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SCALE-UP TESTING OF ADVANCED POLARIS MEMBRANE CO_2 CAPTURE TECHNOLOGY

Final Project Report

by

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ABSTRACT

This final technical report describes work conducted by Membrane Technology and Research, Inc. (MTR) for the U.S. Department of Energy (DOE), National Energy Technology Lab (NETL) on the scale-up and testing of advanced Polaris™ membrane CO_2 capture technology at the Technology Centre Mongstad (TCM) under award number DE-FE0031591. The work was performed from August 1, 2018 through January 31, 2023.

The overall goal of this project was to design, build and operate an advanced Polaris membrane CO_2 capture system at TCM. MTR was assisted in this project by Trimeric Corporation (Trimeric), an engineering design services company, the Carbon Capture Simulation for Industry Impact ($CCSI^2$), a partnership among national laboratories, industry, and academic institutions, and the Technology Centre Mongstad (TCM), who provided the host site for the slipstream field test.

This report details the work conducted to scale-up MTR's second-generation (Gen-2) Polaris membrane and advanced planar membrane modules to a final form factor optimized for commercial use; validate their performance in an engineering-scale field test at TCM; and to show the potential of the MTR process to meet DOE CO_2 capture targets from large source point emitters. Work for this project included membrane optimization and scale-up, advanced planar module design and fabrication, design and fabrication of an engineering-scale field test membrane skid, operation of the field test skid processing Residue Fluid Catalytic Cracker (RFCC) industrial flue gas at TCM, and a detailed techno-economic analysis (TEA) of the MTR membrane post-combustion process for CO_2 capture. This project validated recent membrane technology advancements at the engineering-scale, moves the MTR advanced post-combustion capture technology to TRL-6, and mitigates risk in future Large Pilot or Demonstration scale-up activities.

EXECUTIVE SUMMARY

This final report describes work conducted by Membrane Technology and Research, Inc. (MTR) for the Department of Energy (DOE), National Energy Technology Laboratory (NETL) on a small pilot field test of MTR's advanced Polaris™ membrane CO_2 capture technology at Technology Centre Mongstad (TCM) under award number DE-FE0031591. The work was performed from August 1, 2018 through January 31, 2023.

The overall goal of this project was to design, build and operate an advanced Polaris membrane CO_2 capture system at TCM. MTR was assisted in this project by Trimeric Corporation (Trimeric), an engineering design services company, the Carbon Capture Simulation for Industry Impact ($CCSI^2$), a partnership among national laboratories, industry, and academic institutions, and the Technology Centre Mongstad, who provided the host site for the slipstream field test.

Over the past decade, DOE has funded a large research effort to identify low-cost ways to capture CO_2 from the emissions of large point sources, such as power generation facilities, to mitigate the climate impact of unabated CO_2 emissions. Currently, amine absorption is the leading candidate technology for post-combustion CO_2 capture. However, other advanced capture technologies are being considered as alternatives, including various membrane approaches. Membrane processes offer some advantages when applied to post-combustion CO_2 capture, including no hazardous chemical storage, handling or emissions issues, simple passive operation, tolerance to high SO_x and NO_x content, recovery of flue gas water, no modifications to the existing power plant steam cycle (because they use only electric power), and the benefits of a modular technology. The main challenge for post-combustion capture membranes is the low partial pressure of CO_2 in flue gas, which results in very large membrane area being required because of the small driving force for separation. Working with DOE, MTR previously made two transformative innovations to address this problem:

1. A new class of high-permeance membranes, called Polaris, was developed. This membrane was approximately tenfold more permeable than prior commercial membranes, resulting in a large decrease in required membrane area, and thus capital cost.

2. A membrane selective-recycle process (Figure ES-1) was developed. This patented process uses combustion air as a sweep stream to generate driving force for transmembrane CO_2 transport. The separated CO_2 is recycled to the boiler with air. This design increases the concentration of CO_2 in flue gas, which reduces the energy and capital required for capture.

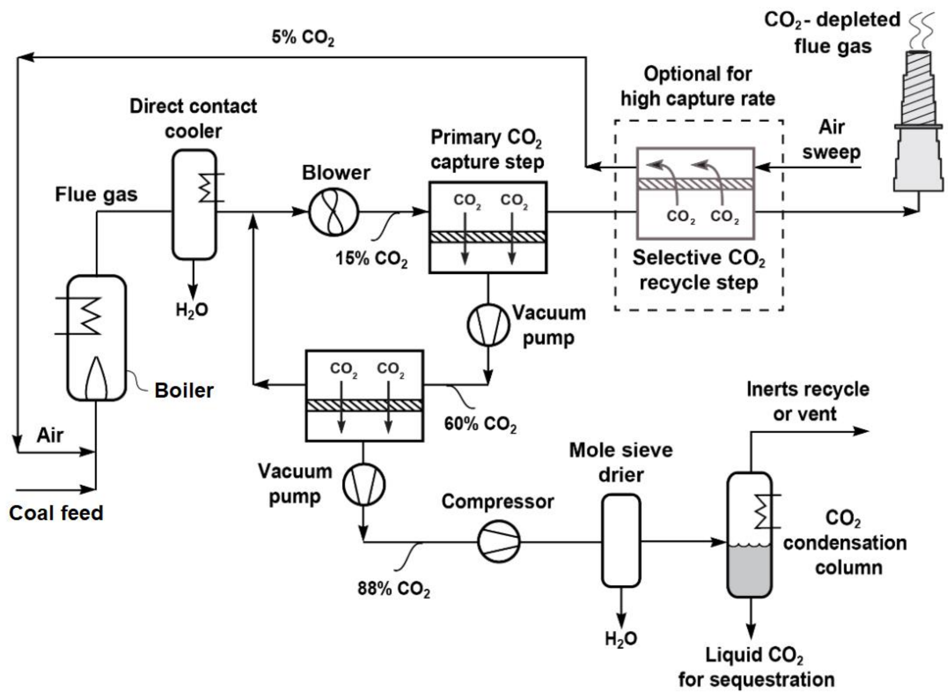

Figure ES-1. Simplified diagram of the MTR CO_2 capture process at a coal-fired power plant.

Subsequently, MTR has worked with DOE to develop these innovations into a cost-effective CO_2 capture process. This effort has included the first test of membrane modules with coal-fired flue gas at the Arizona Public Services (APS) Cholla plant in 2010; the accumulation of >11,000 hours of flue gas operation for Polaris modules on a bench-scale 1 tonne/day (TPD) system at the National Carbon Capture Center (NCCC); scale-up of first-generation (Gen-1) Polaris to a 20 TPD small pilot system, and successful operation of this system on a flue gas slipstream at NCCC and in integrated boiler testing at Babcock & Wilcox (B&W).

Through continued development efforts, a Gen-2 version of the Polaris membrane has been scaled-up to pilot production. This membrane offers 70% higher CO_2 permeance with similar selectivity to the base case Polaris. MTR also developed planar modules designed specifically for the low-pressure, high-volumetric flow rate process conditions of flue gas operation. These new modules have significantly lower pressure-drop values compared to the type originally used (spiral-wound modules), which results in significant energy savings. The overall goal of this field test was to validate the transformative potential of scaled-up Gen-2 Polaris membranes and advanced modules in an engineering-scale field test at TCM.

Various TCM groups supported the MTR field test throughout the installation, commissioning, operation, and decommissioning phases of the campaign. The test system arrived at TCM in Spring 2021 and MTR personnel were on-site to coordinate execution of installation and commissioning tasks. The test system was commissioned on flue gas in late-July 2021 and accumulated over 2,200 hours of flue gas operation during the field test. An MTR engineer was on-site for the entire test campaign to operate the system and coordinate any activities with TCM. Figure ES-2 shows the MTR test system at the TCM site during commissioning activities.

Figure ES-2. MTR test system during commissioning activities in early-July 2021.

During the TCM campaign, parametric testing of system process variables was conducted to identify optimum conditions for different CO_2 capture rates (60 – 90%). By operating the system under different process modes, the inlet CO_2 concentration was varied up to ~25 mol%, which allowed MTR to measure system performance under conditions relevant to CO_2 capture from large industrial point sources, such as cement or steel plants. Through these parametric tests, a relationship between the test system CO_2 capture rate and CO_2 purity was established under different process operation. Figure ES-3 shows the influence of the inlet flue gas flow rate on the test system performance. Over the flow rate range explored, the overall CO_2 capture rate varied between 61 and 91%, with higher flow rates producing a lower amount of CO_2 capture. This is consistent with expected behavior for a system with a fixed amount of membrane area. The CO_2 purity increased from about 86 to 92 mol% as the feed flow rate increased. This higher purity is also expected because the higher feed flow rate generates a higher CO_2 partial pressure driving force on the feed-side of the membrane. Overall, the tradeoff in CO_2 purity versus recovery illustrated in Figure ES-3 is expected behavior for the membrane system. Moreover, the CO_2 purity of >85 mol% produced by the membrane system is consistent with the anticipated feed to the compression and CO_2 condensation portion of the Figure ES-2 process design.

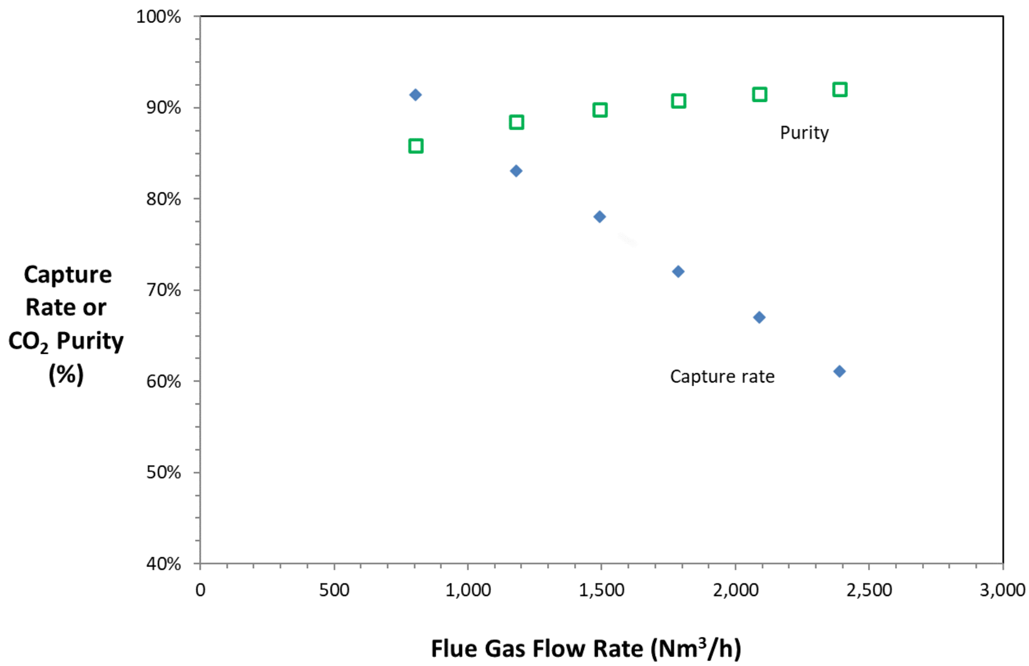

Figure ES-3. Influence of the flue gas flow rate on the MTR test system performance measured during Fall 2021 parametric tests at TCM.

In addition to CO_2 recovery and purity, another key performance metric for a membrane capture system is the pressure-drop through the modules. During parametric testing, the module stacks in the MTR test system experienced a range of flow rates for which pressure-drops were measured. ES-4 shows the feed-to-residue pressure-drop for the three module units (Stage 1, Stage 2, and Step 2) as a function of the feed flow rate divided by cross-sectional area (i.e., the gas superficial velocity through the modules). The pressure-drop of all three module stacks measured during testing falls on the same curve. This result indicates that the membrane modules performed as expected and there was no evidence of flue gas channeling or flow distribution problems on the feed side of the modules. New 2nd Stage modules installed in January 2022 that contained a different feed flow configuration had even lower pressure-drop values under the same field test conditions. Importantly, the feed-to-residue pressure-drop of all membrane stacks is significantly lower than the project target of 13.8 kPa (2 psi) over the entire flow range examined.

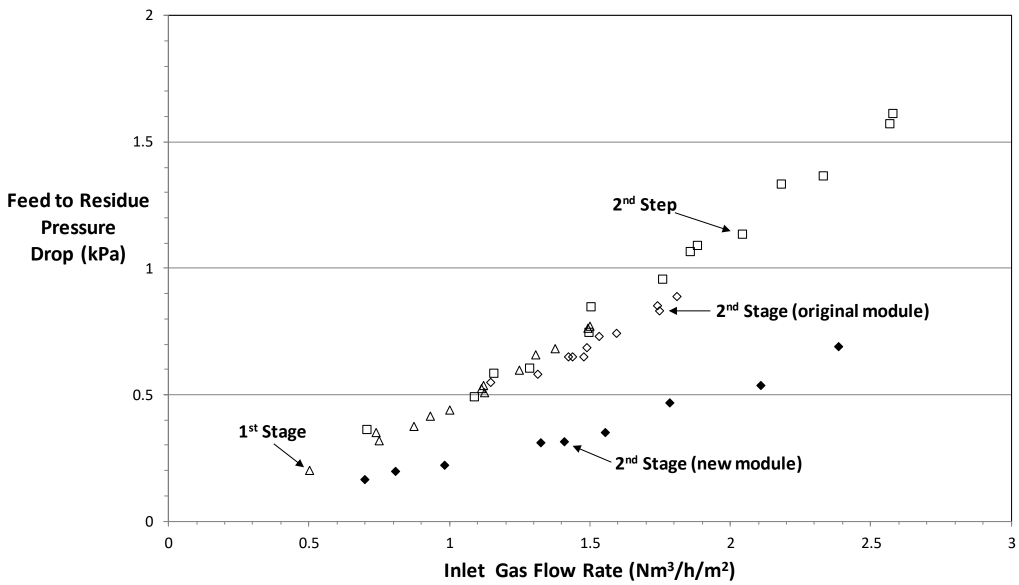

Figure ES-4. Influence of the normalized inlet flow rate on the MTR membrane module stacks feed-to-residue pressure-drop.

The test campaign concluded on March 1, 2022 and the decommissioned test system was completely removed from TCM by mid-June. During post-test analysis of field test modules at the MTR facility, some 1st and 2nd Stage modules were found to have low-performance values caused by deposition of aluminum and ammonium (bi)sulfate compounds on the surface of the membrane. The presence of these corrosion byproducts on the membrane resulted from the use of aluminum module housings that were in contact with acidic condensate during flue gas operation. One of the 2nd Stage modules installed in January 2022 contained a fouling-resistance version of the Polaris membrane and was unaffected by the corrosion. The 2nd Step (sweep) Polaris membrane exhibited expected membrane performance during post-test measurements because the dry flue gas entering this module lacked the ability to form the acidic condensates (the gas was dehydrated by passing through Step 1 modules).

A techno-economic analysis (TEA) of the MTR post-combustion CO_2 capture process was conducted using the most recent Bituminous Baseline Report (Revision 4). The TEA incorporated field test data of the Gen-2 Polaris membrane and advanced planar modules. This TEA provides a comparison of the MTR CO_2 capture process to the reference amine-based CO_2 capture process, Case B12B in the DOE baseline report.

This project and report were funded under a Fall 2017 DOE opportunity where a specific CO_2 capture rate was not required. As a result, MTR chose to analyze a 70% CO_2 capture rate, which was believed to represent a minimum cost operating condition for the membrane process. The TCM field test did include operation at CO_2 capture rates >90% as interest shifted over the course of the project to higher capture rates. CO_2 capture rate scenarios of 95+% for power and industrial emitters are being evaluated in other MTR work outside the scope of this project.

Table ES-1 summaries the key findings of the project TEA. Overall, the MTR cost of capture estimate is slightly higher than Case B12B, although the result is within the 20% uncertainty in purchased equipment cost (PEC). Several factors were identified as areas that could improve the cost competitiveness of the MTR membrane process. These include the performance improvements of Gen-3 Polaris membrane (being developed in a separate DOE program), the impact of a higher CO_2 content in industrial flue gas which is known to favor membranes, and the effect of less stringent CO_2 purity in the liquid CO_2 product.

Table ES-1. Summary of key economic factors for the MTR post-combustion CO_2 capture process compared with Bituminous Baseline Case B12B reference amine CO_2 capture.

Case	Cost of Capture (no TS&M) \$/tonne CO_2	Change vs. MTR Base Case	LCOE \$/MW_h	Change vs. MTR Base Case	CO_2 Capture and Compression Total Plant Cost \$MM
B12B (90% capture)	\$45.63	-	\$105.20	-	\$826
MTR Base Case (70%)	\$48.50	-	\$96.55	-	\$667
MTR PEC (-20%)	\$42.95	-11.4%	\$92.90	-3.8%	\$534
MTR PEC (+20%)	\$54.05	+11.4%	\$100.22	+3.8%	\$801

In summary, this project resulted in the successful scale-up and field test validation of the Gen-2 Polaris membrane and advanced planar modules. The completion of this work advanced the Gen-2 Polaris membrane capture technology from TRL-5 to TRL-6. In addition to this primary accomplishment, the following key results were achieved:

- The Gen-2 Polaris membrane production was successfully scaled-up on commercial roll-to-roll equipment.
- Advanced planar low-pressure-drop membrane modules were designed, fabricated, and proven in the TCM field test. Stacks of the planar membrane module in a containerized skid are the final modular form factor for future large-scale systems.
- The MTR test system at TCM was commissioned on flue gas in late-July 2021 and operated until March 2022. During the campaign, the MTR test system logged over 2,200 hours of flue gas operation.
- Parametric testing included varying the inlet flue gas flow rate (800 – 2,400 Nm^3/h), inlet CO_2 concentration (14.6 – 26.1 mol%), and the sweep air inlet flow rate (500 – 1,450 Nm^3/h). During the test campaign, the system operated in either single pass or various internal recycle process modes.
- Overall CO_2 capture rates up to 91% and a 2^{nd} Stage CO_2 purity up to 92 mol% were achieved during parametric testing.
- For all test conditions, the feed-to-residue or sweep-side pressure-drops were well below the project target of 13.8 kPa.
- Post-test analysis of membrane modules found aluminum and ammonium sulfate corrosion by-products on some of the Polaris membrane surface. These corrosion by-products were formed by condensation of acidic water on the aluminum housings used on the membrane system. The reduction in membrane module performance was related to the particle deposition concentration, which was highest on the feed side of the 1^{st} and 2^{nd}

Stage modules. Future test systems will use only plastic housings and stainless-steel ducting/internals to eliminate the possibility of aluminum as a corrosion source.

- One of the 2nd Stage replacement modules in January 2022 contained Polaris membranes with a modified formulation to protect against fouling. These membranes were resistant to the corrosion foulants.
- The project TEA showed that the MTR CO_2 capture cost was similar (within uncertainty) to the amine capture Baseline Report Case B12B. Several factors were identified as areas that could improve the cost competitiveness of the MTR membrane process including: the performance improvements of Gen-3 Polaris membrane (being developed in a separate DOE program), the impact of a higher CO_2 content in industrial flue gas which is known to favor membranes, and the effect of less stringent CO_2 purity in the liquid CO_2 product. Future work will examine these factors in more detail.

The Gen-2 Polaris membrane performance and advanced module pressure-drop data measured during the TCM field test will be used to design future MTR CO_2 capture systems. One current project (DE-FE0031587) that has incorporated experimental data and lessons learned from the TCM field test is a Large Pilot system currently under construction that will capture 150 tonnes of CO_2 per day at the Wyoming Integrated Test Center (WITC) in Gillette, WY. The Large Pilot is on schedule to be commissioned in mid-2024, and when completed it will be the largest membrane capture system in the world. This important scale up will bring the MTR CO_2 capture technology for coal flue gas to TRL-7.

Going forward, MTR recommends the following future development steps to accelerate commercial deployment of membrane-based CO_2 capture systems:

- Continue advanced Polaris membrane development for improved cost and performance. Advanced membranes will reduce the required membrane area, system footprint, and energy use of the MTR CO_2 capture process. Preliminary sensitivity studies suggest that these improvements could reduce capture costs by 10-20%. MTR is pursuing these activities with both internal resources and through an ongoing DOE transformational capture project.
- Among the largest capital and operating expenses for the MTR process are the vacuum and CO_2 compression equipment. Any improvements in cost and/or performance for this equipment would make a significant impact on capture costs. MTR plans to work with OEM providers, particularly for vacuum machines specifically needed for membrane capture, to optimize equipment selection and performance.
- Front-end engineering and design (FEED) studies of the MTR CO_2 capture membrane approach at specific sites, particularly industrial plants, are an important step in moving the membrane technology toward commercialization. To the extent that DOE funding is available for such activities, we will pursue these opportunities.
- Additional pilot tests at industrial facilities are needed to convince end-users that the technology is a viable capture option for their specific flue gas. Most end-users are looking for capture technology providers to absorb at least the costs of the pilot system itself. Partial DOE funding for these field demonstrations can accelerate capture technology deployment.

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1. INTRODUCTION

1.1 Background

Over the past decade, DOE has funded a large research effort to identify low-cost ways to capture CO_2 from the emissions of large point sources, such as power generation facilities, to mitigate the climate impact of unabated CO_2 emissions. Coal-fired power plants have been a particular focus for CO_2 capture efforts because of the large installed base of these plants, which produce almost 40% of U.S. CO_2 emissions. Moreover, the relative low-cost and large domestic supply of coal suggests that this fuel will remain important to power production in some regions.[1,2]

Currently, amine absorption is the leading candidate technology for post-combustion CO_2 capture. This capture approach is a proven technology used successfully to remove CO_2 from industrial gas streams for decades. Initial capture systems at commercial power stations such as Boundary Dam in Canada and WA Parish in Texas used amine absorption. However, studies indicate that amine absorption, when applied to flue gas CO_2 capture, can be costly and energy intensive.[2,3] Moreover, amine systems have environmental issues including high water use and emissions of toxic degradation compounds. As a result, DOE is funding development of transformative new technologies based on advanced solvents, membranes, or hybrids with a goal of offering alternatives with reduced capture costs and less environmental impact.

Among advanced capture technologies being considered are a number of membrane approaches.[4-7] Membrane processes offer some advantages when applied to post-combustion CO_2 capture, including no hazardous chemical storage, handling or emissions issues, simple passive operation, tolerance to high SO_x and NO_x content, recovery of flue gas water, no modifications to the existing power plant steam cycle (because they use only electric power), and the scaling benefits of a modular technology. The main challenge for post-combustion capture membranes is the low partial-pressure of CO_2 in flue gas, which results in large, required membrane area because of the small driving force for separation. Some years ago, working with DOE, MTR made two innovations to address this problem:

- A new class of high-permeance membranes, called Polaris™, was developed. This membrane was approximately tenfold more permeable than prior commercial membranes, resulting in a large decrease in required membrane area, and thus capital cost.

- A membrane selective-recycle process was developed. This patented process uses combustion air as a sweep stream to generate driving force for transmembrane CO_2 transport.[8] The separated CO_2 is recycled to the boiler with air. This design increases the concentration of CO_2 in flue gas, which reduces the energy and capital required for capture.

Subsequently, MTR has worked with DOE to develop these innovations into a cost-effective CO_2 capture process. This effort has included the first test of membrane modules with coal-fired flue gas at the Arizona Public Services (APS) Cholla plant in 2010; the accumulation of >11,000 hours of flue gas operation for Polaris modules on a bench-scale 1 TPD system at NCCC; scale-up of Gen-1 Polaris to a 20 TPD small pilot system, and successful operation of this system on a flue gas slipstream at NCCC and in integrated boiler testing at B&W.

This experience demonstrates MTR's capacity to scale-up new membrane technology. During this development effort, additional membrane, module, and process improvements that improve the economics of membrane post-combustion CO_2 capture have been identified and efforts are underway to implement these technology enhancements.

1.2 Membrane Basics

Polymer membranes separate the components of a gas or vapor mixture because the components permeate the membrane at different rates. The permeability, P [cm^3(STP)·cm/cm^2·s·cmHg], of a polymer membrane for a gas is defined as the rate at which that gas moves through a standard thickness (1 cm) of the material under a standard pressure driving force (1 cmHg). A related parameter used more frequently in the membrane industry is gas permeance, where permeance = permeability/thickness. The permeance is frequently expressed in gas permeance units (gpu), where 1 gpu = 10^{-6} cm^3(STP)/(cm^2 s cmHg). The higher the membrane permeance, the more gas that can be treated by a given membrane area, and thus the lower the capital cost of a system.

The separating ability of a membrane is determined by the selectivity, α, defined as the ratio of the gas permeabilities, P_1/P_2, or permeances. Selectivity can also be expressed as $\alpha = \left(D_1/D_2\right)\left(S_1/S_2\right)$ where D is the diffusion coefficient of the gas in the membrane, and S is the sorption coefficient, which links the concentration of the gas in the membrane to the pressure in the adjacent gas. In glassy polymers, the dominant contribution to selectivity is the ratio of the diffusion coefficients, D_1/D_2, which depends on the ratio of the molecular sizes. In rubbery polymers, the dominant contribution is from the ratio of the sorption coefficients, S_1/S_2, which is proportional to the ratio of the permeant condensabilities. CO_2 is both smaller than nitrogen and much more condensable, so solution-diffusion membranes are always selective for CO_2 over N_2 to varying degrees. Generally, the higher the selectivity, the better the product purity, and therefore, the lower the operating costs of a membrane system.

Figure 1 illustrates the structure of a typical thin-film composite membrane. A microporous support material, with low resistance to gas permeation, provides mechanical strength for the membrane. The microporous support is often coated with a highly permeable gutter layer, which improves the compatibility between the support and selective layer, as well as conducting the permeating gas to the support membrane pores. The gutter layer is then coated with a selective layer, which largely determines the separation properties of the membrane. Finally, a protective layer may be added to prevent membrane damage during handling and module assembly.

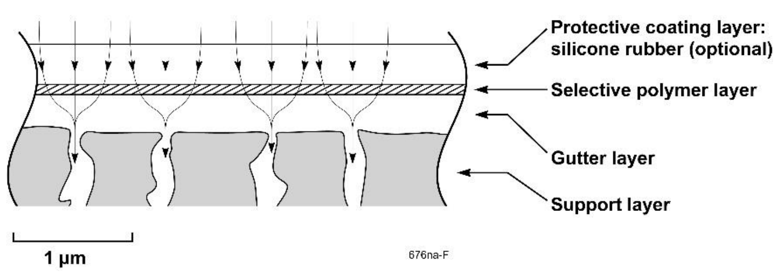

Figure 1. Schematic drawing of the structure of a thin-film composite membrane.

1.3 Polaris Membrane Development

Several years ago, MTR developed a class of composite membranes called Polaris where the selective layer is based on polar polymers that are extremely permeable to CO_2 and other polar species. This Gen-1 Polaris membrane set the standard against which all post-combustion capture membranes are now compared. With an average CO_2 permeance of 1,000 gpu and a CO_2/N_2 pure-gas selectivity of 50, Gen-1 Polaris was a step-change improvement over typical commercial CO_2-selective membranes used for natural gas treatment (which offer a CO_2 permeance of around 100 gpu combined with a pure-gas CO_2/N_2 selectivity of 30). This improvement is illustrated in Figure 2, where membrane performance is compared in the form of a trade-off plot of CO_2/N_2 selectivity versus CO_2 permeance. Better membranes will have properties that move up and to the right on this plot.

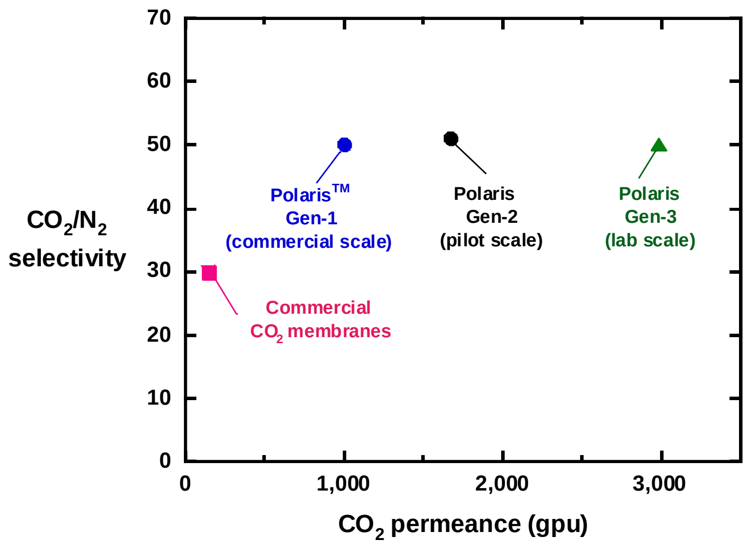

Figure 2. A CO_2/N_2 trade-off plot showing data for several generations of MTR Polaris membrane. Data are pure-gas values at room temperature.

In addition to showcasing the benefits of Polaris over conventional membranes, Figure 2 also shows some of the more recent improvements in the performance of Polaris membranes. A Gen-2 Polaris membrane has been scaled-up to pilot production. This membrane offers about 70% higher CO_2 permeance with similar selectivity to the base case Polaris. These Gen-2 membranes have been fabricated into prototype modules and validated in bench-scale testing at NCCC. Recently, even higher permeance third-generation (Gen-3) Polaris membranes (3,000 gpu) have been produced at the lab scale. These improvements are important because the size and capital cost of a membrane unit scales almost linearly with membrane CO_2 permeance. Thus, these new Polaris membranes would yield a system with one-half to one-third as many membrane vessels as the Gen-1 membranes; this would be a dramatic reduction in system size and cost.

1.4 Process Design Consideration

In addition to a membrane with good separation performance, an energy-efficient and affordable process design is required to make membranes competitive for post-combustion CO_2 capture. Prior membrane process studies have produced the following general conclusions about using membranes for post-combustion capture:[4,8,9]

- To capture CO_2 from flue gas, a membrane process needs partial-pressure driving force. This driving force can be generated by either (a) compression on the feed-side or (b) a vacuum on the permeate-side of the membrane. The energy required is considerably lower for a vacuum process because the vacuum only has to pump the flue gas that permeates the membrane (about 10% of the total flue gas, and largely CO_2), whereas a feed compressor has to pressurize all of the flue gas (CO_2 plus the bulk N_2). While a vacuum process uses less energy, it requires a larger membrane area, because the CO_2 partial-pressure difference across the membrane is relatively small. Consequently, an energy-efficient vacuum-driven process requires very permeable membranes.

- In addition to large membrane area or power requirements, single-stage membrane designs are unable to produce high-purity CO_2 *combined* with high CO_2 capture rates. In fact, a single-stage membrane process alone cannot produce high-purity CO_2 in the permeate with >90% CO_2 capture, regardless of the membrane selectivity. This is because the system performance is limited by the pressure ratio across the membrane – that is, the ratio of the feed pressure to the permeate pressure. Higher pressure ratios for flue gas treatment could be generated, but at a high energy and capital cost. With a maximum affordable pressure ratio of ~10, the ideal membrane selectivity for flue gas CO_2 capture is about three to five times the pressure ratio, or a CO_2/N_2 selectivity of 30-50.[10] Beyond this point, it is much more important to increase membrane permeance to reduce area requirements rather than trying to improve selectivity.

To overcome these driving force issues and achieve a relatively high CO_2 capture rate and high-purity, membrane developers have proposed multi-step/stage membrane designs and/or hybrids with other separation technologies (condensation, adsorption, etc.). For example, MTR developed the selective-recycle process design shown in Figure 3.[8] This process uses a permeate vacuum in a first membrane step to efficiently generate a pressure ratio that will lead to capture of about 70% of the inlet flue gas CO_2. The partially-treated flue gas leaving this primary CO_2 removal unit is then sent to a second membrane step that utilizes a sweep gas of combustion air to selectively recycle CO_2 to the boiler and drive the overall CO_2 recovery to 90+%.

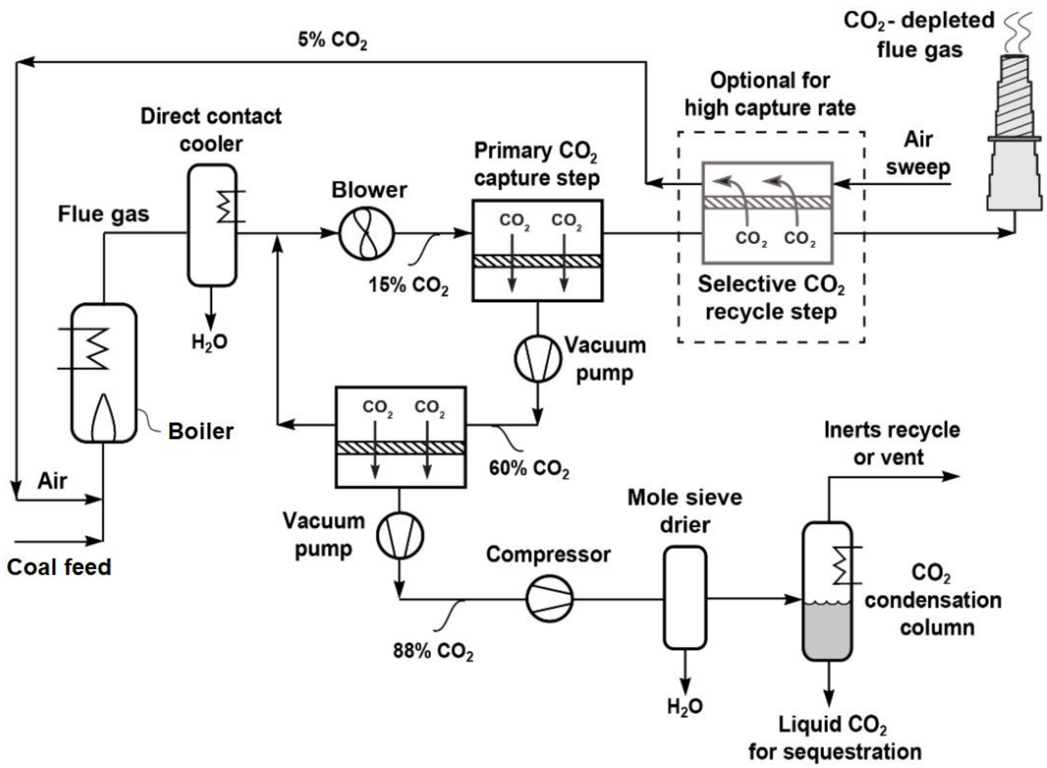

Figure 3. Simplified diagram of the MTR CO_2 capture process at a coal-fired power plant.

