RED TRAIL ENERGY, LLC

"Our Farms, Our Fuel, Our Future"

PO Box 11 Richardton, ND 58652 (701)-974-3308 FAX (701)-974-3309

November 20, 2019

Mr. Jim Duffy
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Dear Mr. Duffy:

Subject: Red Trail Energy Low Carbon Fuel Standard (LCFS) Design-Based Pathway Application – Carbon Capture and Storage Integrated with Ethanol Production

Introduction and Background

Red Trail Energy, LLC (RTE) is a North Dakota-based entity formed to finance, construct, and operate a corn-based 50-million-gallon nameplate capacity ethanol plant located near Richardton, North Dakota (Figure 1). This plant began producing ethanol in January 2007. Over the past decade, the facility has gained significant energy and processing efficiencies, now producing about 64 million gallons of ethanol annually. RTE currently has two approved carbon intensity (CI) values through the Low Carbon Fuel Standard (LCFS) program.

Since 2016, RTE has been focused on the addition of carbon capture and storage (CCS) as a means for reducing the carbon footprint of ethanol production. The RTE facility generates approximately 181,000 tonnes of CO_2 annually from the fermentation process during ethanol production. Initial investigations successfully demonstrated preliminary technical and economic feasibility of CCS technology at the site (Leroux and others, 2017; Leroux and others, 2018). Recent efforts have included more in-depth assessments, including detailed designs for capturing, transporting, and storing CO_2 integrated with the existing ethanol facility operations and the site's specific geology. The resulting detailed process designs are now at a stage such that a comprehensive life cycle analysis (LCA) can be performed for an LCFS design-based pathway application.

RTE CCS Systems

As shown in Figure 1, integration of CCS technology with the existing RTE ethanol facility will consist of a CO_2 liquefaction system, piping the liquid CO_2 nearly 2 miles to an injection well on RTE property and injecting it to an approximate depth of 6500 ft into the Broom Creek Formation (a saline

formation) for permanent geologic storage. Figure 2 provides a summary of the CCS process flow. The high purity [redacted] of CO_2 generated requires limited postprocessing to generate a fluid suitable for subsurface injection and geologic storage. Therefore, a commercially available CO_2 liquefaction system has been designed for the capture component of the RTE CCS system. An underground pipeline will be installed to connect the injection well to the liquefaction system for CO_2 transport, and a monitoring well will be installed to further observe the CO_2 injected and stored. No other processes (e.g., reservoir fluid extraction) are intended.

