rock, which are key features when considering the mobility of fluids and gases within the rock.	Quintessa original FEP	Unlikely to be an issue		Characterize reservoir and caprock pore architecture	2	3	6	Characterize and model reservoir porosity, permeability and heterogeneity and take into account in optimizing reservoir engineering.	Monitor and model CO2 injection performance. Adjust injection strategy if necessary.
280	4.1.08.02.01	Insufficient reservoir injectivity	Injectivity is impacted by porosity and permeability. Low injectivity can be partially compensated for by greater injection pressure.	Low reservoir injectivity will limit the rate of CO2 injection and require increased bottom hole pressure.	Additional [new] FEP	Unlikely to be an issue		Confirm reservoir injectivity	2	3	6	Characterize and model reservoir porosity, permeability and heterogeneity and take into account in optimizing reservoir engineering.	Monitor and model CO2 injection performance. Adjust injection strategy if necessary.
281	4.1.08.02.02	Decreasing reservoir injectivity	Initial injection rate meets expectations but overall pore space is limited. Gradual increase in bottom hole pressure.		Additional [new] FEP	Unlikely to be an issue		Confirm reservoir injectivity	2	3	6	Characterize and model reservoir porosity, permeability and heterogeneity and take into account in optimizing reservoir engineering.	Monitor and model CO2 injection performance. Adjust injection strategy if necessary.
282	4.1.08.02.03	Reservoir porosity	Porosity values greater than 10% in carbonate formations or 15% in clastic formations are generally desirable. (CCP 2009)	Low porosity makes CO2 injection more difficult and can limit the rate of injection into a reservoir.	Additional [new] FEP	Unlikely to be an issue.	Arbuckle porosity ranges from 3-22% with an average of 11%. Bartlesville porosity ranges from 15 to 24% with an average of 18%.	Confirm reservoir porosity	2	3	6	Characterize and model reservoir porosity and take into account in optimizing reservoir engineering.	Monitor and model CO2 injection performance. Adjust injection strategy if necessary.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number Pxs (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
283	4.1.08.02.03	Reservoir permeability	<p>Permeability measures the ability of fluids to flow through a formation. High values indicate a well-connected pore space while low values indicate convoluted conduits that disconnect the pores. Porous rocks have a wide range in permeability between around 0.1 milli-Darcy (mD) for very tight rocks, to several darcies for very permeable formations. (CCP 2009)</p> <p>In general, the better the porosity, the better the permeability (and thus injectivity) - however, large variations in permeability mean the porosity and permeability variations need to be mapped in detail (CCP 2009)</p> <p>Ideally, CO2 storage requires high permeability (>100 mD) to ensure near well bore injectivities for quick access to pore space. However, this is not always possible and near wellbore permeabilities may need to be enhanced by artificially stimulating the wells to allow for improved injectivity. (CCP 2009)</p>	<p>Low permeability makes CO2 injection more difficult and can limit the rate of injection into a reservoir.</p> <p>While high permeabilities are generally desirable, very high permeability pathways or conduits can enhance CO2 migration along concentrated pathways reducing the effective storage within the target formation. (CCP 2009)</p> <p>In moderate to low permeability, or poorly connected reservoirs, a higher well density will be needed to limit pressure evolution and allow for efficient injection. (CCP 2009)</p>	Additional [new] FEP	Unlikely to be an issue.	Arbuckle is known to be more permeable horizontally than vertically. Permeability ranges from 1 mD to 3000 mD. Bartlesville ranges from 1 to 200 mD. With an average of 30 mD.	Confirm reservoir permeability	2	3	6	Characterize and model reservoir permeability and take into account in optimizing reservoir engineering.	Monitor and model CO2 injection pressure and CO2 plume. Watch out for irregularities. Adjust injection strategy if necessary.
284	4.1.09.00.	Unconformities	Geological surfaces separating older from younger rocks and representing a gap in the geologic record. Such a surface might result from a hiatus in deposition of sediments, possibly in combination with erosion, or deformation such as faulting. An angular unconformity separates younger strata from eroded, dipping older strata. A disconformity represents a time of nondeposition, possibly combined with erosion, and can be difficult to distinguish within a series of parallel strata. A nonconformity separates overlying strata from eroded, older igneous or metamorphic rocks.	Unconformities can act both as potential seals or lateral migration pathways for fluids. For example, the impermeable barrier resulting from the widespread development of diagenic anhydritized carbonate associated with the unconformity between the Mississippian beds and overlying Triassic Watrous Formation in the vicinity of the Weyburn pool.	Quintessa original FEP	Possible that some unconformities have not been identified yet.		Use 3d seismic survey to identify unconformities.	3	3	9	Incorporate 3d seismic results into site characterization and modeling and take into account in reservoir engineering.	Monitor and model CO2 plume for irregularities. Determine root cause. If necessary, adjust injection strategy.
285	4.1.10.00.	Heterogeneities	Heterogeneities are variations in the rock properties of a geological formation.	<p>Heterogeneities can result in directional variations in permeability, which affects the mobility of fluids and gases in the rock. For example, experience from the Saline Aquifer CO2 Storage project (SACS) has shown that both stratigraphical and structural local permeability heterogeneities have the potential to profoundly affect CO2 distribution and migration (Chadwick et al., 2003).</p> <p>The image below shows seismic sections through the Sleipner injection site from Zweigel et al. (2001). The strong amplitudes are taken to be CO2 accumulations.</p>	Quintessa original FEP	Likely to be an issue.	The Arbuckle and Bartlesville are known to be heterogeneous.	Characterize reservoir and caprock heterogeneity	4	3	12	Characterize and model reservoir and caprock heterogeneity and incorporate into reservoir engineering.	Monitor and model CO2 plume for irregularities. If necessary, adjust injection strategy.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
286	4.1.10.01.	Reservoir heterogeneity	CO2 cannot be injected at required rates. Unexpected bottom hole pressure increase. Unexpected migration of CO2 plume. Detection of unexpected plume distribution possibly related to stratigraphic or depositional geometry (otherwise structure, high permeability layers or hydrodynamic flow). Lower than expected bottom hole pressure. Baffles or barriers in reservoir influencing CO2 migration		Additional [new] FEP	Likely to be an issue.	The Arbuckle and Bartlesville are known to be heterogeneous.	Characterize reservoir heterogeneity	4	3	12	Characterize and model reservoir heterogeneity and incorporate into reservoir engineering.	Monitor and model CO2 plume for irregularities. If necessary, adjust injection strategy.
287	4.1.10.02.	High permeability layers in reservoir	CO2 migrates rapidly and preferentially along a specific stratigraphic horizon (possibly off structure). Indications of rapid migration through a restricted stratigraphic horizon. Lower than expected downhole pressure and flow rate.		Additional [new] FEP	Possible issue.	Arbuckle is known to be more permeable horizontally than vertically. Permeability ranges from 1 mD to 3000 mD. Bartlesville ranges from 1 to 200 mD. With an average of 30 mD.		3	2	6	Characterize and model reservoir permeability and take into account in optimizing reservoir engineering.	Monitor and model CO2 injection pressure and CO2 plume. Watch out for irregularities. Adjust injection strategy if necessary.
288	4.1.10.03.	Caprock heterogeneity			Additional [new] FEP	Possible issue.	Simpson caprock is known to be heterogeneous.	Characterize caprock heterogeneity	3	3	9	Characterize and model caprock heterogeneity and incorporate into reservoir engineering	Monitor sinks above caprock for CO2 content. Back off on injection pressure if leak is detected. Plug leak or extract CO2 from leaky reservoir and inject into sealed reservoir if necessary.
289	4.1.10.04.	Interstitial layers of shale in reservoir			Additional [new] FEP	Unlikely to be an issue.	Bartlesville is known to have interstitial layers of shale	Characterize reservoir heterogeneity	2	2	4	Characterize and model reservoir heterogeneity and incorporate into reservoir engineering.	Monitor and model CO2 plume for irregularities. If necessary, adjust injection strategy.
290	4.1.10.05.	Heterogeneity of overlying aquifers	Heterogeneity in aquifers overlying the reservoir may increase the difficulty of monitoring them for leaked CO2, which may increase monitoring costs and/or impair project image. Heterogeneity could also increase dispersal or mineral interaction of CO2 with aquifers, reducing physical impacts.		Additional [new] FEP	Unlikely to be an issue.	Groundwater aquifers above the oil reservoirs are very limited at G-E and T-A	Conduct baseline survey of groundwater quality	2	2	4	Characterize and model groundwater aquifers above oil reservoirs. Monitor changes in chemistry.	Monitor aquifer chemistry. Identify any changes and determine root cause.
291	4.1.11.00.	Fractures and faults	Fractures are cracks or breaks in rock. Fractures along which displacement has occurred are called faults. Fractures and faults can occur over a wide range of scales.	Fractures can enhance conductivity, for example, by a conductive fracture connecting permeable regions together. They can also act as seals, by bringing a relatively permeable region into contact with low conductivity rock, for example.	Quintessa original FEP	Possible issue.	Fault(s) exist at G-E. Fractures exist in Arbuckle, but Arbuckle can't be over pressured.	Characterize faults and fractures at injection sites.	3	3	9	Characterize and model fractures and faults at injection sites and incorporate into reservoir engineering.	Monitor and model pressure and plume migration in direction of fault(s). Adjust injection strategy if necessary. Monitor micro-seismicity.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
292	4.1.11.01.	Fault movement		Movement on a fault that transverses a wellbore could damage or sever casing or tubing.	Additional [new] FEP	Unlikely to be an issue	Faults exist at G-E, but are inactive, down dip, don't penetrate the caprock and Arbuckle can't be over pressured.	Characterize faults at injection site	2	3	6	Characterize and model faults at injection sites and incorporate into reservoir engineering.	Monitor and model pressure and plume migration in direction of fault(s). Adjust injection strategy if necessary. Monitor micro-seismicity.
293	4.1.12.00.	Undetected features	Natural or man-made features within the geological environment that may not be detected during site investigations. Examples of possible undetected features are fracture/fault zones, the presence of brines or old mine workings. Some physical features of the storage environment may remain undetected during site surveys and even during preliminary borehole drilling. The nature of the geological environment will indicate the likelihood that certain types of undetected features may be present and the site investigation may be able to place bounds on the maximum size or minimum proximity to such features.	Undetected features could significantly affect the performance of a sequestration system. For example, local permeability heterogeneities with the potential to profoundly affect the distribution and migration of CO2 at Sleipner (within the Saline Aquifer CO2 Storage project, SACS) were only discovered after effectively being illuminated by the sequestered CO2 (Chadwick et al., 2003).	Quintessa original FEP	Possible that some features have been undetected.		Use 3d seismic survey to detect subsurface features.	3	3	9	Incorporate 3d seismic results into site characterization and modeling and take into account in reservoir engineering.	Monitor and model CO2 plume for irregularities. Determine root cause. If necessary, adjust injection strategy.
294	4.1.12.01.	Underground cavities (natural or manmade)			Additional [new] FEP	Possible issue.	Arbuckle is full of karsts at G-E.	Characterize the site for karsts	3	3	9	Characterize and model karsts in reservoir and incorporate into reservoir engineering.	Monitor and model CO2 plume for irregularities. Determine root cause. If necessary, adjust injection strategy.
295	4.1.12.02.	Existing faults or fracture zone	The presence of a fault does not imply a leakage problem. Most rocks are faulted and fractured in some way over geological time. The critical question for CO2 storage is whether there are any faults or fractures that could provide leakage pathways under present day geological conditions. In addition to the basic geometry of connected rocks and flow paths, this involves the study of geomechanics, stress fields and fracture behavior. Simply put many "faults: do not leak at all and many huge oil and gas fields that include faults prove the point. (CCP 2009)	CO2 might leak through open (no-sealing) faults, which extend into the caprock. CO2 might leak through natural fractures in the caprock.	Additional [new] FEP	Possible issue.	G-E has existing inactive fault on west side that doesn't intersect the primary caprock. T-A is 25 miles away from the Humboldt fault zone which is somewhat active but down dip from the injection reservoirs.	Characterize faults at injection site	3	3	9	Characterize and model faults at injection sites and incorporate into reservoir engineering.	Monitor and model pressure and plume migration in direction of fault(s). Adjust injection strategy if necessary. Monitor micro-seismicity.
296	4.1.12.03.	Existing boreholes in the area			Additional [new] FEP	Likely to be an issue.	T-A: 370 boreholes G-E: 247 boreholes	Complete more thorough analysis of existing boreholes	4	3	12	Analyze boreholes. Identify at risk boreholes and plug them prior to CO2 injection.	Monitor boreholes during CO2 injection and replug them if they begin leaking.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
297	4.1.12.04.	Subsurface infrastructure	Subsurface infrastructure can include steam, drainage, electrical, natural gas, water, sewer, and communications lines, and other features. Such features can enable or impede geophysical investigations or complicate the soil-chemical background. They can also become migration paths for CO2 that reaches soil levels.		Additional [new] FEP	Unlikely to be an issue.	G-E and T-A are mature sites and may have some subsurface infrastructure in place.	Use one-call system and consult with previous lease holders about subsurface infrastructure.	2	2	4	Use one-call system before excavating or drilling. Consult with previous lease holders.	Monitor CO2 content in soil air and water. Identify any irregularities/ Define root cause. Remediate leaks.
298	4.1.12.05.	Gas chimneys			Additional [new] FEP	Very unlikely to be an issue.	Mature oil fields. Caprock has demonstrated integrity for 75 - 80 years.		1	2	2	Characterize and model site and incorporate into reservoir engineering.	Monitor and model CO2 plume for irregularities. Determine root cause. If necessary, adjust injection strategy.
299	4.1.12.06.	Shallow gas / drift gas	Shallow gas (above bedrock) can cause drilling problems and impede monitoring. CO2 entry into shallow groundwater could increase drift-gas exsolution.		Additional [new] FEP	Very unlikely to be an issue.	Limited groundwater resources. Multiple stacked sinks and seals.		1	2	2	Characterize and model site and incorporate into reservoir engineering.	Monitor CO2 content on site for irregularities. Determine root cause. Remediate any leaks.
300	4.1.12.07.	Clustered small gas-related amplitude anomalies along fault planes			Additional [new] FEP	Very unlikely to be an issue.	G-E has existing inactive fault on west side that doesn't intersect the primary caprock. T-A is 25 miles away from the Humboldt fault zone which is somewhat active but down dip from the injection reservoirs.		1	2	2	Characterize and model site and incorporate into reservoir engineering.	Monitor and model pressure and plume migration in direction of fault(s). Adjust injection strategy if necessary. Monitor micro-seismicity.
301	4.1.13.00.	Vertical geothermal gradient	Temperature profile in the geosphere prior to the injection of CO2. The critical temperature for CO2 is 31.1 degrees centigrade. The average geothermal gradient is approximately 2.4 degrees centigrade per kilometer. If the surface temperature is 10 degrees centigrade, the critical temperature will be reached at a depth of 840 meters. However, a considerable variation in geothermal gradients and sub-surface temperatures can be expected at a depth of 1000 meters. For example, in Europe temperatures at 1000 m range from 20 to 75 degrees centigrade, with local temperatures of more than 200 degrees centigrade in volcanic areas.	Relevant to temperature dependent physical/chemical/biological/hydraulic processes, such as CO2 phase behavior.	Quintessa original FEP	Not a problem.	G-E and T-A have normal vertical geothermal gradients		1	1	1	NA	NA

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
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302	4.1.14.00.	Formation pressure	The pressure of fluids within the pores of a formation, normally hydrostatic pressure, or the pressure exerted by a column of water from the formations depth to the sea level prior to the injection of CO2. The critical pressure of CO2 is 7.38 mega-Pascals. The average underground hydrostatic pressure increases with depth by approximately 10.5 mega-Pascals per kilometer for aquifers that are in open communication with surface water. Applying this average gradient, the critical pressure of CO2 will be reached at a depth of around 690 meters. However, aquifers or hydrocarbon reservoirs (e.g., EOR and ECBM) that are sealed off from the rest of the sub-surface may be under- or over pressured.	Contributes towards determining the mobility of sequestered CO2.	Quintessa original FEP	Not a problem.	Difficult to increase Arbuckle pressure. Bartlesville pressure needs to be increased 400-500 psi.		1	4	4	Characterize and model formation pressure and incorporate into reservoir engineering.	Monitor and model formation pressure and CO2 migration. Identify any irregularities. Determine root cause. Adjust injection strategy if necessary.
303	4.1.15.00.	Stress and mechanical properties	The stress condition and mechanical properties of the geosphere prior to injection of CO2.	The initial stress state and mechanical properties are a baseline from which the potential effect of injecting supercritical CO2 can be assessed.	Quintessa original FEP	Not a problem.	The Arbuckle can't be over pressured and the Bartlesville is isolated and under pressured.		1	4	4	Characterize and model formation stress and mechanical properties and incorporate into reservoir engineering.	Monitor and model formation stress and CO2 migration. Identify any irregularities. Determine root cause. Adjust injection strategy if necessary.
304	4.1.16.00.	Petrophysical properties	Petrophysical properties of the geosphere prior to the injection of CO2. This includes features such as permeability, porosity, residual saturation, capillary pressure and wettability.	Petrophysical properties influence how injected CO2 will migrate in the geosphere. For example, permeability influences the direction and rate of CO2 movement, and porosity and residual saturation influence the dimensions of the CO2 plume.	Quintessa original FEP	Very unlikely to be an issue.		Confirm petrophysical properties of Arbuckle. Bartlesville and Caprock.	1	3	3	Characterize and model petrophysical properties stress and mechanical properties and incorporate into reservoir engineering.	Monitor and model injectivity and CO2 plume migration. Identify any irregularities. Determine root cause. Adjust injection strategy if necessary.
305	4.2.00.00.	Fluids	Details of fluids in the geosphere, which comprises of the reservoir, overburden and surrounding rock prior to the injection of CO2. Water will generally be present, but other fluids, particularly hydrocarbons (e.g., EOR and ECBM), may be important, dependent on the sequestration concept.	Water and other fluids in the sequestration system will affect the transport and interactions of injected carbon dioxide.	Quintessa original FEP	Unlikely to be an issue,	G-E and T-A have residual oil and brine.	Confirm analysis of residual oil and brine at G-E and T-A.	2	3	6	Characterize and model oil and brine analyses and incorporate into reservoir engineering.	Monitor and model EOR performance. Identify irregularities. Determine root cause. Adjust injection strategy if necessary.
306	4.2.01.00.	Fluid properties	Properties of the geosphere fluids prior to injection of CO2, including composition and geochemistry.	The fluid properties and geochemistry of the geosphere will contribute towards determining how injected CO2 will behave in the geosphere.	Quintessa original FEP	Unlikely to be an issue,	G-E and T-A have residual oil and brine.	Confirm properties of residual oil and brine at G-E and T-A.	2	2	4	Characterize and model oil and brine properties and incorporate into reservoir engineering.	Monitor and model EOR performance. Identify irregularities. Determine root cause. Adjust injection strategy if necessary.
307	4.2.01.01.	Fluid chemical composition		CO2 causing change in fluid chemical composition	Additional [new] FEP	Very unlikely to be an issue.	G-E and T-A have residual oil and brine.	Confirm analysis of residual oil and brine at G-E and T-A.	1	2	2	Characterize and model oil and brine analyses and incorporate into reservoir engineering.	Monitor and model EOR performance. Identify irregularities. Determine root cause. Adjust injection strategy if necessary.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
308	4.2.01.02.	High salinity fluid	The high salinity of deep aquifers is, generally, an indication of very low or insignificant throughput of meteoric waters.	Very high salinity can lead to deposition of halite in pore spaces and cause decreased permeability and injectivity.	Additional [new] FEP	Very unlikely to be an issue.	G-E and T-A have brine.	Confirm analysis of brine at G-E and T-A.	1	2	2	Characterize and model brine composition and salt deposition and incorporate into reservoir engineering. Inject fresh water into the DSA before injecting CO2 to minimize salt build up due to water evaporation near the injection well.	Monitor and model injectivity. Identify irregularities. Determine root cause. Adjust injection strategy if necessary.
309	4.2.02.00.	Hydrogeology	Natural formation water flow pathways (directions, velocities) in the geosphere will be important in determining the long-term migration paths for CO2. This depends on factors including: hydraulic heads, permeability and porosity distribution, the existence of fracture networks, connection between aquifers, position of the recharge and discharge areas.	This will affect the migration of dissolved CO2 in the reservoir and the geosphere (direction, timing), the position of the interface between supercritical CO2 and aquifer water (inclined interface). There may also be a possible effect on overlying aquifers used for drinking water.	Quintessa original FEP	Very unlikely to be an issue.	Arbuckle is a large, very slow moving DSA. The G-E domes and T-A Bartlesville bottles are isolated somewhat from hydrogeology of the Arbuckle.	Characterize the Arbuckle DSA local hydrogeology	1	3	3	Characterize and model the Arbuckle DSA local hydrogeology and incorporate into the DSA engineering.	Monitor and model DSA CO2 plume migration. Identify irregularities. Determine root cause. Adjust injection strategy if necessary.
310	4.2.02.01.	Connection between deep saline aquifer and shallow drinking water aquifer			Additional [new] FEP	Very unlikely to be an issue.	The Arbuckle outcrops and interfaces with shallow drinking water about 200 miles East of T-A. Modeling indicates the CO2 DSA plume will stabilize about a half mile from injection.	Characterize the Arbuckle DSA regional hydrogeology	1	3	3	Characterize and model the Arbuckle DSA regional hydrogeology and incorporate into the DSA engineering.	Monitor and model DSA CO2 plume migration. Identify irregularities. Determine root cause. Adjust injection strategy if necessary.
311	4.2.02.02.	Position of aquifer recharge and discharge areas			Additional [new] FEP	Very unlikely to be an issue.	The Arbuckle outcrops and interfaces with shallow drinking water about 200 miles East of T-A.	Characterize the Arbuckle DSA regional hydrogeology	1	3	3	Characterize and model the Arbuckle DSA regional hydrogeology and incorporate into the DSA engineering.	Monitor and model DSA CO2 plume migration. Identify irregularities. Determine root cause. Adjust injection strategy if necessary.
312	4.2.02.03.	Natural fluid flow pathways	Direction and velocity of fluid in saline aquifer		Additional [new] FEP	Very unlikely to be an issue.	Arbuckle is a large, very slow moving DSA. The G-E domes and T-A Bartlesville bottles are isolated somewhat from hydrogeology of the Arbuckle.	Characterize the Arbuckle DSA local hydrogeology	1	3	3	Characterize and model the Arbuckle DSA local hydrogeology and incorporate into the DSA engineering.	Monitor and model DSA CO2 plume migration. Identify irregularities. Determine root cause. Adjust injection strategy if necessary.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
313	4.2.03.00.	Hydrocarbons	The presence and distribution of hydrocarbons, such as oil and/or gas (e.g., EOR and ECBM), within the storage system.	Hydrocarbons have potentially important implications for a storage system, by both influencing the likelihood of previous geological exploitation of the area, and by being an important component of the system with which sequestered CO2 can interact.	Quintessa original FEP	Likely to be an issue.	G-E and T-A contain residual oil suitable for EOR. CO2 injected near the bottom of the Arbuckle at G-E would ultimately interface with oil in the dome.		4	2	8	Characterize and model the G-E DSA and incorporate into the DSA and reservoir engineering.	Monitor and model G-E DSA CO2 plume migration. Identify irregularities. Determine root cause. Adjust injection strategy if necessary.
314	5.0.00.00.	Boreholes	This category of FEPs is concerned with the way that activity by humans alters the natural system. Both boreholes used in the sequestration operations and those drilled for other purposes are relevant to the long-term performance of the system. The category is divided into two classes for the drilling process, and sealing and abandonment.		Quintessa original FEP		T-A: 370 old wells G-E: 247 old wells		NA	NA	NA	NA	NA
315	5.1.00.00.	Drilling and completion	FEPs relevant to the operation of boreholes drilled within the system domain.	Boreholes can potentially provide short circuits for carbon dioxide transport.	Quintessa original FEP	Possible issue.	T-A: 370 old wells G-E: 247 old wells	How early wells were constructed (primary cement)	3	2	6	Examine and recompleat old wells as needed	Monitor for leaks to stop them early
316	5.1.01.00.	Formation damage	Alteration of the far-field or virgin characteristics of a formation, usually by exposure to drilling fluids. Fracturing associated with formation damage can increase porosity, whereas the water or solid particles in the drilling fluids, or both, can decrease the pore volume and effective permeability of the formation in the near-wellbore region. A number of mechanisms can result in a decrease in porosity, including: - solid particles from the drilling fluid physically plug or bridge across flow paths in the porous formation; - when water contacts certain clay minerals in the formation, the clay typically swells, increasing in volume and decreasing the pore volume; and - chemical reactions between the drilling fluid and the formation rock and fluids can precipitate solids or semisolids that plug pore spaces.	Formation damage has a number of potential implications for assessing CO2 sequestration: - it can make information from affected boreholes non-representative of the true characteristics of the damaged formations; and - damaged regions themselves may provide flow paths for CO2 migration, particularly if damage results in fracturing.	Quintessa original FEP	These are old fields so it seems likely that there has been some formation alteration. However, that may not necessarily be in the caprock	Early wells in T-A used explosive fracing. Later wells used hydrofracing.	Determine damage done by explosive and hydrofracing.	3	3	9	Run fall off tests and characterize responses in overlying formations. Replug and seal at risk wells. Pressurize reservoir with water prior to injecting CO2 to check for leaks.	Monitor wells for CO2 leakage and replug if necessary.
317	5.1.01.01.	CO2 can't be injected at required rates due to formation damage	Unexpected bottom hole pressure increase and change in formation fluid chemistry.		Expansion of Q FEP	Unlikely to be an issue.		Determine damage done by explosive and hydrofracing.	2	3	6	Careful characterization of injection formations to understand fluid and formation chemistry and CO2-water-rock interactions. Replug and seal at risk wells. Pressurize reservoir with water prior to injecting CO2 to check for leaks.	Monitor wells for CO2 leakage and replug if necessary.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Qunitessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
318	5.1.01.02.	Solid particles from drilling plugging pore spaces			Expansion of Q FEP	Very unlikely to be an issue.	This is an old field so it seems like if this were going to be a problem that we would know about it prior to the start		1	3	3	NA	NA
319	5.1.01.03.	Water from drilling causing clay particles to swell			Expansion of Q FEP	Very unlikely to be an issue.	This is an old field so it seems like if this were going to be a problem that we would know about it prior to the start		1	2	2	NA	NA
320	5.1.01.04.	Chemical reaction between drilling fluids and formation fluids precipitating solids		Near wellbore injectivity reduction due to geochemical reactions (CCP 2009)	Expansion of Q FEP	Very unlikely to be an issue.			1	3	3	Characterize the formation fluid and identify any possible reactions. Include in models.	Monitor CO2 injection pressure. Identify irregularities. Determine root cause. Relocate well if necessary.
321	5.1.01.05.	Fracturing near borehole			Expansion of Q FEP	Unlikely to be an issue.	Early wells in T-A used explosive fracing. Later wells used hydrofracing.	Determine damage done by explosive and hydrofracing.	2	3	6	Run FMI in new wells. Do vit or falloff tests in old wells to ID problems. Recomplete wells or find a work-around for problem wells	Monitor wells for CO2 leakage and replug if necessary.
322	5.1.02.00.	Well lining and completion	<p>At the time of drilling, boreholes are lined with a metal casing. Cement is pumped downhole inside the casing string, and it is pushed upward under and outside the casing lower end, between the casing and the rock wall. In multi-stage cement jobs, cement is squeezed between the casing and the rock wall though purpose made perforations. The cement could be pushed behind casing from the bottom hole to the surface, or to a predetermined depth.</p> <p>Curing of cement is the process of maintaining the proper temperature and moisture conditions to promote optimum cement hydration immediately after placement. Proper moisture conditions are critical because water is necessary for the hydration of cementitious materials. As cement hydrates, strength increases and permeability decreases. When hydration stops, strength gain ceases. Therefore, proper hydration of the cement is important in the fabrication of strong, durable concrete.</p> <p>Alteration of borehole linings will occur with time, depending on the natural fluid composition of the deep reservoir and the input of high concentrations of CO2 carrying natural H2S, which may accelerate corrosion.</p>	Borehole lining and completion will contribute to determining the performance of a borehole both during its operational and post-closure phases. This is important from the perspective of CO2 sequestration, since boreholes may provide preferential short circuits to the surface with potential release of CO2 and contamination of upper aquifers.	Quintessa original FEP	Unlikely to be an issue.	Early wells may have no primary cement. Cement never stops hydrating		2	4	8	For new holes use best available methods for completion. Use best cements and characterize using logging tools. For old wells characterize and recomplete if needed	Monitor wells for CO2 leakage and replug if necessary.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
323	5.1.03.00.	Workover	The process of performing major maintenance or remedial treatments on a borehole often associated with the re-use of existing boreholes. Workover techniques include flushing of the formation and the removal and replacement of the borehole lining. Well control procedures during workovers must provide for unique phase behavior of any CO2 being circulated out. (CCP 2009)	Workover will result in modified borehole properties that may need consideration within an assessment.	Quintessa FEP with additional text	Unlikely to be an issue.			2	2	4	Use procedures that allow for workover with CO2 in the formation	Have monitors and alarms in place and standard procedures for dealing with CO2 leakage on site.
324	5.1.03.01.	Improper modification or re-use of existing boreholes			Additional [new] FEP	Unlikely to be an issue.			2	2	4	Recomplete using proper cements and materials. Characterize well after recompletion	Monitor wells for CO2 leakage and replug if necessary.
325	5.1.04.00.	Monitoring wells (Verification wells)	Often, monitoring wells are needed to monitor the physical conditions (pressure, temperature, etc.) of the storage reservoir, both inside and/or outside the area immediately affected by the storage operations, or above the storage reservoir. Monitoring wells could be "adopted", by using existing wells to host the appropriate instrumentation (piezometers, pressure gauges, thermometers, etc.), or they could be purpose drilled anew.	Observation or monitoring wells may provide an accidental leakage route for the stored CO2, particularly wells drilled inside the area of storage.	Quintessa FEP with additional text	Unlikely to be an issue.	There are 100s of old wells available for MVA.		2	2	4	MVA wells need to be designed to account for leakage potential.	Monitor wells for CO2 leakage and replug if necessary.
326	5.1.04.01.	Lack of or insufficient number of monitoring wells	Direct monitoring techniques usually require access from wellbores that penetrate the containment system into the storage reservoir (CCP 2009) Direct measurements can also be obtained from observation wells at shallower horizons above the expected seal. Wells of this type might provide direct and early indication of unexpected movement. (CCP 2009)		Additional [new] FEP	Unlikely to be an issue.	There are 100s of old wells available for MVA.		2	1	2	Design such that the project starts with the right number of MVA wells.	Add more MVA wells if needed.
327	5.1.04.02.	Too many monitoring wells	General the concept is to minimize monitoring wells that penetrate the seal because they are, by default, potential leakage pathways. (CCP 2009)		Additional [new] FEP	Very unlikely to be an issue.	There are 100s of old wells available for MVA.		1	1	1	Design such that the project starts with the right number of MVA wells	NA
328	5.1.04.03.	Improperly located monitoring wells			Additional [new] FEP	Unlikely to be an issue.	There are 100s of old wells available for MVA.		2	2	4	Use characterization and modeling to site or choose wells such that they catch the plume, pressure increase, or monitor sensitive areas	Monitor and model CO2 plume. Modify MVA well spacing if necessary.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
329	5.1.05.00.	Well records	<p>The drilling of boreholes for site investigation, resource exploitation and/or CO2 injection will result in many documents being generated in paper or digital form. Typical well records include location coordinates, depth, electric logs, mud logs, drilling parameter logs, composite log, testing reports (if applicable), coring report (if applicable), and a final report. Physical records from cutting samples, cores and fluid samples will also be documented.</p> <p>The principal tool to gain knowledge about the sequence of drilled rock formations is Borehole Logging. Common measures include hole diameter, natural gamma ray response, spontaneous electrical potential, rock resistivity, velocity of acoustic waves through rock, neutron susceptibility, etc.</p> <p>The documents originating at the time of drilling are often the most accurate records of the succession of events associated with the drilling of the well. The curation of such unique records is an invaluable tool to pass knowledge to future generations.</p>	<p>Well records provide a key source of baseline information regarding the sequestration site. They provide information concerning the nature of the rocks drilled by the well and their petrophysical characteristics in terms of sealing potential and reservoir potential. Additionally, records from wells drilled over a period of time can give a picture of how the system is evolving either naturally, or as a result of the exploitation of geological resources. This baseline information is an important input both into the initial conditions relevant to the system to be assessed, as well as providing an indication of the likely importance of other FEPs.</p> <p>Incomplete well records equate to a potential gap in understanding of the storage system and may result in potentially important features being overlooked in the assessment process.</p>	Quintessa original FEP	Unlikely to be an issue.	Many of the wells are too old for the records to provide the needed info on the initial condition and the condition of concern is the pre-co2 injection condition as opposed to the condition after construction		2	3	6	Characterize the existing wells	Monitor wells for CO2 leakage and replug if necessary.
330	5.1.05.01.	Well records and data management		Large amounts of data will be generated by the project. Data could be poorly communicated between groups, or be badly managed to the point that important data is lost, or used incorrectly.	Additional [new] FEP	Very unlikely to be an issue.	Project currently has secure website for access to and digital retention of documents.		1	1	1	Centralized data repository and planning. Use secure website.	Keep backup database.
331	5.1.05.02.	Lack of or incomplete existing well records			Additional [new] FEP	There are likely to be undocumented wells in G-E and T-A.			4	3	12	Characterize the site. Use magnetic surveys, old photos and other techniques to locate undocumented wells.	Pressurize reservoir with water prior to CO2 injection to locate unknown leaky wells. Replug leaky wells.
332	5.2.00.00.	Borehole seals and abandonment	FEPs relevant to the closure of boreholes drilled within the system domain.	The way that boreholes are closed and sealed is directly relevant to the likelihood that they could act as short circuits for carbon dioxide transport.	Quintessa original FEP	Likely to be an issue.			4	4	16	Characterize abandoned wells. Replug high risk wells	Monitor abandoned wells. Replug leaky wells.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
333	5.2.01.00.	Closure and sealing of boreholes	<p>Features related to the cessation of CO2 injection operations at a site and the sealing of injection and monitoring wells.</p> <p>When a borehole is drilled to the potential storage reservoir, it creates communication with possible overlying reservoirs and with the surface. Cementing and abandonment procedures are designed to permanently plug such communication channel.</p> <p>The cement plugs are commonly located across potential problem spots, to minimize leaking risks. Particular attention should be paid to the quality of the original cement job behind the casing string. If uncemented space is detected, known or suspected behind casing, depending on the lithology across such interval, it may be important to squeeze extra cement between the rock face and the casing to complement the final abandonment plugs inside the casing.</p> <p>Individual boreholes may be closed in sequence, but closure refers to final closure of the whole system, and may include removal of surface installations. The schedule and procedure for sealing and closure may need to be considered in the assessment.</p>	The intention of borehole sealing is to prevent human access to the sequestered CO2 and to prevent the borehole from providing a migration pathway for the CO2. Correct cementing and abandonment operations are essential to achieve restoration of pristine sealing above the designed storage reservoir formation.	Quintessa original FEP	Possible issue.			3	4	12	Use closure plug materials that are compatible with the CO2 and the expected long-term conditions	Post closure MVA and remediation.
334	5.2.02.00.	Seal failure (Wellbore failure)	Degradation of borehole linings (metal and cement) will occur with time, depending on the natural fluid composition of the deep reservoir and the input of high concentrations of CO2. Any H2S present may accelerate corrosion of metal linings. Cement will be attacked by high partial pressures of CO2, low pH and appreciable concentrations of sulphate, chloride, and magnesium ions in the formation fluids. Seal failure will occur once liners have degraded and corroded.	Seal failure may provide preferential short circuits to the surface with potential release of CO2 and associated contaminants to the surface or near-surface environment. The failure may provide a preferential pathway either through the borehole annulus or around the outside of the casing.	Quintessa FEP with additional text	Possible issue.			3	3	9	Recomplete old wells using CO2 resistant materials and use CO2 resistant materials in new construction too	Monitor abandoned wells. Replug leaky wells.
335	5.2.02.01.	CO2 leakage at cement-casing interface	Cement interfaces, not cement matrix are the most likely path for migration. (CCP 2009)		Additional [new] FEP	Very likely to be an issue.			5	3	15	Characterize leakage pathways within wells	Monitor abandoned wells. Replug leaky wells.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
336	5.2.02.02.	CO2 leakage through the cement matrix	<p>Cement interfaces, not cement matrix are the most likely path for migration. (CCP 2009)</p> <p>Portland cement blended with 50% fly ash had a 30 year life in a field that produced 96% CO2 with water saturation of approximately 20%. (CCP 2009)</p> <p>Conventional Portland cement-fly ash systems can inhibit CO2 migration even after carbonation of the cement because permeability remains relatively low and capillary resistance is relatively high. (CCP 2009)</p> <p>Chemically, the degradation of Portland based cements by carbonic acid (H2CO3) is well known and documented. The basic chemical mechanism is as follows: CO2 + H2O => H2CO3 H2CO3 + calcium silicate hydrate => amorphous silica gel +CaCO3 H2CO3 + Ca(OH)2 => CaCO3 +2H2O H2CO3 +CaCO3 +> Ca(HCO3)2</p>		Additional [new] FEP	Unlikely to be an issue.			2	2	4	Characterize leakage pathways within wells	Monitor abandoned wells. Replug leaky wells.
337	5.2.02.03.	CO2 leakage through pathways created by bulk chemical dissolution of the cement		Cement can be attacked by CO2, low pH, and appreciable concentrations of sulfate, chloride and magnesium ions in the formation fluids.	Additional [new] FEP	Unlikely to be an issue. The initial pathways would already have to be present to allow for advective transport.			2	3	6	Characterize (map) the cement in the well to identify potential pathways and remediate them if needed	Monitor wells. Replug leaky wells.
338	5.2.02.04.	CO2 leakage through fractures in the cement			Additional [new] FEP	Possible issue.	Possible		3	3	9	Characterize (map) the cement in the well to identify potential pathways and remediate them if needed	Monitor wells. Replug leaky wells.
339	5.2.02.04.	CO2 leakage through an open annular region due to inadequate cement placement	The Basis of Design for new wells should emphasize barrier performance using fundamentals of wellbore preparation, mud removal and cement placement to provide tight interfaces that inhibit fluid migration. Material selection of cement and metallurgy are important, but should be considered secondary to the process of cement placement. (CCP 2009)		Additional [new] FEP	Possible issue.			3	3	9	Characterize (map) the cement in the well to identify potential pathways and remediate them if needed	Monitor wells. Replug leaky wells.
340	5.2.02.05.	CO2 leakage at the cement-caprock interface	The cement interfaces between the boreholes and the casing through the caprock are the key to well integrity and seal integrity. Good isolation requires tight cement interfaces with the formation and casing. (CCP 2009)		Additional [new] FEP	Possible issue.			3	3	9	Characterize (map) the cement in the well to identify potential pathways and remediate them if needed	Monitor wells. Replug leaky wells.
341	5.2.02.06.	CO2 leakage through corroded or cracked casing		Metal casing can be attacked by H2S contained in the CO2.	Additional [new] FEP	Very unlikely to be an issue.			1	3	3	Characterize the casing using ultrasonic or em tools	Monitor wells. Replug leaky wells.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
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342	5.2.02.07.	CO2 leakage due to improper hydration of cement in borehole linings			Additional [new] FEP	Very unlikely to be an issue.			1	3	3	Characterize (map) the cement in the well to identify potential pathways and remediate them if needed	Monitor wells. Replug leaky wells.
343	5.2.03.00.	Blowouts	<p>Uncontrolled flow from depth leading to gas and/or fluid erupting from a well or borehole to either the terrestrial or marine environments.</p> <p>Blowout is an ordinary drilling hazard, well understood and controlled by current technology. Assuming that ordinary blow-out risk controls are present, particular risks might include: (1) A monitoring or verification well drilled into a porous formation that has elevated pressure due to CO2, or (2) A drilled formation with significant unexpected H2S (MCSG 2009).</p> <p>The frequency of blowouts from offshore gas wells has been estimated at 1 x 10-4 per well per year, based on a database of blowouts in the Gulf Coast of Mexico and the North Sea between 1980 and 1996 (CMPT 1999). Other estimates based on both oil and gas wells give a frequency of 3x10-4 per well per year (IEA GHG, 2300) (Damen 2006).</p>	A surface or undersea blowout would provide a rapid pathway for CO2 to reach the surface.	Quintessa FEP with additional text	Very unlikely to be an issue.			1	4	4	Design, construct and operate wells properly to prevent blowouts.	Have standard procedures in place and train operators to deal with blowouts.
344	5.2.03.01.	Packer failure	In CO2 injectors, the design of the packer assembly should take into consideration the importance of limited or no movement of the packer seal while providing the ability to regularly pull the tubing for inspection. (CCP 2009)	Failure of the back-flow preventer or packer may result in a well blowout (Holloway 1996). A blow out is an uncontrolled flow of reservoir fluids (which can be CO2, but also salt water, oil, gas or a mixture of these) into the well bore to the surface. Apart from the CO2 release, the potential consequences are casualties among operators and economic damage caused by explosion or fire when upcoming hydrocarbons are ignited or by parts of the well, which can be launched by the pressure release.(Damen 2006)	Additional [new] FEP	Unlikely to be an issue.			2	2	4	Design, construct and operate wells properly to prevent blowouts.	Have standard procedures in place and train operators to deal with blowouts.
345	5.2.03.02.	Failure of the blowout preventer (BOP)			Additional [new] FEP	Unlikely to be an issue.			2	2	4	Design, construct and operate wells properly to prevent blowouts.	Have standard procedures in place and train operators to deal with blowouts.
346	5.2.03.03.	Well failure	In the majority of well failures, an amount equal to the content of the well tubing will be released. In normal cases, this leak will be detected by the monitoring system, resulting in the closure of the back flow preventer and the emergency shutdown valve at the well head (Holloway, 1996)		Additional [new] FEP	Unlikely to be an issue.			2	2	4	Design, construct and operate wells properly to prevent well failure.	Monitor and shut down if needed