This CO_2 recycle design has a number of features that optimize membrane system performance:

- Because it is a two-step membrane design, all of the flue gas CO_2 does not have to be removed in a single membrane step. This allows the first-step membrane to operate efficiently as a partial capture step (50 - 80%) with a relatively high partial-pressure of CO_2 on the feed-side.

- The second membrane step performs the difficult task of removing CO_2 to very low levels (i.e., to reach 90+% capture). This step uses an air sweep stream to maintain separation driving force by keeping a relatively low partial-pressure of CO_2 on the permeate-side. Because the air is already being sent to the boiler as the oxidant for combustion, this sweep gas provides essentially free separation (i.e., no compressors or vacuum pumps are used in this step).

- The concentration of CO_2 in the flue gas leaving the boiler is increased (for example, from 12% to 18% CO_2) because CO_2 is recycled to the boiler with the air sweep stream. This enrichment makes CO_2 capture in the first membrane step easier due to the higher CO_2 partial pressure.

1.5 Membrane Module Design

One of the key issues for a membrane post-combustion capture system is how to balance the desire for a small system footprint with the need to process large volumetric flows and minimize parasitic pressure-drops. The pressure-drop issue is particularly important because for a full-scale (550 MW_e power plant) membrane capture system, each 1 psi of pressure-drop through the membrane unit amounts to approximately 3 MW_e of required blower energy. In previous TEA studies of a commercially mature n^{th}-of-a-kind (NOAK) MTR membrane capture system, MTR assumed 1.5 psi pressure-drop through each of the membrane units shown in Figure 3. The ability to reach this pressure-drop target while maintaining a compact system size and good membrane performance depends on the module design.

In earlier work, MTR addressed these module design issues by first adapting existing spiral-wound module technology for low-pressure operation. Early spiral modules showed unacceptably high pressure-drops. Through changes in feed flow geometry and module configuration, the best spiral-wound sweep modules were able to reach a sweep-side pressure-drop of just under 4 psi. Later, recognizing some of the limitations associated with tortuous flow in spirals, new planar modules were designed specifically for flue gas operation. The most important feature of these new modules is the ability for fine control of the flow path on both the feed and permeate/sweep sides of the membrane, which can be used to minimize pressure-drop. Under equivalent laboratory conditions, planar modules with similar packing density to spiral-wound modules can achieve a pressure-drop of less than 0.5 psi.

To validate these laboratory improvements, a prototype planar module was built and tested in a side-by-side comparison with spirals on a small pilot system at NCCC. Figure 4 shows these results, which confirm the improved performance of the new modules. At the same flow rate, the planar module had about 3 psi lower pressure-drop compared to the sweep spirals. Scaled to a full power plant, this would yield savings of approximately 10 MW_e in fan power. In addition to energy savings, we believe the regular geometry of the new design module is more amenable to automated fabrication methods that will reduce cost.

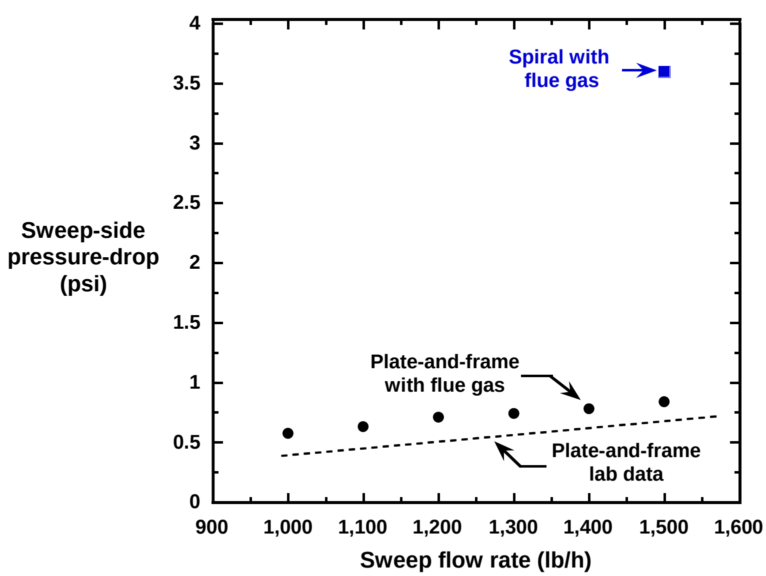

Figure 4. Difference in pressure-drop between spiral and planar modules in the NCCC field tests.

2. DESIGN AND FABRICATION OF GEN-2 POLARIS PLANAR MEMBRANE MODULES

In the first project Budget Period (BP), MTR fabricated the Gen-2 Polaris membrane needed for this project on existing commercial manufacturing roll-to-roll equipment. After passing quality control testing, these membrane rolls were placed in storage until module assembly preparation activities began.

Early in the project, MTR started design work of the low-pressure-drop modules that will constitute the final form factor for CO_2 capture membranes. The original prototype of these planar modules was tested at NCCC and B&W, and confirmed to have superior pressure-drop characteristics. However, this prototype was made from machined parts and enclosed in a stainless-steel pressure vessel. The new advanced planar membrane modules designed for this project are stackable and the module stack will have a pressure rating, eliminating the need for a pressure vessel enclosure and further reducing costs. The planar modules were designed to minimize the pressure-drop caused by moving gases in and out of the module. Computational fluid dynamics (CFD) has been used to determine the velocity profiles and pressure-drop within module stacks. The results from these studies were also shown in the second quarterly report. Figure 5 shows a 1:6 scale version of the molded module stack along with a single module containing membrane.

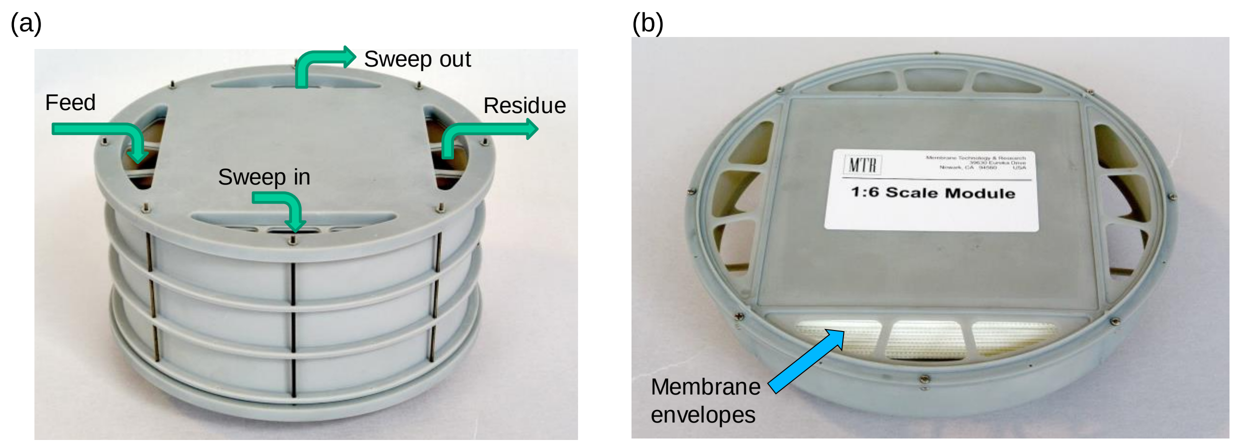

Figure 5. (a) 1:6 scale model of a stack containing three membrane modules. The port labels and gas flow directions reflect stack operation in sweep mode. In the case of the first-step vacuum, permeate will be removed from both the sweep in and out ports. (b) 1:6 scale model of a single module containing membrane.

The initial choice for the planar module material of construction was fiber-reinforced injection molded plastic due to the chemical compatibility and substantial cost reduction benefits. However, due to the effect of the COVID-related shutdown and local quarantine on supply chains, vendors, and product availability, MTR pivoted to alternatives that met the project schedule and budget. A local machine shop (Huffman's Welding Works in Newark, CA) that MTR has worked with for a decade on various research and development (R&D) and commercial projects was selected as the fabricator for the new module housings. Huffman's Welding Works qualified as an essential business and continued to work during the COVID-19 shelter-in-place order. Figure 6 shows a top view of one of the aluminum housings, as well as a photo of an eight-housing stack as they were arranged on the TCM test system.

(a) (b)

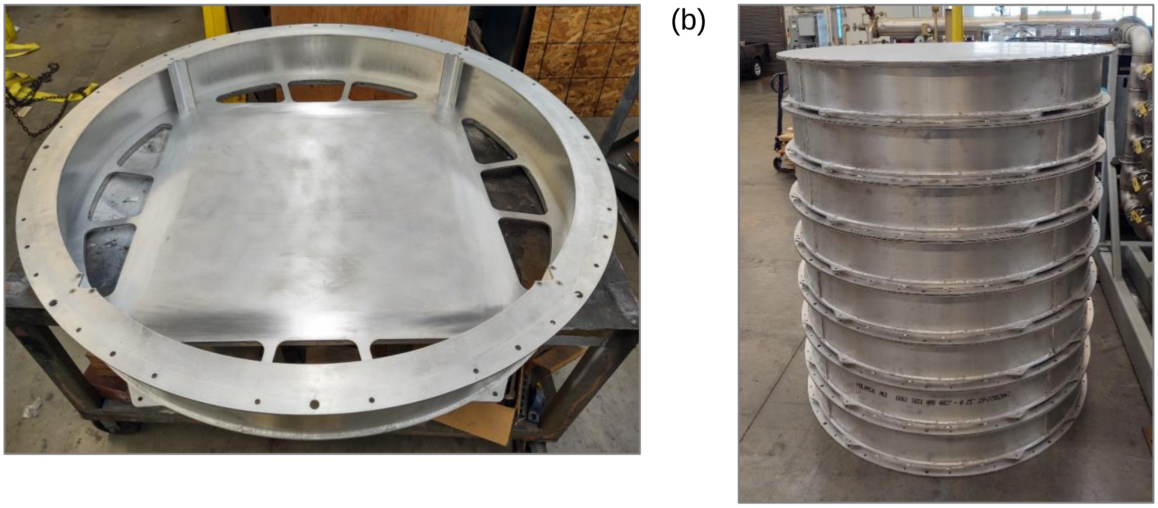

Figure 6. (a) A top view of a single planar module housing and (b) a stack of eight housings.

In parallel to the planar module design and fabrication, MTR developed and refined procedures to fabricate the membrane stacks that will be installed in the planar modules. The fabrication process starts with MTR research engineers and manufacturing technicians cutting membrane and spacer samples to length, folding them into individual membrane envelopes, and then placing the envelopes in storage prior to the assembly of a membrane stack. For each membrane stack, the correct number of membrane envelopes are sorted and stacked to allow for easy transfer to the membrane module assembly device. During the assembly process, MTR personnel alternate membrane envelopes with permeate spacers and apply glue lines after each step. Once the membrane module stack has been completely assembled, the stack is allowed to cure under compression.

After the glue has completely cured, the next step is for the membrane stack to be trimmed to fit in the membrane module housing. A new, improved trimming system was installed at MTR during the project that includes a more powerful trimmer, precision control of the trimming process, and a vacuum system to capture all particulates created during trimming. Figure 7 below shows the new trimming system and the membrane stack trimming process. After trimming, individual membrane stacks are placed in storage prior to installation in a module housing. Figure 8 shows a fully cured and trimmed membrane stack ready for installation in a module housing.

(a) (b)

Figure 7. (a) The new membrane module trimming system installed at MTR during BP2 with a membrane stack ready for trimming and (b) a precision cut on a membrane stack.

Figure 8. A fully cured and trimmed membrane stack ready for installation in a module housing.

Prior to installation in a module housing, the dimensions of each membrane stack are verified, and an initial leak check is conducted. Once the membrane stack has been installed in the housing and the proper fit has been verified, the membrane stack is glued into place.

Once the glue had cured, the membrane modules are placed in a custom apparatus built during BP2 (Figure 9) for further leak testing, and if necessary, patching. MTR worked diligently throughout the summer of 2020 to minimize the delay in membrane module fabrication due to COVID-19 and the associated local shelter-in-place order.

Figure 9. Front (left) and back (right) views of the MTR leak test apparatus for the TCM field test membrane modules.

The membrane units for this field test included a stack of advanced planar membrane modules, a membrane stack base that directs the different gas streams in and out of the membrane modules, and a membrane stack lid. The membrane stack base and lid were designed by MTR and fabricated by Progressive Recovery, Inc. (PRI) at their facility in Dupo, IL. The lids were shipped to MTR for final drilling and additional machining at a local NorCal machine shop. Once ready, the lids were installed on a membrane module by MTR personnel, and the membrane stacks were then subjected to quality control testing to identify any gasket leaks. After passing the quality control tests, each membrane stack and lid was shipped back to PRI for final installation on the test system prior to shipping to Norway. Figure 10 shows one of the completed membrane stacks being loaded for shipping at MTR. The first membrane stack and lid arrived at PRI in January 2021, with the other membrane stacks arriving in February.

Figure 10. Packing of the MTR advanced membrane module stack and lid at MTR (left) and crated stack ready for transport to fabrication shop (right).

3. MTR SMALL PILOT SYSTEM DESIGN AND FABRICATION

3.1 Preliminary Design

Figure 11 shows a simple process flow diagram for the MTR system installed at TCM. This flexible design can route some of the purified CO_2 through a spillback line (stream 9) to the front of the membrane system to increase the concentration of CO_2 in the feed from 13 to ~25%. By recycling CO_2 in this way, the feed to the membrane system will mimic the fully integrated capture case without having to recycle CO_2 to the boiler via the sweep step. With this spillback option, a 20% CO_2 membrane feed contains about 1 MW_e worth of CO_2. Overall, 60 to >90% of the CO_2 in the inlet slipstream can be captured, depending on operating parameters. MTR developed the test system design based on a TCM slipstream (stream 1) flow rate of 2,000 Nm^3/h.

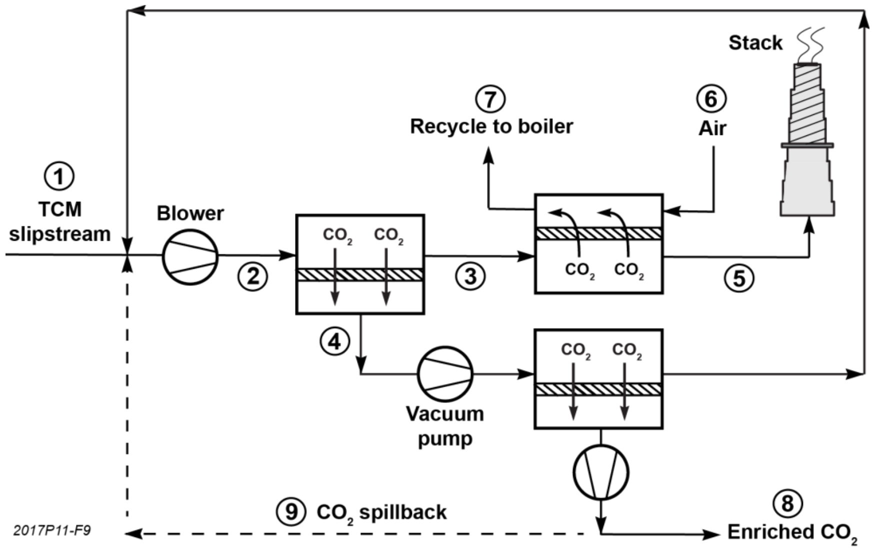

Figure 11. Simple process flow diagram of the MTR membrane test system operated at TCM.

3.2 Review TCM Site Specifications

MTR and TCM evaluated various sites at TCM for the location of the MTR test system (Figure 12). TCM will be hosting a number of new technologies in the coming years, so they took a comprehensive look at the site development needs early in the project. As part of the effort, TCM performed an internal engineering study to determine how to best accommodate technology developers within project timelines.

Figure 12. Aerial view of existing TCM site infrastructure with possible locations for the MTR skid (labeled 1, 2, and 3).

The site eventually selected for testing the MTR skid at TCM is labeled 3 in Figure 12. An artistic rendering of this third site with locations for the MTR system (this project) and the TDA/MTR skid (project DE-FE0031603) is shown in Figures 13 and 14. The third site was undeveloped, so substantial infrastructure work was required to bring flue gas and utilities to both systems. In addition, the infrastructure was designed to be flexible to allow for the support of future test systems after the current projects have been completed and removed from site. TCM performed an internal engineering study to determine how to best accommodate capture technologies at the third site within the project timeline and presented recommendations to the TCM board in late-June 2019. At the same meeting, the TCM board approved an investment decision to fund infrastructure development at the third site, which allowed parallel operation of the MTR and TDA/MTR hybrid tests.

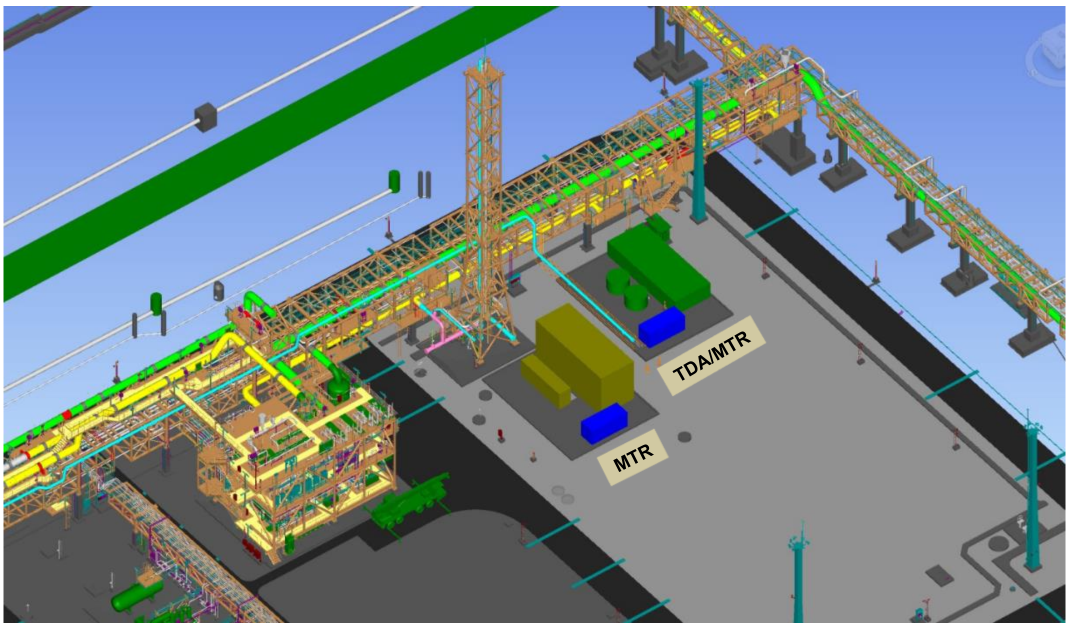

Figure 13. Artist rendering of the third development site at TCM, including the proposed locations of the MTR and TDA/MTR hybrid test systems.

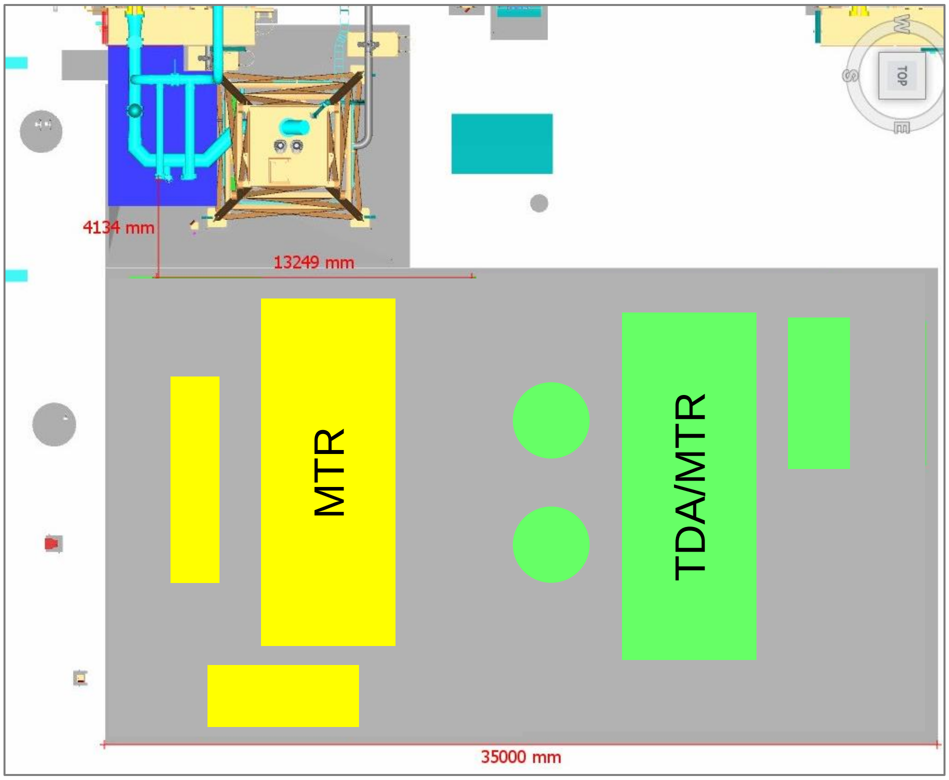

Figure 14. Artist rendering of the third development site at TCM. Flue gas supply and return piping for all systems are the light blue pipes in the upper left-hand corner of the figure. Yellow shapes represent the proposed footprints for the MTR (left) and TDA/MTR hybrid (right) test systems.

Once the third site was approved by the TCM board, MTR was able to complete an initial test system design package and performed an internal hazard and operability (HAZOP) review with MTR engineers and R&D personnel in mid-August 2019. The design package documents produced from that meeting were shared with TCM and an independent safety consultant. The full HAZOP review with MTR and TCM representatives was led by the independent safety consultant on September 5, 2019. The results of the full HAZOP were then incorporated into the final test system design.

3.3 Fabrication of MTR Small Pilot Test System

Early in the project, MTR held discussions with numerous fabricators concerning the field test system to be built for this project. MTR previously built commercial or pilot test skids with all fabrication shops that were under consideration. The fabrication shops considered include Progressive Recovery, Inc. of Dupo, IL; Glex, Inc. of Houston, TX; and Johansing Iron Works of Benicia, CA. After reviewing quotes and discussing internally, MTR chose Progressive Recovery, Inc. (PRI) to fabricate the system. In addition, MTR chose Fulcrum Automation and Controls (Mobile, AL) as the vendor to build the programmable logic controller (PLC) control panel and write the program logic. Fulcrum also assisted in the design, layout, and fabrication of the system motor control center (MCC) control room container.

MTR visited the PRI system fabrication site in early February 2020 to discuss all aspects of the system build. Based on the site visit meetings, MTR revised the piping and instrumentation diagram (P&ID) and used that as a basis for a preliminary general arrangement (GA) drawing (see Figure 15). The system was designed to split into four smaller, flat, rack-sized skids to allow for considerable cost-savings when shipping the system to and from Norway. In addition to the four skids that comprise the main system, PRI also fabricated two smaller skids: a cooling water skid and a wastewater skid that were utilized by both the MTR and TDA-MTR hybrid systems during operation at TCM. MTR held a preliminary general arrangement drawing review meeting in May 2020 with the PRI project manager via video conference due to COVID-19 restrictions.

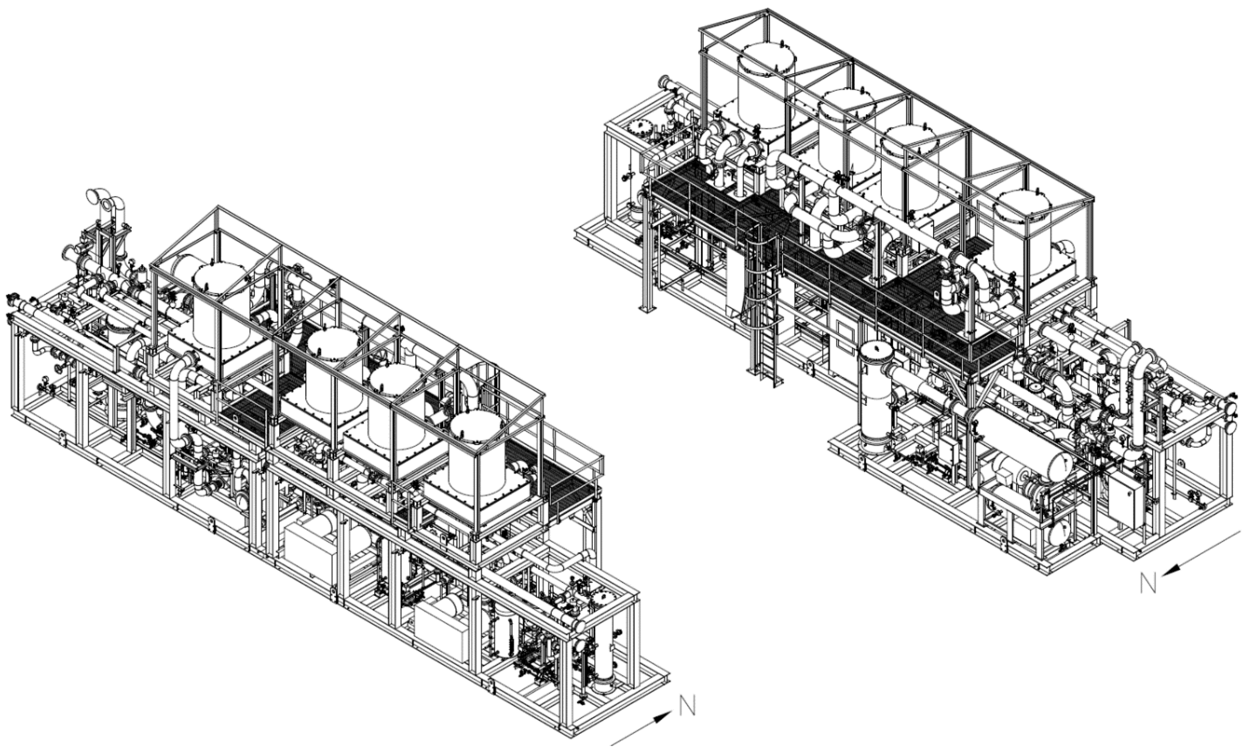

Figure 15. A general arrangement drawing showing north and south facing views of the MTR test system.

Due to COVID-19, there was some delay with supply chain system equipment vendors that necessitated a no-cost extension during the fabrication phase of the project. Most large system equipment ordered from vendors (heat exchangers, gas analyzer system, etc.) arrived at PRI over the summer of 2020; however, the flue gas feed blower and two vacuum pumps arrived later due to delays. Fabrication activities at PRI were also slowed during fall 2020 due to COVID-19 related disruption to supply chains and personnel limitations at the fabrication site.

Figures 16 – 19 provide an overview of the test system fabrication. Mechanical installation of the main test system components (heat exchangers, separator vessels, cooling water lines, and process piping) and welding were completed first. Grating, handrails, and ladders for the second level were finished next and installed. Final fabrication activities that were completed prior to the FAT included heat tracing and insulation installation, wiring the PLC to various junction boxes, and pulling power cables to individual instruments. Some components of the test system were completed and shipped to TCM in late-2020. For example, the wastewater skid and the MCC skid passed the FAT in December, were shipped to Norway, and arrived at the TCM site in January 2021.

Figure 16. An early isometric view of the MTR test system at PRI. The first floor contains the blowers and pumps used to move gas through the system, while the second floor will hold the membrane module stacks.

Figure 17. A view of the second level of the MTR test system with the membrane module stack bases visible prior to installation of the modules.

Figure 18. Another view of the test system at PRI. The smaller skid on the lower left is the feed gas blower skid that shipped to TCM in February.

Figure 19. Picture of the membrane module stacks installed on the second floor of the test system at the PRI fabrication shop.

3.4 Factory Acceptance Test (FAT) at Fabricator Site

MTR worked with the fabrication and PLC subcontractors to limit time delays due to COVID-19 business disruptions. Traditionally, all aspects of the FAT for a test system are completed during a single visit to the fabrication site. For this project, mechanical and electrical (PLC and instrumentation) FATs were conducted for individual skids as fabrication was completed. MTR participated in a remote PLC FAT with the PLC subcontractor in early-December 2020. Items that were reviewed during the remote FAT include control loop action and bumpless transfer, sequence check, interlock check, and graphics check. Changes requested by MTR as a result of the remote FAT were reviewed and approved by MTR prior to the holiday break. The mechanical FAT of the feed gas blower skid was conducted during an MTR site visit to PRI in late-January 2021. A short punchlist was generated based on the FAT findings and the issues were resolved by mid-February. MTR traveled to PRI again in late-February to conduct the FAT on the three remaining sections of the test system. The test system passed the FAT on March 16, 2021. The fabricator completed all punchlist items identified during the FAT prior to transitioning to prepping the individual test system skids for transport to the field test site.

4. TCM HOST SITE PREPARATIONS

Early in the project, TCM realized that given the number of current and future projects coming to their site that will not use the existing solvent capture infrastructure, there was a need to re-think test site locations. TCM conducted a FEED study to evaluate the best way to host field tests of new technologies, such as the MTR and TDA-MTR systems, with parallel operation. The results of the FEED study determined the best location for testing of current and future second-generation technologies was a virtually undeveloped location referred to as the third site. During a meeting in late-June 2019, the TCM board officially approved an investment decision for development of this third site.

4.1 Site Engineering

TCM worked with both MTR and TDA to determine the arrangement of the membrane and sorbent-membrane test systems and the infrastructure required to bring flue gas and utilities to both systems at the third site. A simplified drawing of the skid arrangement for both systems is shown in Figure 20. TCM finished all preparation activities at the third site by Fall 2020 for the arrival of the MTR system. MTR personnel were at TCM for installation of skid components from early-January 2021 to early-March and then again in mid-May 2021 for installation, commissioning, and operation activities.

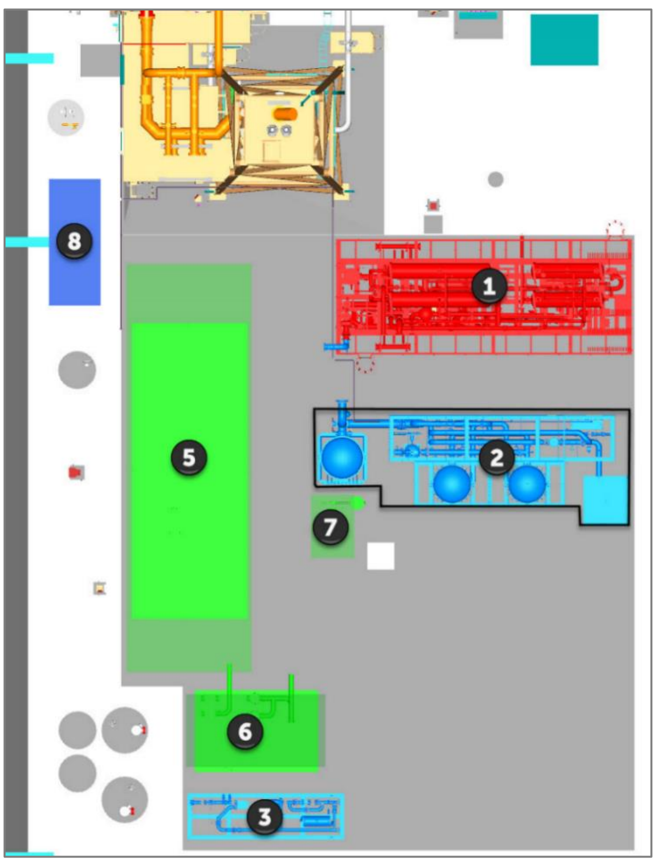

Figure 20. Simplified TCM third site drawing showing the location of all test skids. The #5 green rectangle represents the main MTR system skid. #1 is the prior 20 TPD MTR system tested at NCCC that was used to test the TDA-MTR hybrid system, and #2 is the TDA sorbent portion of the hybrid.

4.2 Skid Foundation

The foundation for all skids at the third site was poured in 2020 for skid placement and anchoring. Figure 21 shows two different views of the third site at TCM after foundations were completed.

(a) (b)

Figure 21. (a) View of the TCM facility with the third test site in the foreground and (b) a close-up view of the third site foundation. These photos were taken in late 2020 prior to the arrival of any skid components.