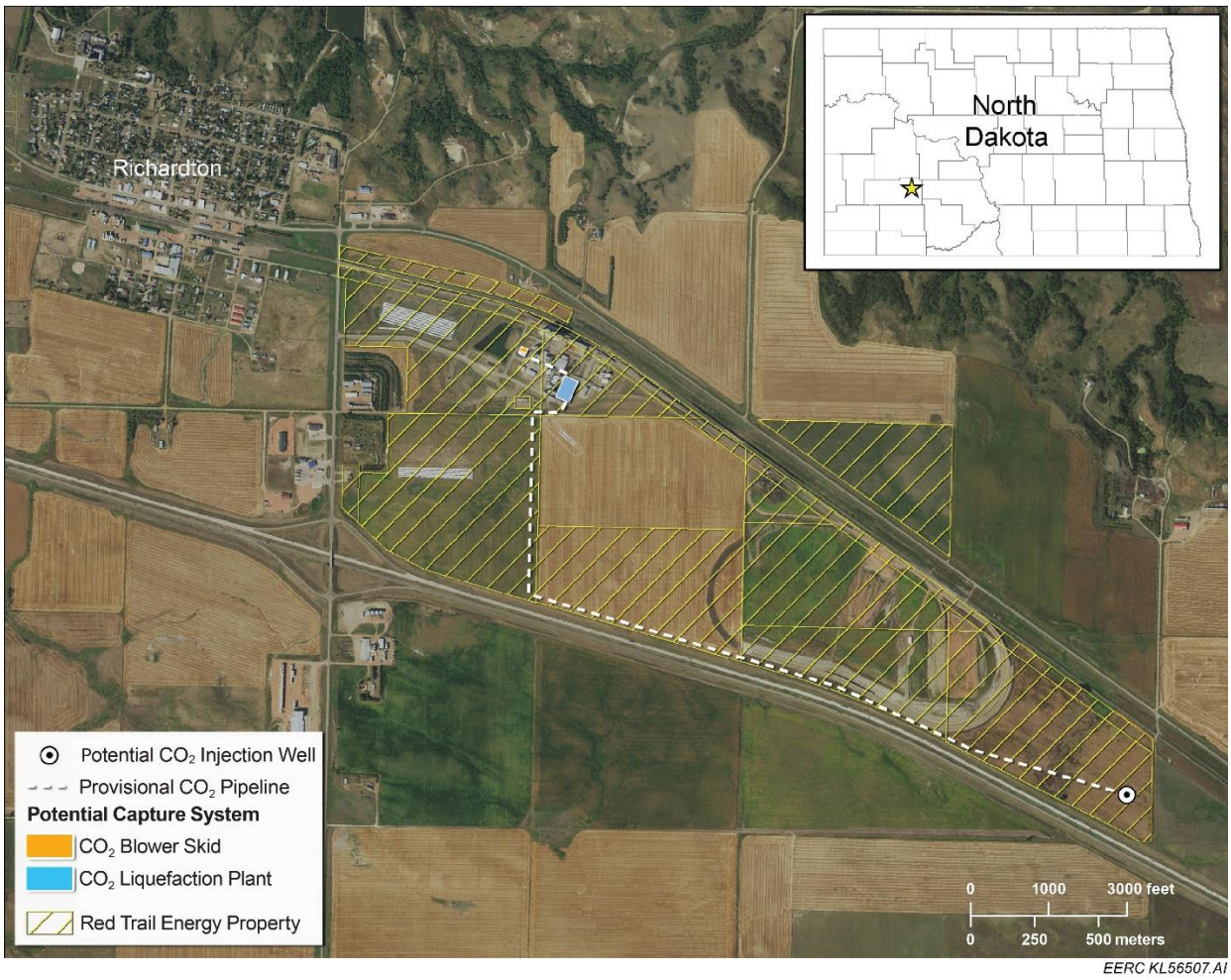

Figure 1. RTE CCS project area near Richardton, North Dakota.

RTE has also been working with the North Dakota Industrial Commission to ensure compliance with permitting for Underground Injection Control (UIC) Class VI for Geologic Sequestration of CO_2. North Dakota has primary enforcement authority (primacy) over all well classifications (Classes I–VI). For a state to obtain primacy, the application must demonstrate that 1) the state's rules are at least as

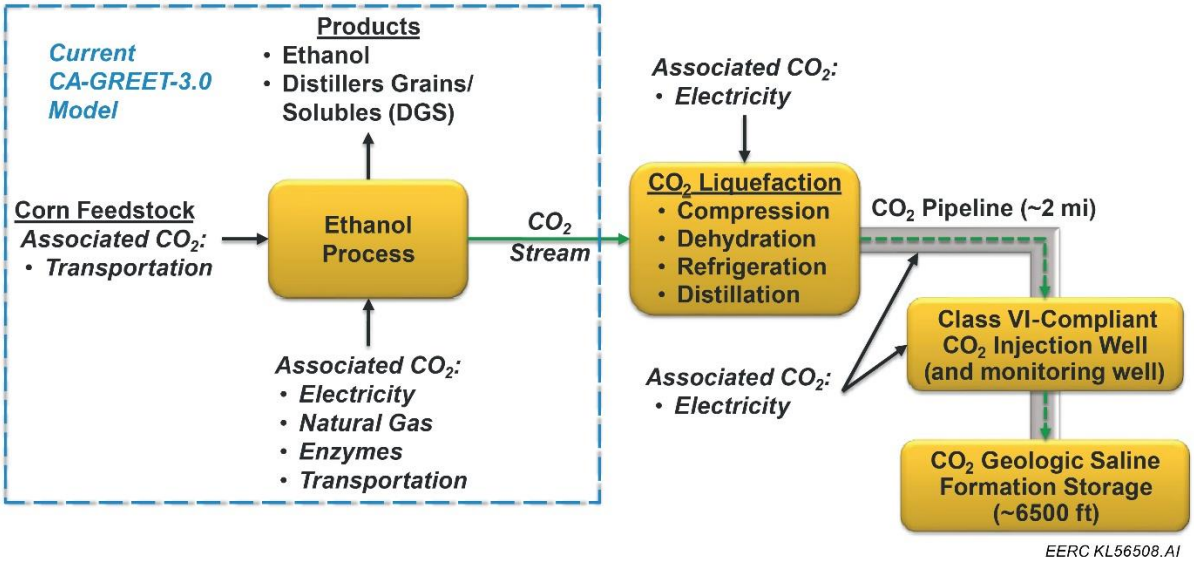

Figure 2. Block diagram showing key elements of ethanol production with CCS.

stringent as those of the federal UIC program and 2) the state's regulatory agency has knowledgeable staff capable of such a responsibility. North Dakota's Class VI Program (North Dakota Industrial Commission, 2013) requires all owners or operators applying to inject CO_2 for the purpose of geologic storage to obtain a storage facility permit, a permit to drill, and a permit to operate prior to commencement of injection activities. These permit applications are issued in accordance with North Dakota Century Code Chapter 38-22 for Carbon Dioxide Underground Storage and North Dakota Administrative Code Chapter 43-05-01 for Geologic Storage of Carbon Dioxide. This effort translates to Class VI-compliant injection and monitoring wells, permitted as such prior to injection start and subsequent CO_2 storage.