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
347	5.2.03.04.	Elastomer seal failure	<p>Since supercritical CO2 is a solvent, many elastomers, plastics, rubber, or resins present in a well could be subject to chemical attack or dissolution. When designing a CO2 injector, material should be based on performance expectations.</p> <p>Elastomers, in particular, are a common part of well hardware used to seal different components. Elastomers must be made of material that is chemically compatible or inert to the injection fluid and must be of sufficient strength or adequately anchored to withstand the different pressure and explosive decompression that might exist across a seal. Since the physical and performance characteristics of many elastomer materials change with pressure and temperature, the elastomer must be able to perform reliably across the full range of differential pressures and temperatures expected through the design life of the well at the location of the seal within the well. (CCP 2009)</p>		Additional [new] FEP	Very unlikely to be an issue. EOR is common now, we should be able to choose proved materials.			1	3	3	Choose proved materials	Monitor and shut down if needed
348	5.2.03.05.	Sand blocking	Sand blocking is a problem when the reservoir is unconsolidated and the wellbore is shut in for maintenance or upsets. (CCP 2009)		Additional [new] FEP	Very unlikely to be an issue.	The reservoir isn't unconsolidated.		1	3	3	Characterize the formations	Monitor
349	5.2.03.06.	Dissolution of sand control resins	Sand control may be necessary to maintain the structure of the reservoir around the wellbore. Migration of sand and fines into the near wellbore area may severely restrict production/injection.		Additional [new] FEP	Very unlikely to be an issue.			1	3	3	Choose CO2 compatible resins if they are needed	Monitor
350	5.2.03.07.	Dehydration and deposition of gravel pack contents	Dehydration and deposition of gravel pack contents that cannot be displaced or removed from the well (CCP 2009)		Additional [new] FEP	Very unlikely to be an issue.			1	2	2	NA	NA
351	5.2.03.08.	Fluids left in wellbore for extended amounts of time	Once the well is completed, impairment implications of the fluids or non-fluids left in the wellbore during startup will need to be considered. (CCP 2009)	Fluids left in the wellbore for extended amounts of time could potentially corrode the tubulars, drop out precipitants, or cause bacterial growth. (CCP 2009)	Additional [new] FEP	Very unlikely to be an issue.			1	3	3	Flush well if needed	Monitor
352	5.2.03.09.	Negative impact of startup fluids on injectivity	It is important to consider the displacement of any fluids into the reservoir during start up and the effect of injectivity resulting from the introduction of the fluids. (CCP 2009)		Additional [new] FEP	Very unlikely to be an issue.			1	1	1	Use compatible fluids	Monitor

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
353	5.2.03.10.	Hydrate formation	<p>The prevention of hydrate formation in the well during startup will need to be considered. It is likely that methanol spacers will need to be used. (CCP 2009)</p> <p>Hydrate potentially could form in the well when starting back up after a shut down. During the process of shutting down, measures should be taken to mitigate the formation of hydrates when starting back up. Often a methanol "cap" is pumped in the top of the tubulars. (CCP 2009)</p> <p>As a consequence of well control using a brine or similar fluid, there can be intermixing of the CO2 and the well control fluid that could result in hydrate formation or hydrate blocks. Using hydrate inhibited fluids or having operational practices that minimize the amount of CO2 inflow during workovers should be considered. (CCP 2009)</p>		Additional [new] FEP	Very unlikely to be an issue.			1	1	1	Identify possible fluid interactions and plan for them	Monitor
354	5.2.03.11.	Lack of sufficient startup pressure	Facilities sometimes do not have sufficient pressures to re-start injection. In these cases, injection tubing should be loaded with sufficient fluids to allow for a re-start. (CCP 2009)		Additional [new] FEP	Very unlikely to be an issue.			1	1	1	Design compression or pumps sufficient to overcome restarting the injection	Monitor
355	5.2.03.12.	Stimulation or hydraulic fracturing compromising the reservoir seal	Fracturing may occur in some of the different stimulation treatments used to increase injectivity around the wellbore. The fractures should not compromise the reservoir seal. (CCP 2009)	Unintended migration of CO2 through stress-induced fractures or faults.	Additional [new] FEP	Very unlikely to be an issue.		Do we plan to frac?	1	4	4	Do not frac above the confining unit's frac pressure	Monitor
356	5.2.03.13.	Stimulation fluids incompatibility	Stimulation fluids should be carefully selected in terms of compatibility with the well materials, workover materials and reservoir. (CCP 2009)		Additional [new] FEP	Very unlikely to be an issue.			1	1	1	Identify possible fluid interactions and plan for them	Monitor
357	5.2.03.14.	Lack of well monitoring	<p>Well monitoring for CO2 storage seeks confident validation that:</p> <ul style="list-style-type: none"> - Cement integrity and bond is maintained - Pressure isolation barriers are maintained and functioning - Corrosion is being controlled - The CO2 injection profile is being maintained - Barriers after plug and abandonment provide confidence. (CCP 2009) 		Additional [new] FEP	Unlikely to be an issue. UIC has min requirements for injection well monitoring.			2	4	8	Monitor wells above the UIC min requirements. Also monitor projection wells	Monitor wells. Replug leaky wells.
358	5.2.03.15.	Inadequate abandonment procedures	<p>A typical well abandonment may include the following:</p> <ul style="list-style-type: none"> - Remove tubing and packer - Permanently seal the formation with a fluid that reduces permeability - Place plugs of cement or other materials for isolation - Test the plugs - Place a cap on the casing at the surface - Backfill with soil and accurately record well location. (CCP 2009) 		Additional [new] FEP	Unlikely to be an issue.			2	2	4	Design plugging plan to account for post injection conditions	Monitor

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Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
359	5.2.03.16.	Submersible pump failure in production well	While normally very reliable, the submersible pump in an EOR or ECBM production well can fail.		Additional [new] FEP	Possible issue. Mechanical stuff fails			3	2	6	Design, construct and operate, and maintain wells properly.	Have a plan or extra parts to replace or repair pumps
360	5.2.04.00.	Orphan wells (Old wells)	CO2 storage projects may be part of an Enhanced Oil Recovery (EOR) project or stand-alone deep saline aquifer projects. Either way, it is likely that the target geological structure has been the object of past exploration efforts, possibly involving drilling wells. The existence of old wells could be obvious if the wells are still active, but could be overlooked if the old (orphan) wells have been long cemented and abandoned. Technical details of such abandoned vintage wells may in fact not be readily available, or altogether lost. In such a case, the old cementing (sealing) job could be substandard.	Old substandard plugged well could provide a potential CO2 leakage route to the surface or to possible reservoirs above the designed CO2 storage reservoir. There is little chance of detecting a substandard well abandonment before the beginning of CO2 injection to the designed reservoir, particularly if the existence of an old well has been overlooked. If old abandoned wells are known in the area of the CO2 injection operations, the risk is minimized by carefully check any potential CO2 leak to the surface at the old well head location. If old wells are unknown and not suspected, it is good practice to run a baseline soil gas survey (if applicable) and successive soil gas surveys at intervals after the beginning of CO2 injection.	Quintessa FEP with additional text	Very likely issue.	There are 100s of old plugged wells		5	3	15	Identify old wells using records, surveys, and photos. Characterize overlying formations and the surface for CO2 and brine composition/concentrations. Replug wells at risk. Pressurize reservoir with water and check for leaks.	Monitor wells. Replug leaky wells.
361	5.2.04.01.	Open borehole collapse	Some coal bed methane operations used open completion wells (no casing). It is possible to stabilize a hole without casing with gravel packing or sorted liners	Open completion wells are more likely to leak than other wells and subject to collapsing.	Additional [new] FEP	Unlikely to be an issue.		Do we have open borehole completions at G-E or T-A?	2	3	6	Try to avoid site with these types of completions	Monitor wells. Replug leaky wells.
362	5.2.04.02.	Failure to properly plug, seal, close old wells		CO2 escapes via poorly plugged old abandoned well	Additional [new] FEP	Likely to be an issue.			4	3	12	Replug the riskiest wells	Monitor wells. Replug leaky wells.
363	5.2.04.03.	CO2 injection impact on old wells	Major operational issue (CCP 2009)		Additional [new] FEP	Possible issue			3	3	9	Characterize all existing wells	Monitor the wells and area for signs of change or leakage
364	5.2.04.04.	CO2 migrates to overlying formations due to old well failure	Indication of CO2 in shallower stratigraphy		Additional [new] FEP	Likely to be an issue.			4	3	12	Characterize abandoned and old wells and replug or recomplete as needed	Monitor potential zones where fluids may enter from the injection zone through old wells
365	5.2.04.05.	CO2 leakage at surface due to old well failure	Elevated CO2 present in vicinity of well(s)		Additional [new] FEP	Unlikely to be an issue.			2	3	6	Characterize abandoned and old wells and replug or recomplete as needed	Surface monitoring
366	5.2.04.06.	Leakage of displaced formation fluid in shallower stratigraphy due to old well failure			Additional [new] FEP	Likely to be an issue.			4	3	12	Characterize abandoned and old wells and replug or recomplete as needed	Monitor potential zones where fluids may enter from the injection zone through old wells

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Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
367	5.2.04.07.	Improper re-completion of old wells	EOR operations often re-complete old wells. Proper re-completion includes: Examining cement bond logs to evaluate bonding between the casing and adjoining formation. Use of squeeze cement if insufficient or inadequate bonding was detected. Wellbore drilling of plugged and abandoned wells to bottom of target formation. Run a casing mechanical integrity test. If pressure fall off was observed, the leaking section of casing should be identified and resealed by squeeze cementing or, in extreme cases, install a liner over the leaking section.		Additional [new] FEP	Unlikely to be an issue. We should be able to log and see how the recompletion goes to get an idea of the quality of the job. It will need to be more than a CBL or temp log			2	2	4	Log to see how the cement looks behind the casing before and after recompletion jobs	Monitor wells. Replug leaky wells.
368	5.2.05.00.	Soil creep around boreholes	The slow downward gravitational movement of soil around boreholes.	This process results in changing properties of the soil around borehole casings after abandonment. It may either increase or decrease the degree of sealing and therefore the potential for the region immediately around the borehole to act as a migration pathway for CO2 and/or associated contaminants.	Quintessa original FEP	Unlikely to be an issue.	There are lots of old wells we should be able to see if this has happened and then know if it will be a risk in the future		2	4	8	Examine existing abandoned wells to get an idea of the problem. If there are wells with this problem. Identify what was the difference between them and the wells without the problem and use the successful techniques on newly abandoned wells	Monitor for this problem.
369	6.0.00.00.	Near-Surface Environment	This category of FEPs is concerned with factors that can be important if sequestered carbon dioxide returns to the accessible environment. The environment could be terrestrial or marine, and human behavior in that environment needs to be described. The category is divided into three classes: Terrestrial Environment; Marine Environment; and Human Behavior.		Quintessa original FEP				NA	NA	NA	NA	NA
370	6.1.00.00.	Terrestrial environment	This class of FEPs is concerned with factors that can be important if sequestered carbon dioxide returns to the accessible terrestrial environment.	The near-surface environment is where most potential impacts would be incurred. The FEPs in this class are relevant if that environment is terrestrial.	Quintessa original FEP	Very unlikely to be an issue.			1	1	1	Take terrestrial environment into account in evaluating site selection.	NA
371	6.1.01.00.	Topography and morphology	Features related to the relief and shape of the surface environment and its evolution.	This FEP refers to local land form and land form changes with implications for the surface environment, e.g. plains, hills, valleys, and effects of river and glacial erosion thereon. In the long term, such changes may occur as a response to other geological changes.	Quintessa original FEP	Very unlikely to be an issue.	The sites are relatively flat.		1	3	3	Characterize injection site for low surface areas.	Monitor low areas for CO2 accumulation. Install alarm systems. Train operators and educate residents what to do if a CO2 leak occurs.

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Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
372	6.1.01.01.	Low surface areas	Valleys	Leaked CO2 can accumulate in low surface areas.	Additional [new] FEP	Very unlikely to be an issue.	None in area		1	3	3	Characterize injection site for low surface areas.	Monitor low areas for CO2 accumulation. Install alarm systems. Train operators and educate residents what to do if a CO2 leak occurs.
373	6.1.01.02.	Rugged terrain		Rugged terrain may make it difficult to access the site, difficult to lay pipeline and difficult to monitor or conduct seismic studies	Additional [new] FEP	Very unlikely to be an issue.	None in area		1	3	3	Avoid areas of rugged terrain in site selection.	Monitor low areas for CO2 accumulation. Install alarm systems. Train operators and educate residents what to do if a CO2 leak occurs.
374	6.1.01.03.	Confined spaces	Caves or canyons		Additional [new] FEP	Very unlikely to be an issue.	None in area		1	3	3	Characterize injection site for confined spaces	Monitor confined spaces for CO2 accumulation . Install alarm systems. Train operators and educate residents what to do if a CO2 leak occurs.
375	6.1.02.00.	Soils and sediments impact on project	Features related to the characteristics of the soils and sediments and their evolution. Different soil and sediment types, e.g. characterized by mineralogy, particle-size distribution and organic content, will have different properties with respect to erosion/deposition, sorption etc.	Soil and sediment characteristics will influence the type of vegetation and land use. They will also determine relevant processes to consider should CO2 and/or associated contaminants migrate to the terrestrial surface environment.	Quintessa original FEP	Very unlikely to be an issue.			1	1	1	Characterize soil and sediments.	Monitor soils for CO2 and H2S. Identify any irregularities. Determine root cause. Locate and plug leaks.
376	6.1.03.00.	Erosion and deposition	FEPs related to all the erosional and depositional processes that operate in the surface environment, and their evolution with time. Relevant processes may include fluvial and glacial erosion and deposition, denudation, aeolian erosion and deposition. These processes will be controlled by factors such as the climate, vegetation, topography and geomorphology.	Erosional and depositional processes will influence the way in which the surface environment has evolved and will evolve over the time-scale of interest.	Quintessa original FEP	Very unlikely to be an issue.	Site areas are relatively flat. About 2.1% of the CVR-T-A pipeline has steep slopes. About 60% of the pipeline ROW is considered highly erodible by wind or water.		1	1	1	Avoid steep slopes >18% in pipeline ROW and site selection if possible. Provide erosion control on slopes.	Regularly inspect steep slopes cuts and gullies for erosion and deposition. Provide erosion control on slopes.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Qunitessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
377	6.1.04.00.	Atmosphere and meteorology	<p>FEPs related to the characteristics of the atmosphere, weather and climate, and their evolution with time. In case of CO2 leakage to the surface, the weather is a relevant factor determining the dispersion or the displacement of the gas: currents, evolution of the concentration of the gas, gas accumulations.</p> <p>Atmospheric characteristics include physical transport of gas, aerosols and dust in the atmosphere and chemical and photochemical reactions.</p> <p>Meteorology is characterized by atmospheric precipitation, temperature, pressure, wind speed and direction. The variability in meteorology should be included so that extremes such as drought, flooding, storms and snow melt are identified.</p>	<p>This information will determine the behavior of CO2 should it reach the atmosphere and is therefore an important factor when considering exposure of the local population and of the local environment.</p> <p>Meteorological characteristics also influence the near-surface hydrological regime with its subsequent consequences for CO2 migration.</p>	Qunitessa original FEP	Very unlikely to be an issue.	The site areas usually have moderate winds which would help with CO2 dispersion. The annual average wind speed in Kansas is 12.1 miles per hour.		1	1	1	Monitor atmospheric CO2 on site. Stop and fix leaks.	Monitor atmospheric CO2 on site. Train operators and educate residents what to do if a CO2 leak occurs.
378	6.1.05.00.	Hydrological regime and water balance	<p>Processes related to near-surface hydrology at a catchment scale and also soil water balance, and their evolution with time.</p> <p>The hydrological regime is a description of the movement of water through the surface and near-surface environment. It includes the movement of materials associated with the water such as gas or particulates and extremes such as drought, flooding, storms and snow melt.</p>	The hydrological regime and water balance will influence the way in which CO2 migrates should it reach the near-surface environment.	Qunitessa original FEP	Very unlikely to be an issue.	The site areas have limited groundwater. There are no public or private water wells.	Conduct baseline survey of groundwater quality	1	2	2	Characterize the local hydrological regime and incorporate results into models.	Monitor near surface aquifers for increases in CO2 or salinity. Determine root cause for any increase. Use tracers if necessary.
379	6.1.05.01.	CO2 and associated contaminants leakage affecting hydrological regime and water balance			Additional [new] FEP	Very unlikely to be an issue.	The sites have multiple stacked seals and sinks separating the injection formations from fresh water aquifer formations.	Conduct baseline survey of groundwater quality	1	3	3	Select sites with multiple stacked seals and sinks. Ensure integrity of seals.	Monitor near surface aquifers for increases in CO2 or salinity. Determine root cause for any increase. Use tracers if necessary.
380	6.1.05.02.	Displaced saline fluids affecting the hydrological regime and water balance			Additional [new] FEP	Very unlikely to be an issue.	Available data indicates the saline aquifers and fresh water aquifers are not connected locally.	Conduct baseline survey of groundwater quality	1	3	3	Characterize the saline aquifer. Confirm that there are no local open connections between fresh and saline water aquifers.	Monitor near surface aquifers for increases in CO2 or salinity. Determine root cause for any increase. Use tracers if necessary.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
381	6.1.05.03.	Groundwater withdrawal causing change in CO2 or brine migration			Additional [new] FEP	Very unlikely to be an issue.	There are no public or private water wells at the sites.	Characterize groundwater levels	1	3	3	Characterize the saline aquifer. Confirm that there are no local open connections between fresh and saline water aquifers. Incorporate information in models.	Monitor near surface aquifers for increases in CO2 or salinity. Determine root cause for any increase. Use tracers if necessary.
382	6.1.06.00.	Near-surface aquifers and surface water bodies	Features related to the characteristics of aquifers and water-bearing features and their evolution.	<p>Shallow Aquifers Aquifers may yield significant amounts of water to wells or surface springs and may thus be a flow path for CO2 to the surface environment. The presence of aquifers and other water-bearing features will be determined by the geological, hydrological and climatic factors.</p> <p>Shallow aquifers will be able to dissolve CO2, reducing further upward migration. The amount of CO2 that can dissolve will depend on factors such as the location of the water table, the chemical composition of pore waters, CO2 flux rates, and hydrogeology.</p> <p>Surface Water Bodies Streams, rivers and lakes often act as boundaries of hydrogeological systems. They may represent a significant source of dilution for CO2 and contaminants entering these systems, or act as reservoirs. In hot dry environments, where evaporation dominates, concentration or exsolution of gas is possible. Water with dissolved CO2 is denser than pure water, which can result in stratification and the potential for limnic eruption.</p>	Quintessa original FEP	Very unlikely to be an issue.	The site areas have limited groundwater. There are no public or private water wells. Surface water is limited to some small ponds.	Conduct baseline survey of groundwater and surface water quality	1	2	2	Characterize groundwater aquifers and surface water bodies near the sites.	Monitor near surface aquifers and surface water bodies for increases in CO2 or salinity. Determine root cause for any increase. Use tracers if necessary.
383	6.1.07.00.	Terrestrial flora and fauna	<p>Features and processes related to the characteristics of terrestrial and freshwater flora and fauna, and their evolution. Includes plants, animals, fungi, algae and microbes.</p> <p>Plants usually have a higher resistance against CO2 than mammals, but persistent leaks could suppress respiration in the root zone. Tree kills associated with soil gas concentrations in the range of 20-30% have been observed at Mammoth Mountain, California, where volcanic outgassing of CO2 (0.13-0.44 Mt/yr) has been occurring since at least 1990. The leakage rate (flux) varies between 25 and 7000 g CO2/day/m2. (Damen 2006).</p>	Flora and fauna may be affected by concentrations of CO2 in the near-surface environment and may be indicators of CO2 leakage.	Quintessa original FEP	Very unlikely to be an issue.	The sites are primarily grass lands with very little flora or fauna.		1	1	1	Characterize the flora and fauna on sites.	Monitor flora and fauna for unexplained dead zones. Determine root cause. Check CO2 content in the area. Locate and plug leaks if any.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
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384	6.1.08.00.	Terrestrial ecological systems	Features and processes related to interactions between terrestrial and freshwater populations of animals, plants, algae, fungi, microbes and their evolution. Characteristics of the ecological system include the vegetation regime, and natural cycles such as forest fires or flash floods that influence the development of the ecology. The plant, animal, algal, fungal and microbial populations occupying the surface environment are an intrinsic component of its ecology. Their behavior and population dynamics are regulated by the wide range of processes that define the ecological system. Human activities have significantly altered the natural ecology of most environments.	The ecology of the terrestrial near-surface environment determines the types of organisms present and their inter-dependencies. These can influence the types of impact of interest and can provide a mechanism for monitoring CO2 leakage.	Quintessa original FEP	Very unlikely to be an issue.	The sites are primarily grass lands with very little flora or fauna.		1	1	1	Characterize the ecological systems on the sites.	Monitor flora and fauna for unexplained dead zones. Determine root cause. Check CO2 content in the area. Locate and plug leaks if any.
385	6.2.00.00.	Marine environment	This class of FEPs is concerned with factors that can be important if sequestered carbon dioxide returns to the accessible marine environment.	The near-surface environment is where most potential impacts would be incurred. The FEPs in this class are relevant if that environment is marine.	Quintessa original FEP	Very unlikely to be an issue.	Not a marine environment.		1	1	1	NA	NA
386	6.2.01.00.	Coastal features	Features and processes related to the characteristics of coasts and the near shore, and their evolution. Coastal features include headlands, bays, beaches, spits, cliffs and estuaries.	The processes operating on these features, e.g. active erosion, deposition, long shore transport, may affect mechanisms for the migration of CO2, and associated contaminants, entering the surface environment.	Quintessa original FEP	Very unlikely to be an issue.	Not a marine environment.		1	1	1	NA	NA
387	6.2.02.00.	Local oceanography	Features and processes related to the characteristics of seas and oceans and their evolution. This includes the topography and morphology of the seabed; thermal stratification and salinity gradients; and marine currents.	The local oceanographic features and processes determine the potential for dilution or accumulation of CO2, or associated contaminants in the marine environment.	Quintessa original FEP	Very unlikely to be an issue.	Not a marine environment.		1	1	1	NA	NA
388	6.2.03.00.	Marine sediments	Features and processes associated with sediments in the marine environment. This includes both the physical and chemical characteristics of the sediments, along with sedimentation and resuspension processes.	Marine bed sediment characteristics will influence the ecology of the marine environment. They will also determine relevant processes to consider should CO2 and/or associated contaminants migrate to the marine environment.	Quintessa original FEP	Very unlikely to be an issue.	Not a marine environment.		1	1	1	NA	NA
389	6.2.04.00.	Marine flora and fauna	Features and processes related to the characteristics of marine flora and fauna, and their evolution. Includes plants, animals, fungi, algae and microbes.	Flora and fauna may be affected by concentrations of CO2 in the marine environment and may be indicators of CO2 leakage.	Quintessa original FEP	Very unlikely to be an issue.	Not a marine environment.		1	1	1	NA	NA
390	6.2.05.00.	Marine ecological systems	Features and processes related to interactions between populations of algae, animals, microbes and their evolution. Characteristics of the ecological system. The algal, animal and microbial populations occupying the marine environment are an intrinsic component of its ecology. Their behavior and population dynamics are regulated by the wide range of processes that define the ecological system.	The ecology of the marine environment determines the types of organisms present and their inter-dependencies. These can influence the types of impact of interest and can provide a mechanism for monitoring CO2 leakage.	Quintessa original FEP	Very unlikely to be an issue.	Not a marine environment.		1	1	1	NA	NA