4.3 Electrical and Water Utilities

TCM provided a 400 VAC 1250 KVA breakdown of the third site power station that was available to the MTR and TDA-MTR test systems. MTR coordinated with TDA on the power requirements and distribution to each field test system. Using input from MTR and TDA, TCM created third site interconnecting electrical and instrument cable drawings and estimated the cost to bring power to both test systems. TCM assisted MTR to locally purchase various electrical cables needed to connect the site power source to the MTR MCC container and from the MTR MCC container to various test system skids.

4.4 Process Connections

Working with TCM and TDA, the location and tie-in points (flue gas interconnecting piping, process water, plant compressed air, cooling water interconnecting piping, and wastewater interconnecting piping) for all skids at the TCM third site were finalized. Minor interconnecting piping and skid tie-in point issues were addressed as they came up. In Figure 22 below, the green rectangles represent the MTR main test and cooling water systems.

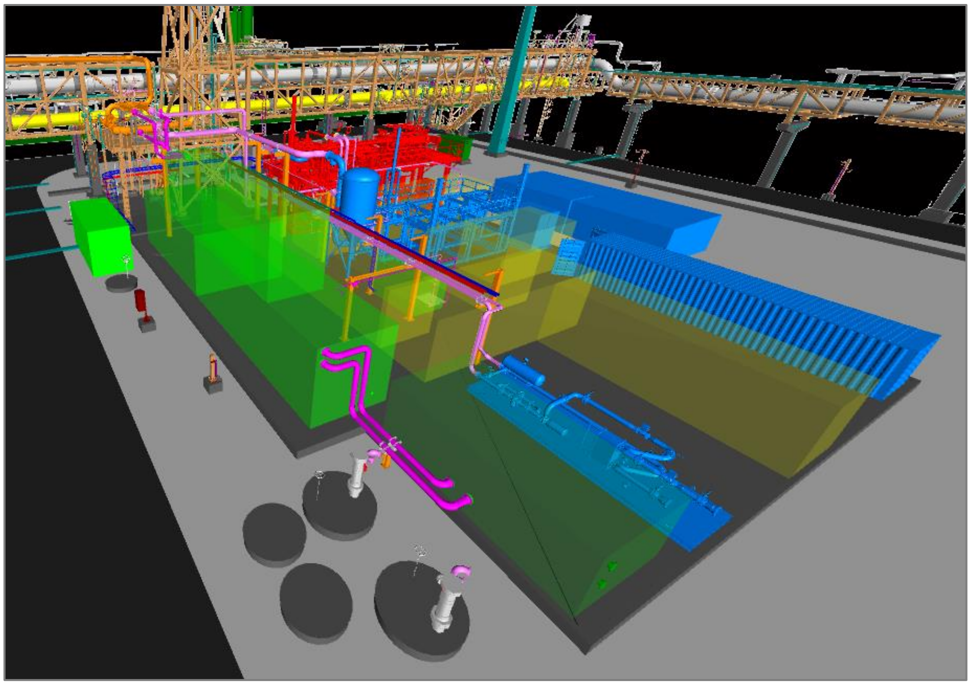

Figure 22. TCM third site drawing showing the location of all test skids and interconnecting piping.

4.5 Shipment of Membrane Test System to TCM Field Test Site

MTR and TCM held discussions on the procedure and documentation needed to ship the membrane test system to Norway and unload at the TCM site. The MTR system main skid was designed to be disassembled into the same dimensions as shipping flat racks to minimize the cost of shipping from the U.S. to Norway. For this project, MTR worked with Apex Logistics and Aeronet (US-based freight forwarders) to issue an ATA Carnets to avoid VAT associated costs and transport the skids from PRI in Dupo, Il to the Bergen, Norway port. BRING (Norwegian transport company) arranged transport from the Bergen port to TCM and assisted in any customs issues, including importer of record documentation. The feed gas blower skid (smallest of the four main system skids) was separated from the test system and prepped for shipment first (Figure 23). This skid was picked up in February 2021 and lessons learned from arranging this shipment aided in scheduling the transport of the remaining test system skids and loose items that shipped in March 2021. The main test system skids arrived at TCM in late-May and all loose items containers arrived at site by early-June.

Figure 23. The feed gas blower skid portion of the MTR test system prepped for transport and ready for pick-up at PRI.

5. MEMBRANE TEST SYSTEM INSTALLATION AND PRE-COMMISSIONING

MTR had discussions with TCM concerning the installation and pre-commissioning of the MTR test system at the field site. MTR and TCM prepared a detailed installation and pre-commissioning schedule and discussed personnel support requirements for all activities. MTR personnel were on-site at TCM from early-January 2021 to early-March to assist with installation of the MCC unit and wastewater skid. MTR personnel were then continuously on-site at TCM starting mid-May to lead installation, commissioning, and operation of the membrane test system.

The four main test system skids arrived at TCM and were set in place with a crane on May 25, 2021. Mechanical installation of process or utility piping and instrumentation for the main skids and cooling water skid continued to mid-June.

The MTR MCC container arrived at the TCM site in January 2021 (see Figure 24). Power cables were connected between the local substation and the MCC container. Within the MCC container, power cables were connected for all test system starter and distribution panels. Power cables were then run to individual test system junction boxes to supply power to all instrumentation and heat tracing. All other utility connections (instrument air, process water, and seawater for the cooling water skid) were added to the test system in June.

Figure 24. State of the third site at TCM in January 2021. The MTR MCC container is visible in the left forefront of the picture.

Flue gas lines near the TCM supply and return header common to both the MTR and the TDA/MTR hybrid systems were installed once the test skids were in place. The wastewater skid arrived at the site in early 2021 and process piping was connected during MTR's first visit to TCM in 2021 (see Figure 25). The installation of process lines and associated instrumentation started once the test system skids were set in place in late-May and activities were completed in late-June.

Figure 25. A photo of the wastewater skid at the TCM third site during initial installation activities in January 2021.

During installation, loop checks of all instrumentation and stroking of control valves were completed. Any issues with the PLC program logic were corrected as they arose. Data logging of all test system process variables, gas compositions, and other system information was set up and arranged to upload to secure cloud storage on an hourly basis.

Mechanical installation and pre-commissioning activities were completed by the end of June. The test system was hot commissioned with air on July 6, 2021. During this test, an issue was identified with the 1st Stage vacuum pump that required repair. Support from TCM personnel, local shipping company BRING, and a pump repair facility in Germany minimized the repair-related downtime. Once the repaired pump was reinstalled, the MTR test system was commissioned on flue gas on July 28 (Figure 26).

Figure 26. MTR test system during commissioning activities in early July 2021.

6. TEST PLAN FOR OPERATION AT TCM

6.1 Objectives of MTR Field Test at TCM

The overall goal of the TCM field test was to validate the transformative potential of scaled-up Gen-2 Polaris planar modules in an engineering-scale field test at TCM. This field test was an important step in that it demonstrated the performance of these advanced membrane modules in a final form factor optimized for commercial use. Specific field test objectives were to identify optimum conditions for different CO_2 capture rates (60 – 90%) through parametric testing, determine system performance under different inlet CO_2 concentrations, and demonstrate low module pressure-drops. Through parametric testing, a relationship between the system CO_2 capture rate and CO_2 purity was established under different process operation (i.e. sweep versus non-sweep). By operating the system with inlet CO_2 concentrations up to ~20%, MTR was able to measure system performance under conditions relevant to CO_2 capture from large industrial point sources, such as cement or steel plants. Results from the TCM field test have helped refine the MTR CO_2 capture process for power plants and other large point sources.

6.2 Key Performance Indicators for the MTR Field Test System

In the project field test, the overall membrane system performance was measured by the CO_2 capture rate and the CO_2 product purity. Beyond membrane performance, the pressure-drop of the advanced planar modules is important to minimize parasitic energy losses in the MTR process design. The individual Key Performance Indicators for the MTR TCM field test are listed below.

- MTR test system demonstrates CO_2 capture rates up to 50% without the air sweep step
- MTR test system demonstrates CO_2 capture rates up to 80% with the air sweep step
- CO_2 purity in the 2nd Stage permeate gas stream reaches 80% for operation with simulated coal flue gas
- Module pressure-drops (feed-to-residue and sweep-side) are <2 psi (13.8 kPa)
- CO_2 capture rate and CO_2 purity are constant within 10% during steady state operation

6.3 Description of MTR Field Test System Operation

Figure 27 shows a simple process flow diagram for the MTR engineering-scale system that operated at TCM. For simplicity, this process flow diagram does not include all major equipment or process streams, in particular water knock-out streams. A slipstream of flue gas is sent to the membrane system (stream 1). After passing through a feed blower, the flue gas (stream 2) goes to the first membrane skid where a vacuum on the permeate is used to remove CO_2. The membrane permeate (stream 4) is sent to a 2nd Stage CO_2 purification unit. Some of this purified CO_2 can be routed through a spillback line (stream 9) to the front of the membrane system to increase the concentration of CO_2 in the feed from 13 to ~20%. In this way, the feed to the membrane system will mimic the fully integrated case without having to recycle CO_2 to a boiler. The partially-treated flue gas that leaves the first membrane step (stream 3) is sent to the sweep membrane unit. Air (stream 6) flows on the permeate-side of these membranes and removes additional CO_2 from the flue gas. The CO_2-enriched air (stream 7) would be sent to the boiler in integrated operation, but here it is combined with the other flue gas streams and returned to the TCM infrastructure for local stack venting after analysis. Finally, the cleaned flue gas (stream 5) flows to the stack. Overall, 60 – 90% of the CO_2 in the inlet slipstream can be captured, depending on operating parameters. The flow rates and process conditions for the major Figure 5 streams are summarized in Table 1 for a 70% capture case.

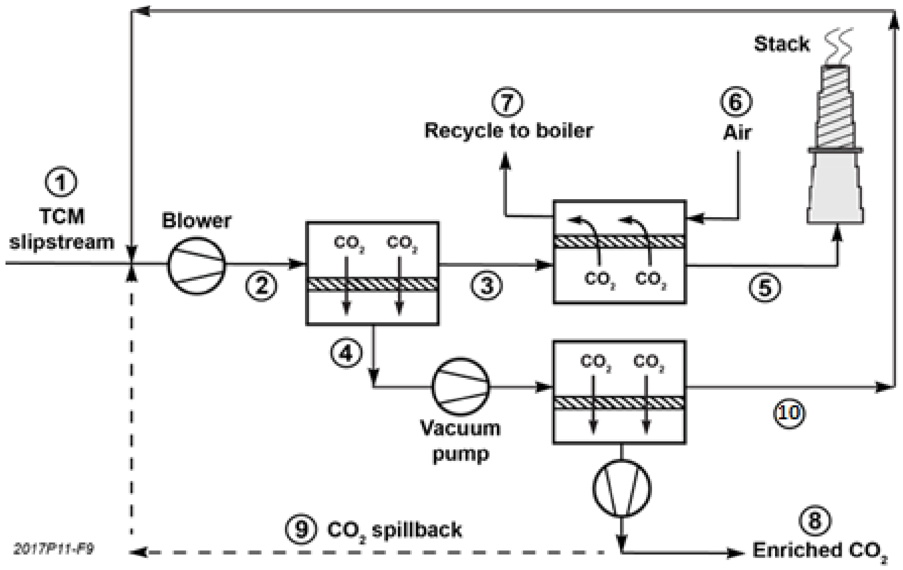

Figure 27. Simple process flow diagram for the MTR skid used during the TCM field test.

Table 1. Simulated Stream Conditions for the MTR Test System at TCM.

Stream No.	1	2	3	4	5	6	7	8	9	10
Stream Name	**TCM Slipstream**	**Membrane Feed**	**Membrane Residue**	**Membrane Permeate**	**Gas to Stack**	**Air Sweep**	**Recycle to Boiler**	**Enriched CO_2**	**CO_2 Spillback**	**2nd Stage Residue**
Temp (°C)	35	30	30	30	30	30	30	30	30	30
Pressure (bar)	1.1	1.2	1.1	0.2	1.0	1.1	1.0	1.1	1.1	1.1
Mass flow rate (kg/h)	2,676	3,057	2,535	522	2,340	1,931	2,125	120	181	200
Flow (Nm^3/h)	2,000	2,243	1,909	335	1,800	1,500	1,608	65	98	146
Components (mole %)										
CO_2	13.0	16.3	10.6	48.6	5.7	0.04	6.3	86.1	86.1	15.4
N_2	79.0	75.7	82.5	37.1	87.1	78.1	74.1	8.2	8.2	76.1
O_2	5.0	5.1	5.2	4.4	6.7	20.9	18.2	1.8	1.8	8.1
H_2O	3.0	2.9	1.6	9.8	0.5	0.0	1.4	3.8	3.8	0.4

The MTR test system is equipped with instrumentation to continuously measure and record the experimental conditions and composition of all system gas streams. The MTR data collection program allowed for real-time data analysis of the system performance and individual membrane unit mass balances. The MTR test system was designed to allow for local control of flue gas or sweep air flow rates, temperature control of various gas streams, and the 1st Stage membrane inlet flue gas CO_2 concentration. The rotating equipment used in this field test were chosen due to their reliability and availability at the small pilot-scale. Therefore, the utility consumption of the MTR test system is not representative of a larger MTR membrane CO_2 capture system and should not be used for a scale-up evaluation. Through separate DOE-funded projects (DE-FE0031846 and DE-FE0031587), MTR has identified different commercially available blower and vacuum equipment for use in Large Pilot, demonstration, or full-scale versions of the MTR CO_2 capture process.

7. OPERATION OF THE MTR SMALL PILOT SYSTEM AT TCM

7.1 July – September 2021 Test System Shakedown Operation

The test system was hot-commissioned on air in early-July but was shut down by MTR operators due to a vacuum pump issue. Once the vacuum pump was reinstalled after repairs at a German shop, the test system was commissioned on flue gas on July 28. Similar to commissioning on air, the test system went from a cold start to processing flue gas smoothly. The start-up process takes approximately twenty minutes, with the majority of the time set by the programmable logic controller (PLC) sequence timers to safely start-up the system rotating equipment on air and then slowly ramping up to operating conditions before switching to flue gas. Initial flue gas feed conditions to the 1st Stage membrane were 2,000 Nm^3/hr at 120 kPa and 30°C.

Under the initial flue gas shakedown conditions in late-July, the test system had a CO_2 capture rate over 70% with a 2nd Stage permeate CO_2 concentration of 87%. These results were promising and met key performance recovery and purity indicators, although the system conditions had not yet been optimized. In addition, all advanced module pressure-drop values were significantly lower than the KPI benchmark value of 2 psi (13.8 kPa). It should be noted that the second-step permeate (sweep-side) spacers are denser than the feed spacers used in the membrane modules. This is due to the additional requirement of permeate-side spacers to provide mechanical support to the membrane along with creating a channel for fluid flow and limiting concentration polarization (boundary layers) in the gas stream. A denser spacer will inherently have a higher pressure-drop, which was experimentally confirmed. Table 2 summarizes the pressure-drop measurement points on the MTR test system and the associated pressure-drop value under initial operating conditions.

Table 2. MTR Advanced Membrane Module Pressure-Drop Values During Initial Flue Gas Operation at TCM. Target values are <13.8 kPa.

Test System Pressure-Drop Location	Pressure-Drop (kPa)
1st Stage modules feed-to-residue	0.70
2nd Stage modules feed-to-residue	0.74
Sweep modules feed-to-residue	1.5
Sweep modules sweep side	5.4

During this initial period of operation, it was determined that better control of module stack temperature was preferable for parametric testing. Design of heat trace and insulation for membrane module stacks and bases to prevent the potential of flue gas water condensation in these units began in mid-August with installation activities occurring between August 23 and September 13, 2021 (see Figure 28).

Figure 28. 1st Stage membrane stacks with heat trace (left) and insulation (right) installed.

The test system was able to operate during heat trace and insulation installation activities. In August and September, the test system operated on both flue gas and air. Downtime during these months were due to a scheduled maintenance shutdown, failure of a vacuum pump starter panel contactor, and mechanical support issues related to test system pressure relief valves. All test system issues were resolved by late-September and normal flue gas operation started at this time.

7.2 October – December 2021 Test System Operation

In early-October, the test system processed flue gas under conditions designed to verify skid instrumentation operation and system performance. During these tests, MTR engineers checked mass balances, recalibrated the system flow meters to improve the accuracy of the skid data, and verified stable system performance. Next, a series of parametric tests were conducted with the system in single-pass process mode, meaning both the 2nd Stage residue and permeate gas streams were sent to the third site stack. The first set of parametric tests was conducted with a constant flue gas feed flow rate to the 1st Stage membrane unit of 1,800 Nm^3/h while the inlet sweep air flow rate to the 2nd Step membrane unit was varied between 500 and 1,450 Nm^3/h. Figure 29 shows the influence of the sweep air flow rate on the sweep module performance. As the sweep air flow rate to the membrane modules increases, the CO_2 capture rate of the system increases.

This increase in CO_2 removal occurs because the air sweep maintains a low CO_2 partial pressure on the permeate-side of the membrane, and thereby provides additional driving force for CO_2 permeation. In a pressure-ratio limited membrane application like CO_2 capture, even a small increase in the CO_2 partial pressure driving force can have a large effect. Over the relatively small range of sweep air flow rates tested, the CO_2 removal rate by the sweep step improves by 45%.

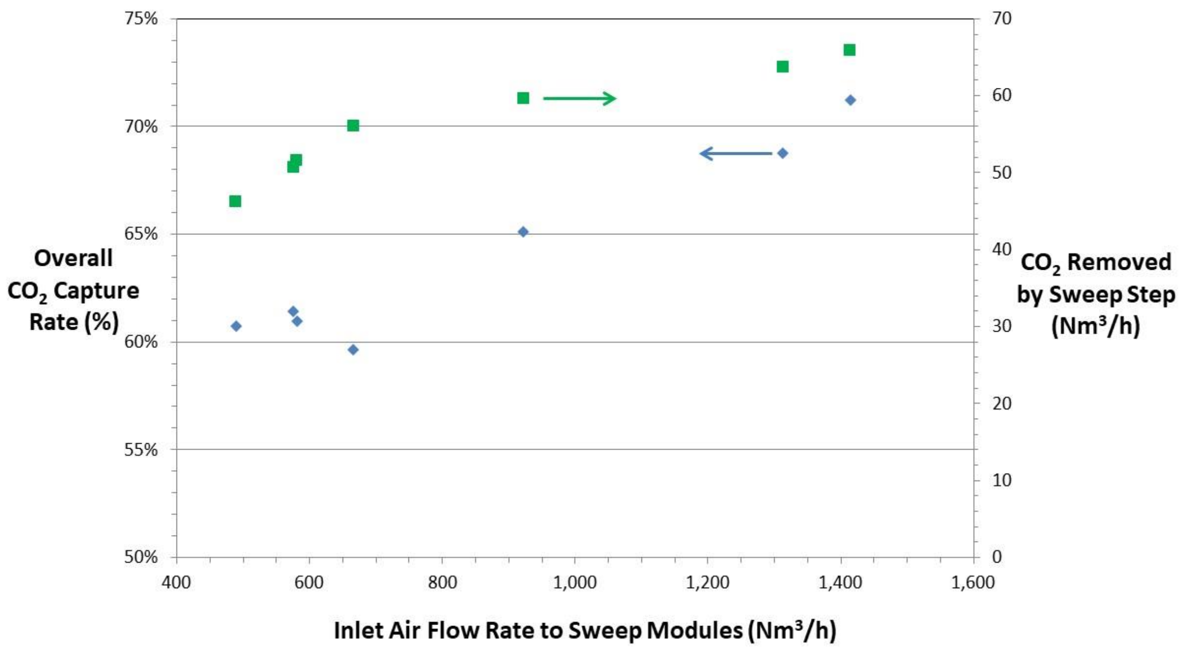

Figure 29. Influence of the sweep air flow rate on the 2nd Step sweep module performance measured during the Fall 2021 parametric tests.

For context, the maximum amount of air sweep that could be used in capture from a coal facility is all of the secondary air used for combustion, which amounts to about 70% of the flue gas flow rate. In the TCM parametric test, the flue gas flow rate was 1,800 Nm^3/h, so a maximum realistic amount of air sweep that could be used for selective recycle is ~1,260 Nm^3/h. From the Figure 29 data, it appears CO_2 removal is still increasing up through this amount of air sweep. As long as the pressure-drop associated with this higher air sweep flow rate is relatively low, the benefit of increased CO_2 removal typically dictates that a higher air sweep optimizes overall capture system performance.

Another set of parametric tests consisted of varying the inlet flue gas flow rate to the 1st Stage membrane unit between 800 and 2,400 Nm^3/h, while maintaining a constant sweep air flow rate of 1,200 Nm^3/h. Figure 32 shows the influence of the inlet flue gas flow rate on the test system performance. Over the flow rate range explored, the overall CO_2 capture rate varied between 61 and 91%, with higher flow rates producing a lower amount of CO_2 capture. This is consistent with expected behavior for a system with a fixed amount of membrane area. The CO_2 purity increases from about 86 to 92 mol% as the feed flow rate increases. This higher purity is also expected because the higher feed flow rate generates a higher CO_2 partial pressure on the feed-side of the membrane. Overall, the tradeoff in CO_2 purity versus recovery illustrated in Figure 30 is expected behavior for membrane systems.

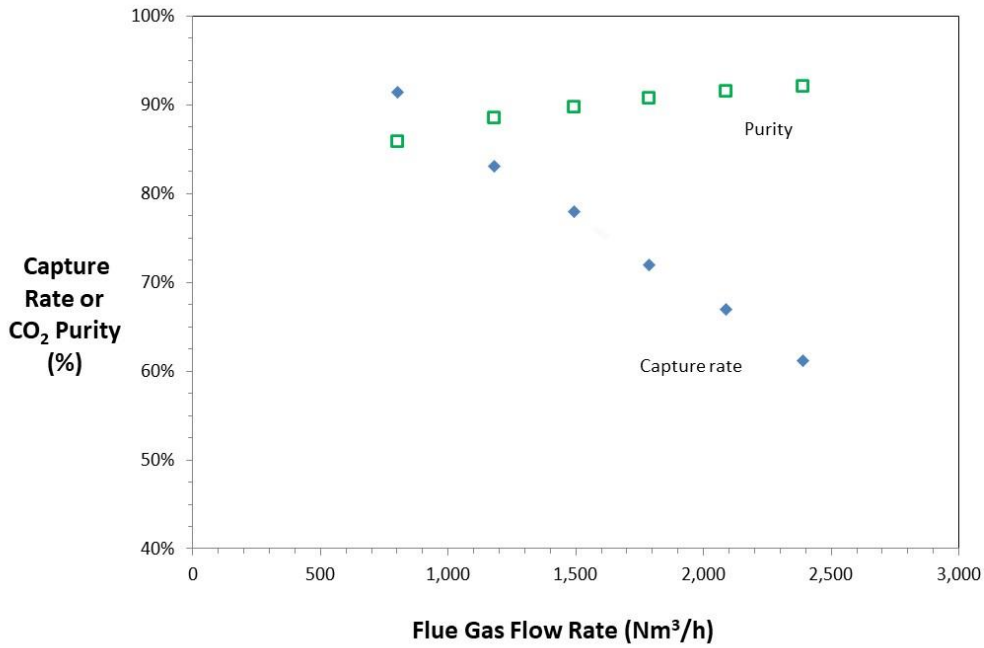

Figure 30. Influence of flue gas flow rate on the MTR test system performance measured during the Fall 2021 parametric tests.

TCM scheduled a utility shutdown at the third site during the first two weeks of November 2021. MTR and TCM personnel used this shutdown to inspect test system equipment and instrumentation, perform general preventative maintenance, and prepare the skid for cold weather operation. Once flue gas was available in mid-November, the test system was restarted with no issues. The initial restart flue gas test conditions of a feed flue gas flow rate to the 1st Stage of 1,800 Nm^3/h and a sweep air flow rate to the 2nd Step of 1,200 Nm^3/h were chosen to verify stable test system performance. Table 3 compares the MTR system with October and November steady-state performance under the same single-pass operation conditions. As detailed in the table, the test system performance before and after the shutdown is in excellent agreement. This highlights the stable performance of the test system during this period.

Table 3. Comparison of the MTR Test System Performance in Single-Pass Operation.*

Date	Flue Gas CO_2 Concentration to 1st Stage (mol%)	1st Stage Permeate CO_2 Concentration (mol%)	2nd Stage Permeate CO_2 Concentration (mol%)	1st Stage CO_2 Capture Rate (%)	Overall CO_2 Capture Rate (%)
October 23	15.5	54.2	93.1	50.4	73.1
November 20^	15.6	51.8	92.1	51.8	73.8

**Inlet flue gas flow to the 1st Stage = 1,800 Nm^3/h*
^*24 hour average*

After the test system performance had been verified under single pass operation, MTR changed the test system process mode from single pass to recycle of the 2nd Stage residue to the front of the system. This recycle process mode increases the CO_2 concentration in the inlet flue gas to the 1st Stage membrane modules above 20 mol%. Test system flow conditions of 1,800 Nm^3/h and a sweep air flow rate of 1,200 Nm^3/h were maintained in recycle mode to compare the test system performance under different process modes. Table 4 summarizes the test system performance results under both operation conditions along with the associated project key performance targets. All of the performance targets were easily met except for the overall CO_2 capture rate, which was slightly lower. Because the CO_2 purity was well above the 80% target, in a real system, it would have been easy to tradeoff a little purity to reach the higher capture rate (as shown in Figure 30). Following this process mode comparison, parametric tests continued with the MTR test system operating in recycle mode through the end of the year.

Table 4. Comparison of the MTR Test System Performance in November.*

Test System Parameter	Units	Single Pass Mode[1]	Recycle Mode[2]	Project KPI Target
Flue gas CO_2 concentration to 1st Stage	mol%	15.6	24.3	-
1st Stage permeate CO2 concentration	mol%	51.8	71.6	-
2nd Stage permeate CO_2 concentration	mol%	92.1	96.9	80
1st Stage feed-to-residue pressure-drop	kPa	0.53	0.51	13.8
1st Stage feed-to-residue pressure-drop	kPa	1.03	0.92	13.8
2nd Step feed-to-residue pressure-drop	kPa	0.67	0.94	13.8
2nd Step air sweep pressure-drop[3]	kPa	9.22	8.39	13.8
1st Stage CO_2 capture rate	%	51.8	57.2	Up to 50%
Overall CO_2 Capture Rate	%	73.8	77.0	Up to 80%

**Inlet flue gas flow to the 1st Stage = 1,800 Nm^3/h*
[1]*November 20 (24 hour average)*
[2]*November 23 (24 hour average)*
[3]*Note the 2nd Step permeate (sweep) side spacers are more dense than the feed-to-residue feed spacers used in the membrane modules*

In addition to CO_2 recovery and purity, another key performance metric for a membrane capture system is the pressure-drop through the modules. The MTR planar stack modules have been specifically designed to minimize pressure-drop while maintaining good flow distribution and separation performance. During parametric testing, the module stacks in the test system experienced a range of flow rates for which pressure-drops were measured. Figure 31 shows the feed-to-residue pressure-drop for the three module units (Stage 1, Stage 2, and Step 2) as a function of the feed flow rate divided by cross-sectional area (superficial velocity of gas through the modules). The pressure-drop of all three module stacks measured falls on the same curve. This result indicates that the membrane modules are performing as expected and there is no evidence of flue gas channeling or flow distribution problems on the feed-side of the modules. Importantly, the feed-to-residue pressure-drop of all membrane stacks is significantly lower than the project target of 13.8 kPa (2 psi) over the entire flow rate range examined.

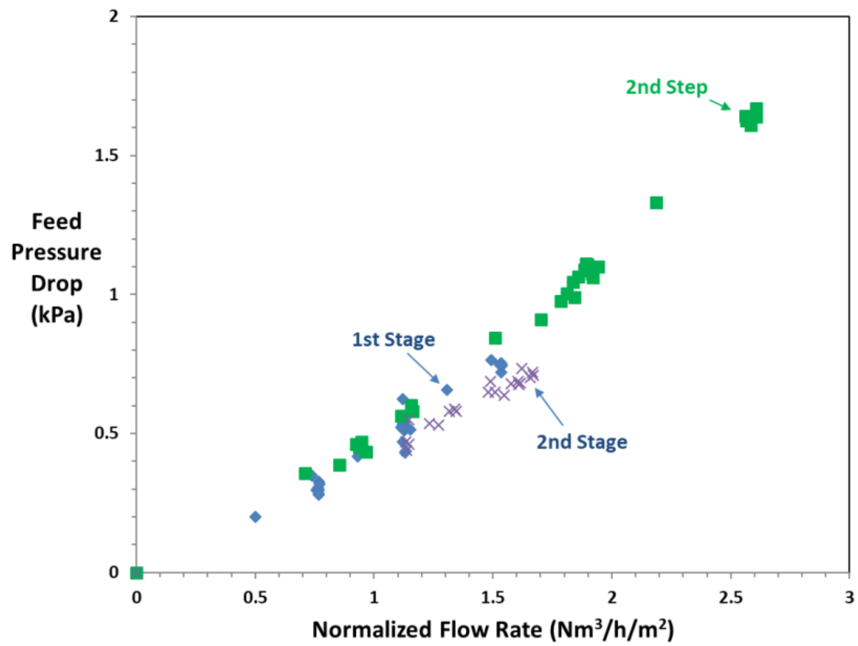

Figure 31. Influence of the normalized inlet flow rate on the MTR membrane module stacks feed-to-residue pressure-drop during parametric tests.

As previously mentioned, the 2nd Step permeate (sweep-side) flow channel spacers are more dense than the feed spacers used in the membrane modules. This is due to the additional requirement of permeate-side spacers to provide mechanical support to the membrane along with creating a channel for fluid flow and limiting concentration polarization (boundary layers) in the gas stream. A denser spacer will inherently have a higher pressure-drop, which is confirmed in the Figure 32 data. Similar to other measured module pressure-drops, all sweep-side pressure-drop data points fall on the same curve, indicating the membrane modules continued to operate as expected. As indicated in the figure below, all 2nd Step membrane sweep-side pressure-drop values are lower than the project pressure-drop target.

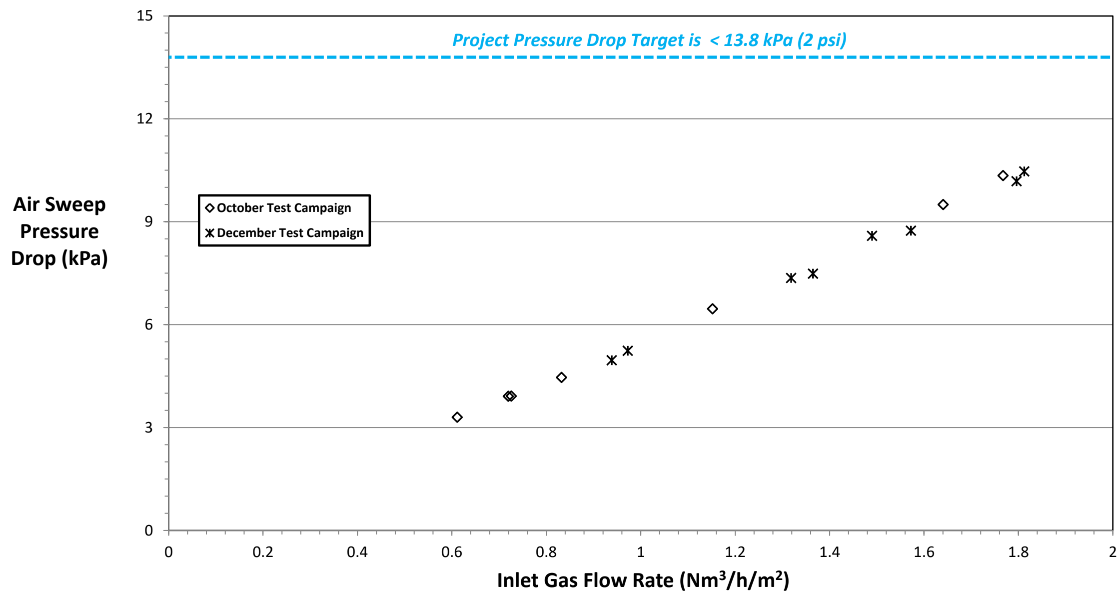

Figure 32. Influence of the normalized inlet air flow rate on the 2nd Step membrane module sweep-side pressure-drop during the October and December 2021 parametric tests.

The test system was shut down on December 17 by the on-site MTR engineer and prepped for long-term idle mode during the scheduled holiday break. During Fall 2021, the MTR test system operated on flue gas for over 1,100 hours. Table 5 summarizes skid operation during the flue gas parametric tests. Over these months, a minor amount of unscheduled downtime occurred with only a single unscheduled cold weather test system trip. All other unscheduled system trips were handled by the MTR engineer on-site with support from TCM and resolved quickly. As a result of the unscheduled shutdowns, the test system proved the ability to restart in cold conditions with no Issues.

Table 5. Monthly Run Time Totals for the MTR Test System at the TCM Third Site.

Month	Flue Gas Run Time (hours)	Air Run Time (hours)	Total Run Time (hours)
October	590	119	709
November	258	15	273
December	291	12	303
Quarter Total	1,139	146	1,285

7.3 January–- February 2022 Test System Operation

MTR personnel arrived at TCM in early-January 2022 to address a short test system punchlist and change-out the 2nd Stage membrane modules. MTR had been coordinating the module change-out activities with TCM since October 2021 and all module installation and test system maintenance activities were completed on schedule. The test system was restarted on January 20 after a short delay due to rust and sulfur deposits on the feed blower casing and rotors that caused the equipment to seize. The initial test system conditions after the extended holiday shutdown are summarized in the Table 6 below.