CO_2 Liquefaction System

The CO_2 liquefaction process primarily includes compression, dehydration, refrigeration, distillation, and a booster pump. A blower skid (containing [redacted] blowers) and pipe will be installed to connect the existing CO_2 scrubber at the current RTE ethanol facility to the new CO_2 liquefaction plant, as shown in Figure 1. Upon entering the liquefaction plant, the CO_2 will pass through [redacted] compressors, followed by [redacted] of coolers and filters to condense and remove water, respectively. A condenser, stripper column, and subcooler removes noncondensable gases (e.g., nitrogen) and cools the CO_2 stream to a pure liquid, which is then pumped (via one high-pressure booster pump) to the CO_2 pipeline for transport to injection (see the following section for further details). A closed-loop ammonia refrigeration unit (containing two compressors) is the chief cooling agent. Additional cooling water pumps and cooling tower fans (two each, incorporated with the existing cooling system) will also contribute to the CO_2 liquefaction system energy requirements. The system has been designed to minimize CO_2 losses, with one small vent (i.e., [redacted] CO_2, equating to [redacted] CO_2 stream) at the

stripper column top to purge noncondensable gases. Electricity consumption is the only other associated CO_2 source factoring into the LCA for CI calculation.

CO_2 Transport, Injection, and Monitoring Systems

The Broom Creek Formation, a saline formation situated at a depth of about 6500 ft directly below the RTE facility, allows for a maximum 2-mi pipeline to the planned injection well location to the east of the facility on RTE property (Figure 1). Shales and salts of the Opeche, Piper, and Swift Formations overlying the Broom Creek Formation create a sealing barrier of over 1000 ft, providing a secure, permanent geologic storage reservoir for the injected CO_2 (Sorensen and others, 2009; Glazewski and others, 2015; Leroux and others, 2017). One monitoring well will also be installed as required for compliance with North Dakota's Class VI Program. The pipeline and injection well system are also designed to minimize CO_2 losses with no planned venting. Associated CO_2 sources factoring into the LCA for CI calculation include only electricity consumption for monitoring equipment (e.g., CO_2 flow rates, pressure–temperature [P/T] gauges, and fiber optic cable) and related supervisory control and data acquisition (SCADA) systems.

Estimated RTE Ethanol-CCS Process CI Value

Using the CA-GREET-3.0 Tier 1 Simplified CI Calculator for Starch and Fiber Ethanol (California Air Resources Board, 2019), a comprehensive LCA, including the additional CCS inputs, was then used to calculate a design-based CI value for RTE as required by the 2019 LCFS regulation for design-based pathways, as summarized in Table 1 and detailed in the attached spreadsheets.

Table 1. Summary of Rounded CI Values for RTE Ethanol CCS Using CA-GREET-3.0

System Component	DDGS* Coproduct, gCO_2e/MJ	MDGS* Coproduct, gCO_2e/MJ	Comments
Current RTE Ethanol (without CCS)	75	68	Conventional corn ethanol production, based on 24 months of RTE operational data
CCS System Operations	+5	+5	Based on 198.6 kWh/tonnes CO_2 processed and monitored through transport and injection (see Table 2 for details)
CO_2 Geologic Storage	– 36	– 36	Based on 180,000 tonnes/yr CO_2 injected and permanently stored
Net CI Value**	**= 43**	**= 37**	

*DDGS = dried distillers grains with solubles; MDGS = modified distillers grains with solubles.
**Net values may not equate due to rounding.

Model inputs began with RTE's currently approved ethanol production values, generating a CI value of 75 gCO_2e/MJ with DDGS and 68 gCO_2e/MJ with MDGS. Because the CA-GREET-3.0 model does not currently allow for entry of CCS-specific components, expected energy consumption was

calculated from the detailed process designs and added to the electrical demand for the RTE facility. A total [redacted] kWh/tonnes CO_2 was estimated for liquefaction and monitoring of the transported and injected CO_2 during projected CCS operations. This equates to an added [redacted]. Table 2 shows the contribution of each CCS system component to the calculated CI value, with the liquefaction system accounting for nearly all [redacted] of the CI addition. The expected power draw from the monitoring/SCADA systems related to the pipeline and two Class VI compliant wells contributes the remaining [redacted] to the calculated CI value. The efficiency of the CCS system is assumed to be 99% with regard to capture and storage of the 181,000 tonnes/yr CO_2 generated to account for the stripper column vent and any other minimal CO_2 losses. About 180,000 tonnes/yr is thus anticipated to be injected and permanently stored equating to a subtraction of 36 gCO_2e/MJ from the CI value. Therefore, the final net RTE ethanol CCS LCFS CI calculated is 43 gCO_2e/MJ with DDGS (= 75 gCO_2e/MJ + 5 gCO_2e/MJ – 36 gCO_2e/MJ) and 37 gCO_2e/MJ with MDGS (= 68 gCO_2e/MJ + 5 gCO_2e/MJ – 36 gCO_2e/MJ).