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
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391	6.3.00.00.	Human behavior	Details of the human behavior in the near-surface environment where impacts may be incurred.	Human behavior will affect the nature and magnitude of potential impacts to human beings.	Quintessa original FEP	Very unlikely to be an issue.	Population is very sparse at sites. T-A: no residences G-E: 216 residences		1	1	1	Avoid densely populated areas. Train operators and educate residents what to do in case of a CO2 leak.	Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2 leak.
392	6.3.01.00.	Human characteristics	Features and processes related to characteristics, e.g. physiology, metabolism, of individual humans. This includes considerations of variability, in individual humans, of physiology and metabolism due to age and other variations. Physiology refers to body and organ form and function. Metabolism refers to the chemical and biochemical reactions which occur within an organism, or part of an organism, in connection with the production and use of energy. Children and infants, although similar to adults, often have characteristic differences, e.g. metabolism and respiratory rates, which may lead to different characteristics of exposure to CO2 or contaminants.	Human physiology and metabolism determine the affect of exposure to CO2 and associated contaminants.	Quintessa original FEP	Very unlikely to be an issue.	There are no sensitive receptor areas (schools, hospitals, care centers, prisons, churches) near the sites		1	1	1	Avoid densely populated areas or sensitive receptor areas in site selection.	Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2 leak.
393	6.3.02.00.	Diet and food processing	Features related to intake of food and water by individual humans and the compositions and origin of intake. This includes considerations of how diets, of individual humans, may vary with age and other variations (ingestion of soil by infants, for example). This FEP also includes processes related to the treatment of foodstuffs and water between origin and consumption. For example, once a crop is harvested it may be subject to a variety of storage, processing and preparational activities prior to human or livestock consumption. Water sources may be treated prior to human or livestock consumption, e.g. chemical treatment and/or filtration.	The human diet provides a potentially important exposure pathway to contaminants released into the food chain as a result of the CO2 sequestration system. Food preparation processes may change the distribution and content of CO2 and/or associated contaminants in the product.	Quintessa original FEP	Very unlikely to be an issue.	The sites are primary grass lands and possibly some wheat farming.		1	1	1	Characterize and soils, water and crops in the site areas. Conduct baseline survey for potential contaminants.	Monitor soils and water for contaminants.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number Pxs (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
394	6.3.03.00.	Lifestyles	<p>Features related to non-diet related behavior of individual humans, including time spent in various environments, pursuit of activities and uses of materials. This includes consideration of variability of the habits of individuals due to age and other factors.</p> <p>The human habits refer to the time spent in different environments in pursuit of different activities and other uses of materials. The diet and habits will be influenced by agricultural practices and human factors such as culture, religion, economics and technology.</p>	Human habits will determine the exposure pathways of interest in an assessment. Smoking, plowing, fishing, and swimming are examples of behavior that might give rise to particular modes of exposure to CO2 and/or contaminants mobilized as a result of the CO2 sequestration system.	Quintessa original FEP	Very unlikely to be an issue.	Population is very sparse at sites. T-A: no residences G-E: 216 residences		1	1	1	Avoid densely populated areas or sensitive receptor areas in site selection.	Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2 leak.
395	6.3.04.00.	Land and water use	<p>FEPs related to land and water use by humans in the near-surface environment and the resulting implications for CO2 leakage and contaminant transport and exposure pathways. This includes consideration of:</p> <ul style="list-style-type: none">- the use of natural or semi-natural tracts of land and water such as forest, brush, rivers, lakes and the sea;- rural and agricultural land and water use (including freshwater and marine fisheries);- urban and industrial land and water use related to developments, including transport, and their effects on hydrology; and- leisure and other uses of environment.	<p>These FEPs can influence the potential transport and exposure pathways for CO2 and its associated contaminants as well as the potential evolution of the system during the timescales of interest. Particular considerations are relevant for each type of land use addressed, for example:</p> <ul style="list-style-type: none">- special foodstuffs and resources may be gathered from natural land and water which may lead to significant modes of exposure to CO2 or contaminants;- an important set of processes are those related to agricultural practices, their effects on land form, hydrology and natural ecology, and also their impact in determining contaminant uptake through food chains and other exposure paths;- human populations are concentrated in urban areas in modern societies. Significant areas of land may be devoted to industrial activities. Water resources may be diverted over considerable distances to serve urban and/or industrial requirements;- significant areas of land, water, and coastal areas may be devoted to leisure activities. e.g. water bodies for recreational uses, mountains/wilderness areas for hiking and camping activities.	Quintessa original FEP	Very unlikely to be an issue.	The sites are sparsely-populated, mostly grassland, mature oil fields. There have been no conflicts of land and water use over the past 75 to 80 years.		1	1	1	Avoid densely populated areas or sensitive receptor areas in site selection.	Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2 leak.
396	6.3.05.00.	Community characteristics	<p>Features related to characteristics, behavior and lifestyle of groups of humans that might be considered as target groups in an assessment.</p> <p>Relevant characteristics might be the size of a group and degree of self-sufficiency in food stuffs/diet. Associated with this is a consideration of the amount of resources required to meet the needs of the community.</p>	This FEP involves a consideration of aggregated human behavior in order to consider their dependency on and interactions with their environment. It therefore provides input to a consideration of potential human interference with the CO2 storage system as well as input to considering potential exposure pathways.	Quintessa original FEP	Very unlikely to be an issue.	The sites are several miles away from any communities.		1	1	1	Avoid densely populated areas or sensitive receptor areas in site selection.	Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2 leak.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
397	6.3.06.00.	Buildings	Features related to houses, or other structures or shelters, in which humans spend time.	The structure or materials used in building construction be significant factors for determining potential exposure pathways to CO2 or contaminants. For example, given that CO2 is denser than air, it may accumulate in the basements/cellars of dwellings.	Quintessa original FEP	Very unlikely to be an issue.	Buildings near the sites tend to be mostly houses, work sheds or barns.	Survey the type of buildings on site. Check for basements.	1	1	1	Avoid densely populated areas or sensitive receptor areas in site selection. Characterize the buildings on site. Check for basements. Install monitors in basements.	Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2 leak.
398	7.0.00.00.	Impacts	This category of FEPs is concerned with any endpoint that could be of interest in an assessment of performance and safety. The classes of impact considered are: Impacts to Humans; Impacts to Flora and Fauna; and Impacts to the Physical Environment. Note that: - financial impacts are assumed to be implicitly considered within each of the impact FEPs; and - unless stated, the FEPs refer to both CO2 and mobilized contaminants (minerals, heavy metals, hydrocarbons (e.g., EOR and ECBM), gases).		Quintessa original FEP				NA	NA	NA	NA	NA
399	7.1.00.00.	System performance	Performance of the sequestration system from the perspective of its success at preventing sequestered CO2 from reaching the atmosphere.	The fate of sequestered CO2 is a fundamental endpoint for an assessment.	Quintessa original FEP	Very unlikely to be an issue.	Sites are mature oil fields that have demonstrated seal integrity and have multiple stacked seals and sinks.	Need improved methods of verifying and accounting for CO2 stored.	1	3	3	Characterize and model injection sites and optimize reservoir engineering to ensure long-term CO2 storage.	Monitor site performance and document CO2 storage.
400	7.1.01.00.	Loss of containment	Loss of sequestered CO2 from the intended storage reservoir. Loss includes both consideration of loss to other parts of the geosphere and to the near-surface and surface environments, such as loss to marine water and surface water bodies, where CO2 may result in stratification or pooling.	Loss of containment may be an endpoint of interest to the assessment. For example, the assessment context may dictate that near-surface or surface processes are outside the scope of the assessment.	Quintessa original FEP	Unlikely to be an issue.	Sites are mature oil fields that have demonstrated seal integrity and have multiple stacked seals and sinks.		2	4	8	Characterize and model injection sites and optimize reservoir engineering to ensure long-term CO2 storage. Keep reservoir pressure below the fracture pressure.	Monitor and model CO2 plume migration. Identify and plug leaks.
401	7.2.00.00.	Impacts on the physical environment	FEPs relevant to adverse impacts on the physical environment. Note that these may be endpoints of interest in themselves, but may also cause other impacts of interest.	Adverse impacts on the environment can be postulated as a result of sequestration operations, even if there are no associated impacts to humans or on flora and fauna.	Quintessa original FEP	Very unlikely to be an issue.	Sites are mature oil fields that have demonstrated seal integrity and have multiple stacked seals and sinks.		1	3	3	Select sites with multiple stacked seals and sinks. Plug old wells. Avoid over pressuring the reservoir.	Monitor and model CO2 plume migration. Identify and plug leaks.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
402	7.2.01.00.	Contamination of groundwater	The existence of water aquifers may be important if they are subject to CO2-induced chemical changes or CO2-induced saline intrusion. The migration of CO2 into an aquifer will result in the acidification of the water. Depending on the mineralogical composition of the aquifer and the chemical composition of the water, chemical reactions may occur which release heavy metals from the solid phase. The mechanisms which may cause this release include dissolution of metal oxides or oxyhydroxides, the reaction/diagenesis of clay minerals, and the desorption of metals that are adsorbed on clay surfaces or organic complexes.	Contamination of groundwater resources may result in impacts on flora, fauna and/or humans if the water is abstracted or flows to the surface environment. These potential impacts are considered in the subsequent FEP classes, however, contamination of groundwater may be an endpoint of interest in itself. Foundations of buildings could be damaged by seepage of groundwater containing CO2 in shallow unconsolidated sediments and soils. This could be a problem if CO2 were to be stored (and leak) underneath, for example, historical city centers, other heritage objects, or archeological sites (CO2STORE)	Quintessa FEP with additional text	Very unlikely to be an issue.	Sites are mature oil fields that have demonstrated seal integrity and have multiple stacked seals and sinks separating them from groundwater.	Conduct baseline survey of groundwater.	1	3	3	Select sites with multiple stacked seals and sinks. Plug old wells. Avoid over pressuring the reservoir.	Monitor and model CO2 plume migration and groundwater quality. Identify and plug leaks.
403	7.2.01.01.	Contamination of underground drinking water sources	Fresh, potable, groundwater, located in the 100-200 m of the subsurface, could be contaminated by leakage of CO2. Even small CO2 leaks may possibly cause significant deterioration in the quality of potable groundwater.	An increase in CO2 concentration might cause a decrease in pH to a level of 4-5, which might cause calcium dissolution, increase in the hardness of water and alteration of minerals from minerals from rocks and soils that could release elements such as heavy metals into the water supply.	Additional [new] FEP	Very unlikely to be an issue.	There are no public or private water wells at the sites.	Conduct baseline survey of groundwater.	1	3	3	Select sites with multiple stacked seals and sinks. Plug old wells. Avoid over pressuring the reservoir.	Monitor and model CO2 plume migration and groundwater quality. Identify and plug leaks.
404	7.2.01.02.	Contamination of surface waters	Surface water could be contaminated by CO2 leakage, which could affect aquatic ecosystems by decreasing pH, especially in stagnant or stratified waters (Damen 2006)		Additional [new] FEP	Very unlikely to be an issue.	There are only a few small ponds at or near the sites.	Conduct baseline survey of surface water.	1	3	3	Characterize surface water and groundwater aquifer. Monitor third-party activity in the area.	Monitor and model CO2 plume migration and surface water quality. Identify and plug leaks.
405	7.2.01.03.	Contamination of groundwater by displaced brine	The injection of CO2 in aquifers might cause displacement of saline groundwater (brine).	Displaced brine may cause undesirable effects such as a rise of the water table (which could have negative impact on land quality and use) and an increase in salinity of sweet water reservoirs used for drinking water extraction and irrigation (Damen 2006)	Additional [new] FEP	Very unlikely to be an issue.	Available data indicates the saline aquifers and fresh water aquifers are not connected locally.	Conduct baseline survey of groundwater.	1	3	3	Characterize saline aquifer for contact with groundwater.	Monitor and model groundwater salinity. Identify and plug leaks.
406	7.2.02.00.	Impacts on soils and sediments	Soils and sediments may have elevated concentrations of CO2, should it leak from the storage system, and/or other contaminants, such as heavy metals, hydrocarbons (e.g., EOR and ECBM) or even increased salinity resulting from CO2 sequestration. For example, natural CO2 leaking from a trapped reservoir near Mammoth Mountain, in California, has resulted in soil gas concentrations of 20 to 90%.	Increased CO2 concentrations and/or contamination of soils and sediments with associated substances may be sufficient to modify the ecology and/or use of the impacted area by humans.	Quintessa original FEP	Very unlikely to be an issue.	Sites are mature oil fields that have demonstrated seal integrity and have multiple stacked seals and sinks.	Conduct baseline survey of soil.	1	1	1	Characterize soil. Select sites with multiple stacked seals and sinks. Plug old wells. Avoid over pressuring the reservoir.	Monitor and model CO2 plume migration and soil CO2 content. Identify and plug leaks.
407	7.2.02.01.	Contamination of soil			Additional [new] FEP	Very unlikely to be an issue.	Sites are mature oil fields that have demonstrated seal integrity and have multiple stacked seals and sinks.		1	2	2	Characterize soil. Select sites with multiple stacked seals and sinks. Plug old wells. Avoid over pressuring the reservoir.	Monitor and model CO2 plume migration and soil CO2 content. Identify and plug leaks.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
408	7.2.03.00.	Release to the atmosphere	Release of CO2 to the atmosphere from the storage system or other contaminants, such as radon or methane, mobilized as a result of the sequestration.	<p>Release of sequestered CO2 or mobilized methane to the atmosphere will reduce the effectiveness of the storage system at preventing greenhouse gases from being emitted to the atmosphere.</p> <p>Atmospheric contamination could also lead to health impacts on humans and wildlife.</p> <p>Rapid release likely to effectively disperse the CO2 higher in the atmosphere.</p> <p>Moderate release likely to concentrated CO2 near the ground, representing the highest risk.</p> <p>Slow release likely to disperse CO2 in the soil and atmosphere.</p>	Quintessa FEP with additional text	Unlikely to be an issue.	Sites are mature oil fields that have demonstrated seal integrity and have multiple stacked seals and sinks. Sites are relatively flat and exposed to wind to help disperse any CO2 leaks.	Conduct baseline survey of atmospheric CO2 at the sites,	2	4	8	Characterize the site. Select sites with multiple stacked seals and sinks. Plug old wells. Avoid over pressuring the reservoir.	Monitor atmospheric CO2 at the sites. Identify any irregularities in CO2 content. Determine root cause. Model CO2 dispersion in air. Locate and plug any leaks. Train operators and educate residents on what to do if a CO2 leak occurs.
409	7.2.04.00.	Impacts on exploitation of natural resources	<p>The impact of CO2 sequestration on the exploitation of natural resources such as oil and gas.</p> <p>Enhanced oil recovery (EOR) and enhanced coal bed methane (ECBM) recovery projects involving the injection of CO2 are based on improved recovery of oil and methane respectively resulting from CO2 sequestration. However, CO2 sequestration may result in the contamination of geological resources (such as hydrocarbons and minerals) or inhibit their recovery or future exploitation.</p> <p>Note that the potential impact on groundwater resources is considered in Impacts on groundwater.</p>	Impacts on the exploitation of natural resources can be positive (such EOR and ECBM) and/or negative (such as inhibited recovery). These may result in other (for example, financial) impacts, or may be endpoints of interest in themselves.	Quintessa original FEP	Very unlikely to be an issue.	No known mineral resources other than oil at sites.		1	2	2	NA	NA
410	7.2.04.01.	Contamination of mineral resources			Additional [new] FEP	Very unlikely to be an issue.	No known mineral resources other than oil at sites.		1	2	2	NA	NA
411	7.2.04.02.	Contamination of mineable coal seams			Additional [new] FEP	Very unlikely to be an issue.	No mineable coal seams in the area		1	2	2	NA	NA
412	7.2.04.03.	Contamination of oil resources			Additional [new] FEP	Unlikely to be an issue.	G-E and T-A oil reservoirs are isolated from other oil reservoirs in the area.		2	2	4	Obtain leaseholds for the entire isolated reservoir for EOR. Avoid exceeding the spill point	Monitor and model CO2 plume. Adjust injection strategy if necessary.
413	7.2.04.04.	Contamination of natural gas resources			Additional [new] FEP	Very unlikely to be an issue.	There is very little underground drinking water in the G-E and T-A. There are no public or private water wells in the areas.		1	2	2	NA	NA
414	7.2.04.05.	Contamination of geothermal resources			Additional [new] FEP	Very unlikely to be an issue.	There are no geothermal resources in the area.		1	2	2	Maintain a buffer around the project area and CO2 plume.	Monitor legislation on pore space ownership.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
415	7.2.04.06.	Contamination of pore space owned by others		CO2 could migrate into pore space owned by others resulting in trespassing.	Additional [new] FEP	Possible issue.	Kansas does not have any regulations on pore space ownership. Arbuckle has been widely used for disposal by others. EOR sites are isolated.		3	2	6	Maintain a buffer around the project area and CO2 plume.	Monitor legislation on pore space ownership.
416	7.2.05.00.	Modified hydrology and hydrogeology	The injection of CO2 may result in modifications to both the deep hydrogeology and near-surface hydrology.	Changes in the deep hydrogeology or near-surface hydrology may affect aquifer abstraction or even surface hydrology for groundwater driven features. These impacts may be either positive or negative.	Quintessa original FEP	Unlikely for CO2 injection at these sites to modify both deep and near-surface hydrology except through leaks in old boreholes.	Near-surfaced and deep aquifers separated by multiple stacked seals and sinks.		2	2	4	Characterized and model stratigraphy and hydrology of sites. Plug old boreholes.	Monitor and model CO2 migration and near-surface water chemistry. Identify irregularities. Determine root cause. Locate and plug leaks. Extract CO2 from leaky sinks and reinject into sealed sinks of necessary.
417	7.2.06.00.	Modified geochemistry	The injection of CO2 will modify the geochemistry of the sequestration system. This may be confined to the immediate vicinity of the storage location, or, through leakage from the reservoir, may affect other locations.	The extent of geochemical modifications may be an endpoint of interest, due to resulting changes to geological processes. For example, the acidification of the geochemical regime may cause minerals to be dissolved, with potential implications for the porosity and stability of the geological formations.	Quintessa original FEP	Unlikely to be an issue.	CO2 may react with Arbuckle dolomite.		2	2	4	Characterize and model the geochemistry of sites.	Monitor and model CO2 migration and near-surface water chemistry. Identify irregularities. Determine root cause. Locate and plug leaks. Extract CO2 from leaky sinks and reinject into sealed sinks of necessary.
418	7.2.07.00.	Modified seismicity	Injection of supercritical CO2 into a geological formation may induce seismic events and processes.	Induced seismicity may be an endpoint of interest in itself, or it can result in other impacts, such as physical disruption of the surface environment.	Quintessa original FEP	Unlikely to be an issue.	T-A Bartlesville Sandstone has demonstrated operation at 1700 psig with water flooding. The CO2 EOR will operate below that. The G-E can't be pressurized. Volume increase from CO2 injection will be compensated for by water/oil production in EOR.		2	3	6	Operate below 80% of fracture pressure. Volume increase from CO2 injection will be compensated for by water/oil production in EOR.	Operate below 80% of fracture pressure. Monitor injection pressure, tiltmeter and micro-seismicity. Volume increase from CO2 injection will be compensated for by water/oil production in EOR.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
419	7.2.08.00.	Modified surface topography	The gradual or sudden sinking (subsidence) or elevation (uplift) of the topography of the terrestrial surface or marine sea-bed.	Deformation of the terrestrial surface or sea-bed may be an endpoint of interest in itself, or may result in other impacts, such as damage to property.	Quintessa original FEP	Unlikely to be an issue.	T-A Bartlesville Sandstone has demonstrated operation at 1700 psig with water flooding. The CO2 EOR will operate below that. The G-E can't be pressurized. Volume increase from CO2 injection will be compensated for by water/oil production in EOR.		2	3	6	Characterize seals and sinks and model CO2 injection.	Monitor surface change with tiltmeters. Compare with model. Identify any irregularities and take corrective action if necessary.
420	7.2.08.01.	Sinkhole formation	Addition of CO2 in a limestone or carbonate-rich aquifer could result in dissolution of the rock matrix and the enlargement of voids. If this process takes place at relatively shallow depth collapse may result in subsidence at the surface and sinkhole formation. For example, CO2 leakage around a borehole drilled to extract natural CO2 from a reservoir in Florina, Greece, resulted in subsidence around the borehole that filled up with water.	Large scale collapse structures may cause significant change to surface topography and possible CO2 migration paths. Sinkholes can provide locations where leaking CO2 can accumulate.	Quintessa original FEP	Unlikely to be an issue due to the limited amount of CO2 injected at the sites and depth of injection	CO2 may react with Arbuckle dolomite. The injection depth in the Arbuckle is 2900 to 3800 ft.		2	3	6	Characterize seals and sinks and model CO2 injection in Arbuckle.	Monitor surface change with tiltmeters. Monitor subsurface change with 3d seismic and/or VSP. Compare with model. Identify any irregularities and take corrective action if necessary.
421	7.3.00.00.	Impacts on flora and fauna	FEPs relevant to impacts on flora and fauna.	Impacts on flora and fauna can be postulated as a result of sequestration operations, even if there are no associated impacts to humans.	Quintessa original FEP	Very unlikely to be an issue.	The sites are primarily grass lands with very little flora or fauna.		1	1	1	Characterize the flora and fauna on sites.	Monitor flora and fauna for unexplained dead zones. Determine root cause. Check CO2 content in the area. Locate and plug leaks if any.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
422	7.3.01.00.	Asphyxiation effects	<p>Asphyxiation effects of CO2 on terrestrial and aquatic fauna.</p> <p>Oxygen is an essential requirement for respiration in animals and is therefore needed to sustain life. High concentrations of CO2 in air or water will lead to suffocation of terrestrial and aquatic animals due to a lack of oxygen reaching the blood stream.</p> <p>If meteorological conditions do not disperse CO2 released to the atmosphere, it can gather close to the surface and remain in depressions, such as natural hollows. This property allows CO2 to reach high concentrations if released in sufficient quantities under particular atmospheric conditions.</p> <p>The 1986 Lake Nyos disaster in Cameroon provides a graphic example of the potential effects of high atmospheric concentrations of CO2. A large limnic eruption resulted in the death of wildlife and approximately 1800 people in the surrounding area and up to 27 km away.</p> <p>In a similar way to gaseous CO2 being denser than air, water containing high concentrations of dissolved CO2 is denser than pure water, a factor that contributes to the limnic eruption phenomenon observed at</p>	Levels of CO2 from a sequestration project sufficient to cause asphyxiation of fauna would be an endpoint of concern in assessing the geological sequestration of CO2.	Quintessa original FEP	Very unlikely to be an issue.	Population is very sparse at sites. T-A: no residences G-E: 216 residences		1	5	5	Avoid densely populated areas. Train operators and educate residents what to do in case of a CO2 leak.	Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2 leak.
423	7.3.02.00.	Effect of CO2 on plants and algae	<p>Plants and algae (in both terrestrial and marine environments) use energy in sunlight to photosynthesize carbohydrates from CO2 and water (H2O). Increasing concentrations of CO2 around the photosynthetic tissues, increases the rate of photosynthesis and therefore growth and productivity in terrestrial and aquatic plants and algae.</p> <p>However, the roots of most plants need oxygen to breakdown carbohydrates to provide energy for root growth and healthy metabolism, a process called aerobic respiration. High concentrations of CO2 in the soil reduces the availability of O2 and can cause roots and therefore plants to die.</p> <p>At Mammoth Mountain, in California, CO2 has accounted for up to 95% of the gas concentration in soil at the edge of Horseshoe Lake due to release from natural geological CO2 reservoirs caused by volcanic activity. These high soil concentrations have resulted in areas of forest being killed.</p>	Concentrations of CO2 in the soil, atmosphere and/or water sufficient to impact on the growth of plants and algae would be an endpoint of interest in assessing the geological sequestration of CO2.	Quintessa original FEP	Very unlikely to be an issue.	The sites are primarily grass lands with very little plants and algae.		1	1	1	Characterize the plants and algae on sites.	Monitor plants and algae for unexplained dead zones. Determine root cause. Check CO2 content in the area. Locate and plug leaks if any.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
424	7.3.03.00.	Ecotoxicology of contaminants	Contaminants other than CO2 may be introduced to the biosphere as a result of geological CO2 sequestration due to: - impurities associated with the sequestration fluid, such as hydrogen sulphide (H2S), methane (CH4), nitrogen oxides (NOx) and mercaptans; - the mobilization of substances in the geological environment due to the sequestration of CO2, such as hydrocarbons (e.g., EOR and ECBM), brine, CH4 and heavy metals. These substances may have a toxic effect on organisms in the biosphere, including plants, animals, algae and fungi.	The potential for contaminants associated with and/or mobilized by CO2 sequestration to have a toxic effect on organisms should they migrate to the biosphere will be of interest in an assessment of the geological sequestration of CO2.	Quintessa original FEP	Possible issue.	H2S has been reported in the Arbuckle.	Characterize the sites for contaminants.	3	3	9	Characterize and monitor the sites for contaminants	Monitor and model the sites for contaminants. Maintain a risk management plan. Train operators how to deal with contaminants.
425	7.3.03.01.	Methane leakage	CO2 injection might cause methane (CH4) present in the reservoir to migrate out of the reservoir to other formations and possibly into the atmosphere. (Damen 2006)	Methane leakage may affect shallow water quality and pose a lethal threat when accumulating in confined spaces such as basements/cellars. The global warming potential of methane is circa 23 times that of CO2 (Damen 2006)	Additional [new] FEP	Very unlikely to be an issue.	Production records indicate an absence of methane at the sites.		1	3	3	Characterize the sites for methane.	Monitor for methane. Train operators how to deal with methane leaks.
426	7.3.04.00.	Ecological effects	Geological sequestration of CO2 may have an impact on the biosphere at a community, population and/or ecological level, with subsequent implications for biodiversity. The potential impact of releases of CO2 and associated or mobilized contaminants into the biosphere may disrupt biological interactions sufficiently to modify the terrestrial or marine ecosystems affected. For example, the sudden release of natural CO2 due to the limnic eruption at Lake Nyos, Cameroon, resulted in the sudden death of wildlife, but was unlikely to affect the ecology in the longer term. However, the continued gradual release of natural CO2 into soil near Mammoth Mountain, California, has been sufficient to kill trees and damage the local ecosystem since 1996 until the present day.	The degree of potential ecological disruption resulting from geological CO2 sequestration may be an endpoint of interest, especially if the ecosystem affected is considered valuable and/or sensitive to perturbations.	Quintessa original FEP	Very unlikely to be an issue.	Sites are sparsely populated grasslands		1	1	1	Characterize site ecology.	Monitor and model CO2 migration and near-surface water chemistry. Identify irregularities. Determine root cause. Locate and plug leaks. Extract CO2 from leaky sinks and reinject into sealed sinks of necessary.
427	7.3.05.00.	Modification of microbiological systems	Microbes will be present in the geosphere as well as in the terrestrial and/or marine environments above the CO2 storage reservoir. CO2 sequestration may disrupt microbial aerobic respiration but may enhance anaerobic respiration, with subsequent implications for the processes in which the microbes are involved. Microbes play an important role in all terrestrial and marine ecosystems, including those associated with extreme environments, such as deep sea hydrothermal vents.	The potential impact of CO2 sequestration on aerobic and anaerobic microbial respiration in the geosphere, terrestrial and marine biosphere may be an endpoint of interest.	Quintessa original FEP	Very unlikely to be an issue.		Identify any significant subsurface microbial cultures at the injection sites.	1	1	1	Monitor for microbial activity if injection pressures increase unexpectedly. Avoid O2 content in the CO2 stream.	Use chemical treatment if necessary to control microbial growth.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
428	7.4.00.00.	Impacts on humans	FEPs relevant to adverse impacts on people.	A range of possible impacts to human beings can be postulated as a result of sequestration operations.	Quintessa original FEP	Very unlikely to be an issue.	Population is very sparse at sites. T-A: no residences G-E: 216 residences		1	4	4	Avoid densely populated areas. Train operators and educate residents what to do in case of a CO2 leak.	Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2 leak.
429	7.4.01.00.	Health effects of CO2	<p>Elevated atmospheric concentrations of CO2 can result in both acute and chronic health effects in humans. If meteorological conditions do not disperse CO2 released to the atmosphere, it can gather close to the surface and remain in depressions, such as the basement of buildings or at the surface of lakes. This property allows CO2 to reach high concentrations if released in sufficient quantities under particular atmospheric conditions.</p> <p>The primary health effect of concern is asphyxiation. High concentrations of CO2 in air will lead to suffocation of humans due to a lack of oxygen reaching the blood stream. Asphyxiation can occur once atmospheric concentrations reach approximately 10% CO2.</p> <p>Other health effects include those directly associated with elevated concentrations of CO2 in the blood stream, such as acidosis and physiological responses to the elevated blood CO2.</p> <p>The 1986 Lake Nyos disaster in Cameroon provides a graphic example of the potential effects of high atmospheric concentrations of CO2. A large limnic eruption resulted in the death of approximately 1800 people in the surrounding area and up to 27 km away.</p> <p>Asphyxiation requires high CO2</p>	The potential for CO2 to be released to the atmosphere in sufficient quantities to cause health effects in humans will be an endpoint of interest in assessing the geological sequestration of CO2.	Quintessa FEP with additional text	Very unlikely to be an issue.	Population is very sparse at sites. T-A: no residences G-E: 216 residences		1	4	4	Avoid densely populated areas. Train operators and educate residents what to do in case of a CO2 leak.	Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2 leak.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Qunitessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
430	7.4.01.01.	Elevated CO2 in air	<p>CO2 = 5000 ppm (0.5%) OSHA permissible exposure limit: Time weighted average concentration for 8-hour work day. American Conference of Governmental Industrial Hygienists (ACGIH) threshold limit value: Time weighted average concentration for normal 8-hour work day or 40-hour work week.</p> <p>CO2 = 30,000 ppm (3%) Breathing increases to twice normal rate and a person would experience impaired hearing, headache, and increased blood pressure (Shell). Occupational Safety & Health Administration (OSHA) short-term exposure level: Maximum concentration for 15-minute period (maximum of 4 periods per day with at least 60 minutes between exposure periods).</p> <p>CO2 = 40,000 ppm (4%) National Institute for Occupational Safety and Health (NIOSH) immediate danger to life and health: The maximum level to which a healthy individual can be exposed to a chemical for 30 minutes and escape without suffering irreversible health effects or impairing symptoms.</p> <p>CO2 = 50,000 ppm (5%) Breathing increases to approximately 4 times normal rate, symptoms of intoxication become evident and slight choking may be felt (Shell).</p>		Additional [new] FEP	Very unlikely to be an issue.		Baseline survey of atmospheric CO2 at the sites.	1	4	4	Monitor CO2 content in air. Model CO2 dispersion. Train operators and educate residents what to do if a CO2 leak occurs.	Monitor CO2 content in air. Model CO2 dispersion. Train operators and educate residents what to do if a CO2 leak occurs.