Table 6. MTR Test System Initial Flue Gas Test Conditions in January 2022.

Test System Parameter	Test System Set Point
Flue gas flow to 1st Stage membranes	2,000 Nm^3/h
1st Stage feed pressure	120 kPa
1st Stage permeate pressure	15 kPa
2nd Stage feed pressure	115 kPa
2nd Stage permeate pressure	15 kPa
2nd Step sweep air in	1,200 Nm^3/h
Test system process mode	2nd Stage residue and permeate streams directed back to the front of the test system

Under the initial test conditions, the recycle of both the 2nd Stage residue and permeate to the front of the test system increased the flue gas concentration to the 1st Stage modules to above 20 mol%. Next, the test system process mode was changed to direct the 2nd Stage permeate stream to the local third site stack and recycle of the 2nd Stage residue stream continued to the front of the test system. This change in process mode lowered the CO_2 concentration in the 1st Stage inlet flue gas to ~16.5 mol%. Table 7 compares the average skid conditions and CO_2 capture rates for the two different recycle process modes that the test system operated under during January. Late in January, the test system was switched from flue gas to air operation and the process mode was changed to single pass. Single pass flue gas operation, in which both the 2nd Stage residue and permeate streams are sent to the local third site stack, continued through the end of the field test.

Table 7. Comparison of MTR Test System Performance in January 2022.

Test System Parameter	Units	Process Operating Mode		Project KPI Target
		Residue Recycle	Residue and Permeate Recycle	
Flue has CO_2 concentration to 1st stage	mol%	16.6	23.8	-
1st Stage permeate CO_2 concentration	mol%	56.1	70.0	-
2nd Stage permeate CO_2 concentration	mol%	86.8	92.9	80
1st Stage feed-to-residue pressure-drop	kPa	0.66	0.60	13.8
2nd Stage feed-to-residue pressure-drop	kPa	0.21	0.38	13.8
2nd Step feed-to-residue pressure-drop	kPa	1.32	1.15	13.8
2nd Step air sweep pressure-drop*	kPa	6.8	8.2	13.8
1st Stage CO_2 capture rate	%	33.9	49.1	Up to 50%
Overall CO_2 capture rate	%	54.1	67.6	Up to 80%

**Note the 2nd step permeate (sweep) side spacers are more dense and expected to have higher pressure-drop than the feed-to-residue feed spacers used in the membrane modules*

During flue gas operation in 2021 at TCM, all three module units (Stage 1, Stage 2, and Step 2) contained the same feed flow configuration. The new 2nd Stage modules installed in January 2022 contained a different feed configuration and testing allowed for a direct performance comparison.

Figure 33 shows the test system feed-to-residue pressure-drop data from flue gas operation in both 2021 and 2022 as a function of the feed flow rate divided by the module cross-sectional area (effectively the feed superficial velocity). As shown earlier in this report, the 2021 pressure-drop of all three stacks falls on the same curve, while the new 2nd Stage modules exhibit even lower pressure-drop performance under the same conditions. This is an important finding because overcoming feed-to-residue pressure-drop represents a significant energy cost for the capture system. Overall, the feed-to-residue pressure-drop of the old and new configurations is significantly lower than the project target of 13.8 kPa over the entire experimental flow rate range.

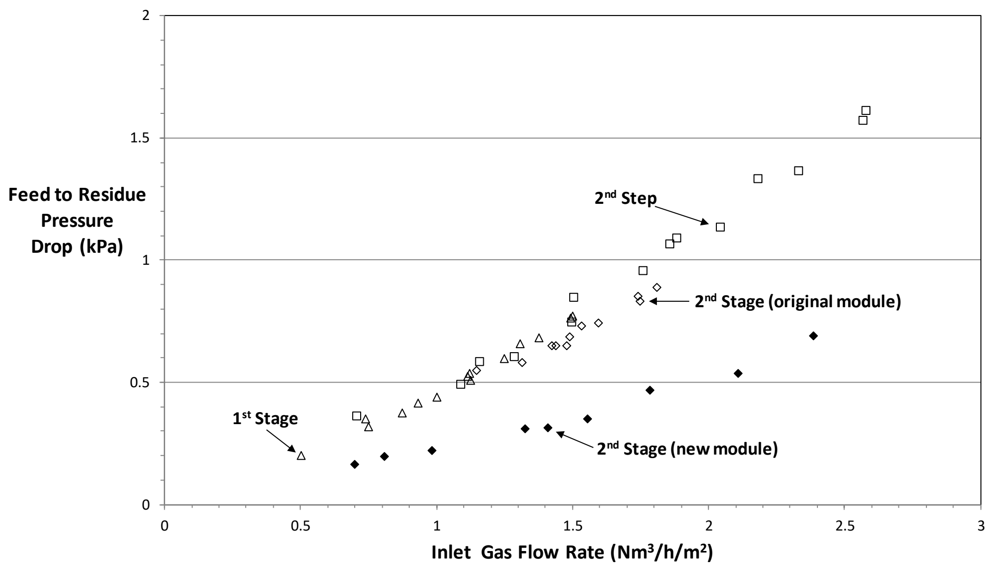

Figure 33. Influence of the normalized inlet flow rate on the MTR membrane module stacks feed-to-residue pressure-drop.

The MTR on-site engineer transitioned the test system from flue gas to air operation during the afternoon of February 28 and the purged test system was shut down on March 1. During the Winter 2022 operation, only a minor amount of downtime occurred due to unscheduled system shutdowns. All system trips were handled by the on-site MTR engineer with support from TCM and were related to a MTR test system PLC program code error, likely water ingress into the test system wiring, and a power outage at TCM. Overall, the MTR test system operated on flue gas for ~2,230 hours during the TCM field test campaign.

Table 8. Monthly Run Time Totals for the MTR Test System at the TCM Third Site.

Month	Flue Gas Run Time (hours)	Air Run Time (hours)	Total Run Time (hours)
January*	168	62	230
February	521	74	595
March**	0	13	13
Quarter Total	689	149	838

Test system was restarted on during the afternoon of January 20
***Test campaign concluded on March 1*

8. POST-FIELD TEST ACTIVITIES

8.1 Decommissioning of MTR Field Test System

Weekly decommissioning meetings between MTR and the TCM modification and operations teams started in early-March 2022. MTR supplied TCM with documents detailing how to disassemble the MTR test system and how pipe spools or loose items were previously packaged in shipping containers. TCM developed a detailed decommissioning schedule to coordinate crane use at the third site and minimize the decommissioning timeline. MTR made a brief visit to TCM in late-March to review decommissioning plans and remove additional modules from the test system for air-shipment to MTR for post-test analysis.

Decommissioning activities progressed in April and May, including dismantling of items that shipped loose (ladders, grating, pipe spools), mechanical destruction, preservation, and preparation for transport. Figures 34 and 35 show the MTR test system during these decommissioning activities.

Figure 34. TCM third site during decommissioning activities in Spring 2022.

Figure 35. The main skids of the MTR test system ready for removal from the TCM third site during decommissioning activities.

In early-June 2021, final mechanical destruction and test system shipment preparation work was completed. TCM coordinated the crane rental and the removal of all main skids and loose items from the third site during the week of June 13. Transport of test system components from TCM to storage at the Bergen, Norway port was arranged and performed by BRING Cargo, AS (Bergen, Norway). All MTR test system components were removed from the TCM third site by June 15. Figure 36 shows the test system being transported off-site during the final days of decommissioning activities.

Figure 36. The MTR test system cooling water skid loaded and ready for transport from TCM to the Bergen, Norway storage site.

8.2 Analysis of Returned Modules from Field Test

The 2nd Stage planar membrane modules removed from the TCM field test in January 2022 arrived at the MTR facilities in mid-February for post-test analysis. A number of quality control and analytical tests were conducted within MTR and through local laboratories to fully characterize the returned modules and Polaris membrane.

The feed-side of both returned modules showed significant corrosion and scale build-up on the aluminum housings. The flue gas entering the modules was saturated with water vapor, which based on prior measurements of condensate, is very acidic (pH ~ 3). We believe condensation of this water during shutdowns allowed acidic water (containing dilute sulfuric acid) to sit on the aluminum housings and react. Analysis of the scale material scrapped off the housings showed that it was predominately aluminum sulfate. The Polaris membrane removes water vapor, so the residue gas was relatively dry, and therefore a minimal amount of corrosion or scaling was found on the residue-side of the modules.

The module housing corrosion impacted membrane performance. During operation at TCM, we had noticed a decline in performance for the 2nd Stage modules. After the modules were disassembled at MTR, stamps were cut from the membrane sheets and tested with pure gases. The membrane samples showed low CO_2 and N_2 permeances compared to pre-field test quality control data. Subjecting the membrane samples to vacuum on the permeate-side, heating to 45°C, or flowing CO_2 through the membrane overnight did not improve membrane performance. Individual samples were soaked in various solvents, and water washing was found to partially restore membrane performance. This result suggested that water soluble species may be fouling the membrane surface.

Scanning electron microscopy (SEM) images of membrane samples from the returned modules were taken and Figure 37 compares the surface of a fresh Polaris membrane with one returned from TCM. The returned Polaris membrane shows a coating of submicron crystal-like deposits on the membrane surface. These particles were present on all membrane samples removed from the returned modules and were most prevalent on the feed-side of the modules.

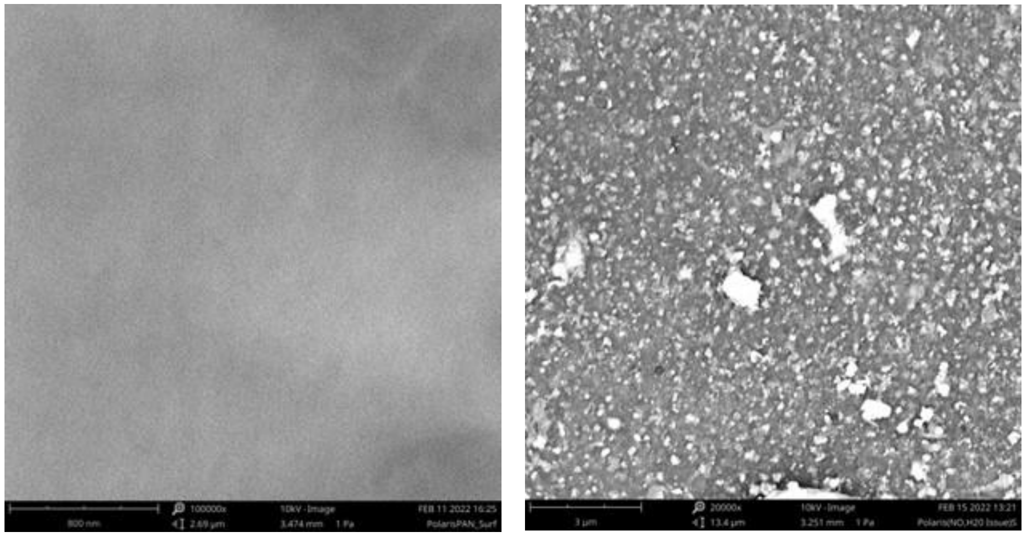

Figure 37. SEM surface image of a new Polaris membrane sample (left) and a Polaris membrane sample from the TCM field test (right).

MTR sent samples of the returned membranes to a local lab for surface and depth-profile x-ray photoelectron spectroscopy (XPS) analysis to identify the compounds present on the membrane. In parallel, water from the membrane soaking experiments was sent to another lab for inductively-coupled plasma mass spectroscopy (ICP-MS) measurements to identify all the ions dissolved from the fouled membranes. Results from both of these tests were consistent and showed the presence of aluminum, smaller amounts of nickel, nitrogen (as ammonium) and sulfur (as sulfates). The only source of aluminum in the system or gas is the aluminum module housings. Nickel was used as a coating on the feed blower rotors, while sulfur is present in the flue gas as SO_2 and SO_3. Nitrogen appears in flue gas as NOx and N_2.

The lab test results indicate that corrosion byproduct salts, primarily aluminum sulfate with some ammonium bi(sulfate), were present on the membranes. We believe these species formed on the aluminum housings in the presence of acidic condensate and were fluidized into the flue gas stream and deposited on the membrane surface. Subsequent testing at MTR of fresh Polaris membranes soaked in aluminum or ammonium sulfate solutions, confirmed that these salts can absorb onto/into the membrane and reduce permeance.

In prior MTR test systems, all module housings and system components in contact with flue gas were stainless-steel (SS) or plastic. In fact, our original NCCC small pilot system that uses all SS components participated in a hybrid membrane/sorbent flue gas field test with TDA at the TCM third site during the same test window as the MTR test system. Treating the exact same flue gas stream from TCM, the Polaris modules on the hybrid SS-only system showed no surface fouling and completely stable performance. Together with the lab analysis information, this result is strong evidence that the source of the fouling on the returned modules was the aluminum housings on this system. It is worth noting aluminum was not the first choice for the housing material on the MTR test system. Originally, plastic housings were going to be used, but due to complications related to COVID-19, MTR had to switch to aluminum to make testing deadlines. Ultimately, this is an important lesson learned about the necessity for proven corrosion resistance materials of construction for the capture system. All future MTR capture systems will return to using only SS or plastic components validated for use in a corrosive flue gas environment.

The 1st Stage, 2nd Stage, and 2nd Step (sweep) membrane modules removed from the TCM test system in late-March were also analyzed after arrival to MTR in May. Consistent with the first set of module post-field test analysis work, each module was subjected to a number of quality control and analytical tests to fully characterize the returned modules and Polaris membrane.

Both replacement 2nd Stage membrane modules had no visible signs of corrosion or fouling, unlike the original modules. The most likely reason for the lack of visible contaminants is that the replacement modules were on-line for roughly half of the time compared to the original modules. However, SEM images of membrane samples confirmed the presence of submicron particle deposits on the membrane surface consistent in size and shape to deposits characterized on the original 2nd Stage membrane modules. These membrane samples were analyzed by XPS and energy-dispersive x-ray spectroscopy (EDS) to identify the species on the membrane surface. These techniques confirmed the presence of aluminum and ammonium sulfates. Also consistent with previous results, membrane sheets with these fouling components showed lower CO_2 and N_2 permeances.

Based on prior experience at NCCC with sulfate salt fouling, one of the replacement 2nd Stage modules installed at TCM contained a Polaris membrane formulation that was previously shown to be resistant to buildup of these species. After operation at TCM, membrane samples removed from this module showed stable performance. We believe the primary method to prevent membrane fouling should be to use only corrosion-resistant materials in future capture systems (plastic or stainless-steel, and no aluminum). However, it is comforting to know that a corrosion-resistant Polaris formulation is available for added security.

Water analysis results of condensate samples taken from different locations on the TCM test system confirm that the samples are highly acidic and contain a variety of species. Table 9 summarizes the analytical results of the TCM flue gas and 1st Stage permeate condensate samples. The TCM flue gas condensate has a lower pH and higher concentration of most species compared to the 1st Stage permeate condensate. The 1st Stage permeate gas stream is in contact with the 1st Stage vacuum pump liquid ring, which is highly acidic water that is recirculated within the vacuum pump package. Both water samples confirm the presence of species that were previously identified during characterization of membrane surface particle deposits by XPS or ICP-MS.

Table 9. Water Analysis Results of TCM Test System Condensate Samples.

Species	TCM Flue Gas Condensate (mg/L)	1st Stage Permeate Condensate (mg/L)
Chloride	Not Detectable	2.8
Nitrate as N	3	1.4
Nitrate as NO3-	14.4	6.4
Sulfate	1,320	250
Ammonium	44.4	2.3
Aluminum	0.73	Not Detectable
Calcium	Not Detectable	1.1
Magnesium	Not Detectable	Not Detectable
Nickel	1.8	0.067
Iron	5.88	0.52
Potassium	Not Detectable	Not Detectable
Sodium	Not Detectable	Not Detectable
Sulfur	408	86
Silica	Not Detectable	Not Detectable
pH	2.78	3.28

In summary, the post-test analysis of returned modules showed that corrosion byproducts deposited on the surface of the Polaris membrane can adversely affect performance. This type of membrane fouling should be avoided to allow reasonable membrane lifetimes. The identification of these foulants as aluminum sulfate salts, combined with the lack of fouling on the hybrid system membrane treating the same TCM flue gas but outfitted with only stainless-steel housings, is strong evidence that the aluminum module vessels on the new system were the source of the corrosion problems. This information represents an important lesson learned from the project that will guide future design work. In addition, the observation that the fouled membrane performance could be recovered with water washing is an important finding that MTR plans to follow-up outside the scope of the current project.

9. TECHNO-ECONOMIC ANALYSIS

A techno-economic analysis (TEA) of MTR's post-combustion CO_2 capture process was conducted following the format, and containing the information and data, as defined in Appendix C of DE-FOA-0001791. The TEA incorporated TCM field test data of Gen-2 Polaris membrane performance and advanced planar module pressure-drop. A sensitivity analysis of the MTR cost of capture was performed by changing the purchased equipment cost (PEC) by ± 20%. Highlights of the TEA are summarized below, with the full TEA report located in Appendix A. It should be noted that in this analysis, for simplicity, the selective-recycle step in the generic MTR capture process was not used. This step has been shown to lower the cost of capture, particularly at higher capture rates, but it may be difficult to implement as a retrofit on coal boilers and it makes the cost analysis more complicated. For these reasons, it was decided that a simple two-stage membrane process without selective-recycle would be the design basis for the TEA.

A simplified process flow diagram of the MTR CO_2 capture process used for the TEA is shown in Figure 38. Flue gas from the power plant flue gas desulfurization (FGD) unit crosses the MTR process system boundary and enters a direct contact cooler (DCC) with an SO_2 polisher section to reduce the flue gas SO_2 concentration in the flue gas to 5 ppmv. SO_2 permeates the Polaris membrane so polishing is conducted in the DCC so that the liquid CO_2 product is within purity specifications. The flue gas leaves the top of the DCC, enters a booster fan to increase the gas stream pressure from 0.97 bara to 1.09 bara, to overcome pressure-drop throughout the MTR process, and is then feed to Membrane A. CO_2 is selectivity removed from the flue gas in Membrane A and the residual CO_2-depleted flue gas is routed to the power plant stack.

The CO_2-enriched permeate stream leaves the membrane under vacuum (0.1 bara) and is compressed through a series of fans and compressors to 1.19 bara and then fed to Membrane B. The Membrane B permeate stream is further enriched with CO_2 and the residue gas stream is combined with the inlet flue gas upstream of Membrane A. The CO_2-rich permeate stream leaves Membrane B under vacuum (0.2 bara) and a series of fans and compressors are utilized to cool and compress the gas stream. The gas stream is then dried via a molecular sieve dehydration unit before entering the CO_2 purification unit. The CO_2 is cooled and liquefied in a distillation column, with the high purity liquid CO_2 product compressed to 153 bara for transport by pipeline. The small distillation column overhead gas stream containing CO_2 along with non-condensable species is feed to Membrane C and Membrane D (in series) to recover the CO_2. The Membrane C permeate stream is routed to the Membrane B permeate compression train while the Membrane D permeate stream is combined with the Membrane A permeate stream prior to entering Membrane B. The residue from Membrane D is depleted of CO_2 and is routed to the power plant stack.

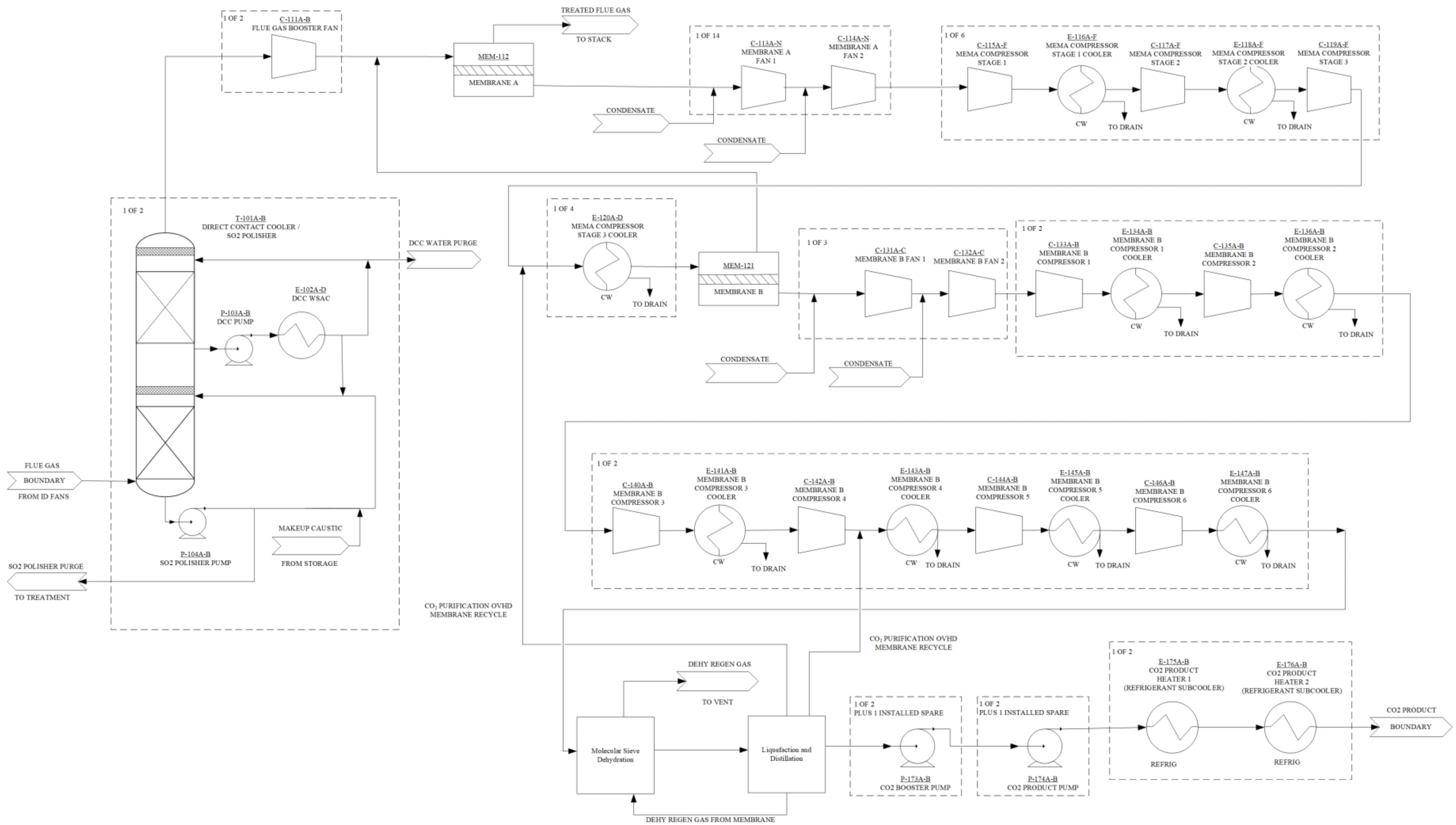

Figure 38. Simplified process flow diagram of the MTR CO_2 Capture Process.

The TEA design basis chosen for this analysis defines technical process inputs and economics inputs, as well as the system boundaries. In the original funding opportunity announcement (DE-FOA-0001791), the DOE specified that the system boundaries of the TEA include the entire base power plant as well as the CO_2 capture and compression systems. The funding opportunity, issued in Fall 2017, did not require a specific capture rate. Discussions with the DOE project manager led MTR chose a 70% CO_2 capture rate, which is believed to represent a near maximum efficiency condition for the membrane process. Nevertheless, MTR recognized the growing interest in higher capture rates over the course of this project. As a result, the MTR field system tested in this project at the Technology Centre Mongstad in Norway operated over a range of CO_2 capture rates including >90% during the 2021/22 field campaign. Moreover, in a recently awarded project in response to DE-FOA-002738, MTR has included tasks to update the full FEED study of capture at Basin Electric's Dry Fork Station coal power plant to a ≥ 90% CO_2 capture rate. This future work will benefit from the testing and analysis done in the current program.

The benchmark for comparison to MTR's CO_2 capture process is represented by Case B12A (without capture) and Case B12B (capture with Shell CANSOLV® amine-based technology) in the NETL Rev 4 Baseline Report. Note that Appendix C of the project funding opportunity (DE-FOA-0001791) states the following: *The Techno-Economic Analysis (TEA) shall follow the analysis documented in the NETL report "Cost and Performance Baseline for Fossil Energy Plants - Volume 1a: Bituminous Coal and Natural Gas to Electricity (Rev 3, July 6, 2015)," aka Bituminous Baselines Study (BBS).* However, MTR received instruction from DOE that the TEA should follow later Revision 4 of the BBS, which is the basis for this TEA. Case B12B represents carbon capture and compression from a supercritical coal-fired power plant. The power plant generates 650 MWe (net) of electricity after accounting for the parasitic energy demands of the CANSOLV CO_2 capture process and downstream associated CO_2 compression and dehydration. The power plant and capture system reflect a representative commercial-scale greenfield application and the CANSOLV process represents an industry-standard solvent as a reference for comparison. The flue gas feed composition to the membrane process matches the flue gas feed composition to the CANSOLV process in Case B12B.

The process design and economic evaluation are based on a 650 MW_e net basis, i.e., *after* the energy requirements for the CO_2 capture system are deducted. Therefore, the size for both the base power plant (reflected in gross power plant output) and capture system are "escalated" based on the parasitic energy consumption from all sources. The term "escalation factor" is used to quantify the approximate increase in the size of the base power plant, when compared to a reference case, due to derating from the CO_2 capture portion of the plant.

Table 10 summaries the project TEA key findings. Overall, the MTR cost of capture estimate is slightly higher than Case B12B, although the result is within the 20% uncertainty in PEC. Several factors were identified as areas that could improve the cost competitiveness of the MTR membrane process. These include the performance improvements of Gen-3 Polaris membrane (being developed in a separate DOE program), the impact of a higher CO_2 content in industrial flue gas which is known to favor membranes, and the effect of less stringent CO_2 purity in the liquid CO_2 product. Full TEA details are provided in Appendix A.

Table 10. Summary of Key Economic Factors for the MTR Post-Combustion CO_2 Capture Process Compared with Bituminous Baseline Case B12B Reference Amine CO_2 Capture.

Case	Cost of Capture (no TS&M) \$/tonne CO_2	Change vs. MTR Base Case	LCOE \$/MW_h	Change vs. MTR Base Case	CO_2 Capture and Compression Total Plant Cost \$MM
B12B (90% capture)	\$45.63	-	\$105.20	-	\$826
MTR Base Case (70%)	\$48.50	-	\$96.55	-	\$667
MTR PEC (-20%)	\$42.95	-11.4%	\$92.90	-3.8%	\$534
MTR PEC (+20%)	\$54.05	+11.4%	\$100.22	+3.8%	\$801

10. PROJECT CONCLUSIONS AND FUTURE PLANS

In summary, this project resulted in the successful scale-up and field test validation of MTR's Gen-2 Polaris membrane and advanced planar modules. The successful completion of this work advanced the Gen-2 Polaris membrane capture technology from TRL-5 to TRL-6. In addition to this primary accomplishment, the following key results were achieved:

- The Gen-2 Polaris membrane production was successfully scaled-up on commercial roll-to-roll equipment. We now consider this membrane ready for commercial production.
- Advanced planar low-pressure-drop membrane modules were designed, fabricated, and proven in the TCM field test. Stacks of the planar membrane module in a containerized skid are the final modular form to be used in future large-scale systems.
- The MTR test system at TCM was commissioned on flue gas in late-July 2021 and operated until March 2022. During the campaign, the MTR test system logged over 2,200 hours of flue gas operation.
- Parametric testing included varying the inlet flue gas flow rate (800 – 2,400 Nm^3/h), inlet CO_2 concentration (14.6 – 26.1 mol%), and the sweep air inlet flow rate (500 – 1,450 Nm^3/h). During the test campaign, the test system operated in either single pass or various internal recycle process modes.
- Overall CO_2 capture rates up to 91% and a 2nd Stage CO_2 purity up to 92 mol% were achieved during parametric testing.
- For all test conditions, the feed-to-residue or sweep-side pressure-drops were well below the project target of 13.8 kPa.
- Post-test analysis of membrane modules found aluminum and ammonium sulfate corrosion by-products on the Polaris membrane surface. These corrosion by-products were formed by condensation of acidic water on the aluminum housings used on the membrane system. The reduction in membrane module performance was related to the particle deposition concentration, which was highest on the feed side of the 1st and 2nd

Stage modules. Future test systems will use only plastic housings and stainless-steel ducting/internals to eliminate the possibility of aluminum as a corrosion source.

- In addition to identifying the species responsible for membrane fouling, testing showed that these water-soluble salts could be removed by water washing. In future work, MTR will explore the possibility of in-situ cleaning of fouled membrane modules.
- One of the 2nd Stage replacement modules in January 2022 contained Polaris membranes with a modified formulation to protect against fouling. These membranes were resistant to fouling.
- The project TEA showed that the MTR CO_2 capture cost was slightly higher (within uncertainty) than the amine capture Baseline Report Case B12B. Several factors were identified as areas that could improve the cost competitiveness of the MTR membrane process. These include the performance improvements of Gen-3 Polaris membrane (being developed in a separate DOE program), the impact of a higher CO_2 content in industrial flue gas which is known to favor membranes, and the effect of less stringent CO_2 purity in the liquid CO_2 product. Future work will examine these factors in more detail.

Going forward, MTR recommends the following future development steps to make membrane-based point source CO_2 capture a viable option in the near future:

- Continue advanced Polaris membrane development for improved cost and performance. Advanced membranes will reduce the required membrane area, system footprint, and energy use of the MTR CO_2 capture process. Preliminary sensitivity studies suggest that these improvements could reduce capture costs by 10-20%. MTR is pursuing these activities with both internal resources and through an ongoing DOE transformational capture project.
- Among the largest capital and operating expenses for the MTR process are the vacuum and CO_2 compression equipment. Any improvements in cost and/or performance for this equipment would make a significant impact on capture costs. MTR plans to work with OEM providers, particularly for vacuum machines specifically needed for membrane capture, to optimize equipment selection and performance.
- Front-end engineering and design (FEED) studies of the MTR CO_2 capture membrane approach at specific sites, particularly industrial plants, are an important step in moving the membrane technology toward commercialization. To the extent that DOE funding is available for such activities, we will pursue these opportunities.
- Additional pilot tests at industrial facilities are needed to convince end-users that the technology is a viable capture option for their specific flue gas. Most end-users are looking for capture technology providers to contribute at least the costs of the pilot system itself. Partial DOE funding for these field demonstrations can accelerate capture technology deployment.

The Gen-2 Polaris membrane performance and advanced membrane module pressure-drop data measured during the TCM field test will be used to design future MTR post-combustion CO_2 capture systems. One current project (DE- FE0031587) that has incorporated learning from the TCM field test is a Large Pilot system currently under construction that will capture 150 tonnes of CO_2 per day at the Wyoming Integrated Test Center (WITC) in Gillette, WY. This project is in the build-and-operate stage (Phase III) after two down-select rounds where project feasibility, site selection, team creation, FEED study, and required permitting tasks were completed. This Large

Pilot membrane system will use six containers (Figure 39) of the advanced membrane module stacks proven at TCM to capture CO_2 from a 10 MW_e flue gas slipstream from the Basin Electric Dry Fork Station coal power plant adjacent to the WITC.

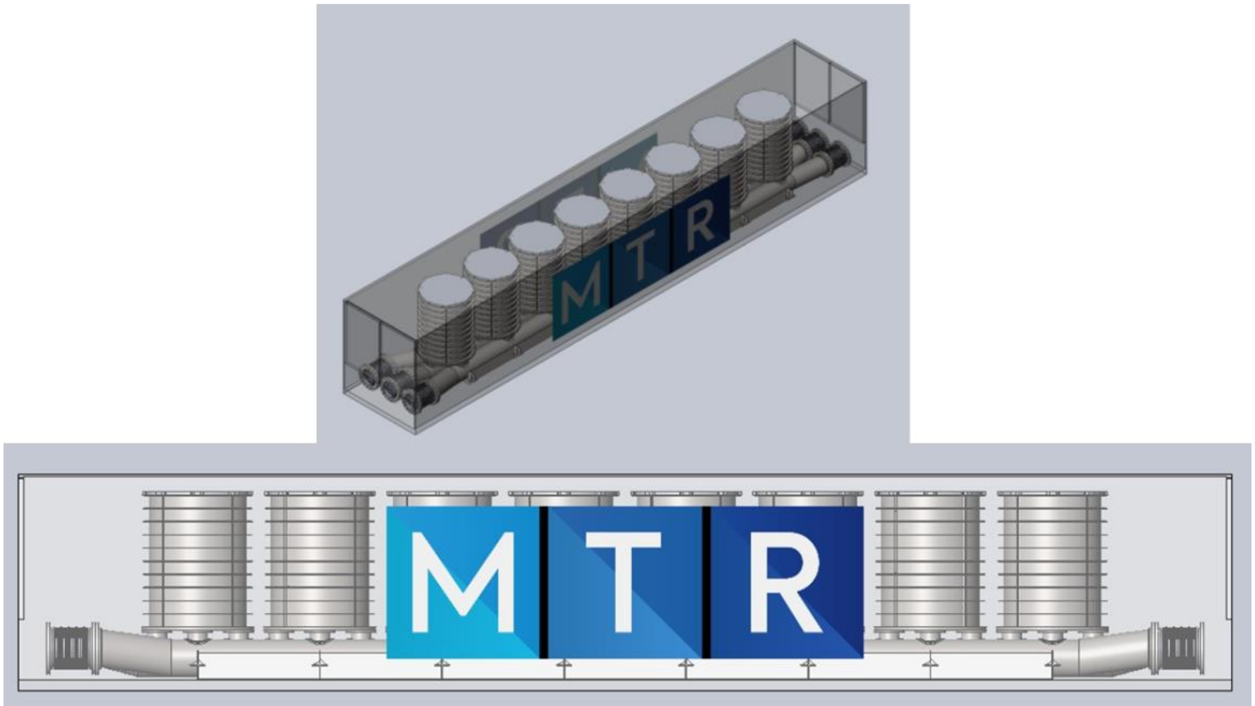

Figure 39. Artist rendering of the scaled-up final form factor of the MTR containerized membrane modules to be built for the WITC Large Pilot field test.