Table 2. Breakdown of Energy Requirements for CCS System Operations

System Component	CI Calculations, gCO_2e/MJ	Comments
CO_2 Liquefaction System	[redacted]	Based on [redacted] kWh/tonnes CO_2 processed for compression, dehydration, refrigeration, distillation, and final booster pump
CO_2 Pipeline Transport	[redacted]	Based on [redacted] kWh/tonnes CO_2 transported for underground monitoring equipment (e.g., flow rates, P/T gauges) and related SCADA system
Class VI-Compliant CO_2 Injection and Monitoring Wells	[redacted]	Based on [redacted] kWh/tonnes CO_2 injected for downhole monitoring equipment (e.g., P/T gauges, fiber optic) and related SCADA systems
CCS System Operations	**= 5**	**Sum of associated CO_2 from energy consumption**

Conclusion

The project is in an advanced stage of planning and engineering. The values and statements presented are based on current conditions. We understand that the final CI value will be dependent on as-built data and that this CI application will be used for investment purposes only. We also understand that credit generation will only occur after a provisional pathway is approved. In accordance with the CCS protocol, permanence certification will be addressed and coordinated with the LCFS team concurrently with CCS site development. Ultimately, a provisional pathway application is intended to be submitted when the system is installed and the required 3 months of operational data are obtained.

RTE requests an opportunity to review the draft staff analysis prior to its posting for public comment. Please contact me with any questions at (701) 974-3308 or gerald@redtrailenergy.com.

Sincerely,

Gerald Bachmeier
Chief Executive Officer
Red Trail Energy, LLC

GB

Attachments

ATTACHMENT A – REFERENCES

California Air Resources Board, LCA Models and Documentation, ww3.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm (accessed August 28, 2019).

Glazewski, K.A., Grove, M.M., Peck, W.D., Gorecki, C.D., Steadman, E.N., and Harju, J.A., 2015, Characterization of the PCOR Partnership region: Plains CO_2 Reduction (PCOR) Partnership value-added report for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, EERC Publication 2015-EERC-02-14, Grand Forks, North Dakota, Energy & Environmental Research Center, January.

Leroux, K.M., Klapperich, R.J., Azzolina, N.A., Jensen, M.D., Kalenze, N.S., Bosshart, N.W., Torres Rivero, J.A., Jacobson, L.L., Ayash, S.C., Nakles, D.V., Jiang, T., Oster, B.S., Feole, I.K., Fiala, N.J., Schlasner, S.M., Wilson IV, W.I., Doll, T.E., Hamling, J.A., Gorecki, C.D., Pekot, L.J., Peck, W.D., Harju, J.A., Burnison, S.A., Stevens, B.G., Smith, S.A., Butler, S.K., Glazewski, K.A., Piggott, B., and Vance, A.E., 2017, Integrated carbon capture and storage for North Dakota ethanol production: Final report (November 1, 2016 – May 31, 2017) for North Dakota Industrial Commission and Red Trail Energy, Grand Forks, North Dakota, Energy & Environmental Research Center, May.

Leroux, K.M., Klapperich, R.J., Jensen, M.D., Kalenze, N.S., Daly, D.J., Crocker, C.R., Ayash, S.C., Azzolina, N.A., Crossland, J.L., Doll, T.E., Gorecki, C.D., Stevens, B.G., Schlasner, S.M., Botnen, B.W., Foerster, C.L., Hamling, J.A., Nakles, D.V., Peck, W.D., Glazewski, K.A., Harju, J.A., Piggott, B., and Vance, A.E., 2018, Integrated carbon capture and storage for North Dakota ethanol production – Phase II: Final report (November 1, 2017 – July 31, 2018) for North Dakota Industrial Commission and Red Trail Energy, Grand Forks, North Dakota, Energy & Environmental Research Center, July.

North Dakota Industrial Commission. North Dakota Class VI Underground Injection Control Program (1422) Description, June 2013.

Sorensen, J., Bailey, T., Dobroskok, A., Gorecki, C., Smith, S., Fisher, D., Peck, W., Steadman, E., and Harju, J., 2009, Characterization and modeling of the Broom Creek Formation for potential storage of CO_2 from coal-fired power plants in North Dakota: Search and Discovery Article No. 80046.

ATTACHMENT B – CA-GREET-3.0 SPREADSHEETS