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CO2 Geologic Sequestration Risks for the IMCCS Project						Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index No.	Risk Area	Description	Relevance	Quintessa FEP Category	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number PXS (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
431	7.4.02.00.	Toxicity of contaminants	<p>Contaminants other than CO2 may be introduced to the biosphere as a result of geological CO2 sequestration due to:</p> <ul style="list-style-type: none"> - impurities associated with the sequestration fluid, such as hydrogen sulphide (H2S), methane (CH4), nitrogen oxides (NOx) and mercaptans; - the mobilization of substances in the geological environment due to the sequestration of CO2, such as hydrocarbons (e.g., EOR and ECBM), CH4 and heavy metals. <p>Such contaminants may be toxic to humans and could cause harm if exposure pathways exist.</p> <p>The toxicity will depend on: the form of exposure, e.g. ingestion or inhalation, leading to internal exposure or proximity to concentrations of contaminants leading to external exposure; the metabolism of the contaminant and physico-chemical form if inhaled or ingested, which will determine the extent to which the element/species may be taken up and retained in body tissues.</p>	The potential for contaminants associated with an/or mobilized by CO2 sequestration to cause harm to humans is an endpoint of interest when assessing the geological sequestration of CO2.	Quintessa original FEP	Possible issue.	H2S has been reported in the Arbuckle.	Characterize the sites for contaminants.	3	3	9	Characterize and monitor the sites for contaminants	Monitor and model the sites for contaminants. Maintain a risk management plan. Train operators how to deal with contaminants.
432	7.4.03.00.	Impacts from physical disruption	Impacts on humans due to physical disruption of the environment caused by geological CO2 sequestration. For example, damage to buildings due to induced seismicity, damage to farmland due to subsidence or uplift.	Physical disruption of the environment caused by CO2 sequestration may have a detrimental impact on humans.	Quintessa original FEP	Very unlikely to be an issue.	Population is very sparse at sites. T-A: no residences G-E: 216 residences		1	3	3	Avoid densely populated areas. Train operators and educate residents what to do in case of a CO2 leak.	Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2 leak.
433	7.4.04.00.	Impacts from ecological modification	Impacts on humans due to ecological modification. These may be negative (for example, reduced timber yields due to damage caused to trees by CO2 in the soil) or positive (for example, increased crop yields due to higher atmospheric CO2).	Ecological modification caused by CO2 sequestration may have a positive or negative impact on humans.	Quintessa original FEP	Very unlikely to be an issue.	Population is very sparse at sites. T-A: no residences G-E: 216 residences		1	3	3	Avoid densely populated areas. Train operators and educate residents what to do in case of a CO2 leak.	Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2 leak.

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Appendix 6-B

Surface and Programmatic Risks for the IMCCS Project

CO2 Surface and Programmatic Risk List for the IMCCS Project					Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index #	Risk Area/FEP	Description	Relevance	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number P x S (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
1	8.00.00	ECONOMIC						3	4	12		
2	08.01.00.	Cost escalation / inflation	<p>Cost escalation/inflation may be higher than budgeted. Cost escalations are of particular concern because field-service costs (drilling, geophysics, etc.) and equipment may continue to increase as the price of oil stays high. Key cost items that may be effected by escalation/inflation include:</p> <ol style="list-style-type: none"> 1. Steel cost 2. Other material cost 3. Equipment cost 4. Labor cost 5. Imported goods cost (due to currency exchange) 	The risk of cost escalations is significant; cost increases may force a change in scope-of-work.	<p>1-4. The project requires a detailed budget over 5 years. This could be a time period of significant inflation.</p> <p>5. Under ARRA, imported goods must be kept to a minimum for this project. Therefore the project will not be affected by differences in foreign currency.</p>	Phase 2 of project is 5 years duration.	Projected escalation/inflation over next 5 years.	3	3	9	<p>1-4. Use updated/current information on labor and material rates with escalation over job period.</p> <p>5. Buy American!</p>	<p>1-4. Allow for time sensitive information to be updated to expose any issues asap.</p> <p>5. Purchase contract to be in low risk currency.</p>
3	08.02.00.	CO2 value/cost	<p>Incentives for CO2 capture and storage are particularly important for CO2 sequestration in deep saline aquifers. In this case, the value or cost of CO2 may be determined by cap-and-trade, carbon tax or emission credits.</p> <p>In EOR and ECBM the value of CO2 may be tied to the price of oil or natural gas. However, the cost of CO2 capture and transport may be higher or lower than the assigned value.</p> <p>Value of emission credits provide incentive for CO2 sequestration, particularly in deep saline aquifers (DSA).</p> <p>CO2 purchase cost higher than budgeted. CO2 has traditionally been purchased for EOR and ECBM use. Economic arrangements among project participants could have negative project impacts under changed or unanticipated conditions.</p> <ol style="list-style-type: none"> 1. Value of CO2 emissions credits lower than budgeted 2. CO2 purchase cost higher than budgeted 	A low value for emission credits may be insufficient to cover the cost of CO2 capture and sequestration in deep saline aquifers.	Unlikely to be a problem	This project currently doesn't rely on CO2 emission credits. Tax credits of \$10/t of CO2 for EOR and \$20/t of CO2 for DSA are available for the fertilizer plant.	CO2 legislation.	2	3	6	<p>Use a CO2 transfer formula that protects the supplier and user.</p> <p>Tie CO2 purchase price to oil price.</p>	Monitor CO2 legislation and take corrective action as necessary.
4	08.03.00.	Price of related commodities	<p>The prices of related commodities can impact the value and/or availability of CO2.</p> <ol style="list-style-type: none"> 1. Oil price - impacts EOR economics 2. Natural gas price - impacts ECBM economics 3. Fertilizer price - impacts CO2 supply from fertilizer plants 4. Ethanol price - impacts CO2 supply from ethanol plants 5. Cement plant - impacts CO2 supply from cement plants 	Low commodity prices can impact the viability of a CO2 capture and storage project.	<p>Oil price will have a significant impact on EOR feasibility.</p> <p>Fertilizer plant could be impacted by low fertilizer prices.</p> <p>Ethanol plant could be impacted by low ethanol prices and high natural gas prices.</p>	<p>Fertilizer plant supplies 760,000 t/y of CO2</p> <p>Ethanol plant supplies 145,000 t/y of CO2</p>	Commodity price forecasts.	2	3	6	Analyze trends in commodity prices. Plan for worst case scenarios.	Look at backup sources for CO2

CO2 Surface and Programmatic Risk List for the IMCCS Project					Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index #	Risk Area/FEP	Description	Relevance	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number P x S (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
5	08.04.00.	Project development costs	<p>Project development costs that could be higher than expected or budgeted include:</p> <ol style="list-style-type: none"> 1. Surface land and/or pore space access costs -purchase or lease 2. Water rights costs 3. Mineral rights costs - needed for EOR or ECBM 4. Pipeline right-of-way (ROW) costs 5. Site characterization costs 6. Permitting costs 7. Technology licensing costs 8. Engineering, procurement and construction (EPC) costs 9. Insurance costs 10. Project financing costs 11. Legal costs 	<p>High project development costs can make the project economically infeasible.</p> <p>Project may be halted if some of the necessary requirements are unobtainable.</p>	<p>1-8. Unlikely to be a problem.</p> <p>9. Insurance and project financing costs likely to be high.</p>	IMCCS uses existing pipeline corridors. EOR does not normally involve pore space issues.	Insurance availability and costs.	3	2	6	<ol style="list-style-type: none"> 1. Focus on EOR rather than DSA to avoid pore space issues. 3. Work out mineral rights leases early. 4. Use existing pipeline corridors. 5. Select brownfield site with characterization data. 	<ol style="list-style-type: none"> 1. Have back ups for site selection, 4. Have backup for pipeline right of way. 6. Use public outreach effectively to keep permitting costs down. 9. Self insure. 10. Get equity financing.
6	08.05.00.	Project capital costs	<p>Project capital costs that could be higher than budgeted include:</p> <ol style="list-style-type: none"> 1. CO2 capture system 2. CO2 dehydration 3. CO2 compression 4. CO2 pipeline 5. Well head system 6. CO2 recycle system - for EOR 7. Oil tankage - for EOR 8. Natural gas processing system - for ECBM 9. Water tankage - for EOR or ECBM 10. Water treatment system - for EOR or ECBM 11. New well drilling and completion 12. Old well remediation/replugging 13. Old well workover 14. Site preparation 15. Access roads 16. Power supply system 17. Water supply system 18. Communications system 19. Monitoring system costs 20. Accidental loss 	<p>High project capital costs can make the project economically infeasible.</p> <p>Accidental loss can result in Business Interruption / Advanced Loss of Profit type exposure, or even result in the project becoming uneconomic to continue.</p> <p>CO2 capture and CO2 compression tend to be big ticket items and long lead time.</p>	Unlikely to be a problem	CO2 capture existing at Coffeyville and Kansas Ethanol.	Need final site selection and hard quotes on major items	2	3	6	<p>Obtain hard quotes from manufacturers with time sensitive escalation and time period of validity defined.</p> <p>Use conservative estimates and escalations.</p> <p>Use experienced contractors.</p>	<p>Track actual vs. budgeted expenses.</p> <p>Prioritize expenses and cut low priority costs.</p> <p>Renegotiate scope of work.</p> <p>Obtain additional equity funding.</p>

CO2 Surface and Programmatic Risk List for the IMCCS Project					Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index #	Risk Area/FEP	Description	Relevance	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number Pxs (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
7	08.06.00.	Operating and maintenance costs	<p>Project operating and maintenance costs that could be higher than budgeted include:</p> <ol style="list-style-type: none"> 1. CO2 capture operating costs 2. CO2 dehydration/compression operating costs 3. CO2 pipeline operating costs 4. Injection operating costs 5. Monitoring costs 6. Simulation modeling costs 7. Maintenance costs 8. Lease operating expenses 9. Management fees 10. Working capital 11. Severance and ad valorem tax 12. Investor reporting costs 13. Power cost 14. Make-up water cost 15. Water treatment/disposal cost 16. Labor cost 17. Security costs 18. site close costs 19. Verification costs 20. Regulatory compliance costs 21. Insurance costs 22. Cost for losses 23. Post-closure costs 24. Accidental loss 	<p>High operating and maintenance costs can impair project economic viability.</p> <p>Accidental loss can result in Business Interruption / Advanced Loss of Profit type exposure, or even result in the project becoming uneconomic to continue.</p>	Unlikely to be a problem	O&M costs may vary depending on final site selection.	Need final site selection and hard quotes on major items	2	2	4	Use historical O&M data and cost estimators with O&M experience to prepare budgets.	Implement a comprehensive maintenance program prior to startup.
8	08.07.00.	Project Financing	<p>Factors which could impact project financing include:</p> <ol style="list-style-type: none"> 1. Government project funding withdrawn for technical reasons. 2. Government project funding withdrawn for political reasons 3. Change in equity project funding 4. National/global economic downturn impact on project financing 5. Lack of economic incentives for CCS impact on project financing 	Lack of or loss of project financing could halt the project.	Possible problem.	Phase 2 project cost estimate is over \$500 million.	Need confirmation on equity and DOE/NETL funding.	3	4	12	Secure major equity partner(s) to provide cost share. Secure DOE/NETL funding	Secure major equity partner(s) to provide cost share. Secure DOE/NETL funding
9	09.00.00.	PERMITTING RISKS										

CO2 Surface and Programmatic Risk List for the IMCCS Project					Project Specific Information			Risk Ranking			Prevention and Mitigation	
Line #	Index #	Risk Area/FEP	Description	Relevance	Individual Comments	IMCCS Project Specific Information	IMCCS Project Information Gaps or Uncertainties	Failure Probability (1-5)	Failure Severity (1-5)	Risk Priority Number P x S (1-25)	Risk Prevention Steps (Actions taken to reduce risk probability)	Risk Mitigation Steps (Actions taken to reduce risk severity)
10	09.01.00.	Permit compliance	<p>Permitting and NEPA compliance are lengthy processes, and are subject to even more delays because of uncertainty associated with permitting sequestration (a relatively new issue for regulatory agencies). The procedures for permit compliance could cause delays. Potential permits required for a CCS project include:</p> <ol style="list-style-type: none"> 1. National Environmental Policy Act (NEPA) <ul style="list-style-type: none"> - Environmental Assessment (EA) - Environmental Impact Statement (EIS) 2. Underground Injection Control (UIC) permit 3. CO2 storage permit 4. Drilling permit 5. Water discharge/disposal permit 6. Crossing permits for wetlands, federal land, tribal land, railroads, highways, roads 7. Construction general permit 8. Storm water discharge permit 9. Air quality construction permit 10. Seismic permit 11. Storage tank permit 	Lack of permit could halt or restrict construction or operation; permit delay could have other impacts including increased costs.	Unlikely to be a problem	Using existing injection sites and pipeline corridors.	Need to make final site and pipeline ROW selections.	2	3	6	Use experienced permitting manager / consultant.	Use experienced permitting manager / consultant
11	09.02.00.	Public outreach and education	<p>Public acceptance support and trust is critical to obtaining environmental permits. Public outreach and education can be more difficult than expected.</p> <ol style="list-style-type: none"> 1. Lack of public acceptance that CO2 emissions contribute to global warming 2. Lack of public acceptance that global warming is an eminent danger to society 3. Lack of public that carbon capture and storage (CCS) is safe 4. Poor public perception of CCS projects 5. Local community actions and reactions 6. Special interest groups or non-governmental organizations actions and reactions 7. Lack of political support for the project 	<p>Failure to get public acceptance for a project can lead to significant delays in, and costs for, permitting</p> <p>An unexpected situation arises that is not technically impacting but the appearance of unpreparedness spurs public concern.</p>	Unlikely to be a problem	Local public have long history of good working relationship with oil companies.	Need to make final site and pipeline ROW selections.	2	4	8	Comprehensive public outreach program based on DOE best practices manual.	Comprehensive public outreach program based on DOE best practices manual.

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12	09.03.00.	Saline water treatment and disposal	<p>Large amounts of saline water are pumped out of the ground for EOR and ECBM.</p> <p>EOR water production increases over time. In high water cut cases, water may represent 99% of the production volume and oil only 1% of the volume.</p> <p>ECBM employs water production to lower the over pressure in the coal seam.</p> <p>CO2 changes water composition and makes water more acidic (pH 4-5). Therefore EOR and ECBM production water may require more treatment before it can be disposed of. The acidic water may also include trace amounts of arsenic and other metals.</p>	Saline water disposed could be one of the most critical issues in permitting.	Unlikely to be a problem	Saline water will be disposed into the Arbuckle formation which is approved for Class 1 hazardous waste.	Need to make final site selections.	2	2	4	Get permit for water disposal into the Arbuckle formation.	Comply with all State water disposal regulations.
13	9.04.00	Natural resources nearby	<p>1. Mineral resources</p> <p>2. Mineable coal seams</p> <p>3. Oil reservoirs</p> <p>4. Natural gas reservoirs</p> <p>5. Underground drinking water sources</p> <p>6. Surface waters - lakes, rivers, streams</p> <p>7. Geothermal resources</p> <p>8. Pores space owned by others</p> <p>9. Deep saline aquifers</p> <p>10. Microbial resources</p> <p>11. Soil - farmland</p> <p>12. Flora and fauna - endangered species and critical habitats</p>	CO2 or brine fluid migration could contaminate others' natural resources and lead to permitting delays due to legal contest.	Unlikely to be a problem	No significant natural resources identified at prospective sites other than oil resources which will be leased.	Need to make final site and pipeline ROW selections.	1	2	2	Characterize sites for natural resources. Avoid sensitive sites.	Monitor and model CO2 plume and brine migration.
14	09.05.00.	Dense population nearby	<p>Present and future urban sprawl.</p> <p>1. Sensitive receptors (schools, hospitals, care centers, churches, prisons) in or near injection site</p> <p>2. Dense population located downhill or downwind of injection site</p> <p>3. Populated subsurface structures located nearby</p>	Additional safety precaution measures are required to protect against CO2 leakage in dense population areas..	Unlikely to be a problem depending on site selection.	Sites under consideration are mature EOR sites.	Need to make final site and pipeline ROW selections.	2	2	4	<p>Avoid selecting sites near densely populated areas.</p> <p>Use existing pipeline corridors.</p>	Provide additional monitoring, pipeline integrity management program and emergency response plan.

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15	09.06.00.	Conflicts with use of surface	Conflicts with use of the surface may include 1. Agriculture 2. Fishing 3. National parks/monuments 4. Wetlands 5. Timberland 6. Recreational areas 7. Military areas 8. Heavy industry sites 9. Urban areas 10. Archeological sites 11. Tribal sacred ground 12. Endangered species critical habitats 13. Bird sanctuaries 14. Historical sites 15. Groundwater protection zones. 17. Change in land use (zoning change)	Some land uses may impact site selection and permitting. Others may require additional monitoring and modeling to provide added protection from CO2 leakage. Nearby heavy industry can interfere with seismic readings. Land use changes could restrict access to and use of land for CO2 sequestration	Unlikely to be a problem	Existing injection sites and pipeline corridors. No activity except farming, ranching and oil production at injection site areas.	Need to make final site and pipeline ROW selections.	2	2	4	Use of existing injection sites and pipeline corridors. Avoid sensitive areas or habitats for endangered or protected species. Characterize sites for potential surface land use.	Design around sensitive areas. Monitor CO2 plume and brine migration.
16	09.07.00.	Conflicts with use of subsurface	Conflicts with use of the subsurface may include: 1. Natural gas storage 2. Compressed air storage 3. Geothermal plants 4. Radioactive waste disposal 5. Petroleum production 6. Coal mining 7 Health spas	Could impact site selection and permitting.	Unlikely to be a problem.	No activity except farming, ranching and oil production at injection site areas.	Need to make final site and pipeline ROW selections.	1	2	2	Use of existing injection sites and pipeline corridors. Avoid sites with conflicting subsurface use. Characterize sites for potential subsurface.	Design around conflicting areas. Monitor CO2 plume and brine migration.
17	09.08.00.	Permit denied or modified by government agency	A permit may be modified by government agency to require increase data access and approval by NGOs and/or public 1. Permit denied because the project is considered high risk to public 2. Permit denied because there is uncertainty over the safety of the project 3. Permit revoked due to owner failing to comply with regulations (action or inaction) 4. Permit delayed due to owner action or inaction	Causes delays leading to price escalation. Could halt the project.	Unlikely to be a problem.	Using existing injection sites and pipeline corridors.	Need to make final site and pipeline ROW selections.	2	2	4	Use experienced permitting manager / consultant.	Use experienced permitting manager / consultant.
18	09.09.00.	Pre-existing contaminated site	Site may have already been contaminated by non-CO2 storage related activities.	Pre-existing contamination of groundwater, surface water, and/or soil.	Unlikely to be a problem	Using existing injection sites and pipeline corridors.	Need to make final site and pipeline ROW selections.	2	3	6	Characterize sites for pre-existing contamination. Conduct baseline studies. Use experienced environmental manager / consultant.	Use experienced environmental manager / consultant.

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19	10.00.00.	EXTERNAL RISKS										
20	10.01.00.	Natural disaster risks	1. Fire -wildfires, industrial fires 2. Flood - flood plain, dry wash areas, flash floods, tsunami, debris flows 3. Earthquake - natural seismic activity, rock slides, mud slides 4. Winter storms - blizzards, ice storms, arctic cold 5. Hail storm 6. High winds - tornadoes, hurricanes, typhoons, cyclones 7. Heat wave 8. Drought 9. Heavy rain - monsoons, tropical storms, thunder storms 10. Lightning 11. Sand/dust storms 12. Avalanche 13. Electromagnetic disturbances - sunspots 14. Volcano 15. Corrosive atmospheres - high humidity, coastal sea breeze, industrial plant acid gas emissions	Natural disasters can delay, impair or shutdown a project.	Possible problem.	Kansas areas susceptible to fire, floods, winter storms, hail, high winds, lightning, drought, microseismicity.	Need to make final site and pipeline ROW selections.	3	3	9	Select sites and right of ways that are less likely to be exposed to natural disasters. Avoid flood plains. Include potential natural disasters in site characterization.	Implement emergency response plan covering all potential disasters. Comply with fire suppression codes. Ground surface equipment to protect from lightning. Cover sensitive equipment. Monitor severe weather reports.
21	10.02.00.	Security Risks	1. Theft 2. Vandalism - onsite equipment or offsite monitoring equipment 3. Employee sabotage 4. Civil unrest - riots, civil war, rebellion, insurrection, military or usurped power or confiscation 5. Terrorist activities 6. War - invasion, acts of foreign enemies, hostilities 7. Nationalization 8. Government sanctions, blockade, embargo 9. Labor disputes - strike, lockout 10. Damage to surface facilities by human activity 11. Hunting season - stray bullets	Risks to employees, public and equipment.	Possible problem.	Sites sparsely populated.	Final site and pipeline ROW selections to determine level of security risks.	3	2	6	Fence in and lock above ground facilities. Bury pipeline sufficiently deep. Do background checks and drug tests on new hires. Supervise all crews during working hours.	Emergency response plan.
22	10.03.00.	Competition	Other projects in the area may compete for the same CO2, labor, infrastructure, land, pore space, funding 1. Interaction with adjacent CO2 sequestration sites 2. Infringement of project's pore space by third-party injection of CO2, water or waste disposal	Could halt the project or increase costs. Potential decreased storage capacity.	Unlikely to be a problem	CO2 supply locked in exclusively.	Final site and pipeline ROW selections to determine if there is competition.	2	2	4	Secure CO2 supply with exclusive long term agreement.	Identify backup CO2 supply.

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23	10.04.00.	CO2 supply	<p>Changes in the operation of the CO2 source plant may impact CO2 properties and/or flow rate.</p> <p>Unanticipated change in demand for injected CO2 (flow rate, pressure, water content, etc.) due to either uncontrollable physical changes or operating decisions, will affect operations of the CO2 source facility and potentially impose stresses upon surface and down hole equipment and borehole. Changes may be gradual or sudden. Also includes changes arising from characterization data, e.g., limits placed by reservoir on injectivity, capacity, etc.</p> <p>CO2 sources and sinks need to coordinate supply and demand and scheduled outages to avoid constraint startup/shutdown of compression facilities and maintain consistent pipeline pressure. This is normally done through a nomination process at least one week in advance.</p> <p>Operators of CO2 storage projects may incorporate excess injection capacity (i.e. spare wells) to permit continued injection during planned or unplanned well downtime. (CCP 2009)</p> <p>1. CO2 outside of design specification - flow rate, composition, pressure, temperature</p> <p>2. Change in CO2 supply conditions</p> <p>3. Change in CO2 demand conditions</p> <p>4. CO2 supply interruptions due to source plant outage/failure</p> <p>5. CO2 supply interruptions due to CO2 capture outage/failure</p> <p>6. CO2 supply interruptions due to compressor outage/failure</p> <p>7. CO2 supply interruptions due to pipeline outage</p> <p>8. Disparity in timing of supply/demand for CO2</p> <p>9. CO2 interruption due to accident at the CO2 supplier</p>	<p>Interruption of CO2 supply could result in a Business Interruption / Advanced Loss of profit type exposure, or even result in the project becoming uneconomic to continue.</p> <p>Lack of adequate CO2 supply could halt or limit injection. Intermittent injection schedule could increase stress on surface and down hole mechanical elements, could affect EOR/ECBM sweep efficiency, and could increase concentrations of various contaminants in the injected gas.</p> <p>The timing of CO2 availability may not match up with the time when CO2 is needed for EOR or ECBM.</p>	Unlikely to be a problem with Coffeyville CO2 supply. Possible problem with Kansas Ethanol CO2 supply.	Kansas Ethanol has not demonstrated that it can maintain a consistent CO2 quality within spec.	Need to confirm the composition and consistency of Kansas Ethanol CO2 supply.	3	3	9	<p>Define CO2 specification.</p> <p>Require historical data or performance test and quality guarantee from CO2 suppliers.</p> <p>Implement a nomination procedure for balancing CO2 supply and demand.</p>	<p>Monitor CO2 quality.</p> <p>Require CO2 supplier to vent off spec CO2.</p>
24	10.05.00.	Water supply	<p>1. Water supply design specifications</p> <ul style="list-style-type: none"> - Flow rates - Composition - Pressure - Temperature <p>2. Water supply interruptions</p>	Could impact water and gas (WAG) flooding	Possible problem.	Water supplied from Arbuckle may contain H2S.	Need to confirm water quality.	3	2	6	<p>Take water supply volume and quality into account in system design.</p> <p>Consider redundant pumps and water storage tanks.</p>	<p>Monitor for leaks in water piping.</p> <p>Add pumps, filtration or water treatment to resolve water volume or quality issues.</p> <p>Treat water for corrosion, scale and/or microbial control.</p>
25	10.06.00.	Power supply	<p>1. Power surges</p> <p>2. Power brown outs</p> <p>3. Power interruptions (black outs)</p>	Could shut operations down.	Possible problem.	Power supply lines in or near injection sites.	<p>Total kva needed/available.</p> <p>Reliability of grid in area.</p>	3	2	6	Install generator/battery backup system if necessary.	Install surge protection if it is an issue.