The WITC Large Pilot test system represents a ten-fold scale-up from MTR's TCM small pilot membrane system. The Large Pilot system will be an integrated demonstration of the total CO_2 capture process including flue gas pretreatment, membrane CO_2 capture, and CO_2 purification to produce pipeline quality, supercritical CO_2 at 152 bar. This test system will also demonstrate blower, fan, and compressor equipment representative of a full-scale commercial system. The Large Pilot system is on schedule to be commissioned and operating on flue gas by mid-2024. Completion of this project will advance the MTR post-combustion capture technology to TRL-7 by the mid-2020s and set the stage for future commercial-scale demonstration projects. Figures 40 and 41 show a general arrangement and conceptual drawings, respectively, of the Large Pilot system.

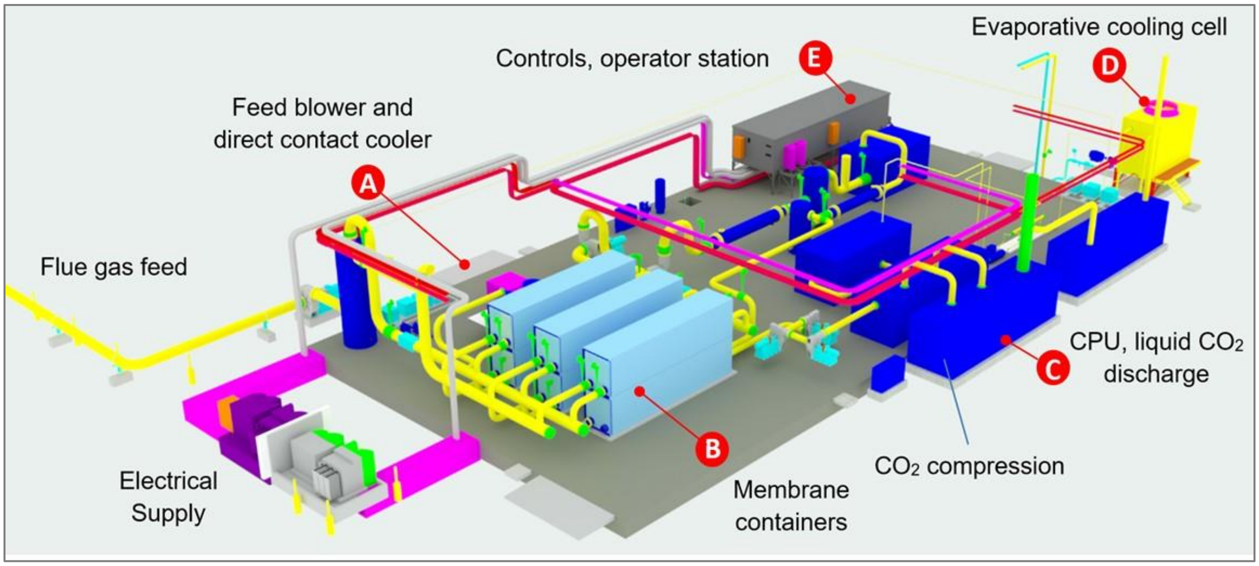

Figure 40. General arrangement of the WITC Large Pilot test system process equipment.

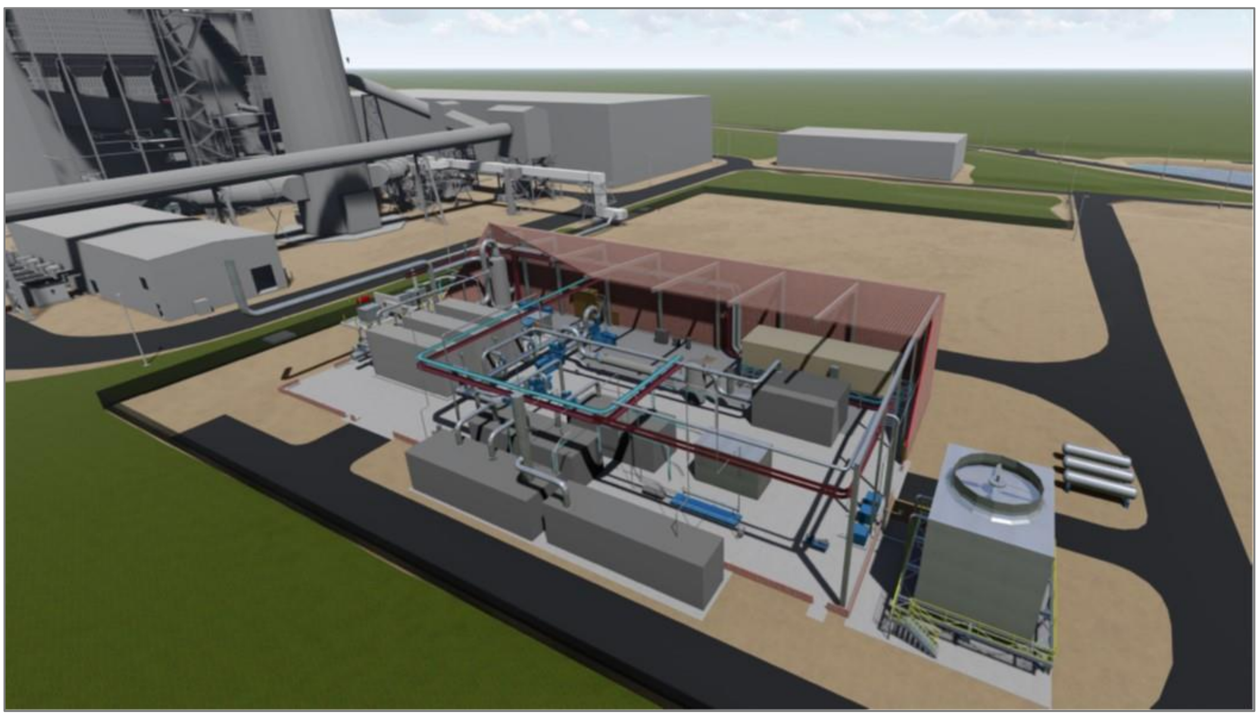

Figure 41. Artist rendering of the MTR Large Pilot test system at WITC.

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APPENDIX A

TECHNO-ECONOMIC ANALYSIS

Membrane Technology and Research, Inc. (MTR)

Scale-Up Testing of Advanced Polaris Membrane CO_2 Capture Technology (DE-FE0031591)

Final TEA

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REV	**DATE**	**DESCRIPTION**	**ORIG**	**CHK**	**APPR**	**CLIENT**

Prepared by: Trimeric Corporation
Prepared for: MTR

Acronyms and Abbreviations

AACE	Advancement of Cost Engineering
AGR	Acid gas removal
B12B	DOE reference case with CO_2 capture from [1]
B12A	DOE reference case without CO_2 capture from [1]
BBS	Bituminous Baselines Study
BEC	Base erected costs
BFW	Boiler Feed Water
BOP	Balance of plant
CAPEX	Capital expenditures
CEPCI	Chemical Engineering Plant Cost Index
CF	Capacity factor
CM H.O.	Construction management, home office
COE	Cost of electricity
DCC	Direct contact cooler
DOE	Department of Energy
EPC	Engineering, procurement, and construction
FD	Forced draft
FEED	Front End Engineering and Design
FG	Flue gas
FGD	Flue gas desulfurization
FOA	Funding opportunity announcement
H&MB	Heat and material balances
HHV	Higher heating value
HP	High pressure
HRSG	Heat recovery steam generator
ID	Induced draft
IECM	Integrated Environmental Control Model
IP	Intermediate pressure
LCOE	Levelized cost of electricity
LHV	Lower heating value
LMTD	Log mean temperature difference
LP	Low pressure
MM	Million
MMscfd	Millions of cubic feet per day at standard conditions
MTR	Membrane Technology and Research, Inc.
MU	Makeup
MWe	Megawatts of electrical power
NETL	National Energy Technology Laboratory
O&M	Operating and maintenance
PA	Primary air
PC	Pulverized coal
PEC	Purchased equipment cost
PFD	Process flow diagram

ppbv	Parts per billion by volume
ppmv	Parts per million by volume
QGESS	Quality Guidelines for Energy System Studies
SCR	Selective catalytic reduction
SDE	Spray dryer evaporator
TASC	Total as-spent cost
TEA	Technoeconomic assessment
TEG	Triethylene glycol
TOC	Total overnight cost
ton	Short ton, 2,000 lb
tonne	Metric ton (long ton), 1,000 kg
TPC	Total plant cost
TS&M	Transportation, storage, and monitoring
WSAC	Wet Surface Air Cooler
WWT	Wastewater treatment
wt%	Percentage by weight

Prepared by: Trimeric Corporation
Prepared for: MTR

Executive Summary

This report evaluates a membrane-based CO_2 capture technology that is under development by Membrane Technology and Research, Inc. (MTR) for post-combustion CO_2 capture. MTR and Trimeric developed a CO_2 capture process for a supercritical pulverized coal power plant consistent with the basis for Case B12B from the Department of Energy (DOE) National Energy Technology Laboratory (NETL) report entitled "Cost and Performance Baseline for Fossil Energy Plants, Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity", Revision 4 [1]. The technoeconomic analysis (TEA) that is the focus of this report provides a comparison of the MTR CO_2 capture process to the reference amine-based CO_2 capture process in Case B12B in the DOE baseline report.

This project and report were funded under a Fall 2017 DOE opportunity where a specific CO_2 capture rate was not required. As a result, MTR after discussions with the DOE project manager, selected a 70% CO_2 capture rate for this evaluation. This capture rate is close a maximum efficiency for the membrane process used at that time. Subsequently, interest has shifted to higher capture rates of 90% or more. These higher capture scenarios are being evaluated in other MTR work outside the scope of this report.

MTR developed the central membrane CO_2 capture unit and Trimeric developed supporting processes upstream (flue gas cooling, pre-treatment) and downstream (CO_2 purification and compression) of the capture unit. Key findings from the TEA are summarized as follows (Note: MTR designed their system for 70% CO_2 capture vs. 90% capture in DOE Case B12B):

- The key economic figures of merit for MTR can be compared to DOE Case B12B:
    - LCOE and Increase in LCOE vs. Case B12A (without CO_2 capture):
        - Case B12B: LCOE = $105.2/MWh (63.4% increase vs. Case B12A)
        - MTR: $96.5/MWh (50% increase vs. Case B12A)
    - Cost of CO_2 Capture (in 2018 USD)
        - Case B12B: $45.63/tonne CO_2 captured
        - MTR: $48.50/tonne CO_2 captured (~6% higher than Case B12B)
    - Sensitivity Analysis (+/-20% change in purchased equipment cost (PEC)):
        - MTR Cost of Capture (+20% PEC): $54.05 (+11% vs. base case)
        - MTR Cost of Capture (-20% PEC): $42.95 (-11% increase vs. base case)
- Energy performance vs. Case B12B
    - Normalized Power Plant Electrical Derating due to CO_2 Capture:
        - Case B12B: 1.14 GJe/tonne CO_2 captured
        - MTR: 1.18 GJe/tonne CO_2 captured (4% increase vs. Case B12B)

The PEC sensitivity analysis reflects the importance of the capital cost of the system for the overall economic performance. In addition, the sensitivity range (+/-20%) is well within the expected uncertainty in equipment costs for this type of study – therefore, since the cost of capture for the sensitivity cases for MTR bracket the cost of capture for Case B12B, the MTR cost of capture metric can be viewed as equivalent to B12B within typical uncertainties in cost estimation.

The energy performance for the MTR process is similarly comparable to Case B12B and is driven by compression requirements and refrigeration energy for CO_2 purification. CO_2 product specifications, therefore, may have a particularly important impact on membrane-based processes such as MTR's process and should be considered carefully on a project-specific basis.

Table of Contents

Prepared by: Trimeric Corporation
Prepared for: MTR

1.0 Introduction

This report summarizes the methods and results of the technoeconomic analysis (TEA) performed by Trimeric to evaluate the membrane post-combustion CO_2 capture process that is under development by Membrane Technology and Research, Inc. (MTR).

The key components of the TEA are as follows:

- Process overview and design basis for the commercial-scale capture process and TEA (see Section 2.0).
- Process flow diagram (PFD), heat and material balance (H&MB) tables, equipment lists, and summaries of process heat duties and electric power requirements to serve as the basis for the TEA or key outputs from the TEA (see Appendices).
- Estimation of energy performance for the CO_2 capture and compression system including power plant derating analysis (see Section 3.0).
- Equipment specification and sizing from H&MB data (See Section 4.0).
- Capital and operating cost estimation, including identification of key cost centers (See Sections 4.0 and 5.0).
- Comparison of energy performance, capital cost, cost of electricity, and cost of CO_2 capture to the U.S. Department of Energy (DOE) reference case[1] (see Sections 3.0, 4.0, and 6.0).
- Conclusions and identification of process improvements or optimization for future testing and/or evaluation (See Section 7.0).

Each of these items will be discussed in detail in subsequent sections. The over-arching goals of the TEA are to characterize the potential advantages of the membrane-based capture process, identify opportunities for process improvement/optimization, identify equipment or operational items that require additional experimental/engineering/technical evaluation in subsequent development, identify and de-risk sources of uncertainty in the technology development process, and summarize the expected performance of the process compared to the DOE reference case.

[1] The reference case for this work is Case B12B from the Department of Energy (DOE) National Energy Technology Laboratory (NETL) report entitled "Cost and Performance Baseline for Fossil Energy Plants, Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity", Revision 4 released in September 2019.

2.0 Process Overview and TEA Design Basis

This section presents an overview of the membrane CO_2 capture process configuration and design basis for the TEA.

The design basis corresponds to guidance established in the most recent DOE National Energy Technology (NETL) baseline report [1]. This report will be referred to as the "NETL Rev 4 Baseline Report" or "baseline report" throughout the document.

The membrane process configuration, feed conditions to the membrane, and membrane process performance were all defined by MTR. MTR has extensive experience (including multiple DOE projects) developing and testing their CO_2 capture membrane at relevant conditions for this TEA. Key membrane performance parameters are summarized in Section 2.1.1 (Table 3). Specifically, MTR and Trimeric worked together on a recently completed full-scale FEED study[2] for MTR's CO_2 capture process at the Basin Electric Power Cooperative Dry Fork Station coal-fired power plant. The FEED study served as an important reference for data (e.g., reference costs) and for the development of the process design for this TEA.

Details of the design basis are provided in Section 2.1. Section 2.2 provides an overview of the membrane CO_2 capture process configuration used to treat the flue gas stream from the power plant, including the PFD and H&MB that serve as the detailed basis for the TEA. Air emissions (Section 2.3) and carbon, sulfur, and water balances (Section 2.4) from the membrane-based CO_2 capture systems are also summarized.

2.1 Design Basis

The design basis defines technical process inputs and economics inputs, as well as the system boundaries. In the original funding opportunity announcement (DE-FOA-0001791), the DOE specified that the system boundaries of the TEA include the entire base power plant as well as the CO_2 capture and compression systems. The funding opportunity, issued in Fall 2017, did not require a specific capture rate. Discussions with the DOE project manager led to the selection of a CO_2 capture rate 70% for this evaluation only to produce a data point for a partial capture case where membranes were believed to be relatively efficient. Nevertheless, MTR recognized the growing interest in higher capture rates over the course of this project. As a result, the MTR field system tested in this project at the Technology Centre Mongstad in Norway operated over a range of CO_2 capture rates including >90% during the 2021/22 field campaign.

While this techno-economic analysis is focused on 70% CO_2 capture, the overall capture program at MTR is investigating capture rates of 90% or higher. For example, in a proposal currently under review in response to DE-FOA-002738 (submitted in early December 2022), MTR has included tasks to update the full FEED study of the MTR CO_2 capture process previously conducted at Basin Electric's Dry Fork Station to a $\geq$ 90% CO_2 capture rate. A life cycle analysis is also

[2] https://netl.doe.gov/sites/default/files/netl-file/21CMOG_CCUS_Freeman.pdf

included in the proposal as an end of project deliverable to demonstrate the potential environmental impacts of capturing at least 90% of carbon oxide emissions at Dry Fork Station and storing the captured carbon oxides in secure geologic formations.

The benchmark for comparison to MTR's CO_2 capture process is represented by Case B12A (without capture) and Case B12B (capture with Shell CANSOLV®) in the NETL Rev 4 Baseline Report[3]. Case B12B represents carbon capture and compression from a supercritical coal-fired power plant. The power plant generates 650 MWe (net) of electricity after accounting for the parasitic energy demands of the CANSOLV CO_2 capture process and downstream associated CO_2 compression and dehydration. The power plant and capture system reflect a representative commercial-scale greenfield application and the CANSOLV process represents an industry-standard solvent as a reference for comparison. The flue gas feed composition to the membrane process matches the flue gas feed composition to the CANSOLV process in Case B12B. Figure 1 presents the block flow diagram for Case B12B (labeled as Exhibit 4-63 in the NETL Rev 4 Baseline Report) and Figure 2 is the analogous diagram for the MTR membrane CO_2 capture process evaluated in this report. Appendix A replicates the Case B12B stream tables (from Exhibit 4-64) in the NETL Rev 4 Baseline Report and includes the analogous stream tables for the MTR process corresponding to Figure 2. The membrane CO_2 capture "box" shown in Figure 2 includes CO_2 compression and purification. The CO_2 purification process includes a mole sieve dehydration step – the heat source for regeneration of the mole sieve beds is an electric heater and the power requirement for this heater is accounted for in the TEA. Therefore, there are no analogous steam and condensate streams associated with dehydration in the MTR process as depicted in Figure 1 for the Case B12B process.

The process design and economic evaluation are based on a 650 MWe net basis, i.e., *after* the energy requirements for the CO_2 capture system are deducted. Therefore, the size for both the base power plant (reflected in gross power plant output) and capture system are "escalated" based on the parasitic energy consumption from all sources. The term "escalation factor" is used to quantify the approximate increase in the size of the base power plant, when compared to a reference case, due to derating from the CO_2 capture portion of the plant.

[3] Appendix C of FOA 1791 states the following: *The Techno-Economic Analysis (TEA) shall follow the analysis documented in the NETL report "Cost and Performance Baseline for Fossil Energy Plants - Volume 1a: Bituminous Coal and Natural Gas to Electricity (Rev 3, July 6, 2015)," aka Bituminous Baselines Study (BBS).* However, MTR received instruction from DOE that the TEA should follow later Revision 4 of the BBS, which is the basis for this TEA.

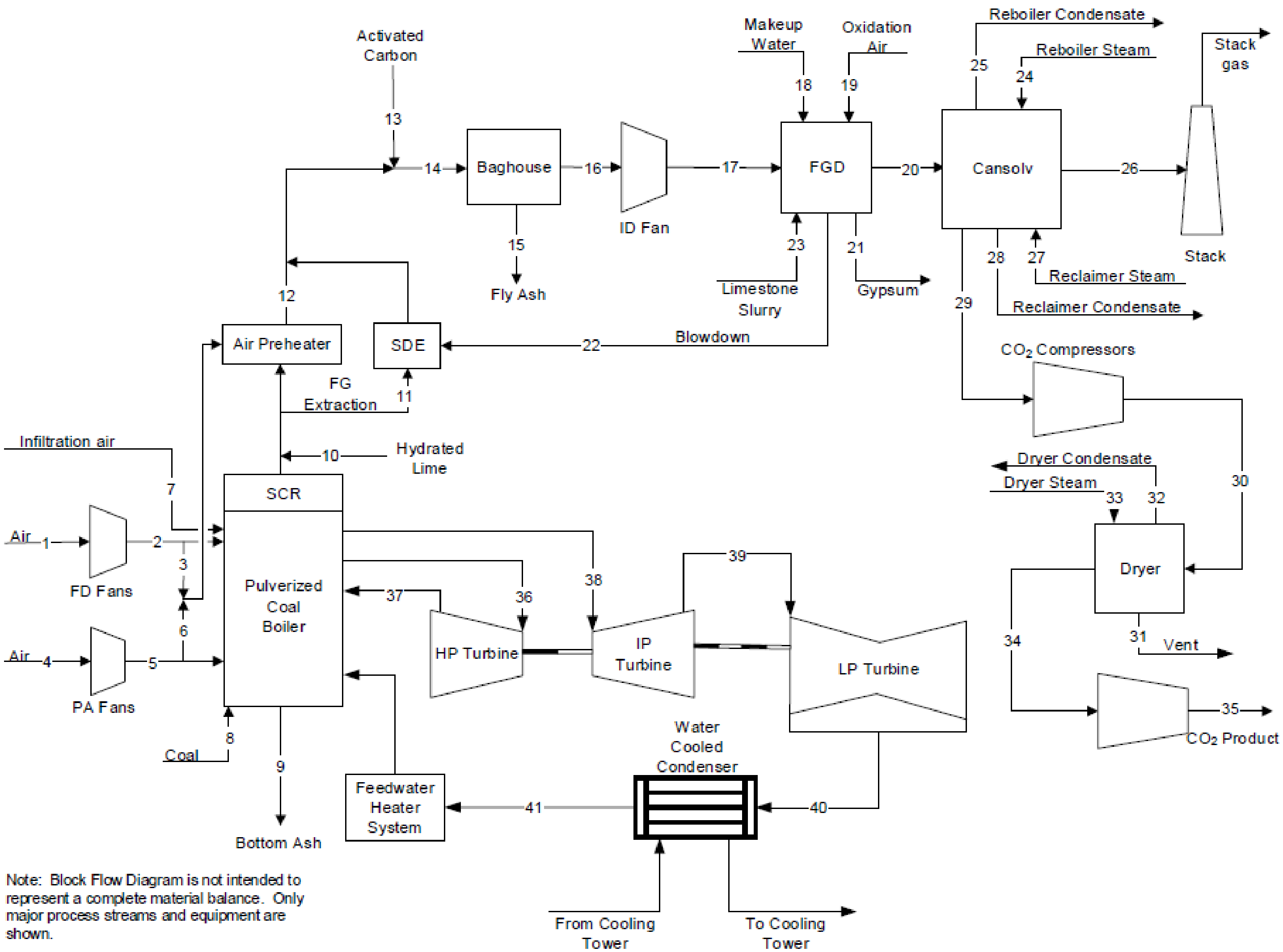

Figure 1. Base Power Plant Block Flow Diagram [1]

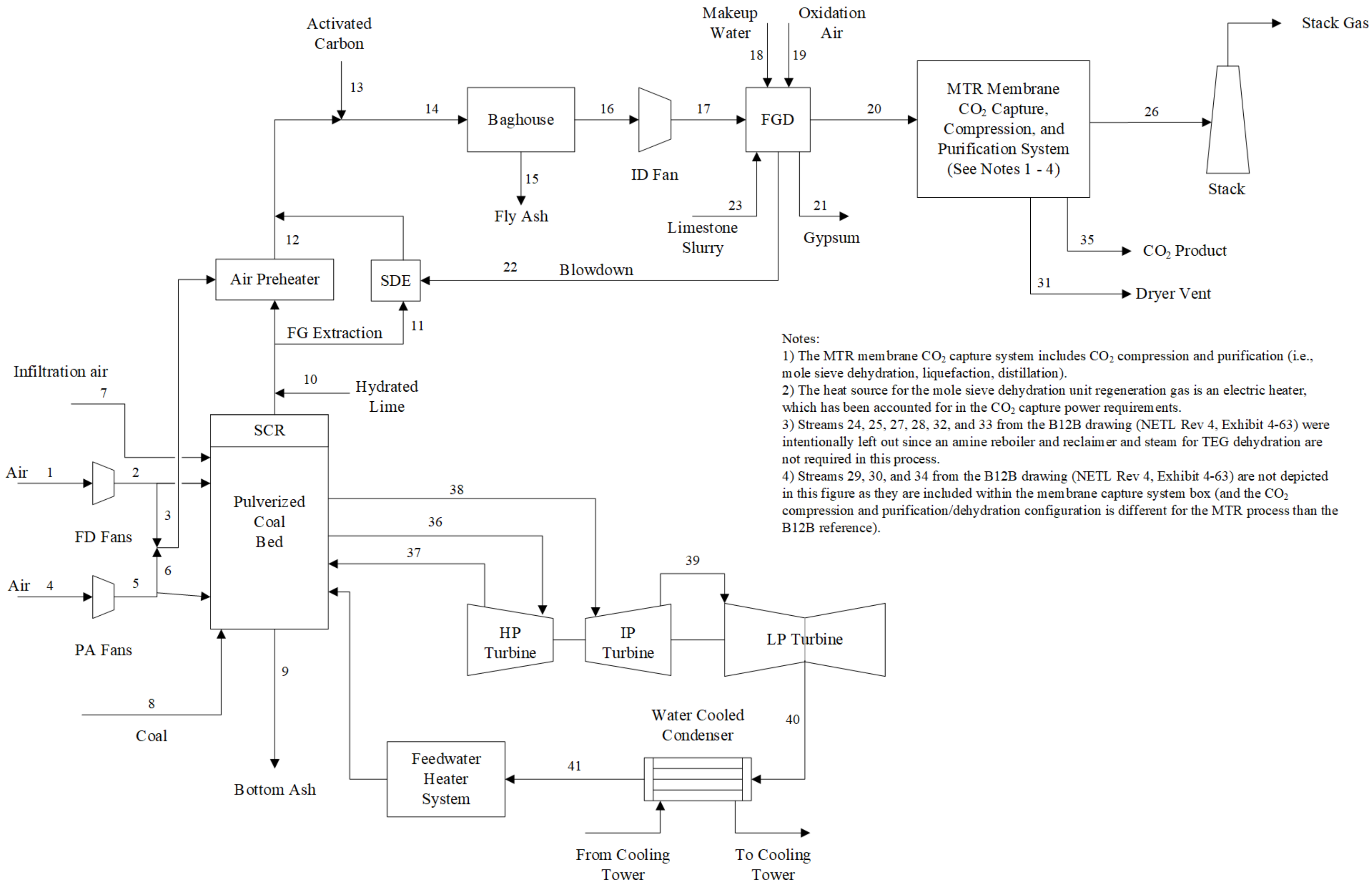

Figure 2. Base Power Plant Block Flow Diagram for MTR CO_2 Capture Membrane Process

Table 1. Technical Design Basis

	SI		English		
	Units	**Value**	**Units**	**Value**	**Comment**
General					
Target Net Capacity	MWe	650			DOE specification
Capacity Factor	%	85			DOE specification
CO_2 Capture	%	70			Defined by MTR after consultation[4] with DOE
Stream Data					
Inlet Flue Gas					
Temperature	°C	57	°F	135	NETL Rev 4 Baseline Case B12B
Pressure	MPa	0.10	Psia	14.5	NETL Rev 4 Baseline Case B12B
Mass Flow Rate	kg/h	3,385,665	lb/h	7,464,114	NETL Rev 4 Baseline Case B12B
Composition					
CO_2	vol%	12.46			NETL Rev 4 Baseline Case B12B
H_2O	vol%	14.97			NETL Rev 4 Baseline Case B12B
N_2	vol%	68.12			NETL Rev 4 Baseline Case B12B
O_2	vol%	3.64			NETL Rev 4 Baseline Case B12B
Ar	vol%	0.81			NETL Rev 4 Baseline Case B12B
SO_x	ppmv	37			NETL Rev 4 Baseline p.350
CO_2 in Inlet Gas	tonne/h	646	short ton/h	712	NETL Rev 4 Baseline Case B12B

[4] MTR received approval on 3/30/2020 from NETL project manager Isaac "Andy" Aurelio to define a CO_2 capture basis other than 90% capture (Case B12B basis) for this project.

Table 1. Technical Design Basis (Continued)

	SI		English		
Description	**Units**	**Value**	**Units**	**Value**	**Comment**
Outlet CO_2 Specification					
Temperature	°C	30	°F	86	DOE specification[5]
Pressure	MPa	15.27	psia	2,215	DOE specification
CO_2	mol%	>95			DOE specification
Cooling water					
Supply Temperature	°C	15.6	°F	60	NETL Rev 4 Baseline Case B12B
Return Temperature	°C	26.7	°F	80	NETL Rev 4 Baseline Case B12B
Capture System Steam	No major steam users for MTR CO_2 Capture Process				

[5] The CO_2 product temperature reflects a design choice for the NETL Rev 4 Baseline report – the report does not provide context for the design choice. In Trimeric's experience, CO_2 pipelines typically have an upper temperature limit specification due to material integrity considerations (e.g., running ductile fractures) – therefore, for this study, the DOE CO_2 product temperature was treated as a de facto upper limit on temperature.

The final product specification for the CO_2 will be expected to meet specifications outlined in NETL's QGESS CO_2 Impurity Design Parameters document (Table 2):

Table 2: CO_2 Product Specification for Carbon Steel Pipeline from NETL QGESS Document[6] [2]

Component	CO_2 Purity Specification for Carbon Steel Pipeline
CO_2	> 95 vol%
H_2O	< 500 ppmv
N_2	< 4 vol%
Ar	< 4 vol%
O_2	< 10 ppmv
SO_2	< 100 ppmv
NO_X	< 100 ppmv
NH_3	< 50 ppmv
Particulate	< 1 ppmv
Glycol	< 46 ppbv

2.1.1 Membrane Heat and Material Balance and Performance Specifications

The membrane process configuration, feed conditions to the membrane, and membrane process performance were all defined by MTR for this study. MTR has a proprietary process simulation package for their CO_2 capture membranes. Using the flue gas input conditions for this study and overall CO_2 capture basis for this TEA, MTR developed heat and material balance data for the membrane CO_2 capture portion of the process. This heat and material balance served as an input to Trimeric, who developed the upstream flue gas conditioning/pre-treatment steps and downstream CO_2 compression and purification process to develop a complete heat and material balance from the CO_2 capture process for the boundaries defined in Figure 2. The key inputs from the MTR heat and material balance data (primarily regarding the membrane performance and specifications) are summarized in Table 3.

[6] Table 2 is a truncated version of the CO_2 specifications list provided in NETL's QGESS CO_2 Impurity Design Parameters document representing the relevant species for this study.

Table 3: Component Permeation and Operating Pressure by Membrane – via MTR

	Fractional Permeation by Membrane			
	Membrane A	**Membrane B**	**Membrane C**	**Membrane D**
Carbon Dioxide	72.5%	90.4%	84.0%	95.0%
Nitrogen	7.3%	11.4%	11.3%	11.9%
Oxygen	13.2%	20.7%	20.2%	21.9%
Water	85.0%	95.2%	95.2%	95.2%
Sulfur Dioxide	85.0%	95.2%	95.2%	95.2%
Nitrogen Dioxide	85.0%	95.2%	95.2%	95.2%
Nitrogen Oxide	13.2%	20.7%	20.2%	21.9%
Argon	17.1%	33.5%	0.4%	0.4%
	Operating Pressure by Membrane (bara)			
	Membrane A	**Membrane B**	**Membrane C**	**Membrane D**
Feed	1.06	1.11	25	24.95
Permeate	0.1	0.2	5.5	1.11

2.2 Membrane CO_2 Capture Process Overview

The PFDs for MTR's membrane CO_2 capture process are included in Appendix B with this report. The associated H&MB table for the process is provided in Appendix C.

The CO_2 capture flowsheet can be divided into the major process areas:

- Inlet Gas Conditioning
  - Includes combined SO_2 Polisher/ Direct Contact Cooler (DCC)
- CO_2 Capture
  - Includes Flue Gas Boosting, First Membrane Stage (Membrane A), Membrane A Permeate Compression, Second Stage Membrane (Membrane B), Membrane B Permeate Fans Only
    - Membrane B Permeate Compression is included in CO_2 Compression and Purification
- CO_2 Compression and Purification
  - Includes Membrane B CO_2 Permeate Compression, Mole Sieve Dehydration, CO_2 Liquefaction and Distillation (including membrane-based CO_2 recovery from the distillation vent), and CO_2 Product Pumping and Heating.

Note that the distinction between compression steps included in the CO_2 capture area (e.g., Membrane B permeate fans vs. compression) and the downstream CO_2 compression and purification is somewhat arbitrary since compression is an integral part of the membrane-based capture process. As such, defining separate CO_2 capture and compression costs are not straightforward for the MTR process (compared to Case B12B, for example). However, the preceding grouping of unit operations was used to define areas and associated costs by area in subsequent parts of this TEA. Figure 3 provides an overview of the two-stage membrane process in a simplified schematic.

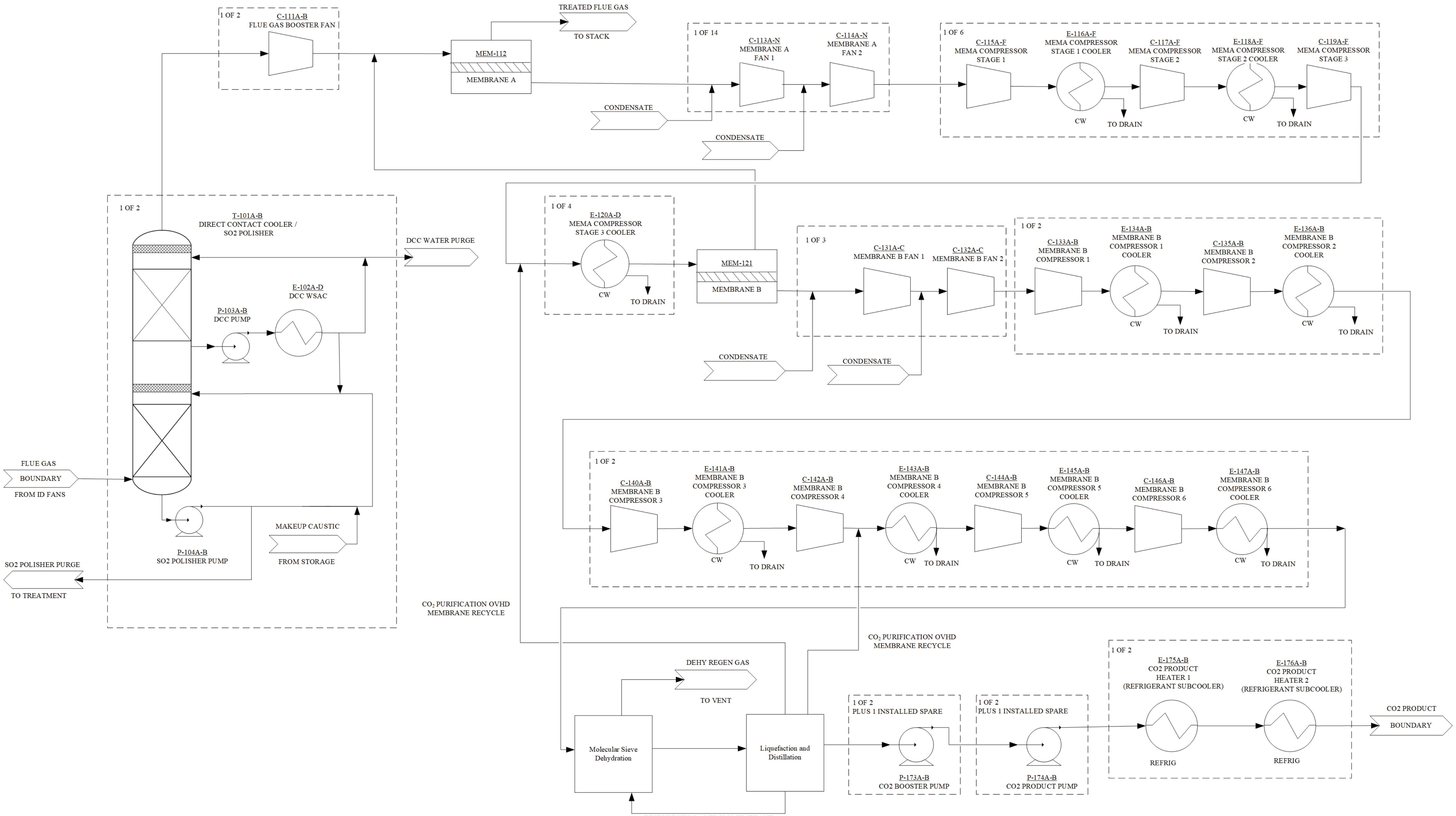

Figure 3: MTR Membrane CO_2 Capture, Purification, and Compression (Simplified Schematic)

2.2.1 Inlet Gas Conditioning Area (PFD-01)

The flue gas from the power plant flue gas desulfurization (FGD) system requires cooling and SO_2 removal prior to entering the CO_2 capture system. Inlet gas conditioning is shown on PFD-01 in Appendix B. The flue gas feed to the inlet gas conditioning system is summarized in Table 4.

Table 4: Flue Gas Feed Stream Conditions, Flow, and Composition at 650 MWe Net Power

Properties	Stream 100 (Flue Gas from FGD)
Temperature (°C)	57
Pressure (MPa)	0.10
Mass Flowrate (kg/hr)[Note 1]	3,212,986
Molar Flowrate (kmol/hr) [Note 1]	111,742
Component Mole Fractions	
CO_2	0.1246
H_2O	0.1497
N_2 & Ar (Inerts)	0.6892
O_2	0.0364
SO_2	37 ppmv
NO_x	46 ppmv

Note 1: Flue gas flow corresponds to the power plant with MTR CO_2 capture process integrated into the facility. See Section 3.1 for discussion of derating calculations that define the power plant size required to produce 650 MWe Net power.

The flue gas from the FGD flows to two parallel contactors (T-101A/B). Each contactor contains an SO_2 polisher section in the bottom and a direct contact cooler (DCC) section in the top. The flue gas enters the bottom portion of the contactor that uses dilute caustic (10 wt%) to react with SO_2 and reduce the SO_2 concentration in the flue gas from approximately 37 ppmv to 5 ppmv. Makeup caustic (50 wt%) is pumped from a storage tank on-site to the SO_2 polishing recirculation loop. Trim SO_2 recirculation pumps (P-104) circulate the caustic solution through the packed bed in the contactors. Dilution water is added from the DCC system in the upper portion of the contactors to reduce the caustic strength from 50 wt% to 10 wt%. The blowdown from the SO_2 polishing section will contain Na_2SO_3, $NaHSO_3$, and possibly Na_2CO_3 and $NaHCO_3$ depending on the operating pH and temperature of the system. This dilute salt solution can be sent to wastewater treatment.

Flue gas exits the SO_2 polisher and enters the DCC portion of the contactor. In the DCC, cooling media (water) is recirculated to cool the gas from 57 ºC to 26 ºC (134 ºF to 78 ºF). The DCC pumps (P-103) recirculate water over the packed bed in the contactors. Wet surface air coolers (WSAC, E-102) cool the recirculating water in the DCC loop to maintain the necessary recirculating water temperature for flue gas cooling. MTR and Trimeric have experience specifying a wet surface air cooler for this service from a past FEED study, which included input from a supplier of WSAC. The basic operating principle of a wet surface air cooler is similar to a cooling tower. The process fluid is circulated within coils/tube bundles. Water is sprayed over the coils and provides cooling via evaporation. A fan pulls air over the coils as well and removes the water vapor. WSACs have specific advantages over cooling water exchangers:

- Single approach temperature between the process fluid and the wet bulb temperature of the air vs. two approach temperatures for a cooling water system (one approach in the cooling tower, second approach between the cooling water and process fluid).
- WSAC can use "low" quality water for the spray water and there is no cooling water medium, so water consumption is reduced and can facilitate re-use of water that would otherwise have no process use.

As evident from the water balance for the power plant (see Section 2.4), the CO_2 capture process "produces" water via condensation at several points in the process. In particular, the DCC condenses water from the flue gas. One advantage of the sequential SO_2 polisher-DCC system proposed for the MTR process is that the blowdown from the SO_2 polisher is segregated from the bulk of the water condensed from the flue gas in the DCC section (vs. a single combined SO_2 polisher and DCC operation which would contaminate condensed water with polisher blowdown). The condensed water from the DCC can then be re-used elsewhere (e.g., WSAC).

The DCC/SO_2 polisher contactors (T-101 A/B) operate under a slight vacuum. The downstream flue gas booster fans (C-111 on PFD-02) pull the flue gas through the contactors and provides the motive force to move the flue gas through the downstream first-stage membrane.

2.2.2 CO_2 Capture Area (PFD-02 and -03)

PFD-02 in Appendix B depicts flue gas boosting/compression, the first-stage membrane unit (Membrane A), Membrane A permeate compression, and the second-stage membrane (Membrane B). The flue gas from the DCC/SO_2 polisher enters the flue gas booster fans (C-111). The booster fans increase the pressure of the flue gas from 0.97 bara to 1.09 bara (14.13 psia to 15.85 psia) prior to feeding Membrane A (MEM-112). The retentate from Membrane B (MEM-121, second stage membrane downstream) is also recycled to the feed of Membrane A to increase CO_2 recovery.

The stream conditions around Membrane A are included in the H&MB tables and summarized in Table 5 below. The separation reported for the membrane was provided by MTR via simulation of their membrane modules under the design conditions for this study. CO_2 is selectively removed from the combined feed stream (Stream 105) that is comprised of the flue gas feed (Stream 104) and the retentate recycle (Stream 106) from Membrane B downstream. The separated CO_2 (along with other impurities that permeate the membrane) leaves the membrane via the permeate stream (Stream 109) at vacuum conditions (0.10 bara, 1.45 psia) via the Membrane A permeate compression downstream. The retentate (Stream 108), or treated flue gas, is vented via the flue gas stack.

Table 5: Membrane A (MEM-112) Streams

	Streams

	104 **Flue Gas to Membrane A**	**106** **Membrane B Retentate Recycle**	**105** **Feed to Membrane A**	**108** **Retentate to Stack**	**109** **Permeate**
Temperature (°C)	38	21	37	37	37
Pressure (kPa-abs)	109	113	109	103	10
Mass Flowrate (kg/hr)	2,969,635	217,185	3,186,820	2,466,073	720,747
Molar Flowrate (kmol/hr)	98,245	7,032	105,276	84,928	20,348
Component Mole Fractions					
CO_2	0.1417	0.1510	0.1423	0.0485	0.5339
H_2O	0.0329	0.0025	0.0309	0.0057	0.1358
N_2 & Ar (Inerts)	0.7839	0.7753	0.7834	0.8991	0.3004
O_2	0.0414	0.0712	0.0434	0.0467	0.0296
SO_2	5.0 ppmv	3.0 ppmv	4.9 ppmv	0.9 ppmv	21 ppmv
NO_x	49 ppmv	28 ppmv	47 ppmv	8.8 ppmv	209 ppmv

The permeate from Membrane A flows to two fans in series, Membrane A Fan 1 (C-113) and Membrane A Fan 2 (C-114). The fans maintain vacuum on Membrane A to provide driving force for the CO_2 separation from the flue gas and serve as the initial stages of permeate compression. The permeate is compressed from 0.1 bara to 0.22 bara (1.45 psia to 3.23 psia) across both fans. Note that the gas cooling for these fans is provided by direct water spray into the fans themselves. This is an established gas cooling approach from commercial suppliers of these fans. The water required for cooling (Streams 227, 228) is expected to be provided via condensate recovered in downstream compression steps.

The permeate leaving the Membrane A fans (Stream 113) enters a three-stage permeate compression system (C-115, 117, 119) before reaching Membrane B downstream (Stream 123). The permeate compression system includes intercoolers (E-116 Stage 1 and E-118 Stage 2) and an aftercooler (E-120 Stage 3). Note that all exchangers associated with permeate compression include an integrated water knockout/drain within the exchanger itself in lieu of separate standalone knock-out vessels as in a conventional compression system. This design was provided by an established commercial supplier of compression equipment specifically for the application associated with MTR's CO_2 capture membrane.

The Membrane A permeate pressure increases from 0.22 bara (Stream 113) to 1.19 bara (Stream 120) (3.23 psia to 17.29 psia) across the three stages of Membrane A permeate compression. A small flow (Stream 166) of CO_2 recovered via Membrane D (MEM-166) from the overhead of the CO_2 distillation unit downstream is recycled to the discharge of the 3rd stage of Membrane A compressor (C-119). The combined stream (Stream 121) is cooled via the aftercooler/Stage 3 cooler before feeding Membrane B (Stream 123).

The conditions and compositions for the streams around Membrane B (MEM-121) are summarized in Table 6 below. Approximately 90% of the CO_2 in the feed to Membrane B (Stream 123) is transferred to the permeate stream at vacuum conditions (0.2 bara or 2.9 psia). The permeate (Stream 124) contains ~72% of the CO_2 in the inlet flue gas to the system (Stream 100), i.e., an overall CO_2 capture rate of 72% across the two membrane stages. The retentate from Membrane B is recycled to Membrane A to capture the CO_2 in this retentate stream.

Table 6: Membrane B (MEM-121) Streams

Properties	Streams		
	123 Feed	106 Retentate/Recycle	124 Permeate
Temperature (°C)	21	21	21
Pressure (kPa-abs)	118	113	20
Mass Flowrate (kg/hr)	690,945	217,185	473,760
Molar Flowrate (kmol/hr)	18,293	7,032	11,261
Component Mole Fractions			
CO_2	0.6065	0.1510	0.8909
H_2O	0.0201	0.0025	0.0312
N_2 & Ar (Inerts)	0.3386	0.7753	0.0659
O_2	0.0345	0.0712	0.0116
SO_2	24 ppmv	3.0 ppmv	37 ppmv
NO_x	229 ppmv	28 ppmv	354 ppmv

PFD-03 includes the last steps of what was defined to be part of the CO_2 capture process. CO_2-rich permeate (Stream 124) from Membrane B (MEM-121) is compressed via two sets of fans in series - Membrane B Fan 1 (C-131) and Fan 2 (C-132). The heat of compression from these fans is dissipated by introducing water spray (recycled condensate from compression) into the gas upstream of the fan. The gas leaves the two-step compression via fans (Stream 127) at 0.44 bara (6.38 psia).

2.2.3 CO_2 Compression and Purification Area (PFD-03, -04, and -05)

PFD-03 depicts the start of the CO_2 product compression and purification as defined for this study, starting immediately downstream of the Membrane B fans. Stream 127 leaving the Membrane B fans enters a 6-stage compression system with intercooling (cooling water heat exchangers) between each stage. The Membrane B compressor system compresses the gas from 0.44 bara (6.38 psia) to 26.8 bara (389 psia) at Stream 146; the gas is cooled to 20.6°C (69°F) after each compression stage. A small flow (Stream 167) of CO_2 recovered via Membrane C (MEM-165) from the overhead of the CO_2 distillation unit downstream is recycled to the discharge of the 4th stage of Membrane B compressor (C-142).

Stream 146 enters PFD-04, which represents the mole sieve dehydration system[7]. Mole sieve dehydration is required because CO_2 will be liquified and distilled in subsequent steps to remove impurities (e.g., oxygen). The operating temperature for liquefaction and distillation of CO_2 requires deep dehydration of CO_2 to avoid freezing/hydrate formation. Stream 146 enters a feed chiller (E-150, cooling to 10°C, 50°F) and separator (V-151) to remove bulk water. The CO_2 is

[7] Mole sieve dehydration is part of a packaged unit that includes the CO_2 liquefaction and distillation steps.

then re-heated (E-152) before entering the mole sieve dehydration system. The heat exchange for the feed gas into the dehydration unit is integrated with the refrigerant system for the CO_2 liquefaction distillation system to maximize the efficiency of the refrigerant system. Mole sieve dehydration is a well-established commercial dehydration technology and will not be described in detail here. However, mole sieve dehydration system design choices that were specific to this study include the following:

- Source of Regeneration Gas: Recycle of non-condensable gases (Stream 164) from the overhead of the CO_2 distillation system after a two-step membrane process (Membrane C and D) to recover residual CO_2.
- Use of an electric regeneration heater (E-154): Other heat sources (gas fired, steam heated) can be used in this application, but these alternate sources would increase the CO_2 emissions within the plant boundary and/or further derate the power plant

The dry CO_2 leaving the mole sieve dehydration unit (Stream 149) contains < 2 ppmv water and enters PFD-05, the CO_2 purification section of the process. There are two parallel/identical CO_2 purification trains for the scale of the technoeconomic analysis. The CO_2 is cooled and partially liquefied via cross-exchange with the main reboiler (E-170) of the CO_2 distillation column (T-162) and via a refrigerant-cooled CO_2 condenser (E-161) to produce the two-phase feed to the distillation column (Stream 151, -35ºC / -31ºF, 25.5 bara / 370 psia). Non-condensable gases that are present in the CO_2 (primarily N_2, O_2, Argon) are distilled from the CO_2 into the column overhead fraction, while the purified product liquid CO_2 is recovered as the distillation column bottoms (Stream 156), meeting the CO_2 purity specifications for oxygen and nitrogen outlined in Table 2. The product liquid CO_2 is pumped via a booster pump (P-173) that is nominally part of the CO_2 purification system and a main CO_2 product pump (P-174) – the two pumps in series increase the CO_2 product pressure from 25 bara (362 psia) for Stream 156 to 153 bara (2,219 psia) for stream 158. A two-step heating process (E-175, E-176 integrated with the refrigerant system) heats the CO_2 from the product pump outlet temperature of -0.5ºC (31ºF) to the final temperature of 20ºC (68ºF) for transport by pipeline (Stream 160); the final CO_2 product pressure at this point is just below 153 bar (2,213 psia). The conditions of the product CO_2 are shown in Table 7.

Table 7: CO_2 Product Stream from Compression and Purification

Properties	Stream 160
Temperature (°C)	20
Pressure (bara)	153
Mass Flowrate (kg/hr)	430,992
Molar Flowrate (kmol/hr)	9,793
Molar Composition	
CO_2	>99.9%
N_2	< 1 ppmv
O_2	< 10 ppmv
H_2O	< 2 ppmv
SO_2	42 ppmv
NOx	397 ppmv

The final CO_2 product purity meets the Quality Guidelines for Energy System Studies (QGESS) target (>95 vol%) guidance summarized in Table 2. The only specification that is not met is for total NO_x (NO_2 + NO) which is present at ~400 ppmv in the CO_2 vs. the specification of 100 ppmv or less in Table 2. NOx (which is primarily NO_2 at this point in the system due to membrane selectivity) is not effectively separated from CO_2 in the distillation process. Potential approaches to prevent NO_2 from reaching the CO_2 product include removal upstream of the CO_2 capture process or modification of CO_2 capture membrane performance to reject more NO_2 (potentially at the expense of CO_2 recovery). While the goal of the TEA process design is to meet the QGESS specification for the TEA (and the CO_2 product largely does meet the specification), it was beyond the scope of the current TEA to look at more detailed approaches to managing NO_2.

2.3 Air Emissions

A summary of the plant air emissions is shown in Table 8. Note that the base power plant MTR CO_2 capture process is smaller (by ~5%, see Table 12) than Case B12B, so the total mass flow rate of SO_2, CO_2, NOx, particulates, and Hg from the power plant entering the CO_2 capture boundary are lower than the corresponding values for B12B.

Table 8. Air Emissions

Compound	kg/GJ	lb/MMbtu	tonne/yr	ton/yr	kg/MWh	lb/MWh
SO_2	0.0007	0.0016	36.5	40.3	0.00590	0.01300
Case B12B	*0.000*	*0.000*	*0*	*0*		
NOx	0.0060	0.0138	312	344	0.050	0.111
Case B12B	*0.033*	*0.077*	*1,819*	*2,006*	*0.318*	*0.700*
Particulates	0.004	0.010	225.5	248.7	0.036	0.080
Case B12B	*0.004*	*0.010*	*234*	*258*	*0.041*	*0.090*
Hg	1.41E-07	3.28E-07	0.007	0.008	1.19E-06	2.63E-06
Case B12B	*1.41E-07*	*3.28E-07*	*0.008*	*0.009*	*1.36E-06*	*3.00E-06*
CO_2	25.73	59.8	1,349,810	1,488,166	218	480
Case B12B	*9*	*20*	*480,897*	*530,098*	*84*	*185*
CO_2 Note 1	-	-	-	-	279	615
Case B12B	-	-	-	-	*99*	*219*

Note 1: Calculated based on net electricity produced.

The following summarizes key points from the emissions results:

- SO_2 emissions to the air are negligible in Case B12B since the CANSOLV solvent is expected to react with residual SO_2 entering the system whereas the membrane process will reject some SO_2 to the treated flue gas – this is reflected in the higher emissions for the MTR capture process.
- NO_x emissions are higher for Case B12B. As discussed previously, the MTR capture process will remove some NO_x with the CO_2 that ends up in the CO_2 product. In addition, the lower NOx entering the capture boundary to the power plant also explains the lower total emissions of NOx.
- Only 70% of the CO_2 is being captured by the MTR process, so the CO_2 emissions are higher than B12B.

2.4 Carbon, Sulfur, Water Balances

The following tables display the carbon, sulfur, and water balances, respectively, for the entire facility. For the MTR CO_2 capture process, the power plant is ~5% smaller than Case B12B, so the carbon, sulfur, and water rates are correspondingly lower than Case B12B. Because the MTR capture unit captures 70% of the CO_2, there is less product carbon and more carbon in the stack than Case B12B. Finally, the MTR capture process does have a lower process cooling requirement than Case B12B, reducing the major water demand in the system (cooling tower) compared to B12B. The corresponding tables for Case B12B are Exhibits 4-68, 4-69, and 4-70 in the NETL Baseline report [1].

Table 9. Carbon Balance

Carbon In	kg/hr	lb/hr	Carbon Out	kg/hr	lb/hr
Coal	165,532	364,936	Stack Gas	49,470	109,061
Air (CO_2)	385	850	FGD Product	196	433
PAC	56	123	Baghouse	850	1,874
FGD Reagent	2,549	5,619	Bottom Ash	198	438
			CO_2 Product	117,559	259,170
			CO_2 Dryer Vent	146	323
			CO_2 Knockout	19	42
Total	168,522	371,529	Total	168,439	371,341

Note: Total Carbon Out is within ~ 0.05% of Total Carbon In.

Table 10. Sulfur Balance

Sulfur In	kg/hr	lb/hr	Sulfur Out	kg/hr	lb/hr
Coal	6,508	14,349	Stack Gas	2.5	5
			FGD Product	6,119	13,490
			Polishing Scrubber	117	257
			Baghouse	262	578
			Product CO_2	13	29
Total	6,508	14,349	Total	6,514	14,359

Note: Total Sulfur Out is within ~0.08% of Total Sulfur In.

Table 11. Water Balance

	Water Demand		Internal Recycle		Raw Water Withdrawal		Process Water Discharge		Raw Water Consumption	
	m^3/min	gpm	m^3/min	gpm	m^3/min	gpm	m^3/min	gpm	m^3/min	gpm
FGD Makeup	2.7	712	2.6	699	0.0	12	0.0	0	0.0	12
Carbon Capture System	3.4	907	3.4	907	0.0	0	0.0	0	0.0	0
CO_2 Drying	*0.0*	*0*	*0.0*	*0*	*0.0*	*0*	*0.0*	*0*	*0.0*	*0.0*
CO_2 Capture Process (incl. DCC Recovery)$^{Note\ 1}$	*3.4*	*907*	*3.4*	*907*	*0.0*	*0*	*0.0^1*	*0^1*	*0.0*	*0*
CO_2 Compression KO$^{Note\ 1}$	*0.0*	*0*	*0.0*	*0*	*0.0*	*0*	*0.0^1*	*0^1*	*0.0*	*0*
Deaerator Vent	0.0	0	0.0	0	0.0	0	0.1	20	-0.1	-20
BFW Makeup	0.1	20	0.0	0	0.1	20	0.0	0	0.1	20
Cooling Tower	27	7,250	0	0	27	7,250	6.2	1,630	21.3	5,619
Total	**34**	**8,889**	**6.1**	**1,607**	**28**	**7,282**	**6**	**1,650**	**21**	**5,632**

Note 1: Process water discharge for CO_2 capture and CO_2 compression areas are zero because any water that is not recycled internally within the capture unit is recycled to the FGD system (i.e., included in the "internal recycle" for the FGD area).

3.0 Energy Performance Evaluation of Membrane CO_2 Capture Process

3.1 Power Plant Derating and Parasitic Power Demand

The energy performance of the membrane CO_2 capture process was primarily dictated by electrical power requirements for flue gas compression, permeate compression, CO_2 product compression and pumping, and refrigeration for the liquefaction and distillation unit. The membrane process does not have any steam usage requirements; therefore, steam is not a material contributor to the parasitic energy demand of the capture process on the power plant. This is an important distinction when comparing MTR's membrane-based CO_2 capture process to the reference CANSOLV solvent process in Case B12B. Steam extraction from the power cycle for amine regeneration is a significant part of the total parasitic energy demand for Case B12B. The following major steps describe the process of comparing the MTR CO_2 capture process energy performance to Case B12B:

- The first step of the energy performance evaluation was to use the original heat and material balance[8] developed by MTR and Trimeric to calculate a parasitic power demand for the MTR membrane process configuration. This parasitic power demand is primarily from the direct process electrical requirements of the equipment in the MTR process, but also includes a portion of the energy used in power plant auxiliary systems (e.g., cooling water system) to support the capture process.
- The flue gas flow rate in the original heat and material balance developed by Trimeric and MTR corresponded to a specific <u>gross</u> generating capacity for the power plant, including capture (gross power is estimated by analogy to the flue gas flow and gross power basis of Case B12B). Trimeric estimated the gross power plant generating capacity for the original MTR case to be 927 MWe.
- The basis for this TEA is a 650 MWe (net) power plant – i.e., after deducting the parasitic power requirements of the CO_2 capture process from the gross generating capacity of the power plant, there should 650 MWe left strictly for power generation/sales. Since the original heat and material balance for the MTR capture case is an a priori estimate before the CO_2 capture parasitic power demands are quantified, the resulting net generating capacity of the power plant is not 650 MWe for this first iteration and the heat and material balance must be re-scaled. For this study, a scaling factor of **0.8979** was required to scale the original heat and material balance data to a 650 MWe (net) facility with the membrane capture process integrated into the facility. The resulting gross power plant capacity for the re-scaled heat and material balance is 832 MWe yielding 650 MWe (net) after deducting parasitic demand due to CO_2 capture.
  - Note that the MTR membrane system is capturing 70% of the incoming CO_2 and this is reflected in the gross power plant size.

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[8] MTR supplied material balance data for the membrane-based capture system and Trimeric generated a complete process simulation (including upstream flue gas conditioning and downstream CO_2 purification) and associated H&MB tables.

- With the material balance for each case scaled to 650 MWe (net), the parasitic energy demand for the membrane process configuration can be compared directly to DOE Case B12B. To facilitate comparison on a common basis, Trimeric needed to assign an electrical equivalent value to the steam extracted from the power cycle in Case B12B. Trimeric calculated this electrical equivalent value by using the steam flow and IP/LP crossover conditions in Case B12B (Exhibit 4-72 in the NETL Baseline Report [1]) as the basis for a process simulation to let the steam down across an LP turbine to 1 psia to mirror the LP turbine in the Case B12B power plant. Based on the electricity generated in the turbine, the thermal energy of the steam that is used in the amine system reboiler in B12B can be represented as an electrical equivalent. Trimeric has verified this electrical equivalent value of the steam using other methods and as part of past TEAs for the Rev 4 Baseline report as well.
- The key inputs and results of the analysis are summarized in Table 12 alongside relevant information for Case B12B.

Table 12: Power Plant Generating Capacity Summary

		MTR Membrane CO_2 Capture	**NETL Rev 4 Baseline, Case B12B**
Gross Generating Capacity + Electrical Value of Process Steam	**MWe**	**832**	**877**
Total Steam Derate (Indirect elec. derate)	**MWe**	**0**	**107**
Reboiler/Regeneration Duty	*MWth*	*0*	*392*
Direct Electrical Derate	**MWe**	**142**	**77**
CO_2 Compression and Processing	*MWe*	*See Note 1*	*44*
CO_2 Capture including Cooling (Other Compression, Pumps, etc.)	*MWe*	*See Note 1*	*33*
Total Derate for CO_2 Capture	**MWe**	**142**	**184**
Normalized Derate for CO_2 Capture	*GJe/tonne CO_2 captured*	*1.18*	*1.14*
Power Plant Auxiliary Requirements for Capture	**MWe**	**41**	**43**
Total Parasitic Demands for Entire Plant	**MWe**	**182**	**227**
Net Electricity Produced	**MWe**	**650**	**650**

Note 1: MTR CO_2 Capture direct electrical derating cannot be separated into "CO_2 compression" vs. "CO_2 Capture" due to the close integration of compression power and the capture process.

Each row in the table lists the major components of energy demand or “derating” for the power plant due to the presence of the CO_2 capture plant. The portion of the power plant derating that directly reflects the energy requirements of the capture and compression process is labeled “Total Derate for CO_2 Capture”. The table depicts a build-up of the CO_2 capture derating from the major components – steam derating for solvent regeneration (Case B12B only) and electrical derating for compression and other rotating equipment. The portion of the power plant derating that is due to capture plant demands on the power plant systems (e.g., the additional load on cooling tower fans) is denoted "Power Plant Auxiliary Requirements for Capture". The combination of these two derating categories is labeled "Total Parasitic Demands".

Tables 13 provides a detailed summary of the energy requirements for the specific areas of the CO_2 capture and compression process for the MTR membrane capture process.

Table 13: Detailed Energy Performance Summary – MTR CO_2 Capture Process

CO_2 Capture and Compression Processes				
Description	**Power Requirement (MWe)**	**CO_2 Product Rate (tonne/hr)**	**Normalized Energy Requirement (GJe/tonne CO_2)**	**Normalized Energy Requirement (% of Total)**
Flue Gas Compression (C-111)	11	431	0.09	7%
Membrane A Compression (C-113 through C-119)	52	431	0.43	36%
Membrane B Compression (C-131 through C-145)	52	431	0.43	37%
Misc. Pumps and Fans (P-103/104, WSAC Fan)	4	431	0.03	3%
Cooling Tower Pumps/Fans (Balance of Plant)	3	431	0.02	2%
Total	**120**	**431**	**1.01**	**85%**
CO_2 Purification and Pumping				
Refrigeration & Dehydration (Packaged Units)	19	431	0.16	13%
CO_2 Product Pumps (P-173/174)	2	431	0.02	2%
Total	**21**	**431**	**0.18**	**15%**
TOTAL OVERALL CAPTURE & COMPRESSION	**142**	**431**	**1.18**	

The following general conclusions can be derived from a review of the tables:

- The total derate for CO_2 capture in Table 12 for the MTR CO_2 capture process is ~23% lower than NETL Case B12B (142 MWe vs. 184 MWe). Note that the MTR process is capturing 70% of the incoming CO_2. If the CO_2 capture derate values are normalized to the CO_2 captured, the derate requirement for MTR is ~4% higher than Case B12B (~1.18 GJe/tonne CO_2 vs. ~1.14 GJe/tonne CO_2). Therefore, while the power plant for the MTR CO_2 capture case is smaller than B12B (reflected in the gross generating capacity), this is driven by the difference in CO_2 capture rate (70% vs. 90%), not by energy performance differences.

- As expected, the overall CO_2 capture derating/energy demand (Table 13) is dominated by the permeate compression systems associated with the two membrane modules (~80% of the total CO_2 capture energy demand). As discussed previously, the Membrane B permeate compression can also be viewed as providing part of the CO_2 product compression requirements as the pressure is elevated (~26.8 bara, 389 psia) when reaching the CO_2 purification system.
- The refrigeration power requirements are the next major contributor to CO_2 capture power demand (13%) – no other individual component makes up 10% of the total power demand for the MTR CO_2 capture process.

The energy performance can also be summarized in the following plant performance summary table (Table 14), mirroring Exhibit 4-65 for Case B12B in the NETL Rev 4 Baseline report [1].

Table 14: Plant Performance Summary

	MTR Membrane CO_2 Capture	NETL Rev 4 Baseline, Case B12B
Total Gross Power, MWe	**832**	**770 (See Note 1)**
CO_2 Capture/Removal Auxiliaries, kWe	117,722	27,300
CO_2 Compression, kWe	21,197	44,380
Balance of Plant, kWe	43,206	48,320
Total Auxiliaries, MWe	**182**	**120**
Net Power, MWe	**650**	**650**
HHV Net Plant Efficiency, %	33.2%	31.5%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	10,841 (10,266)	11,430 (10,834)
LHV Net Plant Efficiency, %	34.4%	32.7%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	10,456 (9,902)	11,024 (10,449)
HHV Boiler Efficiency, %	Not Estimated	88.1%
LHV Boiler Efficiency, %	Not Estimated	91.3%
Steam Turbine Cycle Efficiency, %	Not Estimated	57.5%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	Not Estimated	6,256 (5,930)
Condenser Duty, GJ/hr (MMBtu/hr)	2,299 (2,179)	2,127 (2,016)
Acid Gas Removal (AGR) Cooling Duty, GJ/hr (MMBtu/hr)	710 (673)	2,344 (2,222)
As-Received Coal Feed, kg/hr (lb/hr)	259,680 (572,490)	273,628 (603,246)
Limestone Sorbent Feed, kg/hr (lb/hr)	25,120 (55,379)	26,469 (58,354)
High Heating Value (HHV) Thermal Input, kWt	1,957,344	2,062,478
Low Heating Value (LHV) Thermal Input, kWt	1,887,883	1,989,286
Raw Water Withdrawal, (m^3/min)/MWnet (gpm/MWnet)	0.046 (12.3)	0.058 (15.3)
Raw Water Consumption, (m^3/min)/MWnet (gpm/MWnet)	0.033 (8.7)	0.041 (10.8)
Excess Air, %	Not Estimated	20.3%

Note 1: The gross power generating capacity for Case B12B does not include the electrical value of the steam that is produced by the boiler for the solvent-based CO_2 capture system. The gross generating capacity plus the electrical value of the process steam is 877 MWe. See Table 12.

4.0 Equipment Sizing and Capital Cost Evaluation

The final material balance tables, after re-scaling to 650 MWe net, are available in Appendix C for the MTR CO_2 capture process. The material balance tables serve as the basis for equipment sizing and economic estimates. The economic evaluation utilizes cost estimates for the purchased equipment cost of individual equipment in the membrane processes combined with appropriate scaling factors to develop a total plant cost estimate for the capture plant that can be compared to the NETL Rev 4 Baseline Case B12B. [1] The Case B12B baseline does not include itemized equipment costs for the capture system, so the aggregate plant-level economics represent the appropriate level of comparison.