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26	10.07.00.	Communication system	Communications could be interrupted. The SCADA system may be dependent on one or more of the following communications systems: 1. Phone line 2. Fiber optics 3. Satellite 4. Internet	Loss of communication system could impair operations especially if the SCADA link is disconnected.	Unlikely to be a problem.	Redundant systems being installed, including fiber optic system.	System specifics needed.	3	2	6	Install fiber optics and backup system.	System maintenance.
27	10.08.00.	Road access	Road to injection site could be blocked by snow, accident, washout, wildfire, flooding	Lack of road access to sites could impair operations	Possible problem.	Existing injection sites and pipeline corridors likely to have road access.	Final site selection and location of roads.	3	2	6	Road construction and maintenance procedures in place.	Road construction and maintenance procedures in place.
28	11.00.00.	PROJECT MANAGEMENT RISKS										
29	11.01.00.	Management team	The project may include some unfamiliar activities and workflows, may acquire and respond to a wide range of newly acquired data, and may experience changes in objectives. Operational conflicts, anticipated or not, could impact project values. Inexperienced managers tend to be over optimistic in taking risks and taking short cuts. for example: failing to avoid high risk sites. 1. Inexperienced management team 2. Inability to execute contracts among project partners in a timely manner 3. Lack of stakeholder coordination	An inexperienced management team has a higher potential for mistakes and poor judgment Inefficient interface management can result in delays and failure to achieve project goals.	Unlikely to be a problem.	Partners negotiating with an experienced EOR operator to join the project.	Finalize who the experienced partner will be.	2	4	8	Project managers experienced in pipeline, EOR and DOE projects.	Hire additional experienced project managers if necessary.
30	11.02.00.	Operator training	1. Under qualified operators 2. Untrained operators	Inadequate operator training can result in low labor productivity and greater potential for human error.	Unlikely	Operator training program to be implemented	Finalize positions for training.	2	4	8	Implement operator training program in design phase.	Maintain ongoing operator training program in the operation phase.
31	11.03.00.	Execution strategy	Poor execution strategy can result from: 1. Insufficient funding 2. Insufficient resources 3. Unrealistic schedule 4. Schedule and planning conflicts 5. Poor timing 6. Lack of risk management plan	Poor execution strategy can result in project delays and increased project costs.	Unlikely to be a problem	Team will include members experienced in all phases of project.	Finalize key EOR partner and site selection.	2	3	6	Work with experienced team members to develop and execute the project. Update and follow project management plan and risk management plan.	Use quarterly meetings to review and fine tune execution strategy resolve schedule conflicts

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32	11.04.00.	Record keeping	Large amounts of data will be generated by the project. Data could be poorly communicated between groups, or be badly managed to the point that important data is lost, or used incorrectly. 1. Poor data management 2. Loss of archives/records 3. Unable to accurately verify the amount of CO2 retained in storage	Insufficient record keeping could lead to noncompliance with regulations and failure to achieve project goals.	Unlikely to be a problem.	Data management for the project coordinated by PNNL.	Scope of data and system to bed.	2	3	6	Set up electronic data management system with off-site backups. Standardize data formats.	Maintain data management system and standardized formats.
33	11.05.00.	Multi-party project	CCS projects may involve multiple participants for CO2 supply, CO2 transportation, EPC (engineering, procurement and construction), CO2 storage, computer simulation, MVA (monitoring, verification and accounting), carbon trading, and risk management. There are challenges and risks in coordinating the responsibilities and liabilities among multiple organizations involved in a project.	Lack of communication, coordination and cooperation among project participants can lead to project delays and failure to achieve project objectives.	Unlikely to be a problem.	Project involves multiple parties. Successful system set up in Phase I to coordinate work.	Finalize parties that will be involved in Phase 2.	2	3	6	Maintain weekly secure website, weekly conference calls, cross-functional working groups and management team.	Maintain weekly secure website, weekly conference calls, cross-functional working groups and management team.
34	12.00.00.	ENGINEERING RISKS										
35	12.01.00.	Technical design	Technical design errors can be cause by: 1. Insufficient data 2. Lack of data - typical of greenfield sites 3. Inaccurate data 4. Misinterpretation of data 5. Use of wrong standards - unit conversion 6. Specification errors 7. Undefined specifications 8. Ignoring data 9. Calculation and modeling errors 10. Failure to design for full range of operating conditions and climate conditions. 11. Failure to design for high operating availability 12. Failure to design for failsafe protection for compression, pipeline, injection well control systems to ensure no unintended release of CO2	Technical design errors can lead to poor performance or failure of equipment/systems and possible CO2 release.	Possible problem.	Sites may have large number of existing wellbores that may have insufficient records.	Accuracy and completeness of subsurface and wellbore data.	3	3	9	Conduct periodic design reviews with cross-functional team of experts.	Conduct periodic design reviews with cross-functional team of experts.
36	12.02.00.	Modeling and simulation	Use of multiple static and dynamic models that are populated and run by different people using different assumptions and methods can result in errors.	Modeling and simulation errors can result in uncertainties, interpretive disagreements and poor operational choices.	Possible problem.	Using Eclipse as basic simulation model	Accuracy and completeness of subsurface and wellbore data. Accuracy of model(s).	3	3	9	Standardize on model(s) to be used. Review of simulation model results for accuracy and completeness by cross-functional team of experts.	Periodic review of simulation model results.

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37	12.03.00.	Baseline studies	Baseline surveys are important for determining ambient or background conditions prior to CO2 injection. They include: 1. Soil baseline 2. Water baseline 3. Atmosphere baseline 4. Seismic baseline	Without baseline surveys the project will be unable to quantify what impact the project has had on the environment.	Not a problem.	Baseline studies planned for injection sites.	Results of baseline studies.	1	3	3	Complete baseline studies before CO2 injection.	Review results of baseline studies.
38	13.00.00.	PROCUREMENT RISKS										
39	13.01.00.	Procurement delays	Procurement delays may threaten project goals. Infrastructure components may include power block, compressors, gas processing equipment, pumps, valving, metering and monitoring equipment. 1. Procurement delays - equipment and infrastructure 2. Procurement delays - drilling services 3. Vendor supply chain disruptions 4. Material supply shortages 5. Changes in materials and equipment costs	Could delay completion of construction	Possible problem.	Project can meet current startup schedule even with some delays in procurement.	Confirm long -lead times.	3	2	6	Establish lead times for historically long-lead time items (like compressors) and build it into the schedule.	Monitor delivery schedule after orders are placed.
40	13.02.00.	Vendor errors	1. Vendor engineering errors 2. Defective manufacturing	Potential poor performance or failure of equipment/systems. Potential CO2 leakage.	Possible problem.	Vendors not finalized yet.	Finalize site selection, equipment specs and vendors.	3	2	6	Use qualified vendors. Review vendor engineering design and QC testing.	Review vendor engineering design and QC testing.
41	13.03.00.	Contracting	The ability of project partners to formulate and execute contracts with third parties (non-partners) in a timely manner (not causing delays) apart from their specific contents. 1. EPC contract omissions 2. EPC contract insufficient detail 3. EPC contract change orders	The principal risk is delay and its impact upon achieving goals including cost.	Possible problem.	Contractors not finalized yet.	Finalize contractor bidding list.	3	2	6	Use experienced contract administrator. Implement procedure for preparing request for quote (RFQ), RFQ review and bid review. Get at least 3 bids on large contracts. Establish change order procedure.	Use experienced contract administrator.
42	13.04.00.	Transportation logistics	Project-related traffic in and out of site; its effects upon both injection well, monitoring and CO2 supply operations. 1. Site traffic impact on injection and monitoring 2. Limitations on size/height/weight shipments to site	Could cause interruptions and delays.	Unlikely to be a problem.	Sites have access to major highways. Major items unlikely to exceed normal weight and size restrictions.	Finalize site selection.	2	2	4	Identify major weight/size items, supply/destination route and transportation mode.	Monitor transportation logistics after orders are placed.
43	14.00.00.	CONSTRUCTION RISKS										

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44	14.01.00.	Cost overruns	Construction cost overruns can be due to 1. Change orders 2. Cost escalation 3. Unexpected problems 4. Rework 5. Poor management.	Increased costs	Possible problem.	Detailed budget will be prepared.	Finalize site selection and budget.	3	3	9	Negotiate not to exceed EPC contracts. Prepare detailed budget. Have experienced experts review budgets for accuracy and completeness.	Use experienced project managers. Monitor actual versus budgeted expenses. Monitor quality of work. Address deviations from plan early. Prioritize expenses. Cut low priority expenses if necessary. Adjust scope of work if necessary to stay within budget.
45	14.02.00.	Schedule delays	Construction schedule delays can be due to 1. Permitting delays 2. Bad weather 3. Labor issues 4. Procurement delays 5. Accidents 6. Poor planning/management 7. Funding delays	Startup delay and increased costs.	Possible problem.	Procedure for resolving schedule delays will be addressed in the project management plan.	Finalize site selection and schedule	3	3	9	Build in cushion in schedule to accommodate unexpected delays. Address procedure for resolving schedule delays in project management plan.	Monitor work in progress versus schedule. Adjust schedule to accommodate unexpected delays.
46	14.03.00.	Construction defects	Construction defects may be identified during or after construction. They may include 1. Improper installation 2. Wrong installation 3. Damage during installation 4. Defective welding 5. Omissions	Increased costs, project delays due to need for rework, and potential human injury and equipment/systems damage	Possible problem.	Project will use qualified contractors.	Finalize contractor lists and scopes of work.	3	3	9	Use qualified contractors. Issue detailed contracts and drawings. Inspect work.	Inspect work. Require contractors to repair any defects.
47	15.00.00.	COMMISSIONING AND STARTUP RISKS										
48	15.01.00.	Major rework	Major rework may be required to correct poor performance or failure of equipment/systems due to improper design, manufacturing, construction or operation.	Project delays and added costs.	Unlikely to be a problem.	Experienced contractors will be used.	Finalize scopes of work.	2	2	4	Use experienced contractors. Construction management supervision.	Periodic site visits by stakeholders to inspect the work through the construction phase.

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49	15.02.00.	Unable to achieve design capacity	Operating capacity may be limited due to improper design, manufacturing, construction or operation.	Loss of revenues and increased costs.	Unlikely to be a problem.	Pipelines will be designed for expansion. Additional wells can be installed if necessary.	Finalize site selection and equipment specs.	2	2	4	Design review process including sign off on drawings by competent engineers.	Performance testing. Resolution of bottlenecks.
50	15.03.00.	Operator error	Incorrect operation due to lack of operator training	Potential human injury, equipment damage, project delays, added costs.	Possible problem.	Operator training program to be implemented	Finalize positions for training.	2	3	6	Implement operator training program in design phase.	Maintain ongoing operator training program in the operation phase.
51	16.00.00.	FIELD SAFETY RISKS										
52	16.01.00.	Accidents	<p>Project related accidents can be caused by human error or equipment/system failure/malfunction. Accidents may occur during construction, commissioning, operation, maintenance or closure.</p> <p>Non-project related accidents may include: rupture of train or truck transport vessel, train derailment, site or water supply contamination.</p> <p>1. Project related accidents 2. Non-project related accidents</p>	<p>Potential for human injury and/or equipment damage</p> <p>Accidental loss can result in Business Interruption / Advanced Loss of Profit type exposure, or even result in the project becoming uneconomic to continue.</p>	Possible problem.	IMCCS project personnel will receive HSE training before working in the field. An emergency response plan and risk management plan will be developed early in Phase 2.	Final site selection and associated safety risks.	3	2	6	<p>HSE training for operators and HSE audits during construction and operation.</p> <p>Emergency response planning. Risk management plan.</p>	<p>HSE training for operators and HSE audits during construction and operation.</p> <p>Emergency response planning. Risk management plan.</p> <p>Liability insurance.</p>
53	16.02.00.	Moving equipment	<p>Moving equipment risks may include:</p> <p>1. Hitting other equipment 2. Hitting personnel 3. Hitting power lines</p>	Potential for human injury and/or equipment damage	Possible problem.	IMCCS project personnel will receive HSE training before working in the field. An emergency response plan and risk management plan will be developed early in Phase 2.	Final site selection and associated safety risks.	3	3	9	<p>HSE training for operators and HSE audits during construction and operation.</p> <p>Emergency response planning. Risk management plan.</p>	<p>HSE training for operators and HSE audits during construction and operation.</p> <p>Emergency response planning. Risk management plan.</p> <p>Liability insurance..</p>
54	16.03.00.	Excavation/drilling	The one-call system should be used to locate underground utilities and pipelines before excavating or drilling. Excavation/drilling could hit other subsurface hazards such as gas pockets or underground storage tanks.	Potential for equipment damage, release of gases or liquids, fire, explosion, and/or human injury.	Possible problem.	IMCCS project personnel will receive HSE training before working in the field. An emergency response plan and risk management plan will be developed early in Phase 2.	Final site selection and associated safety risks.	3	3	9	<p>HSE training for operators and HSE audits during construction and operation.</p> <p>Emergency response planning. Risk management plan.</p>	<p>HSE training for operators and HSE audits during construction and operation.</p> <p>Emergency response planning. Risk management plan.</p> <p>Liability insurance.</p>

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55	16.04.00.	Defective equipment	Equipment should be properly maintained and regularly inspected. Equipment defects may include: 1. Exposed electric wiring 2. Leaky hoses 3. Loose connections 4. Frayed cables	Higher risk for equipment failure and human injury	Possible problem.	IMCCS project personnel will receive HSE training before working in the field. An emergency response plan and risk management plan will be developed early in Phase 2.	Final site selection and associated safety risks.	3	3	9	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan.	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan. Liability insurance..
56	16.05.00.	Use of power tools	Operators should be properly trained in the use of power tools.	Potential for human injury and/or equipment damage	Possible problem.	IMCCS project personnel will receive HSE training before working in the field. An emergency response plan and risk management plan will be developed early in Phase 2.	Final site selection and associated safety risks.	3	3	9	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan.	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan. Liability insurance.
57	16.06.00.	Contact with rotating equipment	Proper safeguards should be used to prevent contact with rotating equipment	Higher risk for being injured	Possible problem.	IMCCS project personnel will receive HSE training before working in the field. An emergency response plan and risk management plan will be developed early in Phase 2.	Final site selection and associated safety risks.	3	3	9	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan.	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan. Liability insurance.

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58	16.07.00.	Working near pinch points	Proper safeguards should be used to prevent contact with pinch points	Higher risk for being pinched	Possible problem.	IMCCS project personnel will receive HSE training before working in the field. An emergency response plan and risk management plan will be developed early in Phase 2.	Final site selection and associated safety risks.	3	3	9	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan.	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan. Liability insurance.
59	16.08.00.	Working in confined areas	Working in confined areas can represent high risk especially where CO2 is involved.	Higher risk of asphyxiation or being crushed.	Possible problem.	IMCCS project personnel will receive HSE training before working in the field. An emergency response plan and risk management plan will be developed early in Phase 2.	Final site selection and associated safety risks.	3	3	9	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan.	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan. Liability insurance.
60	16.09.00.	Working in high places	Working in high places is a common industrial occurrence	Higher risk of injury due to falling	Possible problem.	IMCCS project personnel will receive HSE training before working in the field. An emergency response plan and risk management plan will be developed early in Phase 2.	Final site selection and associated safety risks.	3	3	9	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan.	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan. Liability insurance.

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61	16.10.00.	Working in trench/ditch	Pipeline construction involves trenching which is subject to cave-ins. Sufficient shielding or cave-in protection devices should be used if people go into a trench	High risk of being crushed and/or asphyxiated	Possible problem.	IMCCS project personnel will receive HSE training before working in the field. An emergency response plan and risk management plan will be developed early in Phase 2.	Final site selection and associated safety risks.	3	3	9	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan.	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan. Liability insurance.
62	16.11.00.	Working under a lifted load	Working under a lifted load should be avoided	Higher risk for being crushed	Possible problem.	IMCCS project personnel will receive HSE training before working in the field. An emergency response plan and risk management plan will be developed early in Phase 2.	Final site selection and associated safety risks.	3	3	9	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan.	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan. Liability insurance.
63	16.12.00.	Contact with venomous snakes or insects	Field operations and data collection can be in close proximity to venomous snakes and insects in some parts of the country.	Potential for human injury.	Unlikely problem.	IMCCS project personnel will receive HSE training before working in the field. An emergency response plan and risk management plan will be developed early in Phase 2.	Final site selection and associated safety risks.	2	2	4	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan.	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan. Liability insurance..

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64	16.13.00.	Contact with poisonous plants	Field operations and data collection can be in close proximity to poisonous plants such as poison ivy or poison oak in some parts of the country.	Potential of human rash/irritation	Unlikely problem.	IMCCS project personnel will receive HSE training before working in the field. An emergency response plan and risk management plan will be developed early in Phase 2.	Final site selection and associated safety risks.	2	1	2	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan.	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan. Liability insurance.
65	16.14.00.	Contact with hot surface, or exposure to heat or flame	Overheated equipment, welding areas, heaters and open flames are present at industrial sites.	Contact with hot surface or flame can cause burn injuries. Exposure to prolonged high temperatures can cause heat exhaustion or dehydration.	Possible problem.	IMCCS project personnel will receive HSE training before working in the field. An emergency response plan and risk management plan will be developed early in Phase 2.	Final site selection and associated safety risks.	3	3	9	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan.	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan. Liability insurance.
66	16.15.00.	Exposure to noise	Operation of heavy equipment, pumps and compressors can generate loud noise.	Prolonged exposure to loud noise can cause hearing damage.	Possible problem.	IMCCS project personnel will receive HSE training before working in the field. An emergency response plan and risk management plan will be developed early in Phase 2.	Final site selection and associated safety risks.	3	2	6	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan.	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan. Liability insurance.

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67	16.16.00.	Exposure to dust	Dust is generated in pipeline construction and field operations.	Prolonged exposure to dust can cause respiratory health problems.	Possible problem.	IMCCS project personnel will receive HSE training before working in the field. An emergency response plan and risk management plan will be developed early in Phase 2.	Final site selection and associated safety risks.	3	1	3	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan.	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan. Liability insurance.
68	16.17.00.	Exposure to hazardous materials	Fluids, fuels and chemicals used in field operations may be classified as hazardous materials.	Prolonged exposure to hazardous materials are known to cause health problems.	Unlikely problem.	IMCCS project personnel will receive HSE training before working in the field. An emergency response plan and risk management plan will be developed early in Phase 2.	Final site selection and associated safety risks.	2	2	4	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan.	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan. Liability insurance.
69	16.18.00.	Exposure to flying debris	Drilling can often generate flying debris	Flying debris can cause human injury and/or equipment damage.	Unlikely problem.	IMCCS project personnel will receive HSE training before working in the field. An emergency response plan and risk management plan will be developed early in Phase 2.	Final site selection and associated safety risks.	2	3	6	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan.	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan. Liability insurance.

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70	16.19.00.	Release of compressed gases or liquids	Compressed CO2 pipelines, pressurized water lines, compressed air tanks are at risk for rupture.	Release of compressed gases or liquids can cause human injury and/or equipment damage.	Possible problem.	IMCCS project personnel will receive HSE training before working in the field. An emergency response plan and risk management plan will be developed early in Phase 2.	Final site selection and associated safety risks.	3	3	9	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan.	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan. Liability insurance.
71	16.20.00.	Ignition of flammable gases or liquids	Acetylene tanks, natural gas lines, liquid fuel lines could be ignited.	Ignition of flammable gases or liquids can cause explosions, severe injuries and property damage.	Unlikely problem.	IMCCS project personnel will receive HSE training before working in the field. An emergency response plan and risk management plan will be developed early in Phase 2.	Final site selection and associated safety risks.	2	4	8	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan.	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan. Liability insurance.
72	16.21.00.	Trips, slips and falls	Trips, slips and falls are common at industrial sites.	Potential for human injury	Possible problem.	IMCCS project personnel will receive HSE training before working in the field. An emergency response plan and risk management plan will be developed early in Phase 2.	Final site selection and associated safety risks.	3	1	3	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan.	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan. Liability insurance.

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73	16.22.00.	Leaks and spills	Leaks and spills of lubricants, fuels, chemicals or hazardous materials are common at industrial sites. If they are not promptly taken care of they can lead to more serious problems.	Potential for human injury, equipment damage, fire or environmental damage.	Possible problem.	IMCCS project personnel will receive HSE training before working in the field. An emergency response plan and risk management plan will be developed early in Phase 2.	Final site selection and associated safety risks.	3	1	3	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan.	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan. Liability insurance.
74	16.23.00.	Head bumping	Industrial sites are prone to have low hanging or falling objects that could injury unprotected heads	Potential for human head injury	Possible problem.	IMCCS project personnel will receive HSE training before working in the field. An emergency response plan and risk management plan will be developed early in Phase 2.	Final site selection and associated safety risks.	3	1	3	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan.	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan. Liability insurance.
75	16.24.00.	Manual heavy lifting or pulling	Improper lifting or pulling heavy loads.	Potential for human back injury	Possible problem.	IMCCS project personnel will receive HSE training before working in the field. An emergency response plan and risk management plan will be developed early in Phase 2.	Final site selection and associated safety risks.	3	2	6	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan.	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan. Liability insurance.

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76	16.25.00.	On-road driving	Vehicle travel to and from the site is typically among the highest risks in similar projects	Potential for human injury and/or equipment damage	Possible problem.	IMCCS project personnel will receive HSE training before working in the field. An emergency response plan and risk management plan will be developed early in Phase 2.	Final site selection and associated safety risks.	3	3	9	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan.	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan. Liability insurance.
77	16.26.00.	Off-road driving	Field data collection often requires off-road driving, sometimes in rocky, muddy, or steep terrain. Some personnel may lack experience with safe driving under challenging conditions.	Potential for human injury and/or equipment damage	Possible problem.	IMCCS project personnel will receive HSE training before working in the field. An emergency response plan and risk management plan will be developed early in Phase 2.	Final site selection and associated safety risks.	3	3	9	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan.	HSE training for operators and HSE audits during construction and operation. Emergency response planning. Risk management plan. Liability insurance.
78	17.00.00.	LEGAL RISKS										
79	17.01.00.	CO2 legislation	<p>Some outstanding CO2 legislation issue are as follows:</p> <ol style="list-style-type: none"> 1. Cap and Trade or Carbon tax incentives for CCS 2. Certification process for tradable carbon credits 3. Pore space access and ownership 4. Certification for transfer of long-term stewardship/liability for closed CO2 sites from operator to competent legal authority 5. Eminent domain authority 6. Forced unitization for EOR or ECBM 7. Priority of mineral rights over pore space rights 8. Value of escaped CO2 	<p>Legislation can have a significant impact on CCS project economics.</p> <p>Lack of, or gaps in, CO2 legislation can create uncertainty for the project and make it more difficult to permit and finance the project.</p> <p>Concerns that enacted CO2 legislation could be repealed or changed also contribute to uncertainty for the project and make it more difficult to finance.</p>	Possible problem.	IMCCS project is focusing on EOR in the short term until sufficient incentives are in place for CCS.	Timing and content of CCS legislation.	3	3	9	Focus short-term on EOR until there is sufficient incentives in place for CCS. Encourage CCS legislation to incentivize CO2 capture and storage (CCS). Implement public outreach program.	Monitor CCS legislation and analyze the impact of legislation on the project. Continue public outreach program.

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80	17.02.00.	CO2 regulations	<p>Some outstanding CO2 regulation issue are as follows:</p> <ol style="list-style-type: none"> 1. CO2 storage permitting and compliance requirements 2. Permitting and compliance for Class VI wells 3. Permitting and compliance for hybrid Class II and VI wells (wells used for both EOR and DSA) 4. Post-injection site care (monitoring) period - EPA proposing 50 years with some flexibility 5. Safety guidelines - DOE best practices guidelines 6. Monitoring protocols - DOE guidelines 7. Verification and accounting procedures 8. Classification of CO2 as a pollutant rather than a commodity 9. CO2 emission controls and reporting 	<p>Regulations can have a significant impact on CCS project economics.</p> <p>Lack of, or gaps in, CO2 regulations can create uncertainty for the project and make it more difficult to permit and finance the project.</p> <p>Classification of CO2 as a pollutant rather than a commodity could impact EOR/ECBM operations.</p>	Possible problem.	IMCCS project is focusing on EOR in the short term because current/proposed regulations would make DSA sequestration uneconomic.	Timing and content of CCS regulations.	3	3	9	Focus short-term on EOR until regulations for CCS are finalized. Implement public outreach program.	Comply with regulations as they are issued.
81	17.03.00.	CO2 liabilities	<p>Responsibility for the injected CO2 and any associated liability, during and after active project phase, is currently an unresolved legal issue. Project participants could reduce their involvement if this issue remains unresolved, or is resolved in a manner that unacceptably increases their exposure.</p> <ol style="list-style-type: none"> 1. CO2 ownership and custody 2. Tort-injury to a third party (person or property) 3. Property-rights dispute 4. Trespass - contamination of third-party natural resources 5. Trespass - infringement on third-party pore space 6. Breach of duty - leakage sufficient to undermine the value of carbon credits 7. Frivolous lawsuits private or organizational based legal challenges 8. Surface ownership and associated liability 9. Assigning liability responsibility in a multi-party project 	<p>Liability for potential damages associated with sequestration or operational aspects could preclude the project from moving forward.</p> <p>Property-right disputes over surface rights, mineral rights or pore space could halt or restrict construction, CO2 injection or monitoring operations for CCS projects.</p>	Possible problem.	IMCCS project is focusing on EOR in the short term. This is likely to have fewer liability issues than CCS.	Availability and cost of insurance to cover liabilities.	3	2	6	Obtain liability insurance.	Obtain liability insurance.
82	17.03.01	Lack of available insurance	<p>There are many types of insurance coverage. Some of those that pertain to CCS include:</p> <ol style="list-style-type: none"> 1. physical damage 2. machinery breakdown 3. business interruption (advanced loss of profit) 4. environmental, and 5. third-party liability. 	Insurance coverage may not be available for CCS projects until there is a sufficient track record of performance (or failure) to determine the probability of failure occurring.	Very likely to be a problem.	Marsh has been assigned to obtain insurance for the IMCCS project.	Availability and cost of insurance.	4	3	12	Self insure. Work with a competent insurance broker to prepare Estimated Maximum Loss Analyses and underwriting reports for the project and source insurance coverage	Self insure. Work with a competent insurance broker to prepare Estimated Maximum Loss Analyses and underwriting reports for the project and source insurance coverage

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83	17.03.02	Transfer of long-term liability/stewardship	Public companies cannot take on long-term liability for 50 years or more. There is no guarantee companies will stay in business that long. Therefore it is up to a government entity to take on responsibility. The federal government would be preferred because it would level the playing field among states and spread the risks. A sinking fund could be used to cover the costs of such a program.	Companies are unlikely to invest in deep saline aquifer (DSA) sequestration projects without some assurance that the long-term liability is transferable or manageable.	Unlikely to be a problem with EOR but definitely a problem with DSA.	The IMCCS project has focused on EOR rather than DSA in part because of the additional liabilities associated with DSA.	Legislation covering long-term liability of CO2 sequestration.	4	3	12	Encourage the federal government to establish a sinking fund for CCS and pass legislation to allow transfer of long-term liability	Monitor CO2 legislation and take corrective action as necessary.
84	18.00.00.	CO2 CAPTURE RISKS										
85	18.01.00.	CO2 capture system performance	Performance risks for CO2 capture systems could include: 1. Production below design capacity 2. Unable to meet product specification 3. Low CO2 recovery 4. Low thermal efficiency - greater heat losses than expected, low heat recovery 5. Excess solvent or sorbent consumption 6. Excess power consumption 7. Excess steam consumption 8. Excess cooling water circulation required 9. Excess maintenance 10. Low process availability 11. Low mechanical availability	Poor performance of the CO2 capture system can result in higher operating and maintenance costs, interruption of CO2 supply, and/or off spec CO2.	Likely problem at Kansas Ethanol meeting CO2 specification due to batch operation resulting in inconsistent CO2 quality.	CO2 capture existing at Coffeyville Resources and Kansas Ethanol. C	CO2 quality and consistency at Kansas Ethanol.	4	3	12	Require performance data from Kansas Ethanol to prove they can consistently meet CO2 spec. Require CO2 quality guarantee from Kansas Ethanol and Coffeyville Resources.	Adjust Kansas Ethanol system design to consistently meet CO2 specification.
86	18.02.00.	CO2 capture system design	Design deficiencies for CO2 capture systems could include: 1. Scale-up errors 2. Equipment undersized/oversized for proper residence time 3. Equipment undersized/oversized for proper surface area 4. Excess velocities 5. Inadequate expansion joints 6. System bottlenecks 7. Inadequate instrumentation 8. Inadequate process controls and alarms 9. Inadequate computer simulation models 10. Wrong sorption model for the contacting devise 11. Insufficient winterization 12. Wrong materials of construction 13. Lack of emergency flare/vent 14. Lack of surge capacity 15. Lack of redundancy -backup systems	Design deficiencies can result in poor performance, higher operating and maintenance costs, interruption of CO2 supply, and/or off-spec CO2..	Not a problem.	CO2 capture existing at Coffeyville Resources and Kansas Ethanol. No new CO2 capture unit in IMCCS project.	CO2 quality and consistency at Kansas Ethanol.	1	3	3	Source CO2 from existing capture facilities with proven reliability and consistent product quality. .	Identify backup sources of CO2 supply.