4.1 Capital Cost Estimation Methodology

As noted previously, MTR and Trimeric worked together on a recently completed FEED study[9] for MTR's CO_2 capture process at the Basin Electric Power Cooperative Dry Fork Station (DFS) coal-fired power plant. The FEED study information available to Trimeric for this TEA included detailed sizing basis information, utilities requirements, and vendor quotes/cost estimates for all equipment. Therefore, Trimeric used the DFS FEED equipment information as the reference for nearly all cost estimates developed as part of this TEA. The primary exception to this approach was the membrane modules themselves – MTR provided size and cost information specific to this TEA for the membrane module costs, which are discussed in the subsequent text reviewing the cost estimation methodology.

The general approach used for preliminary equipment sizing and associated cost estimation can be summarized as follows:

- Specify equipment type and estimate sizes of equipment in the membrane-based CO_2 capture process. Trimeric used the H&MB data developed for this TEA with scaling from the DFS equipment sizing basis, standard engineering sizing methods, and bottom-up sizing (as-needed) to generate characteristic equipment sizing for all equipment.
    - For example, compression power requirements were estimated directly from the H&MB data for this study (via process simulation). The type of compression equipment is expected to be identical to the DFS FEED.
- Identify a reference or baseline equipment cost with an associated equipment sizing metric and cost scaling exponents to allow estimation of the cost of the equipment in the membrane process as described in Equation 1:

$$\frac{C^{MTR\,TEA}}{C^{REF}} = \left(\frac{A^{MTR\,TEA}}{A^{REF}}\right)^{x} \left(\frac{CEPCI^{2018}}{CEPCI^{REF}}\right) \qquad (1)$$

where:

[9] https://netl.doe.gov/sites/default/files/netl-file/21CMOG_CCUS_Freeman.pdf

C = Cost of equipment (REF = reference equipment);
A = Characteristic size of equipment used for cost-scaling;
x = Cost-scaling exponent (0.6 is used as a general value when no other data are available);
CEPCI = Chemical Engineering Plant Cost Index (Base year for this report is 2018);

- Aspen Capital Cost Estimator (ACCE) was used to generate a new cost estimate for key process equipment or those without a suitable reference cost for cost scaling.
  - **ACCE was only required for storage tanks in this TEA – all other equipment had suitable references from the DFS project (see subsequent discussion on sizing and costing of specific equipment below).**
- Summarize the contributions of each piece of equipment to the total purchased equipment costs.
- Scale the purchased equipment costs (PEC) to bare erected costs (BEC) for capture and compression using values based on Trimeric's experience with similar systems (referred to as equipment install factors) and input from MTR on the membrane modules and skids. The install factors used in this report can be summarized as follows:
  - Compressors, Fans, and Packaged Units (e.g., CPU): 1.9
  - All Others (Pumps, Exchangers, Vessels, Columns): 3
  - MTR provided membrane skid purchased equipment costs and membrane replacement, disposal, and maintenance costs. In addition, MTR indicated that the installation cost of a membrane skid would be 85% of the purchased equipment cost. In other words, the PEC to BEC factor would be 1.85 for membranes.
- Scale the BEC to a total plant cost (TPC) and ultimately to a total overnight cost (TOC) for the entire plant.
  - To scale from BEC to TPC, Trimeric used a factor of 1.39, which is consistent with methodologies in literature [3] and is very close to the implied factor (~1.41) for the CO_2 compression system in Case B12B [1]. As the MTR CO_2 capture process is largely modular (membranes) and consists primarily of rotating equipment, consistency with the CO_2 compression system factor for Case B12B is logical.[10]
    - In practice, this factor represents engineering, procurement, and construction (EPC) costs and fees and process and project contingencies.
  - To build from TPC to TOC, Trimeric utilized a build-out approach that mirrors Case B12B. That is, each of the cost categories from TPC to TOC was independently estimated by Trimeric, using the TPC and O&M costs estimated for

[10] One limitation to this "logic" is that the TPC should account for process contingency (reflects the maturity of the technology). The MTR CO_2 process, while modular like the CO_2 compression process in Case B12B, represents a less mature process (i.e., higher process contingency). The factored approach to scale from BEC to TPC in this study does not explicitly consider process contingency, but the technical maturity of the MTR process is one reason to believe the factor to scale from BEC to TPC should be higher than the B12B CO_2 compression, not similar.

the membrane processes and scaling approaches matching Case B12B as a basis, where appropriate (e.g., spare parts were estimated as 0.5% of TPC, just as in Case B12B).

The sizing approach for all equipment will not be discussed in detail in this report. Sizing and costing approaches for select key equipment or categories of equipment are summarized below:

- Membranes: MTR provided membrane skid costs and related information based on the initial heat and material balance data for this TEA. Trimeric re-scaled the information from MTR accordingly to the 650 MWe (net) basis.

Table 15: MTR Membrane Skid Information

	MEMBRANE A	MEMBRANE B	MEMBRANE C	MEMBRANE D
CAPEX				
Skid Cost Scaled to 650 MW net basis (2018 $)	$34,652,229	$8,623,148	$486,000	$486,000
Installed skid cost (2018 $)	$64,106,624	$15,952,823	$899,100	$899,100
Annual OPEX				
Replacement cost ($/yr)[Note 1]	$6,175,104	$1,536,664	$44,700	$30,540
Disposal Cost ($/yr)	$152,000	$40,000	$45	$31
Input from MTR				
Ratio Installed to Skid Cost	1.85	1.85	1.85	1.85
Membrane Lifetime (years)	5	5	5	5

Note 1: Membrane replacement cost includes annual maintenance costs and labor to replace the module.

- Heat Exchangers:
    - Duties for all cooling-water exchangers were estimated via process simulation (i.e., heat and material balance data for this TEA).
    - Cooling water supply temperature of 15.6 °C (60 °F) and return temperature of 26.7 °C (80 °F) were applied to estimate cooling water flows.
    - Only two exchangers were outside of the packaged systems (either compression or CPU packages) and necessitated an independent estimate of exchanger cost:
        - E-120 A-D DCC Wet-Surface Air Cooler: Trimeric estimated the duty for the WSAC (via process simulation) and recirculation rate for the DCC water (matched the liquid loading of water for the DCC packing from the DFS design) to estimate the cost for the WSAC from the DFS reference.
        - E-102 A-D Membrane A Stage 3 aftercooler: Trimeric estimated the duty for the exchanger via process simulation and calculated a log-mean temperature difference (LMTD) for the TEA to estimate a required area for the exchanger based on the DFS reference (this approach implies that the

heat transfer coefficient will be the same for the DFS exchanger and the TEA).

- CO_2 Compression Equipment and Pumps (Flue Gas, Permeate, CO_2 product): The compression equipment and CO_2 product pumps were simulated using the Symmetry software package. Specific criteria used in simulating and sizing the rotating equipment are summarized below:
    - The rotating equipment efficiency was specified to match the power from the DFS vendor design for each piece of rotating equipment for the flow rates and pressure profile for the DFS plant. The efficiency was then fixed for each piece of rotating equipment and the simulation was revised for the flue gas and pressure profile for the TEA. The reason for using this approach is that the vendor-specified equipment design from DFS includes efficiency and performance specific to the actual equipment specified for the process. Since the TEA will mirror very similar pressure differences across rotating equipment as DFS, mirroring the efficiency implies that the equipment outlet temperature from DFS has also been replicated to estimate cooling demand.
    - Costs for the compression equipment and CO_2 pumps came directly from DFS. The DFS costs were scaled to the current TEA basis vis the estimated power requirement and number of trains required for this TEA study basis. Since the DFS compression equipment is already at a representative size for this TEA application (i.e., FEED study was for a full-scale power plant application), the scaling exponent for Equation 1 would be 1 (unity).
- DCC and SO_2 Polisher: The contactors were sized based on the flue gas flow and superficial velocity from the DFS reference column with a DCC and SO_2 polisher in a single tower for each train.
- CO_2 Purification Unit (CPU): The DFS FEED included a packaged unit cost for the CO_2 purification unit. For the TEA, the cost of the CPU was scaled based on the CO_2 throughput for the unit since the processing conditions are expected to be similar to the DFS case.
- Storage Tanks: Storage tanks are required for the makeup caustic to the SO_2 polisher, wastewater, and water recycled internally in the process. The makeup caustic tank (V-300) has approximately 10-day inventory of 50 wt% caustic. The wastewater water tank (V-200) is ~50,000 gallons and the recycled water tank (V-100) is ~ 100,000 gallons.
    - ACCE was used to estimate the capital cost of storage tanks.

The capital cost estimation approach outlined in this section (i.e., factored cost estimation) is consistent with an AACE[11] Class 4 Estimate, which has an expected accuracy range of -15% to -30% low and +20% to +50% high.

[11] AACE Inc. (2005). "Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries. TCM Framework: 7.3 – Cost Estimating and Budgeting". AACE International Recommended Practice No. 18R-97.

In addition, unless specifically discussed in this section, capital cost estimation, scaling, and build-out (particularly for balance of plant items) conformed to the DOE Baseline Report and/or QGESS Standards [4].

4.2 Capital Cost Summary

The purchased equipment costs for the MTR CO_2 capture process are summarized in Table 16. The table includes a breakout of costs by process area and equipment.

Table 16: MTR Membrane CO_2 Capture Process Capital Cost Summary

Equipment	Purchased Equipment Cost MM$	% of Area Cost	% of Total Plant Purchased Equipment Cost
Inlet Gas Conditioning	**$35.3**		**15%**
T-101A/B DCC/SO_2 Polisher	*$14.8*	*42%*	*6%*
E-102 A-D WSAC	*$12.0*	*34%*	*5%*
C-111 A/B Flue Gas Booster Fan	*$7.3*	*21%*	*3%*
All Other (Includes storage tanks, pumps)	*$1.1*	*3%*	*0%*
CO_2 Capture	**$119.1**		**51%**
MEM-112 Membrane A	*$34.7*	*29%*	*15%*
C-113/114 A-N Membrane A Fan 1 & 2	*$13.1*	*11%*	*6%*
C-115/117/119 A-F MEM A Compressors (incl. all coolers/KOs)	*$57.1*	*48%*	*24%*
MEM-121 Membrane B	*$8.6*	*7%*	*4%*
C-131/132 A-C Membrane B Fan 1 & 2	*$5.6*	*5%*	*2%*
CO_2 Compression and Processing	**$80.4**		**34%**
C-133/135/140/142/144/146 A-B MEM B Compressors (incl. all coolers/KOs)	*$17.1*	*21%*	*7%*
Packaged CPU System	*$60.68*	*76%*	*26%*
MEM 165/166 Membrane C & D	*$1.0*	*1%*	*0%*
P-173/174 A-B CO_2 Pumps	*$1.6*	*2%*	*1%*
Total PEC for MTR CO_2 Capture Process	**$234.7**		

Several high-level results can be summarized from the preceding table:

- The membrane units are ~19% of the total PEC.
- Membrane A permeate compression (24% of total PEC) and the CPU (26% of total PEC) are the two largest single line-item costs and represent half of the PEC for the entire process.
- Compression/rotating equipment in aggregate (Flue gas compression, Membrane A permeate fans and compression, Membrane B permeate fans and compression, CO_2 product pumps) represents 43% of the PEC in the entire system.
- SO_2 polishing/DCC (including the DCC cooler) is the only other significant cost center, making up ~11% of the total PEC.

While viewing the cost centers separately is useful to understand potential cost sensitivity and optimization, it is important to remember that the different components of the system are not independent. For example, the flue gas and permeate compression equipment is essential to provide the driving forces necessary for the membrane-based CO_2 capture. Similarly, the CPU is required to remove contaminants that are separated alongside the CO_2 in the membranes. Attempts to reduce compression costs or the CPU size would likely directly impact the membrane module costs. Therefore, a true optimization which considers the marginal costs of each unit operation in response to the change in the performance/specification of other unit operations would be needed to guide modifications to system design.

Case B12B does not report purchased equipment costs for individual pieces of equipment. Thus, Table 17 compares the TPC of Case B12B to those of the membrane processes.

Table 17: Comparison of TPC – Case B12B vs. MTR Membrane

	NETL Rev 4 Case B12B (90% CO_2 Capture)	MTR Membrane (70% CO_2 Capture)
CO_2 Capture (MM US$)	$739	$456
CO_2 Compr. & Purification (MM US$)	$88	$212
TOTAL (MM US$)	**$826**	**$667**
DIFFERENCE		**-19%**
CO_2 Captured (tonne/day)	**13,947**	**10,340**
Normalized TPC ($/tonne/day)	**$59,246**	**$64,555**
DIFFERENCE		**+9%**

In Table 17, CO_2 capture costs for the MTR case include inlet gas conditioning, CO_2 capture via membrane separation through the Membrane B permeate fans, and storage tanks. The table indicates that the total TPC for the MTR capture process is approximately 20% lower than Case B12B. Given the difference in the amount of CO_2 captured for each case, the comparison of overall TPC is not meaningful as a standalone comparison. The normalized TPC provides a more representative comparison – the MTR case normalized TPC is ~9% higher than B12B. Given the level of uncertainty in cost estimates at this stage of process development, the difference in capital costs between the systems could be interpreted as negligible.

Finally, the itemized costs for the full power plant listed by the code of accounts are presented for MTR in Table 18 (analogous to Exhibit 4-74 and 4-75 for Case B12B in the NETL Rev 4 Baseline Report [1]).

Table 18: Total Plant Cost Summary, MTR Membrane CO_2 Capture Process (70% CO_2 Removal)

	Net Plant Output (MWe)	650		Labor			Contingencies		Total Plant Cost	
Acct No.	Item/Description	Equipment Cost	Materials Cost	Direct	Bare Erected Cost $	Engineering CM H.O. & Fee	Process	Project	1,000 $	$/kW
1	Coal & Sorbent Handling	$48,476	$2,048	$13,520	$64,044	$11,208	$0	$11,289	$86,541	$133
2	Coal & Sorbent Prep & Feed	$13,544	$761	$3,768	$18,073	$3,162	$0	$3,184	$24,419	$38
3	Feedwater & Misc. BOP Systems	$50,101	$12,566	$39,593	$102,260	$17,896	$0	$22,635	$142,791	$220
4	PC Boiler	$297,934	$385	$170,099	$468,418	$81,974	$0	$82,558	$632,950	$974
5	Flue Gas Cleanup	$316,206	See Note 1	See Note 1	$583,261	See Note 1	See Note 1	See Note 1	$806,220	$1,240
5.1	*CO_2 Capture System*	*$154,359 (PEC)*			*$327,978*				*$455,525*	*$701*
5.4 & 5.5	*CO_2 Compression & Purification (incl. CO_2 aftercooler)*	*$80,531 (PEC)*			*$152,618*				*$211,970*	*$326*
7	HRSG, Ducting & Stack	$8,740	$945	$5,838	$15,523	$2,716	$0	$2,763	$21,001	$32
8	Steam Turbine Generator	$131,475	$275	$33,306	$165,056	$28,885	$0	$29,133	$223,074	$343
9	Cooling Water System	$34,906	$7,142	$16,228	$58,276	$10,199	$0	$10,365	$78,841	$121
10	Ash/Spent Sorbent Handling System	$5,009	$791	$8,294	$14,095	$2,467	$0	$2,588	$19,150	$29
11	Accessory Electric Plant	$34,024	$7,032	$21,289	$62,345	$10,910	$0	$11,037	$84,291	$130
12	Instrumentation & Control	$12,566	$469	$5,630	$18,665	$3,265	$783	$3,407	$26,120	$40
13	Improvements to Site	$2,571	$2,706	$15,336	$20,614	$3,607	$0	$4,844	$29,064	$45
14	Buildings & Structures	$0	$31,230	$29,770	$61,000	$10,675	$0	$10,751	$82,425	$127
	TOTAL COST	$955,575	See Note 1	See Note 1	$1,651,818	See Note 1	See Note 1	See Note 1	**$2,257,157**	**$3,473**
	Owner's Costs									
	Preproduction Costs									
	6 Months All Labor								$13,049	$20
	1 Month Maintenance Materials								$2,017	$3
	1 Month Non-Fuel Consumables								$2,846	$4
	1 Month Waste Disposal								$991	$2
	25% of 1 Months Fuel Cost at 100% CF								$2,714	$4
	2% of TPC								$45,142	$69
	Total								**$66,761**	**$103**
	Inventory Capital									
	60-day Supply of Fuel, Consumables at 100% CF								$26,642	$41
	0.5% of TPC (spare parts)								$11,286	$17
	Total								**$37,928**	$58
	Initial Cost for Catalyst and Chemicals								$2,479	$4
	Land								$900	$1
	Other Owner's Costs								$338,573	$521
	Financing Costs								$60,943	$94
	Total Overnight Costs (TOC)								**$2,764,741**	**$4,253**
	TASC Multiplier								1.154	
	Total As-Spent Cost (TASC)								**$3,190,511**	**$4,908**

Note 1: For Account 5, individual cost categories (materials, labor, Engineering CM H.O. & Fee, process/project contingency) were not itemized for the CO_2 capture and compression subaccounts (5.1, 5.4, and 5.5). See Section 4.1 in this report for the cost estimation method for these sub-accounts. Therefore, these cost categories are not reported for Account 5.

5.0 Operating Cost Summary

The itemized operating and maintenance (O&M) costs analogous to Exhibit 4-76 in Case B12B are presented in Table 19 for MTR. The following approaches were used to calculate the O&M costs for the membrane-based CO_2 capture process:

- Fixed O&M costs and maintenance material costs are primarily calculated as a function of total plant costs (i.e., same percentage of TPC as Case B12B).
    - The only notable exception was the maintenance costs for the membrane skids themselves – this cost was included in the membrane module replacement cost provided by MTR and Trimeric ensured this was not double-counted when estimating maintenance costs for the entire process.
- Operating labor costs for the membrane cases are identical to Case B12B.
    - Note that this may represent an opportunity for differentiation for the membrane-based process vs. the solvent-based capture process. The NETL Baseline Report appears to assign additional operators to the power plant facility when the capture process is present (B12B used 11.3 operators/shift) vs. when it is not (B12A used 9 operators) [1]. It may be possible that the modular nature of the membrane-based operations and other process characteristics (e.g., no solvent handling) could eliminate the need for these additional operators in practice.
- Variable O&M costs for consumables are scaled as a function of the electrical capacity of the boiler or the raw water consumption. The primary exceptions are the following:
    - For membrane replacement costs, MTR provided costs directly (see Table 15).
    - Caustic costs were estimated based on a consumption estimate developed by Trimeric (via SO_2 removal requirements) and a delivered cost ($0.15/lb) for bulk 50 wt% caustic from past project work by Trimeric. The caustic consumption was estimated by Trimeric on the following basis:
        - The SO_2 is treated to 5 ppmv leaving the SO2 polisher (defines the total SO_2 that removed).
        - 2 moles of pure NaOH are required for every mole of SO_2 in the flue gas that is removed (represents stoichiometry of SO_2 absorption in caustic solution).
        - A 10% margin is added to account for CO_2 absorption and other losses.
        - Caustic will be supplied as 50 wt% NaOH (diluted in water).

In addition, unless specifically discussed in this section, operating cost estimates (particularly for balance of plant items) conformed to the DOE Baseline Report and/or QGESS Standards [4].

Table 19: Operating and Maintenance Costs for MTR Membrane Process

					Annual Cost ($)	Annual Unit Cost ($/kW-net)
Annual Operating Labor Cost					$7,161,008	$11.02
Maintenance Labor Cost					$13,718,170	$21.10
Administrative & Support Labor					$5,219,795	$8.03
Property Taxes and Insurance (2% of TPC)					$45,143,103	$69.45
TOTAL FIXED OPERATING COSTS					**$71,242,076**	**$109.60**
Variable Operating Costs						
Maintenance Material Cost					$20,577,255	
	Consumption					
Consumables	Initial Fill	Daily Usage	Unit Cost	Initial Fill Cost	Annual Cost	Annual Unit Cost
Water (per 1000 gallons)	0	5,243	1.90	$0	**$3,090,633**	**$0.63857**
Chemicals						
MU & WT Chem. (ton)	0	15.6	550.00	$0	$2,665,106	$0.55065
Activated Carbon (ton)	0	1.48	1600.00	$0	$733,299	$0.15151
Enhanced Hydrated Lime (ton)	0	37.8	240.00	$0	$2,816,149	$0.58186
Limestone (ton)	0	665	22.00	$0	$4,535,933	$0.93720
Ammonia (19% NH_3) (ton)	0	65.5	300.00	$0	$6,093,291	$1.25897
SCR Catalyst (ft^3)	16526	15.1	150.00	$2,478,968	$702,375	$0.14512
CO_2 Capture System - Membrane	N/A	N/A	N/A	N/A	$6,618,957	$1.36758
CO_2 Capture System - 50 wt% Caustic (lb)	0	33,296	0.15	$0	$1,549,510	$0.32015
CO_2 Capture System - WSAC chemicals	0	See Note 1	See Note 1	$0	$228,778	$0.04727
Triethylene Glycol (gal)	0	See Note 2	6.80	$0	See Note 2	See Note 2
Subtotal Consumables				$2,478,968	**$29,034,030**	**$5.99889**

Note 1: Chemical cost for WSAC scaled based on cooling duty from a reference design. Specific chemical usage rates are not available.
Note 2: No TEG dehydration unit – mole sieve dehydration is used as part of the CO_2 purification process.

Table 19 (continued): Operating and Maintenance Costs for MTR Membrane Process

	Initial Fill	Daily Usage	Unit Cost	Initial Fill Cost	Annual Cost	Annual Unit Cost
Waste Disposal						
Fly Ash (ton)	0	623	38.00	$0	$7,349,840	$1.51859
Bottom Ash (ton)	0	138	38.00	$0	$1,632,707	$0.33734
Membrane	N/A	N/A	N/A	N/A	$163,265	$0.03373
SCR Catalyst (ft^3)	0	15	2.50	$0	$11,706	$0.00242
Prescrubber Blowdown Waste (ton)	0	80	38.00	$0	$947,005	$0.19567
Subtotal - Waste Disposal				$0	**$10,104,523**	**$2.08775**
By-products & Emissions						
Gypsum (ton)	0	1010	0.00	$0	$0	$0.00000
Subtotal By-Products				$0	$0	$0.00000
TOTAL VARIABLE OPERATING COSTS					**$59,715,808**	**$12.33823**
Fuel (ton)	0	7256	51.96	$0	**$110,743,448**	**$22.88135**

The O&M comparison to Case B12B is summarized in Table 20.

Table 20: Comparison of O&M Costs: Case B12B vs. MTR Membrane

(MM US$)	NETL Rev 4 Case B12B (90% CO_2 Capture)	MTR Membrane (70% CO_2 Capture)
Fixed O&M	$78.1	$71.6
Variable O&M	$67.8	$59.7
Fuel	$116.7	$110.7

The O&M costs for MTR primarily scale with the lower CO_2 capture rate (e.g., lower TPC basis for fixed operating costs) and the top-line numbers are not directly comparable to B12B (capture rate difference will be accounted for in the cost of capture metric at the end of this report).

6.0 Process Economics – Figures of Merit and Sensitivity Analyses

6.1 Calculation of Levelized Cost of Electricity and Cost of Capture

The LCOE and cost of CO_2 capture were estimated using the capital and operating and maintenance costs presented in Table 18 and Table 19 for the MTR capture process. Table 21 presents the results along with the values reported for Cases B12A and B12B in the NETL Rev 4 Baseline Report [1]. The costs for Transportation, Storage, and Monitoring (TS&M) of CO_2 will be the same for all cases (estimated in the FOA at $10/tonne CO_2 captured) and were excluded from this analysis.

Table 21: Levelized Cost of Electricity and Cost of Capture Summary

		NETL Rev 4 Case B12A	NETL Rev 4 Case B12B	MTR Membrane (70% Capture)
LCOE	$/MWh	64.4	105.2	96.5
Incremental Cost of CO_2 Capture	$/MWh	-	40.8	32.1
Increase in LCOE vs. Case B12A	%	-	63.4%	49.9%
Cost of CO_2 Capture	**$/tonne**	**-**	**45.63**	**48.50**

To provide further resolution into the cost of capture metric, particularly in light of the different CO_2 capture rate, Table 22 breaks down the cost of capture into the major component costs to highlight the drivers of cost savings for the membrane cases vs. B12B and each other.

Table 22: Cost of Capture – Contributions by Cost Category

CO_2 Capture Cost by Component		**Case B12B**	**MTR Membrane**	**Percent of Overall Increase vs. B12B**
Capital	$/tonne	$25.34	$27.62	79%
Fixed O&M	$/tonne	$7.41	$7.88	16%
Variable O&M (@ 85% Capacity Factor)	$/tonne	$7.05	$7.00	-2%
Fuel	$/tonne	$5.83	$6.01	6%
TOTAL	**$/tonne**	**$45.63**	**$48.50**	
CO_2 Captured (@ 85% Capacity Factor		4,327,715	3,207,949	

The differences in the LCOE and cost of capture are described further in the subsection below.

6.1.1 Discussion of CO_2 Capture Economics

As Table 21 indicates, the LCOE is lower (~8%) for MTR's process when compared to Case B12B. The cost of capture for MTR is ~6% higher than Case B12B. Figure 4 shows a graphical breakdown of the LCOE (no TS&M) for Case B12A, B12B, and MTR.

The discrepancy in the metrics is explained by the difference in the CO_2 capture rate. The LCOE represents an absolute cost and scales with the amount of CO_2 captured. Therefore, MTR's process produces a lower LCOE due primarily to the lower rate of CO_2 captured. The cost of CO_2 capture, however, inherently normalizes the incremental cost of capture to the amount of CO_2 captured. Therefore, the cost of capture provides a comparison to B12B on a common basis and mirrors the earlier findings in this report that normalized energy performance and normalized total plant costs for the MTR process were both slightly higher than Case B12B.

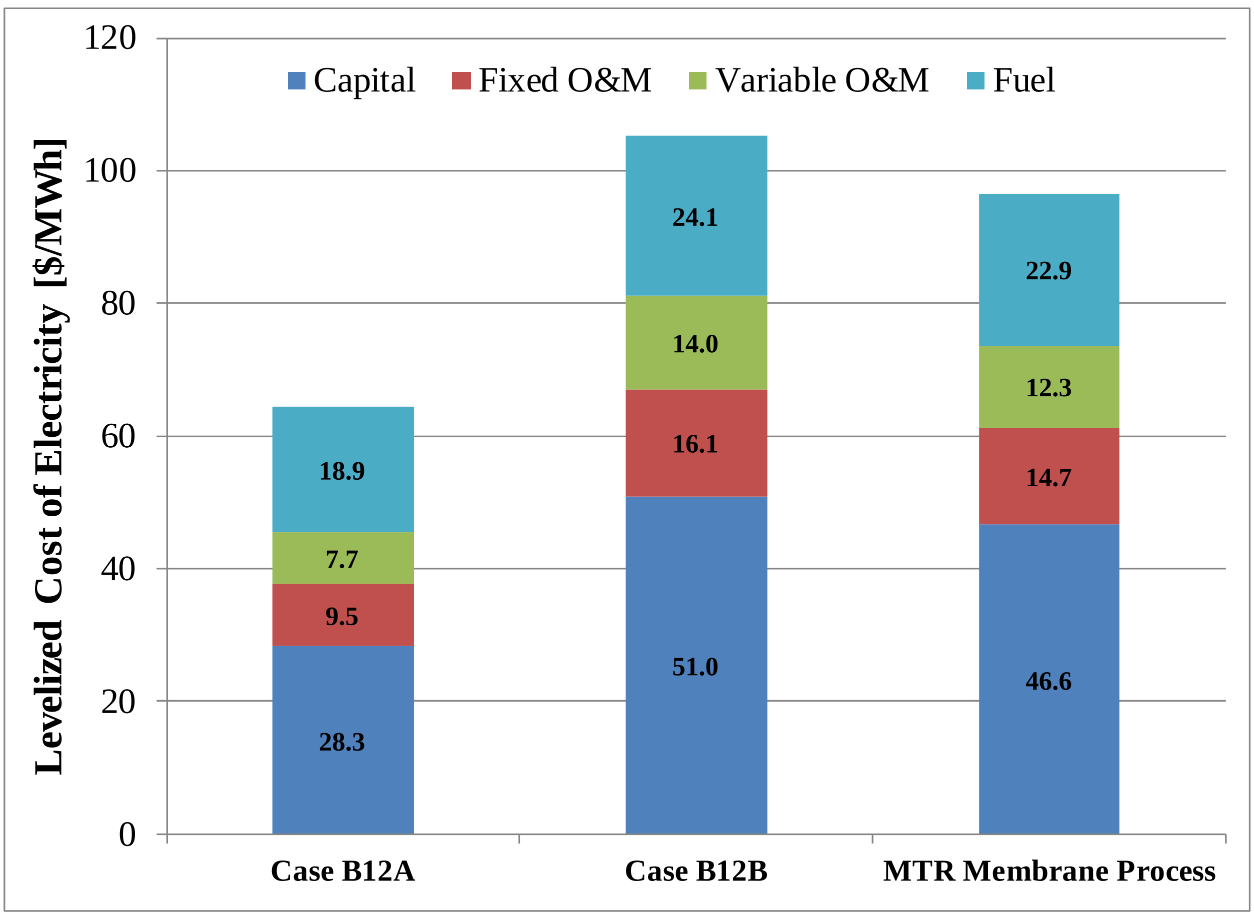

Figure 4: Comparison of Levelized Cost of Electricity Contributions for Case B12A, Case B12B and MTR Membrane Process

6.2 High-Level Cost Sensitivity

MTR asked Trimeric to perform a high-level sensitivity analysis on the purchased equipment cost of the overall CO_2 capture facility. The total PEC was adjusted by +/-20% to ascertain the impact on the key figures of merit for the process. This sensitivity will provide guidance to MTR on whether equipment cost variability or optimization will have meaningful impacts on the overall process economics for their system. As noted earlier, the overall sensitivity of PEC avoids the pitfalls of adjusting individual equipment costs which may be tied to the performance and costs of other unit operations in practice.

6.2.1 Summary of Results

The results of the PEC sensitivity analysis are presented in Table 23. The most notable aspect of the sensitivity is in the cost of capture metric. Changing the PEC by +/- 20% brackets lead to the cost of capture for the MTR CO_2 capture process bracketing Case B12B. This range in equipment costs is well within the potential error in cost estimates for this early stage of estimation, even considering the use of vendor quotes from a similar, recent application (DFS FEED). Therefore, this supports the argument that the MTR CO_2 capture process is effectively identical in terms of economics to Case B12B at this level of study.

A secondary conclusion from the sensitivity analysis is that the change in PEC does have a meaningful impact on the cost of capture in particular (change by more than 10%). This provides support that efforts to reduce capital cost of equipment or market variability in the cost of equipment will impact the overall economic viability of the MTR CO_2 capture process.

Table 23: PEC Sensitivity Analyses Results Summary

SENSITIVTY CASES	Cost of Capture (no TS&M) $/tonne CO_2	Change vs. MTR Base Case	LCOE $/MWh	Change vs. MTR Base Case	CO_2 Capture and Compression Total Plant Cost, $MM	Change vs. MTR Base Case
NETL Case B12B	$45.63		105.2		$826	
MTR (Base Case)	$48.50		96.55		$667	
MTR - Low (-20%) PEC Sensitivity	$42.95	-11.4%	92.9	-3.8%	$534	-20%
MTR - High (+20%) PEC Sensitivity	$54.05	+11.4%	100.22	+3.8%	$801	+20%

7.0 Conclusions and Recommendations

This technoeconomic analysis compared the MTR CO_2 capture process to the DOE reference Case B12B on the common basis of 650 MWe (net) supercritical coal-fired power plant with post-combustion CO_2 capture. In addition to differences in the capture processes themselves (MTR = membrane-based CO_2 capture, Case B12B = solvent-based CO_2 capture), MTR focused their design on 70% CO_2 capture which roughly reflects an optimal fraction of CO_2 capture for their membrane-based system. Therefore, the overall size of the facility (power plant and capture unit) will be smaller for the MTR process than the Case B12B reference, but metrics and numbers normalized to the amount of CO_2 captured should provide insight into the inherent performance of MTR's membrane-based capture process compared to the CANSOLV solvent-based reference in B12B. Therefore, the following discussion will focus on the normalized energy performance and cost/economic results from the study when making comparison to B12B. Absolute values for energy performance and costs are available in the body of the report.

Cost of CO_2 Capture and Cost Centers:

- The cost of CO_2 capture for the MTR process was $48.50/tonne CO_2 captured (~6% higher than Case B12B at $45.63).
- The sensitivity analysis for the study considered the impact of purchased equipment cost on the cost of capture (+/-20% sensitivity for the PEC). The resulting range for the MTR cost of capture [$42.95, $54.05] brackets the cost of capture for Case B12B ($45.63). This is an important result as the +/-20% range on equipment costs is within the expected uncertainty for a conceptual stage cost evaluation. Therefore, the MTR cost of capture may be viewed as statistically indistinguishable from the Case B12B cost of capture when uncertainty in the metrics is considered.
- Trimeric's evaluation of the contributions to the cost of capture for MTR (Table 22) indicates that the capital cost is the most significant driver for the increase in the cost of capture for MTR vs. Case B12B (explains ~80% of the increase in cost of capture). This is amplified further because some of the fixed operating and maintenance costs are also estimated as a fraction of the total plant cost – fixed O&M represents another 16% of the increase in MTR's cost of capture vs. DOE Case B12B.
- Looking further into the capital cost stack for MTR, the rotating equipment/compression at the core of the MTR process design represents ~43% of the purchased equipment costs. The CO_2 purification unit (CPU) represents 26% of the PEC. Therefore, these are by far the most important cost centers for future development work and also represent the most important cost centers to minimize uncertainty in cost estimates for the MTR process.
    - The CPU in particular represents an important area for the MTR CO_2 capture process. As discussed below for energy performance, the refrigeration system associated with the CPU also represents a major energy consumer, which in turn increases the size of the parent power plant. The driver for the CPU design is the CO_2 product specifications required for the captured CO_2. For this TEA, QGESS guidelines were followed to ensure a consistent basis with other DOE studies.