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87	18.03.00.	CO2 capture system economies-of-scale	<p>The limits on scale up of the CO2 capture system could include:</p> <ol style="list-style-type: none"> 1. Equipment size limits - manufacturing, transport, or structural load limits 2. Heat transfer limits 3. Mass transfer limits 4. Diffusion limits 5. Surface area limits 6. Reaction kinetics limits 	Limits in scale up of the CO2 capture system can lead to higher capital cost and higher operating costs.	Not a problem.	CO2 capture existing at Coffeyville Resources and Kansas Ethanol. No new CO2 capture unit in IMCCS project.	Type of CO2 capture unit to be used if source other than Kansas Ethanol or Coffeyville Resources.	1	3	3	Source CO2 from existing capture facilities with proven reliability and consistent product quality. .	Identify backup sources of CO2 supply.
88	18.04.00.	CO2 capture system operations	<p>System operating risks for CO2 capture systems could include:</p> <ol style="list-style-type: none"> 1. Non-equilibrium or non-steady-state conditions 2. Exothermic reactions overheating the process 3. Endothermic reactions overcooling the process 4. Pressure/stress buildup 5. Non-uniform mass distribution/dispersion/mixing – dead zones, stratification 6. Non-uniform temperature distribution – hot/cold spots, stratification 7. Mass and energy imbalance 8. System imbalance 9. Pressure or temperature cycling 10. System upset – unexpected high flow rate/temperature, carryover of upstream contaminants 11. Off-spec or inconsistent feed and/or product 12. Abrasion/erosion 13. Corrosion 14. Fouling 15. Contactor plugging 16. CO2 escape/leakage to the atmosphere 17. Scale build up causing heat exchanger failure 18. Air leakage - nitrogen dilution 19. Equipment failure due to defects, plugging, wear 20. Control system failure 21. Material/weld failure - leaks 22. Operator error 	Operation and maintenance problems can result in higher operating and maintenance costs, CO2 supply interruptions and off-spec CO2.	Unlikely to be a problem.	CO2 capture existing at Coffeyville Resources and Kansas Ethanol. Consistently high plant availability demonstrated.	Actual performance data from Kansas Ethanol and Coffeyville Resources.	2	3	6	Comprehensive maintenance program. Maximize time at steady-state operation.	Comprehensive maintenance program. Maximize time at steady-state operation.

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89	18.05.00.	CO2 capture solvent or sorbent	<p>Solvent or sorbent risks for CO2 capture could include:</p> <ol style="list-style-type: none"> 1. Off-spec or inconsistent solvent or sorbent 2. Unexpected contamination (SOx, NOx, Cl, H2O, hydrocarbons, trace metals, chemical slip, particulate matter) 3. Gradual buildup of contaminants in circulating loads 4. Foaming 5. Chemical reactions with contaminants - precipitation of solids 6. Excess viscosities 7. Chemical degradation of solvent or sorbent 8. Thermal degradation of solvent or sorbent 10. Aging (deactivation) of solvent or sorbent 11. Hazardous material handling 	Off spec or degraded solvent or sorbent can result in poor CO2 capture, higher operating costs, CO2 supply interruptions, and off-spec CO2.	Unlikely to be a problem.	CO2 capture solvents and sorbents not used at Kansas Ethanol.	Performance of Selexol solvent at Coffeyville Resources.	2	3	6	Monitor solvent performance. Avoid conditions that would result in solvent foaming or degradation.	Monitor solvent performance. Avoid conditions that would result in solvent foaming or degradation.
90	19.00.00.	DEHYDRATION RISKS										
91	19.01.00.	CO2 dehydration system performance	<p>Performance risks for CO2 dehydration systems could include:</p> <ol style="list-style-type: none"> 1. Production below design capacity 2. Unable to meet product specification 3. Excess glycol consumption 4. Carryover of glycol into downstream systems 5. Excess utility consumption 6. Excess maintenance 7. Low plant process and/or mechanical availability 	Poor performance of the CO2 dehydration system can result in higher operating and maintenance costs, interruption of CO2 supply, off spec CO2, and corrosion of downstream systems.	Dehydration units are normally fairly reliable as long as they are maintained, and avoid upset conditions and/or contamination. Performance problems are most likely occur in the Kansas Ethanol dehydration unit because of inconsistent feed gas composition and flow rate.	Dehydration units will be installed at Coffeyville Resources and Kansas Ethanol.	<p>Performance data/experience for the specific dehydration units.</p> <p>Performance data for Kansas Ethanol flow rate and gas composition over a batch cycle.</p>	3	3	9	Implement a preventative maintenance program. Try to maximize steady-state operation. Avoid upsets and contamination.	Resolve maintenance, system upset and contamination problems quickly.

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92	19.02.00.	CO2 dehydration system operation	<p>Operating risks for CO2 dehydration systems could include:</p> <ol style="list-style-type: none"> 1. Upset conditions 2. Foaming in the contactor 3. Fouling 4. Buildup of liquid contaminants in recycled glycol 5. Buildup of solid contaminants in recycled glycol 6. Contactor plugging due to fouling 7. Reboiler tube failure due to fouling 8. Heat exchanger failure due to fouling 9. Pump seal failure due to fouling 10. Corrosion - wrong materials of construction 11. Oxidation degradation of glycol 12. Thermal degradation of glycol 	Operating problems in the CO2 dehydration system can result in higher operating and maintenance costs, interruption of CO2 supply, off spec CO2, and corrosion of downstream systems.	Dehydration units are normally fairly reliable as long as they are maintained, and avoid upset conditions and/or contamination. Foaming, fouling and contamination would most likely occur in the Kansas Ethanol dehydration unit because of inconsistent feed gas composition and flow rate.	Dehydration units will be installed at Coffeyville Resources and Kansas Ethanol.	<p>Performance data/experience for the specific dehydration units.</p> <p>Performance data for Kansas Ethanol flow rate and gas composition over a batch cycle.</p>	3	3	9	Implement a preventative maintenance program. Try to maximize steady-state operation. Avoid upsets and contamination.	Resolve maintenance, system upset and contamination problems quickly.
93	20.00.00.	COMPRESSION RISKS										
94	20.01.00.	CO2 compression system performance	<p>Performance risks for CO2 compression systems could include:</p> <ol style="list-style-type: none"> 1. Output below design capacity 2. Unable to meet pressure specification 3. Excess power consumption 4. Excess maintenance 5. Low mechanical availability 	CO2 compressor operating performance is critical to success of a CCS project.	Problems with performance are most likely to occur with the Kansas Ethanol compression unit.	Kansas Ethanol generates CO2 through a batch fermentation process which results in fluctuating flow rates over time. A surge tank may be needed to even out flow rates prior to compression.	<p>Performance data for Kansas Ethanol flow rate and gas composition over a batch cycle.</p> <p>Capability of the specific compressor to handle swings in flow rate.</p>	3	2	6	Assure proper design and installation. Implement a preventative maintenance program. Try to maximize steady-state operation. Avoid upset conditions.	Resolve maintenance, system upset and contamination problems quickly.
95	20.02.00.	CO2 compression system EPC	<p>Engineering, procurement and construction (EPC) risks for compression systems could include:</p> <ol style="list-style-type: none"> 1. Procurement delays - Compressors are typically one of the longest lead items for equipment 2. High capital cost - compression systems are one of the major capital costs for CCS projects 3. Improper specification 4. Metallurgical defect 5. Manufacturing defect 6. Improper installation 	Delays in project startup. Increased capital cost. Operating problems resulting from improper specification or installation.	Possible procurement delays.	Compressor specification may change depending on site selection.	Hard quotes on compressor costs and lead times.	3	2	6	Select qualified EPC contractor.	Inspect and test equipment. Require vendor/contractor to fix defects.

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96	20.03.00.	Compressor type	1. Reciprocating compressors - lower capital, higher maintenance, may require spare capacity 2. Centrifugal compressors - higher capital, lower maintenance 3. Screw compressors (dry type)	Type of compressors selected can impact capital costs, operating costs and operating availability.	Unlikely to be a problem	Kansas Ethanol will use reciprocating compressors. Coffeyville Resources will use centrifugal compressors/pumps.	Performance data/experience for the specific compressor units.	2	2	4	Select qualified engineering company and vendors. Proper selection of the compressor type for the specific application.	Proper installation, operation and maintenance.
97	20.04.00.	Compression system operation	Operating risks for CO2 compression systems: 1. Improper operation - Intermittent operation of the compressor - Operating above/below recommended limits - Upset conditions - Operating compressor with control valve closed - Fouling by dust or liquid droplets - Plugging relief valves during depressurization - Corrosion - due to water in CO2 stream 2. Improper maintenance - Vibration - Noise - Overheating - Leakage 3. Wear and failure - Rod drop due to ring wear on recip. comp. - Rod run out or rod deflection on recip. comp. - Valve failure on recip. comp. - Bearing wear/failure - Tip wear on cent. comp. - Impeller blade failure on cent. comp. - Shaft failure - Compressor catastrophic failure	Downtime, loss of revenue, increased maintenance costs.	Unlikely to be a problem.	The CO2 compression units will operate for a three year period during the project.	Performance data/experience for the specific compressor units.	2	2	4	Assure proper design and installation. Implement a preventative maintenance program. Try to maximize steady - state operation. Avoid upset conditions.	Resolve maintenance, system upset and contamination problems quickly.
98	21.00.00.	PIPELINE RISKS										
99	21.01.00.	Pipeline routing risks										
100	21.01.01.	New versus existing right-of-way (ROW)	ROW issues include: 1. Single or multiple pipeline rights 2. Width of ROW 3. Rights for above ground facilities 4. Access to site for repair/modification and inspections 5. Payment for original and continued use of ROW 6. Damage awards for the property owner 7. Requirement for pipeline removal upon abandonment of the pipeline. 8. Eminent domain - used as a last resort to gain access to ROW	Developing a new ROW is significantly more riskier than using an existing utility ROW.	Unlikely to be a problem.	Pipelines will use existing pipeline corridors.	Final site and pipeline ROW selections.	2	3	6	Maximize use of existing pipeline corridors in laying out pipeline ROW.	Design around problem areas.

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101	21.01.02.	Climate conditions	Weather conditions can impact pipeline surface facilities 1. Severe high or low temperatures 2. Significant winds (tornadoes) 3. Lightning - common cause of pipeline damage 4. Heavy rain fall - flooding 5. Severe winter storms	Delays in construction and damage to surface facilities.	Possible problem with tornadoes, heavy rain, lightning, severe winter storms.	Pipelines will be buried under ground. Surface areas may be exposed to climate conditions.	Final site and pipeline ROW selections.	3	2	6	Design pipeline surface facilities for full range of climate conditions.	Monitor for severe weather reports.
102	21.01.03.	Soil and terrain conditions	1. Thin soil - insufficient to bury pipeline to depth 2. Corrosive soil - high moisture, high electrical conductivity, high acidity, and high dissolved salts 3. Rocky soil - special care needed in backfilling to protect pipeline 4. Unstable land - subsidence - uplift - landslides - earthquake area - active fault zone - high erosion areas - flood plains, dry wash - permafrost - frost heaves - high water table (marshes, swamps, peat bogs) - moving sand dunes - underground mine/coal mine areas - steep slopes >18% (landslides or erosion) 5. Rugged terrain/topography - mountains, hills, canyons, gorges 6. Significant elevation increase or variation over length of pipeline 7. Low lying areas 8. Exposed granite bedrock	1. Need to add soil to achieve 1.2 -1.8 m (4-6ft) burial depth 2. Accelerated external corrosion 3. Need fine backfill to protect pipeline 4. Can lead to unintended movement or abnormal loading of a pipeline resulting in mechanical damage, leakage or rupture. 5. Significantly higher installation cost 6. Increased compression or pumping costs due to higher pressure drop across pipeline 7. Potential for leaked CO2 to accumulate in low lying areas if there is insufficient escape velocity or wind to disperse the leaked CO2 to the atmosphere. 8. Very high costs for blasting a pipeline trench	Possible problems with erosion and flooding.	Pipelines will be buried under ground.	Final site and pipeline ROW selections.	3	2	6	Avoid steep slopes, rugged terrain, flood plains, low-lying areas, rocky areas, unstable land.	Bring in fine backfill for pipeline in rocky areas. Regularly inspect and repair unstable areas.

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103	21.01.04.	Populated areas	<p>A high population area means an urbanized area, as defined by the Census Bureau, that contains 50,000 or more people and has a population density of at least 1000 people per square mile. This is designated a high consequence area. (49 CFR Part 195.450) Other populated areas are also designated as high consequence areas. Non rural areas categorized as high risk. Rural areas categorized as low risk. (49 CFR Part 195 Appendix B)</p> <p>Pipeline right-of-way must be selected to avoid, as far as practicable, areas containing private dwellings, industrial buildings, and places of public assembly. No pipeline may be located within 15 m (50 feet) of any private dwelling, or any industrial building or place of public assembly in which persons work, congregate or assemble, unless it is provided with at least 0.3 m (12 inches) of cover in addition to that prescribed in Section 195.238 (49 CFR Part 195.210).</p> <p>CO2-CRC recommends a 30 m (100 ft) wide easement restricting access to the buried pipeline, a distance of 100 m (330 ft) minimum distance from residential buildings and a 1,000 m (3,300 ft) consultation zone on either side of the pipeline for emergency notification.</p> <ol style="list-style-type: none"> 1. High population density nearby 2. Sensitive receptors (schools, hospitals, nursing homes, prisons) nearby 3. Business/industry/mining nearby 4. Residences nearby 	The greater the number of people, the greater the risk of exposure to CO2.	Unlikely to be a problem.	Pipelines will use existing pipeline corridors.	Final site and pipeline ROW selections.	2	2	4	Avoid dense population areas for pipeline routing.	Design around densely populated areas. Implement a pipeline integrity management program in high consequence areas. Follow 49 CFR Part 195 regulations.

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104	21.01.05.	Land crossings	1. Navigable water ways - Army Corp of Engineers permitting 2. Protected areas - Wetlands, migratory water bird concentration, national parks, habitats for imperiled, threatened, endangered or protected species (aquatic and terrestrial), archeological sites. (49 CFR Part 195.6) 3. Federal land - could trigger the need for permits from the US Army Corp of Engineers, the US Fish and Wildlife, the US Department of the Interior Bureau of Land Management (BLM), the US Department of Agriculture, Forest Service, the US Department of Defense. Also will trigger the National Environmental Policy Act (NEPA) and require Environmental Assessment (EA) or Environmental Impact Statement (EIS) 4. Tribal land - would trigger NEPA (EA or EIS) and the need for a permit from the US Department of Interior Bureau of Indian Affairs (BIA) 5. Transportation corridors - Railroads, highways, roads, bridges, other rights of way could trigger the need for permits from railroad companies, state/county departments of transportation. 6. Drinking water resource areas - 7. Non navigable surface waters - lakes, rivers, streams 8. Existing utility/pipeline rights-of-way	Land crossing increase cost and the need for additional permits.	There are likely to be many crossings for each pipeline but unlikely to be problems if proper procedures are followed.	Pipelines will use existing pipeline corridors.	Final site and pipeline ROW selections.	4	2	8	Avoid sensitive or high consequence areas. Keep crossings to a minimum.	Use seamless pipe and 6 ft burial depth in crossings. Implement pipeline integrity management program in areas of high consequence. Meet or exceed 49 CFR Part 195 regulations. Regularly inspect and repair unstable areas.
105	21.01.06.	Offshore pipeline	The difficulty of offshore construction is roughly proportional to the depth multiplied by the pipeline diameter. (IPCC 2005). Some of the risks include: 1. Sea currents 2. Uneven seabed 3. Biological growth on pipeline 4. Arctic conditions (ice gouging)	Offshore pipeline have significantly higher costs.	Not a problem.	Other than small stream and river crossings, there are no offshore	Final site and pipeline ROW selections.	1	1	1	NA	NA
106	21.02.00.	Pipeline design risks										
107	21.02.01.	Pipeline diameter	1. Large diameter Large diameter pipelines will release more CO2 in a rupture and are thus classified as having greater severity in the case of a failure such as a rupture. 2. Insufficient diameter for capacity Increased pressure required may place too much stress on the pipeline and components. Limits future expansion. 3. Excess diameter for capacity Resulting decreased pressure may put the CO2 at risk of changing from supercritical to two-phases. No room for turndown.	High risk: Pipeline diameter 0.46 m (18 in) and above. Medium risk: Pipeline diameter from 0.25-0.4 m (10 to 16 in). Low risk: Pipeline diameter 0.2 m (8 in) and below. (49 CFR Part 195 Appendix B.	Unlikely to be a problem.	Pipeline diameters are 4 inches for KE to GE and 8 inches for CFV to TA. Therefore they fall into the low risk category.		2	3	6	Size pipeline to effectively handle planned CO2 capacity with option for future capacity expansion by adding booster station(s).	Install block valves to separate sections of pipeline and minimize CO2 release in case of a rupture.

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108	21.02.02.	Pipeline length	The longer the pipeline, the greater the risks.	Long pipeline more expensive, more potential for failure.	Very unlikely to be a problem.	Depending on site selection, the pipeline lengths will range from 14 miles to 120 miles.	Final site and pipeline ROW selections to determine pipeline length.	1	2	2	Keep pipeline length to a minimum without causing right of way issues.	Install block valves to separate sections of pipeline and minimize CO2 release in case of a rupture.
109	21.02.03.	Pipeline failure history (for existing pipeline)	Pipeline failure history for time-dependent defects can indicate probability of future failures.	High risk: >3 leaks in last 10 years. Low risk: ≤3 leaks in last 10 years. (49 CFR Part 195 Appendix B)	Not a problem.	Project will use new pipelines.	NA	1	1	1	NA	NA
110	21.02.04.	Pipeline age(for existing pipeline)	Safety risk increases with the age of the pipeline depending on the pipeline's coating and corrosion condition, and steel quality, toughness, welding.	High risk: >25 years old Low risk: <25 years old (49 CFR Part 195 Appendix C)	Not a problem.	Project will use new pipelines.	NA	1	1	1	NA	NA
111	21.02.05.	Pipeline pressure	All pipeline components must be designed and tested for at least 125% of maximum operating pressure (MOP). If, within a pipeline system, two or more components are to be connected at a place where one will operate at a higher pressure than another, the system must be designed so that any component operating at the lower pressure will not be overstressed. (49 CFR Part 195.104) Pipelines should be designed with sufficient pressure to maintain CO2 as a supercritical fluid. 1. Operating pipeline in excess of maximum operating pressure (MOP). 2. Operating pipeline below the CO2 supercritical pressure (CSP). 3. Insufficient working range between MOP and CSP.	Components operating at excessive operating pressure will be overstressed and subject to failure. Operating the pipeline at or below the supercritical pressure of CO2 can lead to CO2 phase change in the pipeline. If the supercritical CO2 drops back into the liquid-vapor, two-phase region (which occurs below 6.9 MPa (1000 psig) at ambient temperature), there would be freeze-up issues and a much higher pressure drop in the pipeline.	Very unlikely to be a problem.	Pipelines will operate at less than 80% of design pressure.	Final site and pipeline ROW selections to determine pipeline operating pressure.	1	4	4	Operate pipeline at less than 80% of design pressure.	Operate pipeline at less than 80% of design pressure.
112	21.02.06.	Pipeline external loads	Anticipated external loads (e.g.), earthquakes, vibration, thermal expansion, and contraction must be provided for in designing a pipeline system. (See ASME B31.4). The pipe and other components must be supported in such a way that the support does not cause excess localized stresses (49 CFR Part 195.110). The pipe at each railroad and highway crossing must be installed so as to adequately withstand the dynamic forces exerted by anticipated traffic loads (49 CFR Part 195.256).	Insufficient design for external loads could lead to cracking and CO2 leakage.	Very unlikely to be a problem.	Pipelines will be designed to meet or exceed code at crossings.	Final site and pipeline ROW selections to determine pipeline external loads.	1	4	4	Use a qualified contractor to engineer, procure and construct the pipeline. Have experienced engineer check external load factors.	Reinforce pipeline at crossings if necessary.

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113	21.02.07.	Pipeline wall thickness	Thicker pipe is typically used for sensitive areas like crossings. Wall thickness for 0.3 -0.36 m (12-14 in) pipe is typically 9.5 mm (0.375 in) except in sensitive areas like crossings where 12.7 mm (0.5 inch) wall thickness used for road crossings (up to 0.3 m (1 ft) past road right of way) and 15.9 mm (0.625 in) thickness used for railroad crossings. (DGC)	Thicker walls give a better safety margin.	Very unlikely to be a problem.	Seamless pipe will be used for all road, railroad and creek crossings. The KE-GE 102 mm (4 inch) ID pipeline has a wall thickness of 6 mm (0.2737 inch). The CVR-TA 203 (8 inch) ID pipeline has a wall thickness of 12.7 mm (0.5 inch).	Final site and pipeline ROW selections to determine number and type of crossings.	1	4	4	Select pipeline wall thickness that meets or exceeds codes.	
114	21.02.08.	Pipeline steel grade	X65 carbon steel is typically used for CO2 pipeline if CO2 is dry and has low impurities such as H2S.	Pipeline steel grade determines pipeline maximum operating pressure	Very unlikely to be a problem	The KE-GE pipe grade is X-53 and the CVR-TA pipe grade is X-65	Final site and pipeline ROW selections to determine operating pressure and steel grade.	1	4	4	Select pipeline steel grade that meets or exceeds codes.	
115	21.02.09.	Pipeline temperature	CO2 increases in temperature as it is compressed and decreases in temperature as it expands. CO2 entering a pipeline may in the range of 49°C (120°F) however, it will gradually conform to the ambient ground temperature which may be in the range of 10°C (50°F). Components of CO2 pipelines that are subject to low temperatures during normal operation because of rapid pressure reduction or during the initial fill of the line must be made of materials that are suitable for those low temperatures. (49 CFR Part 195.102)	Improper material selection for pipeline components that may experience extreme cold due to rapid pressure reduction may result in component failure and CO2 leakage.	Very unlikely to be a problem.	Pipelines designed for a maximum CO2 inlet temperature of 49°C (120°F). Discharge temperature is 10°C (50°F) or close to ambient ground temperature.	Final site and pipeline ROW selections to determine operating pressure and temperature.	1	4	4	Design compressor interstage coolers to maintain CO2 temperature below maximum.	
116	21.02.10.	Piping type	Seamless pipe is typically used for sensitive areas like crossings or near residences; double submerged arc welded or electric resistance welded pipe is typically used for other areas. (DGC)	Proper piping selection is important in sensitive areas to prevent risk of CO2 leakage.	Very unlikely to be a problem.	Seamless pipe will be used for all road, railroad and creek crossings. Electric resistance welded (ERW) used for all other areas.	Final site and pipeline ROW selections to determine number and type of crossings.	1	3	3	Use seamless pipe for road, rail and creek crossings. Use ERW pipe for other areas.	Use additional reinforcement if necessary.

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117	21.02.11.	Pipeline coating	CO2 pipelines are typically coated with fusion bonded epoxy to prevent corrosion. In addition piping used at bored crossings is overcoated with an abrasion resistant coating to prevent damage to the epoxy coating during installation. (DGC) 1. External coating 2. Internal coating	Damage to pipeline coating during installation or due to third-party excavation can result in external corrosion.	Unlikely to be a problem.	The pipelines will be externally coated with 14-16 mil fusion bond epoxy.	Final site and pipeline ROW selections to determine corrosiveness of the soil.	2	4	8	Coat pipelines with fusion bond epoxy.	Avoid damaging coating during transport or installation.
118	21.02.12.	Pipeline cathodic protection	Cathodic protection on CO2 pipelines is maintained by rectifiers located at main-line valve stations every 32 km (20 miles) or less along the pipeline. Cathodic protection is measured in voltage at test posts located at 1.6 km (1 mi) intervals over the length of the pipeline. The rectifier output is adjusted to maintain voltage levels between 0.85 and 1.4 volts at each test station. (DGC)	Insufficient or lack of cathodic protection could lead to external corrosion and CO2 leakage.	Unlikely to be a problem.	The pipelines will be equipped with cathodic protection.	Final site and pipeline ROW selections to determine corrosiveness of the soil.	2	3	6	Install cathodic protection and voltage test posts at every mile along pipelines.	Monitor cathodic protection voltage over the length of the pipeline and adjust rectifier output to maintain appropriate voltage level.
119	21.02.13.	Pipeline booster stations or pumping stations	Booster or pumping stations are typically needed every 80-320 km (50 to 200 mi) depending on end-use pressure (EERC). Adequate ventilation must be provided in pumping station buildings to prevent the accumulation of CO2 gas. Warning devices must be installed to warn of the presence of CO2 gas in the pumping building. Safety devices to prevent over pressuring of primary and auxiliary pumping equipment and a device for emergency shutdown of each pumping station should be included. If power is necessary to actuate the safety devices, an auxiliary power supply should be included. (49 CFR Part 195.262) Take into account noise levels.	Insufficient booster or pumping stations could lead to low pressure at the end of the pipeline.	Very unlikely to be a problem.	Booster stations not needed at current capacity. Space reserved for booster stations if it is desired to increase pipeline capacity.	Final site and pipeline ROW selections to determine length of pipeline and number of booster stations needed now and in the future.	1	3	3	Size pipeline to effectively handle planned CO2 capacity with option for future capacity expansion by adding booster station(s).	Leave space for booster stations
120	21.02.14.	Pipeline future expansion	If there is potential for future expansion, it is practical to install taps for future branches, leave room for booster stations and design the pipeline to allow for expansion at higher pressure without having to replace piping and components. Pipeline diameter and pressure should take into account potential for future expansion through addition of booster stations and increased operating pressure.	Lack of reserved locations for booster stations, insufficient pipeline diameter, and excess operating pressure may make future expansion of pipeline capacity more difficult and more expensive.	Unlikely to be a problem.	Pipelines will be designed to accommodate future expansion with the addition of a booster station.	Final site and pipeline ROW selections to determine length of pipeline and number of booster stations needed in the future. Also determine likely capacity expansion in the future.	2	3	6	Size pipeline to effectively handle planned CO2 capacity with option for future capacity expansion by adding booster station(s).	Leave space for booster stations

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121	21.02.15.	Pipeline flow velocity	Reported pipeline velocity varies from 0.9 to 4.6 m/s (3 to 15 ft/s). (IPCC 2005)	Excessive flow capacity could cause erosion in pipeline components.	Very unlikely to be a problem.	Pipeline velocity falls within the acceptable range of 0.9 to 4.6 m/s (3 to 15 fps).	Final site and pipeline ROW selections to determine length of pipeline, PVT and velocity.	1	3	3	Design pipeline to stay within the safe range of CO2 velocity.	Adjust capacity or pressure to keep within the safe velocity range.
122	21.02.16.	Pipeline SCADA system	Supervisory control and data acquisition (SCADA) system should have sufficient instrumentation for the central control room to monitor and control flow along the entire pipeline. The system should have built in redundancies to prevent loss of operational capability if a component fails. 1. IT security for SCADA system to protect against cyber-terrorism	Loss of the SCADA system could shut the pipeline down or result in pipeline failure and CO2 release.	Unlikely to be a problem.	The pipelines will have SCADA systems.	Final site and pipeline ROW selections to determine SCADA system needs.	2	4	8	Comply with all 49 CFR 195 requirements for SCADA system.	Maintain SCADA system in good working order.
123	21.02.17.	Pipeline CPM leak detection systems	Computational pipeline monitoring (CPM) leak detection system must comply with section 4.2 of API 1130. (49 CFR Part 195.134). CPM leak detection can be based on acoustics, measurement of chemical release, detecting pressure changes or small changes in mass balance.	Lack of a properly designed CPM leak detection system prevents the pipeline operator from rapid detection and response to CO2 leaks. Inaccurate modeling of CO2 dense phase can cause the computational leak detection system to malfunction.	Unlikely to be a problem.	The pipelines will have a CPM leak detection system	Final site and pipeline ROW selections to determine CPM leak detection system needs.	2	4	8	Comply with all 49 CFR 195 requirements for computational pipeline monitoring leak detection system.	Maintain the CPM leak detection system in good working order.
124	21.02.18.	Pipeline block valves or control valves	Main-line valves (block or control valves) are located on either side of water crossings and approximately every 32 km (20 mi) overland in order to allow for quick isolation and to minimize the impact of a leak. (DGC) Valves must be installed at each of the following locations: on the suction end and discharge end of a pump station, on each mainline at locations along the pipeline system that will minimize damage or pollution from CO2 discharge, on each lateral takeoff from the trunk line, on each side of a water crossing that is more than 30 m (100 ft) wide and on each side of a reservoir that is holding water for human consumption. (49 CFR Part 195.260) Each valve must be installed in a location that is accessible to authorized employees and that is protected from damage or tampering. (49 CFR Part 195.258)	The distance between main-line valves determines the amount of CO2 released in a rupture. Longer spacing means a larger volume of CO2 is likely to escape.	Unlikely to be a problem.	The pipelines will have block valves installed.	Final site and pipeline ROW selections to determine the number, location and type of block valves needed.	2	4	8	Comply with all 49 CFR 195 requirements for block valves.	Maintain all valves in good working conditions.

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125	21.02.19.	Pipeline internal inspection devices	Pipelines must be designed and constructed to accommodate the passage of instrumented internal inspection devices (i.e. smart pig). 49 CFR Part 195.120) No operator may use a launcher or receiver that is not equipped with a relief device capable safely relieving pressure in the barrel before insertion or removal of scrapers or spheres. (49 CFR Part 195.426)	Internal inspection devices are important tools for detecting corrosion or mechanical damage in pipelines before they fail.	Unlikely to be a problem.	The pipelines will be designed to use internal inspection devices (smart pigs)	Final site and pipeline ROW selections to determine the specifications for internal inspection devices.	2	3	6	Comply with all 49 CFR 195 requirements for internal inspection devices.	Maintain internal inspection devices and systems in good working order.
126	21.02.20.	Pipeline seals	Teflon or nylon have been used for seals to prevent swelling. (API 2007).	Improper sealing materials may react with CO2 and cause CO2 leakage	Unlikely to be a problem.	The pipelines will be designed with proper seals for handling CO2.	Final site and pipeline ROW selections to determine number, location and type of seals.	2	2	4	Select seal materials that have been successfully tested for use with CO2.	Maintain seals in good working order. Monitor for leaks.
127	21.02.21.	Pipeline winterization	Winterization (protection from severe cold/ice) may be needed for above ground facilities in cold climates.	Lack of winterization can cause CO2 pipeline instrumentation lines and valves to freeze up in severe cold/icy weather.	Unlikely to be a problem.	Surface facilities will be designed appropriately for Kansas winter climate.	Final site and pipeline ROW selections to determine number, location and type of surface facilities.	2	2	4	Provide sufficient shelter/insulation for sensitive surface facilities.	Monitor severe weather conditions. Train operators how to maintain operation during severe winter weather.
128	21.02.22.	Pipeline burial depth	CO2 pipelines are typically buried a minimum of 1.2 m (4 ft) over the length of the pipeline, ≥1.5 m (5 ft) below roads, ≥3 m (10 ft) below railroads, ≥1.2 m (4 ft) below ditches and ≥3 m (10 ft) below water line on shores. (DGC). Minimum burial depth for pipeline is 0.9 m (36 in) for industrial commercial and residential areas, 1.2 m (48 in) for crossing of inland bodies of water, 0.9 m (36 in) for drainage ditches at public roads and railroads, 1.2 m (48 in) for deepwater port safety zones, 0.9 m (36 in) for offshore areas and 0.8 m (30 in) elsewhere. There are exceptions for rock excavation areas. (49 CFR Part 195.248)	Insufficient burial depth makes pipeline more susceptible to excavation damage, sabotage, climate damage etc.	Very unlikely to be a problem.	Pipelines will be buried deeper than required by 49 CFR 195.	Final site and pipeline ROW selections to determine number of crossings and pipeline burial depth.	1	3	3	Bury pipelines to meet or exceed compliance with 49 CFR 195.	Regularly inspect and maintain burial depth of pipeline.
129	21.02.23	Pipeline bedding and foundation structures	Pipeline bedding and foundation structures are designed to hold a pipeline stable throughout its life. This is particularly important for offshore pipelines.	Improper design of pipeline bedding or foundation structures could result in pipeline shifting or buckling.	Unlikely to be a problem	Pipeline will comply with 49 CFR 195 requirements for pipeline bedding and foundation structures.	Final site and pipeline ROW selections to determine if there are any areas requiring special pipeline bedding and foundation structures.	2	3	6	Comply with all 49 CFR 195 requirements for pipeline bedding and foundation structures.	Regularly inspect pipelines for signs of shifting or buckling.

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130	21.03.00.	Pipeline material defects	<p>During the manufacturing of steel, impurities can sometimes remain in the molten steel. These impurities can cause an incomplete bonding of the material in the steel plate or solid round billet used to produce pipe and other pipeline components. reduce the wall thickness of the pipe or pipeline component, and, if large enough, can reduce the pressure-carrying capacity of the pipe or component.</p> <p>Some pipeline material defects include:</p> <ol style="list-style-type: none"> 1. Propagating cracks - very rapid propagating cracks can occur that "unzip" the pipeline along its length. 2. Laminations and inclusions - caused by oxides or impurities trapped in the steel 3. Blisters and scabs - raised spots on steel surface caused by expansion of trapped gases within the steel 4. Hard spots - created by localized cooling of the steel plate (ERW pipe) during rolling 5. Indentations - formed by the expanders or mandrels used to make seamless pipe 6. Transit fatigue - cracks formed when pipes are repeated flexed during transportation and handling 7. Cyclic fatigue - cracks caused by stress from repeated fluctuating operating pressure within the pipe 8. Elastomer and polymer - failure due to reaction with CO2 	<ol style="list-style-type: none"> 1. Propagating cracks can lead to pipeline rupture. 2. A lamination or inclusion can eventually lead to failure if they eventually grow to the inner or outer wall of the pipe or pipeline component through pressure cycles. 3. Blisters and scabs reduce the wall thickness of the pipe and, if large enough, can reduce the pressure-carrying capacity of the pipe or component. 4. Cracking can occur at hard spots that eventually grows in size over time. 5. Stress risers can occur at indentations if they are too deep, eventually leading to pipe failure. 6. Transit fatigue cracks are typically discovered during the hydrostatic pressure testing however, some can remain and grow during pipeline pressure cycles until a failure occurs. 7. Can lead to CO2 leakage 	Unlikely to be a problem.	<p>Pipelines will be inspected and tested before burial.</p> <p>Crack arrestors will be installed to minimize propagating cracks.</p>	Qualifications and QC programs of pipe manufacturer	2	4	8	<p>Selection of a competent pipe manufacturer.</p> <p>Inspection and testing of pipelines before burial.</p> <p>Proper design, manufacturing, installation and maintenance of the pipelines.</p>	Use of crack arrestors to mitigate propagating cracks.

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131	21.04.00.	Pipeline weld defects	<p>Some pipeline weld defects include:</p> <ol style="list-style-type: none"> 1. Pinholes - small, unwelded area extending through the entire thickness of the weld 2. Toe cracks - occur where the crown of the weld bead intersects the edge of the plate in pipe joined using the Double Submerged Arc Welding (DSAW) 3. Off seam welding - crack caused by the inside and outside welds of the DSAW process being offset 4. Undercutting - occurs when there is an inadvertent reduction in the wall thickness in the area of the weld 5. Incomplete fusion - occurs when there is a lack of complete fusion of the weld and the base metal 6. Porosity - occurs when one or more voids are created in the weld material from shrinkage of the material 7. Slag inclusions - exist when non-metallic material becomes trapped in the weld 8. Weld defects in older pipe <ul style="list-style-type: none"> - Burnt pipe edges - Incomplete fusion - Hook cracks - Cold welds - Weld metal cracks <p>For more details, see PHMSA.</p>	Weld defects can lead to CO2 leakage	Unlikely to be a problem.	Welding will be done by certified welders. Welds will be inspected and tested for defects prior to burial.	Qualifications and QC programs of pipe welders	2	3	6	Comply with all 49 CFR 195 welding requirements. Use certified welders. Inspect and test welds prior to burial.	Replace welds that do not pass inspection and testing.
132	21.05.00.	Pipeline corrosion	About 15% of gas pipeline failures in Europe are caused by corrosion (EGIG 2008)	Corrosion can lead to pipe failure and CO2 leakage.	Unlikely to be a problem.	Pipelines will have appropriate corrosion protection, regular inspections and maintenance.	Final site and pipeline ROW selections to determine soil corrosion conditions.	2	3	6	Comply with all 49 CFR 195 pipeline corrosion protection requirements.	Regular inspections, testing, cleaning and maintenance. Use of dry CO2.
133	21.05.01.	External corrosion	<p>Galvanic corrosion can take place when an unprotected metal pipeline comes in contact with water or soil.</p> <ol style="list-style-type: none"> 1. External corrosion of buried pipe 2. External corrosion of surface pipe 	Corrosion can lead to pipe failure and CO2 leakage.	Unlikely to be a problem.	<p>Pipe will have external coating of fusion bonded epoxy that meets prescribed standards.</p> <p>The pipeline will have monitored and cathodic protection systems.</p>	Final site and pipeline ROW selections to determine soil corrosion conditions.	2	3	6	Comply with all 49 CFR 195 pipeline corrosion protection requirements.	Regular inspections, testing, cleaning and maintenance.

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134	21.05.02.	Internal corrosion	<p>There is potential for rapid corrosion of steel pipeline if free water becomes present in the CO2 stream. There is currently insufficient data to adequately understand the effect of an accidental flow of high water content CO2 into a pipeline and also the influence the various CO2 impurities (O2, H2, SOx, NOx, H2S TEG, MEG and amines/NH3) will have on the corrosion rates. (DNV CO2PIPETRANS Phase 2).</p> <p>Corrosion rate of carbon steel in dry supercritical CO2 is low. For AISI 1080 values around 12.5 microns per year have been measured at 9-12 MPa (90-120 bar) and 160-180 °C for 200 days. During 12 years, the corrosion rate in an operating pipeline amounted to 0.25-2.5 microns per year.</p>	Corrosion can lead to pipe failure and CO2 leakage.	Unlikely to be a problem.	The CO2 will be dried to remove moisture prior to being fed into the pipeline.	Data on CO2 stream contaminants and their impact on internal corrosion.	2	3	6	<p>Comply with all 49 CFR 195 pipeline corrosion protection requirements.</p> <p>Use of dry CO2.</p>	<p>Avoid free water in pipelines.</p> <p>Clean pipeline internals.</p>
135	21.05.03.	Microbial corrosion	Microbial corrosion is corrosion promoted by microorganisms such as chemoautotrophs which can produce hydrogen sulfide, sulfuric acids, other acids or ammonia. Some bacteria directly oxidize iron to iron oxide or iron hydroxide.	Hydrogen sulfide can cause corrosion and sulfide stress cracking.	Unlikely to be a problem. The Dakota Gasification Company pipeline contains both CO2 and H2S. After 10 years of operation, no indication of sulfide stress cracking have been observed nor identified by periodic smart pig inspection.	The pipelines will be externally coated to help protect from microbial corrosion.	Final site and pipeline ROW selections to determine microbial conditions.	2	3	6	<p>Comply with all 49 CFR 195 pipeline corrosion protection requirements.</p>	<p>Regularly inspect pipeline for corrosion. Using smart pigs.</p> <p>Repair any corrosion damage as needed.</p>
136	21.05.04.	Stress corrosion cracking	Stress corrosion cracking (SCC) is a form of corrosion that produces a marked loss of pipeline strength with little metal loss. The combined influence of pipeline stress due to its pressurized contents and a corrosive medium can occasionally result in the formation of interlinking crack clusters that can grow until the affected pipe fails. (PHMSA)	Stress corrosion cracking can result in pipe failure and CO2 leakage.	Unlikely to be a problem.	The pipe being specified is designed to handle the high pressure of the line. Moisture will be removed from CO2 prior to entering the pipeline.		2	3	6	<p>Maintain pipeline pressure below maximum operating pressure. Avoid moisture in the CO2 stream.</p>	<p>Monitor for moisture in the CO2.</p> <p>Regularly inspect pipeline for corrosion. Using smart pigs.</p> <p>Repair any corrosion damage as needed.</p>
137	21.05.05.	Selective seam corrosion	Selective seam corrosion (SSC) is a form of corrosion that tends to affect pipe manufactured prior to 1970 using low-frequency electric resistance welding (LR-ERW) or electric flash welding (EFW) processes. SSC is a localized corrosion attack along the weld bond line of ERW and EFW pipe, that leads to the development of a wedge shaped groove that is often filled with corrosion products. (PHMSA)	Risk for older LF-ERW or EFW pipe, not HF-ERW, DSAW or seamless pipe. (PHMSA)	Very unlikely to be a problem.	Only newly manufactured pipe will be used in the construction of the pipelines.	NA	1	3	3	<p>Use newly manufactured pipe for construction of pipeline.</p>	<p>Regularly inspect pipeline for corrosion. Using smart pigs.</p> <p>Repair any corrosion damage as needed.</p>

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138	21.06.00.	Pipeline equipment failure	Equipment failures involve pumps, compressors, valves, meters, tanks, control/relief equipment and other components and devices on pipeline systems. (PHMSA). Can include broken couplings, stripped threads.	Equipment is often located on company property that is not accessible to the public. Equipment failure usually results in a CO2 release that is contained on public property, typically not resulting in injury to the general public. (PHMSA)	Unlikely to be a problem.	Equipment will be properly operated and maintained.	Final site and pipeline ROW selection to determine the amount and type and size of equipment needed.	2	3	6	Proper operation and regular preventative maintenance program in place.	Monitor for equipment vibration or performance changes. Determine root cause and repair
139	21.07.00.	Pipeline mechanical damage	Mechanical damage consists of dents, gouges, cracks, punctures, stress risers or ruptures.	Mechanical damage of a pipeline can lead to immediate or eventual/accelerated CO2 leakage.								
140	21.07.01.	Excavation damage	About 50% of pipeline failures in Europe and 33% in the US are caused by excavation damage. Excavation damage can include damage to the external coating of the pipe, or dents, scrapes, cuts, or punctures directly into the pipeline itself. The damage can be caused by any type of excavation, including digging, grading, trenching and boring, road and highway maintenance, general construction and farming activities. It normally occurs when excavators fail to call their local one-call system to mark where underground facilities are located prior to excavating. (PHMSA)	Excavation can lead to pipeline damage and CO2 leakage.	Possible problem.	Pipeline ROW will be properly marked and regularly inspected by air and ground. Regular internal inspection with smart pigs. One call system will be employed to protect against third-party excavation damage.	Final site and pipeline ROW selection to determine specific steps to be taken to protect against excavation damage.	3	3	9	Comply with all 49CFR 195 excavation safety requirements including deep burial of pipeline, proper marking of ROW, regular ROW inspections, supervision of third-party excavation and one call system.	Trained emergency response team to rapidly address excavation damage. Educate local residents how to identify and report leaks or damage
141	21.07.02.	Natural force damage	Natural force damage includes damage from landslide, flood, heavy rains, riverbed scouring and washouts, dike breaks, subsidence, earthquakes, high winds, tornadoes, hurricanes, lightning, frost heaves, and frozen instrumentation lines. (PHMSA)	Can lead to unintended movement or abnormal loading of a pipeline resulting in mechanical damage, leakage or rupture.	Possible problem.	Pipeline ROW will be regularly inspected by air and ground. Regular internal inspection with smart pigs.	Final site and pipeline ROW selection to determine likely scenarios for natural force damage.	3	3	9	Comply with all 49CFR 195 ROW inspection requirements.	Maintain ROW to make it visually accessible from the air and physically accessible on the ground. Repair any eroded or damaged areas. Educate local residents how to identify and report leaks or damage.

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142	21.07.03.	Other outside force damage	Other outside force damage excludes excavation but include such things as vehicle accident (hitting above ground valve or booster station), electric arcing from nearby powerlines, vandalism, sabotage, terrorist attack, theft, fires from other businesses or industries, etc. (PHMSA) Most susceptible to this particular type of damage are above ground pipeline facilities which are in close proximity to highways or large population and industrial centers.	Mechanical damage of a pipeline can lead to immediate or eventual/accelerated CO2 leakage.	Possible problem.	Surface facilities will be fenced in and secured to prevent public access.	Final site and pipeline ROW selection to determine specific security and safety needs.	3	3	9	Comply with 49 CFR 195 security requirements. Fence in and secure surface facilities. Direct traffic patterns and speeds to prevent accidents.	Monitor site activity. Train operators to handle security issues and emergencies.
143	21.07.04.	Mechanical damage requiring immediate repair	Metal loss greater than 80% of nominal wall thickness. Dent located on the pipeline (above 4 and 8 o'clock positions) that has any indication of metal loss, cracking or a stress riser. Dent located on the pipeline (above 4 and 8 o'clock positions) with a depth greater than 6% of the nominal pipe diameter. (49 CFR Part 195.452)	Mechanical damage can require immediate repair to prevent CO2 leakage.	Possible problem.	The pipelines will be internally inspected with smart pigs in compliance with 49 CFR 195. Any mechanical damage detected will be repaired.	Final site and pipeline ROW selection	3	3	9	Comply with 49 CFR 195 repair of mechanical damage requirements.	Train employees to repair mechanical damage in a timely basis.
144	21.07.05.	Mechanical damage requiring evaluation and remediation within 60 days of discovery	Dent on the bottom of the pipeline that has any indication of metal loss, cracking or a stress riser. Dent located on the pipeline (above 4 and 8 o'clock positions) with a depth between 3% and 6% of the nominal pipe diameter. (49 CFR Part 195.452)	Mechanical damage can require timely evaluation and remediation to prevent CO2 leakage.	Possible problem.	The pipelines will be internally inspected with smart pigs in compliance with 49 CFR 195. Any mechanical damage detected will be repaired.	Final site and pipeline ROW selection	3	2	6	Comply with 49 CFR 195 repair of mechanical damage requirements.	Train employees to repair mechanical damage in a timely basis.
145	21.08.00.	Pipeline procurement risks								0		
146	21.08.01.	Used pipe or old pipe	Used pipe must comply with the same quality requirements as new pipe. Used pipe must not have any mechanical damage (buckles, cracks, gouges, dents) or corroded areas that threaten the integrity of the pipe. (49 CFR Part 195.114).	Use of defective used pipe could result in pipe failure and CO2 leakage.	Not a problem.	New pipe will be used in construction of the pipelines.	NA	1	3	3	Use new pipe.	Inspect and test all used pipe prior to its use.
147	21.08.02.	Pipeline valves	Each valve must be of sound engineering design, compatible with pipe and fittings, successfully hydrostatically tested, clearly marked for open and closed positions (except check valves), properly marked (nameplate) and properly sized. (49 CFR Part 195.116)	Defective or off-spec valves could result in valve failure and CO2 leakage. Wrong sized valves could lead to additional pressure stress or failure.	Unlikely to be a problem	All valves will be new build and will meet the appropriate specifications for the service for which they are being installed.	Final site and pipeline ROW to determine the number, location, type and size of valves.	2	3	6	Comply with 45 CFR 195 valve requirements. Select competent valve manufacturers. Select the proper type and size of valve.	Inspect and test all valves prior to being used. Properly install, operate and maintain valves.

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148	21.08.03.	Pipeline fittings	Fittings must be suitable for the intended service and be at least as strong as the pipe and other fittings in the pipeline system. There may not be any buckles, dents, cracks, gouges or other defects in the fittings that may reduce the strength of the fitting. (49 CFR Part 195.118)	Defective off-spec fittings could result in fitting failure and CO2 leakage.	Unlikely to be a problem.	All fittings will be new build and will meet the appropriate specifications for the service for which they are being installed.	Final site and pipeline ROW to determine the number, location, type and size of fittings.	2	2	4	Comply with 45 CFR 195 fitting requirements. Select competent fitting manufacturers. Select the proper type and size of fitting.	Inspect all fittings prior to being used. Properly install and maintain fittings.
149	21.08.04.	Other pipeline components	Other components such as fabricated branch connections, closures, flange connections, station piping, and fabricated assemblies must meet applicable requirements. (49 CFR Part 195.122-195.130) Materials for bolts and nuts should be same as flange. At least one full thread of bolt should be exposed beyond the nut. Gasket material should be compatible with CO2.	Defective or off-spec pipeline components could result in component failure and CO2 leakage.	Unlikely to be a problem.	All other components will be new build and will meet the appropriate specifications for the service for which they are being installed.	Final site and pipeline ROW to determine the number, location, type and size of other components.	2	2	4	Comply with 45 CFR 195 requirements for other pipeline component. Select competent manufacturers. Select the proper type and size of components.	Inspect all components prior to being used. Properly install and maintain components.
150	21.09.00.	Pipeline construction defects	About 16% of gas pipeline failures in Europe are caused by construction defect or material failure. (EGIG 2008)	Construction defects could result in pipeline failure and CO2 leakage.								
151	21.09.01.	Pipe installation	All pipeline installed in a ditch must be installed in a manner that minimizes the introduction of secondary stresses and the possibility of damage to the pipe. (49 CFR Part 195.246). This is of particular concern in rocky soil. When a ditch for a pipeline is backfilled, it must be done in a manner that provides firm support under the pipe, and prevents damage to the pipe and pipe coating from equipment or from the backfill material. (49 CFR Part 195.252) Pipeline coating can be damaged during installation by laying the pipeline on sharp rocks in the ditch, dropping rocks on it during backfill, rough contact with equipment or abrasion if installing pipe through a bored hole under a road or railroad crossing.	Pipe damage during installation could result in accelerated pipe failure and CO2 leakage	Unlikely to be a problem.	Pipelines will be installed in compliance with 49 CFR 195 requirements.	Final site and pipeline ROW selection to determine the scope and difficulty of installation.	2	2	4	Install pipeline in compliance with 49 CFR 195. Inspect and test prior to being placed in service.	Repair or replace any pipe damaged during installation.
152	21.09.02.	Valve and other equipment installation	Valves and other equipment must be properly seated and installed.	Valves that are not properly seated or improperly installed could lead to system failure.	Unlikely to be a problem	Valves will be inspected to make sure they are properly installed, properly marked, and seated prior to being placed into service.	Final site and pipeline ROW selection to determine the amount and type of valves and other equipment to be installed.	2	3	6	Install valves and other equipment in compliance with 49 CFR 195. Inspect and test prior to being placed in service.	Repair or replace any valves or other equipment damaged during installation.

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153	21.09.03.	Pipe bending	Pipe must not have a wrinkle bend. A bend must not impair serviceability of the pipe. Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage. On pipe containing a longitudinal weld, the longitudinal weld must be as practicable to the neutral axis of the bend unless the bend is made with an internal bending mandrel or the pipe is 0.32 m (12.75 in) or less nominal outside diameter or has a diameter to wall thickness ratio less than 70. Each circumferential weld which is located where the stress during bending causes a permanent deformation in the pipe must be nondestructively tested either before or after the bending process. (49 CFR Part 195.212)	Pipe damage during bending could result in accelerated pipe failure and CO2 leakage	Unlikely to be a problem	If bending is required for installation of the pipe, all appropriate manufacturing safeguards will be employed. Upon completion and prior to installation, the pipe will be visually inspected to ensure it is in compliance with the appropriate regulations for the intended service.	Final site and pipeline ROW selection to determine the need for any pipe bending.	2	2	4	Bend pipe in compliance with 49 CFR 195. Inspect and test prior to being placed in service.	Replace any pipe bends that do not pass inspection or testing.
154	21.09.04.	Pipe welding	Welding must be performed by a qualified welder in accordance with welding procedures qualified under Section 5 of API 1104 or Section IX of the SASME Boiler and Pressure Vessel Code. Each welding procedure must be recorded in detail, including the results of the qualifying tests. 49 CFR Part 195.214-195.234)	Improper welding procedures could result in CO2 leakage.	Unlikely to be a problem	All welders will be certified. All welds will be x-rayed and the pipeline will be visually inspected prior to burial.	Final site and pipeline ROW selection to determine the amount of welding.	2	2	4	Comply with all 49 CFR 195 welding requirements. Use certified welders. Inspect and test welds prior to burial.	Replace welds that do not pass inspection and testing.
155	21.09.05	Pipeline hydraulic testing	Except as otherwise provided in this section ... no operator may operate a pipeline unless it has been pressure tested ... without leakage, (49 CFR Part 195.300-195.310)	Improper or lack of hydraulic testing may fail to discover leaks before CO2 is fed to the pipeline.	Unlikely to be a problem.	The pipelines will pass hydrostatic testing prior to being placed in service.	Final site and pipeline ROW selection to determine the amount of hydrostatic testing.	2	2	4	Conduct pipeline hydrostatic testing in compliance with 49 CFR 195.	Locate and repair any leaks. Do not place pipeline into service until it has successfully passed hydrostatic testing.
156	21.09.06	Pipeline underground clearance	Any pipe installed underground must have at least 0.3 m (12 in) of clearance between the outside of the pipe and the extremity of any other structure, except that for drainage tile. (49 CFR Part 195.250).	Insufficient clearance could cause mechanical damage under load.	Unlikely to be a problem.	The pipelines will be laid in compliance with 49 CFR 195 requirements.	Final site and pipeline ROW selection to determine any underground infrastructure.	2	2	4	Lay pipeline in compliance with 49 CFR 195. Assure sufficient clearance between the pipeline and other subsurface structures.	Design around subsurface structures if necessary.
157	21.09.07.	Pipeline integrity inspection	No pipe or other component may be installed in a pipeline system unless it has been visually inspected at the site of installation to ensure that it is not damaged in a manner that could impair its strength or reduce its serviceability. (49 CFR Part 195.206)	Improper or lack of integrity inspection may fail to discover mechanical damage or defects before CO2 is fed to the pipeline.	Unlikely to be a problem.	The pipelines will be visually inspected before burial.	Final site and pipeline ROW selection.	2	2	4	Conduct pipeline integrity inspections as required by 49 CFR 195.	Repair any mechanical damage, defects or leaks.

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158	21.09.08.	Protection for above ground components	Above ground components may be installed in areas under direct control of the operator but should be inaccessible to the public. (49 CFR 195.254)	Insufficient protection for above ground components could lead to vandalism, theft and equipment damage by third parties.	Unlikely to be a problem.	Surface facilities will be fenced in and secured to prevent public access.	Final site and pipeline ROW selection.	2	2	4	Fence in, mark and secure surface facilities.	Monitor activity at surface facilities.
159	21.09.09.	Construction records	<p>A complete record must be maintained by the operator for the life of each pipeline facility of girth welds (total, number tested, rejected, disposition), pipe installed (amount, location cover, size), locations of pipeline crossings, utility crossings, overhead crossings, valves, and corrosion test stations. (49 CFR Part 195.266)</p> <p>1. Lack of final as-built drawings 2. Pipeline location not properly documented 3. Valves and other equipment not properly marked</p>	<p>Incomplete or inaccurate construction records or as-built drawings could result in error or confusion during operation, maintenance or emergency response.</p> <p>Improper documentation of pipeline location can lead to confusion when marking a pipeline location prior to excavation.</p> <p>Failure to properly mark valves and other equipment could lead to improper opening or closing of valves or improper equipment operation and/or maintenance.</p>	Unlikely to be a problem.	As-built construction records will be prepared and maintained through the operation of the pipeline.	Final site and pipeline ROW selection.	2	3	6	<p>Maintain an up-to-date set of construction drawings throughout the operation of the pipeline.</p> <p>Properly mark the pipeline location.</p> <p>Properly mark valves and other equipment.</p>	Reconstruct any drawings or records that are missing.
160	21.10.00.	Pipeline operation risks										
161	21.10.01.	Operator error	<p>Operator error can include:</p> <p>1. Leaving the wrong valve open or closed 2. Not following proper procedures 3. Using improper equipment or techniques to affect a repair 4. Improperly assessing a situation or condition resulting in inappropriate actions or decisions</p>	Potential for pipeline failure and CO2 leakage.	Unlikely to be a problem.	Appropriate procedures for safe operation of the pipeline will be developed and all personnel will undergo safety and operation training prior to being allowed to work on the pipeline.	Determine level of training needed for operators.	2	3	6	<p>Standard procedures for safe operation.</p> <p>Personnel trained prior to being allowed to work on the pipeline.</p>	Ongoing training. Failsafe control systems to prevent failure.

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162	21.10.02.	Pipeline over pressuring	Maximum operating pressure (MOP) is limited to 80% of pipeline design pressure. Isolating pipework or facilities with dense phase CO2 can result in doubling the pressure from 10 to 20 MPa (100 to 200 bar) as temperature raises from 25°C to 40°C.	Isolation of pipeline sections could lead to pipeline over pressuring. Operating the pipeline above maximum operating pressure (MOP) could place the pipeline at risk for failure.	Possible problem	Appropriate procedures for safe operation of the pipeline will be developed and all personnel will undergo safety and operation training prior to being allowed to work on the pipeline.	Identify all the operating conditions that would lead to over pressuring the pipeline.	3	3	9	Standard operating procedures for controlling pipeline pressure.	Alarm system if pipeline pressure exceeds 80% of maximum operating pressure.
163	21.10.03.	Pipeline re-pressurization	Re-pressurizing a pipeline results in isenthalpic flash across the re-pressurizing valve causing low temperature in the pipeline, no solid CO2 formation if the CO2 is warm enough. (Anderson 2008).	Low temperature across the re-pressurizing valve	Possible problem.	Appropriate operating guidelines will be developed for safe re-pressuring.	Establish operating conditions likely to occur during repressurization.	3	3	9	Standard operating procedures for re-pressurizing the pipeline.	Alarm system and control safety limits.
164	21.10.04.	Pipeline depressurization	Rapid depressurization on blowdown of a pipeline can lead to low temperatures (isentropic behavior) and possible solid CO2 formation at pressures below 5 bar. (Anderson 2008).	Rapid depressurization of facilities can lead to CO2/hydrate formation in vent system, possibly causing blockage and over pressurization. (Anderson 2008). Solidification of CO2 could lead to plugging of relief valves. Lowering depressurization rate of a compressor can lead to asphyxiation risk. (Anderson 2008).	Unlikely to be a problem.	Appropriate operating guidelines will be developed for safe de-pressuring.	Establish operating conditions likely to occur during depressurization.	2	3	6	Standard operating procedures for de-pressurizing the pipeline.	Alarm system and control safety limits.
165	21.10.05.	Pipeline flow modeling	There is a need for improved understanding of the effect contaminants (O2, H2, SOx, NOx, H2S TEG, MEG and amines/NH3) have on the phase diagram and behavior of a CCS CO2 stream. (DNV CO2PIPETRANS Phase 2) Nitrogen and oxygen in CO2 will shift the boundary of the two-phase region toward higher pressures and would require a higher operating pressure to avoid two-phase flow.	Improper understanding of the impact of CO2 impurities on the phase diagrams could lead to inaccurate pipeline flow modeling. Inaccurate modeling can cause the computational leak detection system to malfunction.	Unlikely to be a problem.	There are several models currently available for modeling transport of dense phase CO2. CO2 stream impurities will be very low in this project.	Confirm composition of Kansas Ethanol CO2 stream. Determine pipeline flow model best suited for the project conditions.	2	3	6	Selection of optimum pipeline flow model. Verification of model accuracy. Sufficient training for modelers.	Monitor actual versus model results and determine the root cause of any discrepancies.

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166	21.10.06.	Boiling liquid expanding vapor explosion (BLEVE)	<p>Boiling liquid expanding vapor explosion (BLEVE) is a type of explosion that can occur when a vessel or pipeline containing a pressurized liquid is ruptured. Such explosions can be extremely hazardous.</p> <p>A BLEVE results from the rupture of a vessel containing a liquid substantially above its atmospheric boiling point. The substance is stored partly in liquid form, with a gaseous vapor above the liquid filling the remainder of the container.</p> <p>If the vessel is ruptured — for example, due to corrosion, or failure under pressure — the vapor portion may rapidly leak, lowering the pressure inside the container. This sudden drop in pressure inside the container causes violent boiling of the liquid, which rapidly liberates large amounts of vapor. The pressure of this vapor can be extremely high, causing a significant wave of overpressure (an explosion) which may completely destroy the storage vessel and project fragments over the surrounding area. (Wikipedia)</p>	Supercritical CO2 can have significant density variations with changes in pressure and temperature. If a pipeline ruptures, this could lead to a boiling liquid expanding vapor explosion (Anderson 2008).	Unlikely to be a problem	The pipeline will be designed and operated to prevent two-phase flow from occurring. The SCADA system and main-line control valves will allow sections of the pipeline to be shut in to maintain line pressure should a section experience a leak and depressurization.	Actual cases of BLEVE occurring with CO2.	2	4	8	Standard procedures for safe operation and maintenance of pipeline.	<p>Monitor pipeline for unsafe operating conditions.</p> <p>Alarm system.</p> <p>Emergency response plan.</p> <p>Train employees and educate local residents what to do in the event of a pipeline rupture.</p>
167	21.10.07.	Pipeline scheduled maintenance	<p>Typical scheduled maintenance jobs and frequency: Aerial patrols 26 times per year. Population density survey every other year. ROW inspection 26 times per year. Emergency systems tested annually. Rectifier maintenance completed 6 times per year. Cathodic protection survey annually. Internal inspection of pipeline using an electronic tool, every 5 years or more frequently if necessary. Overpressure safety devices checked annually. Public awareness and damage prevention program reviewed annually. (DGC). Inspect each mainline valve twice a year</p> <p>1. Pipeline cleaning</p>	Failure to properly inspect and maintain the pipeline could lead to pipeline failure and CO2 leakage.	Unlikely to be a problem	<p>Operation and maintenance of the pipelines will follow 49 CFR 195 safety requirements.</p> <p>Frequency of inspection will be monitored and increased should an issue arise that requires more attention.</p>	Pipeline scheduled maintenance plan	2	3	6	Comply with 49 CFR 195 pipeline scheduled maintenance requirements.	Review status and results of pipeline scheduled maintenance annually.

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168	21.10.08.	Pipeline malfunctions	<p>Some pipeline malfunctions could include:</p> <ol style="list-style-type: none"> 1. Equipment malfunction or failure 2. Unintended valve closure or shutdown 3. Loss of communication (SCADA system) 4. Power outage 5. Pig stuck in pipeline causing a shutdown 	Pipeline malfunctions could lead to unintended shutdown or CO2 leakage.	Possible problem.	Appropriate procedures and systems for handling pipeline malfunctions will be developed.	Comprehensive list of potential project specific pipeline malfunctions.	3	3	9	<p>Alarm system for equipment/valve malfunction or failure.</p> <p>Backup communication system for SCADA.</p> <p>Backup power generator or batteries.</p> <p>Standard operating procedures for inline inspection system (pig system)</p>	<p>Train personnel to properly respond to pipeline malfunctions on a timely basis.</p>
169	21.10.09.	Pipeline leak/rupture	<p>Pipeline leaks/ruptures can include:</p> <ol style="list-style-type: none"> 1. Pinhole leak - small leak (visible due to dry ice forming on the surface) 2. Pipeline puncture small diameter leak 3. Pipeline puncture large diameter leak 4. Pipeline rupture - a circumferential or longitudinal propagation fracture 	CO2 leakage. Low severity for pinhole leak. Moderate severity for pipeline puncture. High severity for pipeline rupture.	Possible problem.	<p>CPM leak detection system will be used to locate leaks,</p> <p>Crack arrestors will be installed to minimize propagating cracks.</p> <p>Block valves will be installed to minimize the volume of CO2 release in a puncture or rupture.</p>	<p>Finalize site and pipeline Row selections to determine potential impact of CO2 leaks/ruptures along the pipeline ROW.</p>	3	4	12	<p>Standard procedures for safe operation and maintenance of pipeline.</p>	<p>CPM leak detection system.</p> <p>Crack arrestors to minimize propagating cracks.</p> <p>Block valves to section off the pipeline in case of a rupture.</p> <p>Personnel training and local resident education on how to identify and respond to a pipeline leak/rupture.</p> <p>Emergency response plan.</p>

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170	21.10.10.	Pipeline safety measures	Pipeline safety measures can include: 1. Emergency response plan 2. Reverse 911 call system - emergency alert 3. One-call system - prior to drilling or excavating 4. Supervision of excavation near pipelines 5. Regular inspection and maintenance of pipeline and ROW 6. CO2 monitors and alarms at booster stations 7. Oxygen packs at booster stations 8. Fire fighting equipment at booster stations 9. Public emergency response plan 10. Fencing and barricades to protect above ground facilities 11. Markers for ROW, valves and equipment	Lack of pipeline safety measures could lead to human injury and/or pipeline damage.	Possible problem if safety measures are not implemented.	The project will employ all of the safety measures required by 49 CFR 195.	Determine appropriate safety measures for the project.	3	3	9	Comply with all safety measures required by 49 CFR 195.	Review safety measures regularly to ensure they are operational. Make adjustments if necessary to ensure safety.
171	22.00.00.	ON-SITE FACILITIES RISKS										
172	22.01.00.	On-site facilities for DSA	On-site facilities for deep saline aquifer (DSA) CO2 injection can include: 1. Injection CO2 distribution system trunk and laterals 2. Power supply 3. Injection and monitoring wells	Potential problems could include, blowout, equipment failure.	Unlikely to be a problem.	DSA is currently not planned in Phase 2 of the project, unless legislation provides sufficient economic justification.	Climate change legislation timing and content.	2	3	6	Experienced/trained operators and managers. Proper specification, engineering, manufacturing and installation of equipment and other components. Appropriate procedures for safe operation and maintenance of on-site facilities. Compliance with Kansas Corporation Commission rules and regulations for CO2 storage facilities.	Risk management plan in place.

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173	22.02.00.	On-site facilities for EOR	<p>On-site facilities for CO2 enhanced oil recovery (EOR) can include:</p> <ol style="list-style-type: none"> 1. Recycle CO2 compression system and building 2. Injection CO2 distribution system trunk and laterals 3. Production gathering system 4. Oil, water and slop storage tanks 5. CO2 dehydration system 6. CO2 gas scrubber/knockout drum 7. Flare system 8. Circulation and transfer pumps 9. Instrument air system 10. Control room, motor control center and building 11. Power supply transformers, UPS, PLCs, cables 12. Injection, production, disposal and monitoring wells 13. Water treatment/disposal facilities 	Potential problems could include blowout, oil leaks/spills ignition/explosion, equipment failure, water quality, water disposal	Possible problem of equipment failure.	EOR operations will be managed by a company with significant EOR experience.	Finalize site selection to determine the on-site facilities required.	3	3	9	<p>Experienced/trained operators and managers.</p> <p>Proper specification, engineering, manufacturing and installation of equipment and other components.</p> <p>Appropriate procedures for safe operation and maintenance of on site facilities.</p> <p>Compliance with Kansas Corporation Commission rules and regulations for EOR operations.</p>	<p>Risk management plan in place.</p> <p>Monitor for CO2, oil or water leaks.</p>
174	22.03.00.	On-site facilities for ECBM	<p>On-site facilities for CO2 enhanced coal bed methane (ECBM) can include:</p> <ol style="list-style-type: none"> 1. Recycle CO2 compression system and building 2. Injection CO2 distribution system trunk and laterals 3. Production gathering system 4. Water storage tanks 5. CO2 dehydration system 6. CO2 capture system - removal of CO2 from nat. gas 7. Flare system 8. Circulation and transfer pumps 9. Instrument air system 10. Control room, motor control center and building 11. Power supply transformers, UPS, PLCs, cables 12. Injection, production, disposal and monitoring wells 13. Water treatment/disposal facilities 	Potential problems could include blowout, methane leaks ignition/explosion, equipment failure, water disposal.	NA	No ECBM is planned at this stage of the project. However there is significant opportunities for ECBM in Southeastern Kansas..	NA	1	1	1	NA	NA

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175	22.04.00.	Injection well components	<p>CO2 injection well components generally include:</p> <ol style="list-style-type: none"> 1. Wellhead and tree 2. Tubing and casing 3. Safety valve 4. Packer 5. Packer fluid 6. Elastomers 7. Sand control - for unconsolidated reservoirs 	Component failure could result in CO2 leakage.	Possible problem.	Injection components will be properly designed to handle CO2 and/or water injection.	Finalize site selection to determine CO2 injection well components needed.	3	2	6	<p>Proper selection of materials of construction to prevent corrosion from mixtures of water and CO2.</p> <p>Proper engineering and installation.</p> <p>Appropriate procedures for safe operation and maintenance.</p>	<p>Risk management plan in place.</p> <p>Monitor for CO2 or water leaks.</p>
176	22.05.00.	Injection well materials of construction	<p>DSA CO2 injection well components are typically carbon steel.</p> <p>Typical materials of construction for EOR CO2 injection wells include:</p> <ul style="list-style-type: none"> - Upstream metering & piping runs: 316 SS, Fiberglass - Christmas tree (trim): 316 SS, Nickel, Monel - Valve packing and seals: Teflon, Nylon - Wellhead (trim): 316 SS, Nickel, Monel - Tubing hanger: 316 SS, Incoloy - Tubing: fiberglass lined carbon steel, internally plastic coated carbon steel, corrosion resistant alloys - Tubing joint seals: Seal ring (fiberglass lined), coated threads and collars (internally plastic coated) - On/off tool, profile nipple: Nickel plated wetted parts, 316 SS - Packers: Internally coated hardened rubber of 80-90 durometer strength (Buna-N), Nickel plated wetted parts - Cements and cement additives: API cements and/or acid resistant specialty cements and additives - Production liner 316 SS, Incoloy - Casing: carbon steel J-55 and K-55 grades; corrosion resistant alloy used in intervals where potential potable water aquifers exist or where H2S is present (API 2007) Elastomers - Teflon or nylon have been used to prevent swelling 	<p>Corrosion can occur when tubulars are exposed to wet CO2.</p> <p>Sufficient quantities of H2S in CO2 can cause corrosion or sulfide stress cracking. (CCP 2009)</p> <p>The reservoir fluid affects corrosivity near the wellbore and compaction resistance where formation dissolution has occurred. In significant dissolution cases, the well tubulars must be designed to resist column buckling in the injection interval. (CCP 2009)</p> <p>CO2 phase behavior can impact velocity. High velocity of injection can cause erosion to materials exposed to the CO2 stream (CCP 2009)</p>	Unlikely to be a problem.	<p>Water from the Arbuckle may contain H2S and be highly corrosive.</p> <p>Materials of construction will be selected for injection wells that are resistant to corrosion.</p>	<p>Finalize site selection.</p> <p>Confirm H2S content and corrosiveness of Arbuckle water.</p> <p>Determine the likelihood of scale build up in the injection well when brine is injected.</p>	4	3	12	<p>Determine the characteristics of brine to be handled in the injection wells.</p> <p>Select materials that will resist corrosion, and/or scale build up.</p>	<p>Monitor corrosion and scale buildup in injection wells and take necessary corrective action such as pre-treating the injected water.</p>

CO2 Surface and Programmatic Risk List for the IMCCS Project					Project Specific Information			Risk Ranking			Prevention and Mitigation	
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177	22.05.01.	Elastomer seals	<p>Since supercritical CO2 is a solvent, many elastomers, plastics, rubber, or resins present in a well could be subject to chemical attack or dissolution. When designing a CO2 injector, material should be based on performance expectations.</p> <p>Elastomers, in particular, are a common part of well hardware used to seal different components. Elastomers must be made of material that is chemically compatible or inert to the injection fluid and must be of sufficient strength or adequately anchored to withstand the different pressure and explosive decompression that might exist across a seal. Since the physical and performance characteristics of many elastomer materials change with pressure and temperature, the elastomer must be able to perform reliably across the full range of differential pressures and temperatures expected through the design life of the well at the location of the seal within the well. (CCP 2009)</p> <p>Teflon or nylon have been used for seals to prevent swelling. (API 2007).</p>	Elastomer seal failure can result in CO2 leakage.	Unlikely to be a problem.	Elastomers will be selected based on successful performance with CO2.	Get performance data for elastomers used in other CO2 EOR projects.	2	2	4	Select elastomers that have a successful track record in handling CO2.	Replace elastomer seals that fail. Determine root cause. Monitor development of improved elastomers.
178	22.06.00.	Injection well safety measures	<p>Safety measures for injection wells include:</p> <ol style="list-style-type: none"> 1. Casing corrosion protection <ul style="list-style-type: none"> - Impressed and passive currents - Oxygen, biocide corrosion inhibiting chemicals 2. Gentle handling to prevent damage to tubing coatings 3. Casing leak detection testing 4. Fencing, monitoring and atmospheric dispersion monitoring if near populated areas 5. Automatic shutdown controls for unsafe conditions 	Lack of safety precautions can lead to greater risk of CO2 leakage	Unlikely to be a pr	The project will comply with Kansas Corporation Commission rules and regulations covering safety measures for injection wells.	Final site selection to determine what well safety measures will actually be required.	2	4	8	Comply with Kansas Corporate Commission rules and regulations covering safety measures for injection wells.	Annual review of safety measures, rules and regulations to confirm the project is in compliance.
179	22.07.00.	Production well submersible pump	While normally very reliable, the submersible pump in an EOR or ECBM production well can fail.	Failure of the submersible pump can result in operating delays and maintenance costs.	Possible problem.	Production well submersible pump will have Teflon coating to minimize asphaltene/paraffin deposition.	Final site selection to determine characteristics of brine and oil.	3	2	6	Proper selection, installation, operation and maintenance of submersible pump.	Monitor submersible pump for corrosion, hydrocarbon deposition or scale buildup.

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180	22.08.00	Production well materials of construction	<p>Production wells tend to be exposed to mixtures of CO2, brine, hydrocarbons (oil and/or gas) and stripped gases such as H2S.</p> <p>Production wells may also be exposed to asphaltene or paraffin deposition. Teflon coating has proven to work well in reducing hydrocarbon deposition.</p> <p>Scale buildup may also be a problem depending on brine chemistry.</p>	The produced mixtures can be very corrosive.	Likely problem depending on the site selected.	Brine from the Arbuckle may contain H2S and be highly corrosive.	Final site selection to determine characteristics of brine and oil.	4	3	12	<p>Determine the characteristics of fluids to be handled by the production well.</p> <p>Select materials that will resist corrosion, hydrocarbon deposition and/or sludge build up.</p>	Monitor corrosion, hydrocarbon deposition and scale buildup in production wells and take necessary corrective action.
181	23.00.00.	MONITORING RISKS										
182	23.01.00.	Data acquisition activities at the well	Activities include logging, drill stem tests, coring, hydrophone installation, etc. Operational HSE risks often decrease with experience and practice.	May include some activities and procedures that are less familiar. Some techniques could limit other MMV techniques.	Possible problem with data interference.	Project will try to gather as much data as possible from wells using the latest technologies and an experienced monitoring team.	Final site selection to determine number and time of wells and type and amount of monitoring required.	3	2	6	<p>Work with an experienced monitoring engineer/consultant to prepare a monitoring plan that optimizes wellbore data acquisition.</p> <p>Standard procedures for monitoring.</p>	Compare monitoring data with simulation data. Identify discrepancies and determine root cause.
183	23.02.00.	Data acquisition activities away from the well	Many activities and procedures will be effectively new and newly trained for. Some monitoring techniques could present risk or barriers to the application or success of other techniques.	Off-site monitoring activities may incur risk of physical accidents and may make the project publicly prominent.	Unlikely to be a problem.	The project will try to gather as much data as possible in the project area.	Final site selection to determine type and amount of monitoring required.	2	2	4	<p>Work with an experienced monitoring engineer/consultant to prepare a monitoring plan that optimizes non-wellbore data acquisition.</p> <p>Standard procedures for monitoring.</p>	Compare monitoring data with simulation data. Identify discrepancies and determine root cause.
184	23.03.00.	Data acquisition conflicts	Data acquisition may involve many techniques including logging, fluid sampling, coring, surface and downhole geophones, surface seismic, surface air measurements, groundwater sampling, and others.	Use of some monitoring techniques can preclude or limit the applicability of other techniques.	Very unlikely to be a problem.	Project team will prepare a monitoring plan that avoids data acquisition conflicts.	Final site selection to determine type and amount of monitoring required.	1	1	1	Prepare a monitoring plan that avoids data acquisition conflicts.	Compare monitoring data with simulation data. Identify discrepancies and determine root cause.

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185	23.04.00.	Seismic surveys	<p>Vertical resolution of seismic imaging is inherently limited such that features less than 10 m thick can rarely be discerned. (CCP 2009)</p> <p>Subsurface CO2 is not seismically resolvable. Limited or absence of plume images via seismic.</p> <p>Seismic readings may be compromised by vibration from nearby heavy industrial facilities.</p> <p>1. 2-D seismic survey 2. 3-D seismic survey 3. 4-D seismic survey 4. Vertical seismic profile (VSP) 5. Crosswell seismic survey</p>	Seismic techniques may be unable to pick up subsurface features or CO2 plume.	Unlikely to be a problem	The project will perform 2d and 3d seismic surveys.	Final site selection to determine if there are any train tracks or heavy industry facilities that may interfere with seismic readings.	2	2	4	Combine seismic survey methods to get better resolution.	Compare monitoring data with simulation data. Identify discrepancies and determine root cause.
186	23.05.00.	Gravity surveys	<p>As a notional rule of thumb, CO2 filled reservoirs with less than 10% porosity, thicknesses of less than 10 m and depths greater than 2,500 m will be very difficult to resolve even with the best gravity data and mathematical inversion techniques. (CCP 2009)</p> <p>Current available standard gravimeters are capable of making repeat measurements valid to about 5 micro-gals. Fixed seal-floor gravimeters are essentially capable of the same. (CCP 2009)</p> <p>Corrections for motion are required for gravity data acquired from moving vessels. A change of only 1 cm of elevation will yield a difference of 3 micro-gals. Studies of oil fields have found that fixed permanent surface gravity monuments (i.e. stations) are essential to maximize repeatability (CCP 2009)</p>	Gravity surveys may be unable to detect CO2 movement	Not a problem.	Gravity surveys are not planned for Phase 2.	NA	1	1	1	NA	NA
187	23.06.00.	InSAR surveys	<p>InSAR is the current state-of-the-art satellite platform radar based technique to measure vertical ground elevations and relative elevation changes with time. (CCP 2009)</p> <p>Validation studies have shown that uplifts of 1-3 mm can be reliably and repeatedly measured when sites make use of special corner reflectors for calibration purposes. (CCP 2009)</p>	InSAR readings compromised by seasonal growth of vegetation	Possible problem with vegetation growth in the project area.	InSAR may be used in the project	Final site selection to determine type and amount of monitoring required.	3	2	6	Avoid areas with high vegetation growth.	<p>Install base pillars to get more accurate readings.</p> <p>Use tiltmeters as an alternative or compliment.</p>

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188	23.07.00.	Well Monitoring	Well monitoring for CO2 storage seeks confident validation that: - Cement integrity and bond is maintained - Pressure isolation barriers are maintained and functioning - Corrosion is being controlled - The CO2 injection profile is being maintained - Barriers after plug and abandonment provide confidence. (CCP 2009)	Unexpected well failure due to lack of well monitoring.	Unlikely to be a problem..	Wells will be monitored	Final site selection to determine type and amount of monitoring required.	2	2	4	Use an experienced monitoring engineer/consultant to prepare a monitoring plan. Determine which wells to monitor and what monitoring tools to use.	Monitor wells. Identify any trends or discrepancies and determine root cause.
189	23.07.00.	General monitoring risks	1. Weather conditions prevent using a monitoring method or retrieving data at a critical point in time 2. Injection site terrain too rugged for surface monitoring 3. Monitoring equipment not properly calibrated 4. Inappropriate monitoring suggests a false alarm for issues that do not exist (CCP 2009) 5. Inappropriate monitoring suggests a false sense of security (CCP 2009) 6. Difficulty of geophysical techniques monitoring below salt caprocks (CCP 2009) 7. Ineffective monitoring 8. Insufficient monitoring 9. Lack or loss of monitoring records 10. Accidental damage or breakdown of custom-made equipment, sensors or tools - repair/replacement delays and irretrievable data loss. 11. Conflicting results from different monitoring techniques. 12. Difficulty of monitoring stacked injection plumes	Ineffective or lack of monitoring can result in missed data. This leads to inadequate engineering control, raising costs and leakage risks; yields insufficient documentation to establish CO2 storage credits, etc.	Possible problem.	The project will utilize a wide range of monitoring methods to gather information.	Final site selection to determine type and amount of monitoring required.	3	3	9	Determine MVA requirements. Select reliable monitoring methods. Standard procedures for monitoring. Backup data logging.	Analyze monitoring data versus simulation data. Identify discrepancies. Determine root cause of discrepancies.

Appendix 6-C

Wellbore Integrity Risk Assessment

Wellbore Integrity Risk Assessment

A wellbore integrity risk assessment was performed for the Thrall-Aagard (TA) field by Dr. Andrew Duguid of Schlumberger Carbon Services. The assessment was reviewed by the risk assessment working group and revised based on the group's comments. The assessment strategy was to use

$$\text{Risk} = \text{Probability of occurrence} \times \text{Severity of the impact} \quad [\text{Equation 1}]$$

$$\text{Risk} = \text{Risk Factor} \times \text{Severity of the impact} \quad [\text{Equation 2}]$$

For the TA site the population of wells was completed between 1922 and 1991 with most in the 1920s and 1950s and most wells were plugged in the 1960s. As shown in Figure 1, there are around 457 abandoned and active wells in the study area with 7 producing wells. Within these wells 13 wells had noted casing issues and 19 wells had noted plug issues

Figure 1: Map of Thrall-Aagard field showing the location of existing wells.

Well records were gathered by Dr. Martin Dubois of CAPCO2 from Kansas Geological Survey and private sources. Well completion and well plugging reports were incomplete or missing and the reports were not standard over time or between operators.

STATE OF KANSAS
STATE CORPORATION COMMISSION

Form CP-1

Lease Name Thrall "A" Well No. W-4
Office Address 1500 Vickars-Knight Bldg. Wichita, Kansas
Character of Well (completed as Oil, Gas or Dry Hole) input
Date well completed unknown 5-17-22 10
Application for plugging filed 10
Application for plugging approved 10
Plugging commenced Nov. 14, 1921 10
Plugging completed Nov. 22, 1921 10
Reason for abandonment of well or producing formation depleted
If a producing well is abandoned, date of last production 10
Was permission obtained from the Conservation Division or its agents before plugging was commenced? Yes
Name of Conservation Agent who supervised plugging of this well Marvin Corkery
Producing formation _____ Depth to top _____ Bottom _____ Total Depth of Well 2352 Feet
Show depth and thickness of all water, oil and gas formations.

OIL, GAS OR WATER RECORDS

FORMATION	CONTENT	FROM	TO	SIZE	PUT IN	PULLED OUT
				5 1/2"		1900 ft.
				7"		757 ft.

Describe in detail the manner in which the well was plugged, indicating where the mud fluid was placed and the method or methods used in introducing it into the hole. If cement or other plugs were used, state the character of same and depth placed, from _____ feet to _____ feet for each plug set.

Sealed pipe down, bridged at 2250', rocks and dumped 5 sacks cement. Pulled casing, bridged hole at 190', rocks, and 15 sacks cement. Filled with mud and soil to 25', rocks and 10 sacks cement to top.

Figure 2: Example of a typical well plugging report

Record of Well No. A F. C. Thrall "A" Farm
Section 28 Town 10 Township 23
County Greenwood State Kansas Acres
Location Made 19 By _____
_____ feet from North line _____ feet from East line
_____ feet from South line _____ feet from West line
Rig com'd _____ Drilling com'd April 13 19 22
Rig comp'd _____ Drilling comp'd May 17 19 22
Company Tools _____ Drilling Con'r. _____
Drilling Contract No. _____
Total depth of well _____ feet at _____ per foot
Commenced Producing _____ 19 _____
Natural Production { 1st 24 hours _____ Bbls.
2nd 24 hours _____ Bbls.
After Shot { 1st 24 hours 500 Bbls.
2nd 24 hours _____ Bbls.
Gas Pressure _____ lbs. Volume _____ cu. ft.
Remarks: July 14th-1923 On July 2nd when the rods and tubing were being pulled the last joint of tubing and the perforated nipple were dropped. As there was no means of fishing for it at that time it was lost in the hole and the tubing was run back in. The three inch tubing that had been in 3/4 was changed to two inch at that time.

Record of Sand		To Top	To Bot.	Thickness
1st or		FIRST OIL		
2nd or		2290	2348	
3rd or				
4th or				
5th or				

Torpedo Record		1st Shot	Qty.	2nd Shot	Qty.
Shot Between	2290 Ft. 2351 Ft.				
Date of Shot	19			19	
No. of Qts.	120	Shot by	F. Banbalar		
No. ft. of Shell	61				
Size of Shell	3 3/8"				
No. ft. of Anchor	5				

Packer set at _____ ft. size & Kind _____		Packer set at _____ ft. size & Kind _____	
Wooden Conductor: Size _____ Feet			

Drive Pipe, Casing, Tubing and Sucker Rods			
Size	Weight Per Foot	Put In	Pulled Out
12 1/2"		282	382
10"		1240	1240
8 1/2"		1568	1568
6 5/8"		1961	
5 3/16"		2284	
3" tubing		2347	
7/8" Rods		2325	

Figure 3: Example of a typical well completion report.

The overall well risk factor was the sum of individual risk factors. The individual risk factors were each ranked between 0 and 5. The factors used were:

- **Completion date:** 1920s, 1930s, 1940s, 1950s, 1960s, 1970s, 1980s, 1990s, 2000s

not found, plug issue

- **Bottom plug depth:** Above 200 ft, between 200 and 1800 ft, below 1800 ft
- **Total plugged length:** Less than 50 ft, between 50 and 100 ft, between 100 and 1000 ft, and greater than 1000 ft
- **Percent plugged:** Less than 5%, between 5 and 15%, between 15 and 50%, greater than 50%
- **Section:** Section 29, section 32, other sections
- **Previous casing issue:** Previous issue, No reported casing issue
- **Well type:** Dry, EOR, gas, injection, oil, other, unknown
- **Well operator:** Sinclair, Cities, others

By selecting a risk factor as a proxy for probability the risk calculation still looks very much like that which uses Equation 1 where the aim is to reduce the risk to the lowest practicable level. For this project the severity of the impact was considered the same for all of the wells, although the actual level was not estimated.

Figure 4: Risk matrix showing the possible combinations of severity and likelihood (probability of occurrence)

In order to calculate data such as hole diameter, location of remaining casing, plug diameter, and plug length, a series of assumptions were made. The assumptions included:

- All strings of casing in the wells originate at the surface (Figure 3). In the few instances where hanging casing was noted in the records, it was taken into account.
- In wells plugged post-1950 that were constructed prior to 1950, casing sizes were assumed to be the early (pre-1950) designations and weights for estimation of casing weight and hole size. For example, in a plugging report where 5.5-inch casing was removed during the plugging operation, it was actually 5 3/16" casing that was installed.
- Cement volume was calculated assuming 1.05 ft³ of cement paste per sack of cement.
- Plug length was estimated by dividing the estimated plug-cement volume by the calculated/estimated plug-cross-sectional area (based on estimated or actual hole diameters).
- Casing was always cut from the top of the string.

Figure 5: Assumed well construction with all casings originating at the top at the time of construction (left) and after partial casing removal (right)

Figure 6 shows the well risk factor based on well age.

Figure 6: Wells plotted in the Thrall-Aagard field indicating age risk factor

Figure 7 shows well risk factor based on well plug category.

Figure 7: Wells plotted in the Thrall-Aagard field indicating plug category risk factor

The individual risk factors were summed to calculate an overall risk factor for each well. The overall risk factors for the wells are shown mapped in Figure 8 and the associated statistics are provided in Table 1

Figure 8: Wells plotted in the Thrall-Aagard Field showing the total risk factor for each well.

Table 1: Total risk factor statistics for wells in the Thrall-Aagard field

Total Risk Factor Statistics	
Mean	12.74
Standard Error	0.12
Median	13
Mode	13
Standard Deviation	2.65
Sample Variance	7.00

It was found that the distribution of the risk factors was normally distributed (Figures 9 and 10)

Figure 9: Histogram of the total risk factor data for the TA wells

Figure 10: Normalized TA wells risk factor data plotted with a normal distribution using the TA well risk factor statistics.

If we assume the severity of impact is equal for all wells, then the risk of leakage is directly proportional to the total risk factor as shown in Figure 11. Expert based scaling will be needed.

Figure 11: Scaling the risk factor density function.

The field development plan calls for recompleting some abandoned wells and monitoring others. Expert opinion sets the average at the boundary between possible and likely. For example, we may choose to replug wells with a risk factor over 13 (270 wells) and monitor wells with a risk factor over 11 (94 wells) as shown in Figure 12.

Figure 12: Example of cut-off points for replugging and monitoring based on expert opinion.