However, in practice, it is Trimeric's experience that CO_2 product specifications are highly project specific and depend strongly on the transport and final disposition of the CO_2. Therefore, the CPU design and cost should be re-assessed in detail for any new application or project.

- The study also highlighted the challenge of managing other flue gas contaminants (e.g., NOx). While development effort could be targeted at managing these contaminants in other ways (e.g., upstream of the capture process), a better understanding of impacts on the CO_2 product disposition should be considered before pursuing such development activities.

Energy Performance:

- Trimeric included a detailed review of the energy penalty and power plant derating comparison of MTR and Case B12B (Table 12) in the report. The key figure for comparison from this table is a normalized derating attributed to the CO_2 capture process for each case. This metric accounts for electrical power requirements of the capture system (including incremental power requirements due to the larger power plant ancillary systems, e.g., cooling water system) and any steam extraction from the power plant (Case B12B only). MTR required 1.18 GJe/tonne CO_2 captured vs. 1.14 GJe/tonne CO_2 captured for Case B12B (MTR required ~4% more energy).
- As expected, the flue gas/CO_2 compression equipment in the MTR process accounted for ~80% of the total energy required for the capture system – the compression power is inherent to the driving force required for the membrane-based separation and represents a point of potential optimization (i.e., tradeoff of compression power/equipment costs with membrane module costs). Note also that CO_2 compression is required for Case B12B also to meet the target CO_2 product pressure of 2,215 psia. For the MTR case, the CO_2 compression is integral to the capture process, so it is difficult to separate compression power contributions for CO_2 capture and CO_2 product compression.
- The only other major energy user is the refrigeration and dehydration system (~13% of energy requirement) associated with the CPU – as discussed in the capital cost discussion above, the CPU cost and energy requirements are dictated by CO_2 product purity requirements and will be project-specific.

In summary, the MTR CO_2 capture process is comparable to the Case B12B reference case in terms of both economics and energy performance, though the lower CO_2 capture rate for the MTR process must be considered alongside these top level metrics. It should be noted, that higher capture rates are possible with the membrane process, as demonstrated by testing in this project at Technology Centre Mongstad, which included >90% capture.   Economic analysis of these higher decarbonization rates will be the subject of future work.

Other benefits of membrane-based processes were not explicitly considered in this TEA but may be important in practice. Membrane process benefits may include limiting chemical solvent handling and byproducts (i.e., amine solvent and waste), eliminating emissions and other environmental impacts of solvents (amine and amine byproduct emissions), and less complex/modular processes (i.e., potentially reduced operating labor requirements/footprint). Finally, CO_2 product specifications represent a potentially more significant burden on membrane-based processes such as the MTR process when compared to the solvent-based systems, but also may represent an obvious cost reduction opportunity if CO_2 product specifications are not as stringent (i.e., membrane-based processes may benefit more from less stringent CO_2 product requirements).

References

[1] DOE/NETL, "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity," United States Department of Energy, Washington D.C., 2019.

[2] NETL, "Quality Guidelines for Energy Systems Studies: CO2 Impurity Design Parameters," U.S. Department of Energy, 2019.

[3] M. S. Peters, K. D. Timmerhaus and R. E. West, Plant Design and Economics for Chemical Engineers, Boston: McGraw Hill, 2003.

[4] NETL, "Quality Guidelines for Energy Systems: Estimation Methodology for NETL Assesments of Power Plant Performance," U.S. Department of Energy, Washington D.C., 2021.

8.0 Appendices

- Appendix A: Base Power Plant Stream Tables Corresponding to Block Flow Diagrams (Figure 1 and Figure 2) For NETL Rev 4 Case B12B, MTR CO_2 Capture Process
- Appendix B: MTR CO_2 Capture Process Flow Diagrams
- Appendix C: MTR CO_2 Capture and Compression Heat and Material Balance Tables
- Appendix D: MTR CO_2 Capture Equipment List

APPENDIX A: BASE POWER PLANT STREAM TABLES CORRESPNDING TO BLOCK FLOW DIAGRAMS (FIGURE 1 AND FIGURE 2) FOR NETL REV 4 CASE B12B, MTR CO_2 CAPTURE PROCESS

Exhibit 4-64. Case B12B stream table, SC unit with capture

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000	0.0087	0.0088	0.0000	0.0087	0.0000
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.1457	0.1379	0.0000	0.1372	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	1.0000	0.0879	0.0837	0.0000	0.0911	0.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001	0.0000	0.0001	0.0000
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.7318	0.7340	0.0000	0.7281	0.0000
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0237	0.0336	0.0000	0.0329	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0020	0.0000	0.0020	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1141
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.8859
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	74,599	74,599	2,210	22,916	22,916	3,154	1,649	0	0	1	4,914	99,723	0	105,468	6
V-L Flowrate (kg/hr)	2,152,703	2,152,703	63,760	661,288	661,288	91,010	47,582	0	0	15	146,141	2,961,204	0	3,122,727	674
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	273,628	5,516	1,491	1,180	22,667	59	24,140	24,156
Temperature (°C)	15	19	19	15	25	25	15	15	1,316	15	385	143	15	143	143
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg)[A]	30.23	34.36	34.36	30.23	40.78	40.78	30.23	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (kJ/kg)[B]	-97.58	-93.45	-93.45	-97.58	-87.03	-87.03	-97.58	-2,119.02	1,267.06	-13,402.95	-2,261.17	-2,394.16	-6.79	-2,452.91	-1,065.72
Density (kg/m³)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	1,003.6	0.5	0.9	---	0.9	2,150.2
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	18.015	29.742	29.694	---	29.608	104.986
V-L Flowrate (lb_{mol}/hr)	164,463	164,463	4,871	50,521	50,521	6,953	3,635	0	0	2	10,833	219,851	0	232,518	14
V-L Flowrate (lb/hr)	4,745,898	4,745,898	140,566	1,457,890	1,457,890	200,642	104,901	0	0	33	322,185	6,528,337	0	6,884,434	1,487
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	603,246	12,161	3,288	2,602	49,972	130	53,220	53,256
Temperature (°F)	59	66	66	59	78	78	59	59	2,400	59	726	289	59	289	289
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.6	14.7	14.6	14.4	14.7	14.4	14.4
Steam Table Enthalpy (Btu/lb)[A]	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb)[B]	-42.0	-40.2	-40.2	-42.0	-37.4	-37.4	-42.0	-911.0	544.7	-5,762.2	-972.1	-1,029.3	-2.9	-1,054.6	-458.2
Density (lb/ft³)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	62.650	0.034	0.053	---	0.053	134.233

[A]Steam table reference conditions are 32.02°F & 0.089 psia

[B]Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit 4-64. Case B12B stream table, SC unit with capture (continued)

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
V-L Mole Fraction															
Ar	0.0087	0.0087	0.0000	0.0092	0.0081	0.0000	0.0000	0.0000	0.0000	0.0000	0.0106	0.0000	0.0000	0.0000	0.0000
CO_2	0.1372	0.1372	0.0000	0.0003	0.1246	0.0001	0.0000	0.0000	0.0000	0.0000	0.0163	0.0000	0.0000	0.9861	0.9977
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0911	0.0911	0.9967	0.0099	0.1497	0.9998	0.9943	0.9999	1.0000	1.0000	0.0358	1.0000	1.0000	0.0139	0.0023
HCl	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.7281	0.7281	0.0000	0.7732	0.6812	0.0000	0.0000	0.0000	0.0000	0.0000	0.8898	0.0000	0.0000	0.0000	0.0000
O_2	0.0329	0.0329	0.0000	0.2074	0.0364	0.0000	0.0000	0.0000	0.0000	0.0000	0.0475	0.0000	0.0000	0.0000	0.0000
SO_2	0.0020	0.0020	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0005	0.0000	0.0000	0.0001	0.0009	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0028	0.0000	0.0000	0.0000	0.0048	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	105,462	105,462	14,497	4,415	117,745	248	832	3,432	33,118	29,914	90,137	146	146	13,394	13,238
V-L Flowrate (kg/hr)	3,122,036	3,122,036	265,252	127,397	3,385,665	4,473	15,382	61,832	596,626	538,904	2,544,772	2,634	2,634	584,619	581,812
Solids Flowrate (kg/hr)	0	0	2,391	0	0	40,233	234	26,469	0	0	0	0	0	0	0
Temperature (°C)	143	154	27	15	57	15	57	15	269	100	30	342	214	30	29
Pressure (MPa, abs)	0.10	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.51	0.10	0.10	4.90	2.04	0.20	3.04
Steam Table Enthalpy (kJ/kg)[A]	287.72	299.40	---	30.23	294.95	---	---	---	3,000.14	417.50	88.41	3,049.81	913.81	37.70	-6.17
AspenPlus Enthalpy (kJ/kg)[B]	-2,463.94	-2,452.26	-15,763.52	-97.58	-2,930.88	-12,513.34	-15,496.74	-14,994.25	-12,980.15	-15,562.79	-528.00	-12,930.48	-15,066.49	-8,964.74	-8,975.08
Density (kg/m³)	0.8	0.9	1,002.5	1.2	1.1	881.1	979.6	1,003.7	2.1	958.7	1.1	19.2	848.5	3.5	63.6
V-L Molecular Weight	29.603	29.603	18.297	28.857	28.754	18.021	18.495	18.019	18.015	18.015	28.232	18.015	18.015	43.648	43.950
V-L Flowrate (lb_{mol}/hr)	232,504	232,504	31,960	9,733	259,583	547	1,834	7,565	73,012	65,948	198,717	322	322	29,528	29,185
V-L Flowrate (lb/hr)	6,882,912	6,882,912	584,781	280,861	7,464,113	9,861	33,912	136,315	1,315,336	1,188,079	5,610,263	5,807	5,807	1,288,863	1,282,675
Solids Flowrate (lb/hr)	0	0	5,272	0	0	88,698	517	58,354	0	0	0	0	0	0	0
Temperature (°F)	289	309	80	59	134	59	134	59	517	211	87	648	416	86	85
Pressure (psia)	14.2	15.3	14.7	14.7	14.8	14.7	14.7	14.7	73.5	14.5	14.8	710.8	296.6	28.9	441.1
Steam Table Enthalpy (Btu/lb)[A]	123.7	128.7	---	13.0	126.8	---	---	---	1,289.8	179.5	38.0	1,311.2	392.9	16.2	-2.7
AspenPlus Enthalpy (Btu/lb)[B]	-1,059.3	-1,054.3	-6,777.1	-42.0	-1,260.1	-5,379.8	-6,662.4	-6,446.4	-5,580.5	-6,690.8	-227.0	-5,559.1	-6,477.4	-3,854.1	-3,858.6
Density (lb/ft³)	0.052	0.055	62.581	0.076	0.067	55.008	61.155	62.658	0.128	59.847	0.071	1.197	52.968	0.218	3.973

[A]Steam table reference conditions are 32.02°F & 0.089 psia

[B]Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit 4-64. Case B12B stream table, SC unit with capture (continued)

	31	32	33	34	35	36	37	38	39	40	41
V-L Mole Fraction											
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0500	0.0000	0.0000	0.9995	0.9995	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.9500	1.0000	1.0000	0.0005	0.0005	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	25	17	17	13,213	13,213	133,851	111,754	111,754	96,268	42,848	66,623
V-L Flowrate (kg/hr)	487	309	309	581,324	581,324	2,411,369	2,013,284	2,013,284	1,734,295	771,916	1,200,232
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	29	203	461	29	30	593	342	593	270	38	39
Pressure (MPa, abs)	3.04	1.64	2.14	2.90	15.27	24.23	4.90	4.80	0.52	0.01	1.26
Steam Table Enthalpy (kJ/kg)[A]	137.79	863.65	3,379.61	-6.32	-231.09	3,477.96	3,049.81	3,652.36	3,000.14	2,343.61	162.36
AspenPlus Enthalpy (kJ/kg)[B]	-15,225.37	-15,116.65	-12,600.69	-8,969.87	-9,194.65	-12,502.33	-12,930.48	-12,327.93	-12,980.15	-13,636.69	-15,817.93
Density (kg/m³)	375.2	861.8	6.4	60.1	630.1	69.2	19.2	12.3	2.1	0.1	993.3
V-L Molecular Weight	19.315	18.015	18.015	43.997	43.997	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	56	38	38	29,129	29,129	295,092	246,376	246,376	212,235	94,463	146,879
V-L Flowrate (lb/hr)	1,074	681	681	1,281,601	1,281,601	5,316,158	4,438,532	4,438,532	3,823,465	1,701,783	2,646,058
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	85	397	862	85	86	1,100	648	1,100	517	101	101
Pressure (psia)	441.1	237.4	310.1	421.1	2,214.7	3,514.7	710.8	696.6	75.0	1.0	183.1
Steam Table Enthalpy (Btu/lb)[A]	59.2	371.3	1,453.0	-2.7	-99.4	1,495.3	1,311.2	1,570.2	1,289.8	1,007.6	69.8
AspenPlus Enthalpy (Btu/lb)[B]	-6,545.7	-6,499.0	-5,417.3	-3,856.4	-3,953.0	-5,375.0	-5,559.1	-5,300.1	-5,580.5	-5,862.7	-6,800.5
Density (lb/ft³)	23.421	53.801	0.402	3.755	39.338	4.319	1.197	0.768	0.131	0.003	62.009

[A]Steam table reference conditions are 32.02°F & 0.089 psia

[B]Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

MTR MEMBRANE CO2 CAPTURE PROCESS (BASE PLANT STREAM TABLES) - 70% CO2 Capture

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
V-L Mole Fraction																	
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000	0.0087	0.0088	0.0000	0.0087	0.0000	0.0087	0.0087
CO2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.1457	0.1379	0.0000	0.1372	0.0000	0.1372	0.1372
H2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	1.0000	0.0879	0.0837	0.0000	0.0911	0.0000	0.0911	0.0911
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001	0.0000	0.0001	0.0000	0.0001	0.0001
N2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.7318	0.7340	0.0000	0.7281	0.0000	0.7281	0.7281
O2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0237	0.0336	0.0000	0.0329	0.0000	0.0329	0.0329
SO2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0020	0.0000	0.0020	0.0000	0.0020	0.0020
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1141	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.8859	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kgmol/hr)	70,796	70,796	2,097	21,748	21,748	2,993	1,565	0	0	1	4,664	94,640	0	100,092	6	100,086	100,086
V-L Flowrate (kg/hr)	2,042,970	2,042,970	60,510	627,579	627,579	86,371	45,157	0	0	14	138,692	2,810,258	0	2,963,547	640	2,962,891	2,962,891
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	259,680	5,235	1,415	1,120	21,512	56	22,909	22,925	0	0
Temperature (°C)	15	19	19	15	25	25	15	15	1316	15	385	143	15	143	143	143	154
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.11
Steam Table Enthalpy (kJ/kg)	30.23	34.36	34.36	30.23	40.78	40.78	30.23	---	---	---	---	---	---	---	---	287.72	299.40
AspenPlus Enthalpy (kJ/kg)	-97.58	-93.45	-93.45	-97.58	-87.03	-87.03	-97.58	-2,119.02	1,267.06	13,402.95	-2,261.17	-2,394.16	-6.79	-2,452.91	-1,065.72	-2,463.94	-2,452.26
Density (kg/m^3)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	1,003.6	0.5	0.9	---	0.9	2,150.2	0.8	0.9
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	18.015	29.742	29.694	---	29.608	104.986	29.603	29.603
V-L Flowrate (lbmol/hr)	156,080	156,080	4,623	47,946	47,946	6,599	3,450	0	0	2	10,281	208,644	0	220,665	13	220,652	220,652
V-L Flowrate (lb/hr)	4,503,978	4,503,978	133,401	1,383,575	1,383,575	190,414	99,554	0	0	31	305,762	6,195,558	0	6,533,503	1,411	6,532,058	6,532,058
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	572,496	11,541	3,120	2,469	47,425	123	50,507	50,541	0	0
Temperature (°F)	59	66	66	59	78	78	59	59	2,400	59	726	289	59	289	289	289	309
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.6	14.7	14.6	14.4	14.7	14.4	14.4	14.2	15.3
Steam Table Enthalpy (Btu/lb)	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---	---	---	---	---	---	---	123.7	128.7
AspenPlus Enthalpy (Btu/lb)	-42.0	-40.2	-40.2	-42.0	-37.4	-37.4	-42.0	-911.0	544.7	-5,762.2	-972.1	-1,029.3	-2.9	-1,054.6	-458.2	-1,059.3	-1,054.3
Density (lb/ft^3)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	62.650	0.034	0.053	---	0.053	134.233	0.052	0.055

A - Reference conditions are 32.02 F & 0.089 PSIA

B - Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

MTR MEMBRANE CO2 CAPTURE PROCESS (BASE PLANT STREAM TABLES) - 70% CO2 Capture

	18	19	20	21	22	23	26	31	35	36	37	38	39	40	41
V-L Mole Fraction															
Ar	0.0000	0.0092	0.0081	0.0000	0.0000	0.0000	0.0100	0.0749	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0000	0.0003	0.1246	0.0001	0.0000	0.0000	0.0485	0.0147	0.9996	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	0.9967	0.0099	0.1497	0.9998	0.9943	0.9999	0.0057	0.0093	1.46E-06	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N2	0.0000	0.7732	0.6812	0.0000	0.0000	0.0000	0.8891	0.7705	1.59E-07	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.2074	0.0364	0.0000	0.0000	0.0000	0.0467	0.1306	8.49E-06	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	9.02E-07	0.0000	4.21E-05	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0005	0.0000	0.0000	0.0001	0.0009	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0028	0.0000	0.0000	0.0000	0.0048	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kgmol/hr)	13,758	4,190	111,743	235	790	3,257	84,928	12,313	9,793	127,028	106,057	106,057	106,057	40,664	63,227
V-L Flowrate (kg/hr)	251,731	120,903	3,213,082	4,245	14,598	58,680	2,466,073	527,352	430,992	2,288,450	1,910,658	1,910,658	1,910,658	732,568	1,139,051
Solids Flowrate (kg/hr)	2,269	0	0	38,182	222	25,120	0	0	0	0	0	0	0	0	0
Temperature (°C)	27	15	57	15	57	15	37	16	20	593	342	593	270	38	39
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	2.45	15.26	24.23	4.90	4.80	0.52	0.01	1.26
Steam Table Enthalpy (kJ/kg)	---	30.23	294.95	---	---	---	N/A	N/A	N/A	3,477.96	3,049.81	3,652.36	3,000.14	2,343.61	162.36
AspenPlus Enthalpy (kJ/kg)	-15,763.52	-97.58	-2,930.88	-12,513.34	-15,496.74	-14,994.25	N/A	N/A	N/A	-12,502.33	-12,930.48	-12,327.93	-12,980.15	-13,636.69	-15,817.93
Density (kg/m^3)	1,002.5	1.2	1.1	881.1	979.6	1,003.7	1.2	29.5	924.0	69.2	19.2	12.3	2.1	0.1	993.3
V-L Molecular Weight	18.297	28.857	28.754	18.021	18.495	18.019	29.037	29.580	44.011	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lbmol/hr)	30,331	9,237	246,351	519	1,741	7,179	187,235	27,144	21,589	280,050	233,817	233,817	233,817	89,648	139,392
V-L Flowrate (lb/hr)	554,972	266,544	7,083,633	9,358	32,183	129,366	5,436,753	1,162,612	950,174	5,045,169	4,212,280	4,212,280	4,212,280	1,615,035	2,511,176
Solids Flowrate (lb/hr)	5,003	0	0	84,177	491	55,379	0	0	0	0	0	0	0	0	0
Temperature (°F)	80	59	134	59	134	59	99	60	86	1100	648	1100	517	101	101
Pressure (psia)	14.7	14.7	14.8	14.7	14.7	14.7	14.9	355.6	2,214.7	3,514.7	710.8	696.6	75.0	1.0	183.1
Steam Table Enthalpy (Btu/lb)	---	13.0	126.8	---	---	---	N/A	N/A	N/A	1,495.3	1,311.2	1,570.2	1,289.8	1,007.6	69.8
AspenPlus Enthalpy (Btu/lb)	-6,777.1	-42.0	-1,260.1	-5,379.8	-6,662.4	-6,446.4	N/A	N/A	N/A	-5,375.0	-5,559.1	-5,300.1	-5,580.5	-5,862.7	-6,800.5
Density (lb/ft^3)	62.581	0.076	0.067	55.008	61.155	62.658	0.072	1.840	57.681	4.319	1.197	0.768	0.131	0.003	62.009

A - Reference conditions are 32.02 F & 0.089 PSIA

B - Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

APPENDIX B: MTR PROCESS FLOW DIAGRAMS

TCM TEA

REVISIONS

REV.	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
A	4/29/2022	PRELIMINARY DRAFT	AIR	RWM		

TRIMERIC CORPORATION
P.O. Box 826
Buda, Texas 78610

MTR TCM TEA – 650 MWe
PROCESS FLOW DIAGRAM
DCC/SO2 POLISHER

FILENAME	MTR TCM TEA PFD_REV A4.VSD
DATE	April 29, 2022
DRAWN BY	Anne I Ryan
CLIENT/SITE	MEMBRANE TECHNOLOGY & RESEARCH
JOB NUMBER	50144.03
DRAWING NUMBER	PFD-01
SCALE	NONE

TCM TEA

REVISIONS

REV.	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
0	4/29/2022	PRELIMINARY DRAFT	AIR	RWM		

TRIMERIC CORPORATION
P.O. Box 826
Buda, Texas 78610

MTR TCM TEA – 650 MWe
PROCESS FLOW DIAGRAM
FLUE GAS CONDITIONING

CLIENT/SITE: MEMBRANE TECHNOLOGY & RESEARCH	JOB NUMBER: 50144.03
DRAWING NUMBER: PFD-02	SCALE: NONE

FILENAME	DATE		DRAWN BY
MTR TCM TEA PFD_REV A4.VSD	April 29, 2022		Anne I Ryan

TCM TEA – 650 MWe

FILENAME	DATE		DRAWN BY
MTR TCM TEA PFD_REV A4.VSD	April 29, 2022		Anne I Ryan

REVISIONS

REV.	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
A	4/29/2022	PRELIMINARY DRAFT	AIR	RWM		

TRIMERIC CORPORATION
P.O. Box 826
Buda, Texas 78610

MTR TCM TEA – 650 MWe
PROCESS FLOW DIAGRAM
MEMB PERMEATE COMPRESSION

CLIENT/SITE	JOB NUMBER
MEMBRANE TECHNOLOGY & RESEARCH	50144.03
DRAWING NUMBER	SCALE
PFD-03	NONE

TCM TEA

FILENAME	DATE		DRAWN BY
MTR TCM TEA PFD_REV A4.VSD	April 29, 2022		Anne I Ryan

REVISIONS

REV.	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
A	4/29/2022	PRELIMINARY DRAFT	AIR	RWM		

TRIMERIC CORPORATION
P.O. Box 826
Buda, Texas 78610

MTR TCM TEA – 650 MWe
PROCESS FLOW DIAGRAM
DEHYDRATION

CLIENT/SITE	JOB NUMBER
MEMBRANE TECHNOLOGY & RESEARCH	50144.03
DRAWING NUMBER	SCALE
PFD-04	NONE

TCM TEA

REVISIONS

REV.	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
A	4/29/2022	PRELIMINARY DRAFT	AIR	RWM		

TRIMERIC CORPORATION
P.O. Box 826
Buda, Texas 78610

MTR TCM TEA – 650 MWe
PROCESS FLOW DIAGRAM
CO2 PURIFICATION

FILENAME	DATE		DRAWN BY
MTR TCM TEA PFD_REV A4.VSD	April 29, 2022		Anne I Ryan

CLIENT/SITE	JOB NUMBER
MEMBRANE TECHNOLOGY & RESEARCH	50144.03
DRAWING NUMBER	SCALE
PFD-05	NONE

APPENDIX C: MTR CO_2 CAPTURE AND COMPRESSION HEAT AND MATERIAL BALANCE TABLES

MTR TCM TEA
Process Stream Table
Rev D, 7/25/2022 (650 MW Net Basis)

Flow rates are total plant flow rates. The total flow rate in the stream table should be divided by the number of trains indicated on the PFD to calculate the flow rate to each piece of equipment.

Stream Number		100	102	104	105	106	108	109	110	113	114	116	117	119	120	121	123	124	126	127	128	130	131	133	134	136	137	138	140	141
Stream Description		**Flue Gas from Boundary**	**Flue Gas from DCC**	**Flue Gas from Booster Fan**	**MemA Feed**	**Recycle from MemB**	**MemA Retentate**	**MemA Permeate**	**MemA Fan 1 Discharge**	**MemA Fan 2 Discharge**	**MemA Compressor Stage 1 Discharge**	**MemA Comp Stage 1 Cooler Vapor Outlet**	**MemA Compressor Stage 2 Discharge**	**MemA Comp Stage 2 Cooler Vapor Outlet**	**MemA Compressor Stage 3 Discharge**	**MemA Comp Stage3 Cooler Inlet with MemD Recycle**	**MemB Feed**	**MemB Permeate**	**MemB Fan 1 Discharge**	**MemB Fan 2 Discharge**	**MemB Compressor 1 Discharge**	**MemB Comp 1 Cooler Vapor Outlet**	**MemB Comp 2 Discharge**	**MemB Comp 2 Cooler Vapor Outlet**	**MemB Comp 3 Discharge**	**MemB Comp 3 Cooler Vapor Outlet**	**MemB Comp 4 Discharge**	**MemB Comp 4 Cooler Inlet**	**MemB Comp 4 Cooler Vapor Outlet**	**MemB Comp 5 Discharge**
PFD Reference		PFD-01	PFD-01	PFD-02	PFD-02	PFD-02	PFD-02	PFD-02	PFD-02	PFD-02	PFD-02	PFD-02	PFD-02	PFD-02	PFD-02	PFD-02	PFD-02	PFD-02	PFD-03	PFD-03	PFD-03	PFD-03	PFD-03	PFD-03	PFD-03	PFD-03	PFD-03	PFD-03	PFD-03	PFD-03
Vapor Fraction (mole basis)		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Temperature, °F		134.0	78.0	100.9	98.8	69.0	98.8	98.8	91.2	108.5	212.5	69.0	165.2	69.0	176.3	173.9	69.0	69.0	78.7	96.2	199.2	69.0	168.1	69.0	168.1	69.0	168.3	154.5	69.0	198.1
Pressure, psia		14.70	14.13	15.85	15.85	16.32	14.87	1.45	2.15	3.23	5.60	5.58	9.84	9.59	17.29	17.27	17.07	2.90	4.27	6.31	12.07	11.82	22.79	22.54	43.46	40.46	78.00	78.00	75.00	172.97
Total Molar Flow, lbmol/hr		246,349	216,592	216,592	232,095	15,502	187,235	44,860	46,708	48,101	48,101	41,293	41,293	40,200	40,200	40,953	40,330	24,827	25,667	26,176	26,176	24,772	24,772	24,427	24,427	24,262	24,262	27,355	27,275	27,275
Total Mass Flow, lb/hr		7,083,422	6,546,924	6,546,924	7,025,735	478,811	5,436,759	1,588,975	1,622,268	1,647,358	1,647,358	1,524,694	1,524,694	1,504,994	1,504,994	1,534,509	1,523,272	1,044,461	1,059,585	1,068,757	1,068,757	1,043,456	1,043,456	1,037,232	1,037,232	1,034,250	1,034,250	1,166,446	1,165,001	1,165,001
Actual Volumetric Flow, acfm		1,776,739	1,472,817	1,368,512	1,460,897	89,709	1,257,274	3,088,199	2,142,630	1,512,003	1,031,756	698,730	468,350	395,437	263,866	268,102	222,488	808,633	577,896	411,542	254,942	197,299	121,426	101,623	62,510	55,859	34,344	37,825	33,439	17,954
Molecular Weight		28.75	30.23	30.23	30.27	30.89	29.04	35.42	34.73	34.25	34.25	36.92	36.92	37.44	37.44	37.47	37.77	42.07	41.28	40.83	40.83	42.12	42.12	42.46	42.46	42.63	42.63	42.64	42.71	42.71
Enthalpy, Btu/hr		1.04E+09	8.15E+08	8.51E+08	9.07E+08	5.70E+07	7.26E+08	1.82E+08	1.88E+08	2.00E+08	2.42E+08	1.56E+08	1.89E+08	1.52E+08	1.88E+08	1.90E+08	1.52E+08	9.52E+07	1.01E+08	1.07E+08	1.31E+08	9.43E+07	1.16E+08	9.25E+07	1.14E+08	9.16E+07	1.12E+08	1.23E+08	1.01E+08	1.32E+08
Vapor																														
Molar Flow, lbmol/hr		246,349	216,592	216,592	232,095	15,502	187,235	44,860	46,708	48,101	48,101	41,293	41,293	40,200	40,200	40,953	40,330	24,827	25,667	26,176	26,176	24,772	24,772	24,427	24,427	24,262	24,262	27,355	27,275	27,275
Mass Flow, lb/hr		7,083,422	6,546,919	6,546,924	7,025,735	478,811	5,436,759	1,588,975	1,622,268	1,647,358	1,647,358	1,524,694	1,524,694	1,504,994	1,504,994	1,534,509	1,523,272	1,044,461	1,059,585	1,068,757	1,068,757	1,043,456	1,043,456	1,037,232	1,037,232	1,034,250	1,034,250	1,166,446	1,165,001	1,165,001
Standard Volumetric Flow, MMSCFD		2,244.64	1,975.28	1,975.28	2,109.96	140.96	1,705.93	408.52	425.58	438.15	438.15	376.20	376.20	366.33	366.33	372.61	367.22	226.26	233.44	238.83	238.83	225.36	225.36	222.67	222.67	220.87	220.87	248.71	248.71	248.71
Density, lb/ft3 @ PT		0.066	0.074	0.080	0.080	0.089	0.072	0.009	0.013	0.018	0.027	0.036	0.054	0.063	0.095	0.095	0.114	0.022	0.031	0.043	0.070	0.088	0.143	0.170	0.277	0.309	0.502	0.514	0.581	1.082
Specific Heat, Btu/lboF		0.258	0.240	0.241	0.241	0.234	0.243	0.231	0.235	0.240	0.248	0.220	0.228	0.217	0.227	0.226	0.216	0.206	0.211	0.215	0.226	0.207	0.218	0.207	0.218	0.208	0.219	0.218	0.211	0.227
Viscosity, cP		0.017	0.017	0.018	0.018	0.017	0.018	0.016	0.015	0.015	0.018	0.015	0.018	0.016	0.018	0.018	0.016	0.015	0.015	0.015	0.018	0.015	0.017	0.015	0.017	0.015	0.018	0.017	0.015	0.018
Thermal Conductivity, Btu/hr-ft-°F		0.015	0.014	0.014	0.014	0.013	0.015	0.012	0.012	0.012	0.015	0.011	0.014	0.011	0.014	0.014	0.011	0.010	0.010	0.011	0.013	0.010	0.013	0.010	0.013	0.010	0.013	0.012	0.010	0.014
Compressibility		0.999	0.999	0.999	0.999	0.999	0.999	1.000	0.999	0.999	0.999	0.999	0.999	0.998	0.998	0.998	0.996	0.999	0.999	0.998	0.998	0.996	0.995	0.992	0.991	0.985	0.984	0.982	0.973	0.969
Components	mol weight	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac
Carbon Dioxide	44.0	0.1246	0.1417	0.1417	0.1423	0.1510	0.0485	0.5339	0.5128	0.4979	0.4979	0.5800	0.5800	0.5958	0.5958	0.5973	0.6065	0.8909	0.8618	0.8450	0.8450	0.8929	0.8929	0.9055	0.9055	0.9116	0.9116	0.9119	0.9146	0.9146
Nitrogen	28.0	0.6811	0.7747	0.7747	0.7737	0.7587	0.8891	0.2918	0.2803	0.2721	0.2721	0.3170	0.3170	0.3256	0.3256	0.3240	0.3290	0.0607	0.0587	0.0576	0.0576	0.0608	0.0608	0.0617	0.0617	0.0621	0.0621	0.0621	0.0623	0.0623
Argon	40.0	0.0081	0.0092	0.0092	0.0097	0.0166	0.0100	0.0086	0.0083	0.0080	0.0080	0.0093	0.0093	0.0096	0.0096	0.0094	0.0096	0.0052	0.0050	0.0049	0.0049	0.0052	0.0052	0.0053	0.0053	0.0053	0.0053	0.0048	0.0048	0.0048
Oxygen	32.0	0.0364	0.0414	0.0414	0.0434	0.0712	0.0467	0.0296	0.0284	0.0276	0.0276	0.0322	0.0322	0.0330	0.0330	0.0340	0.0345	0.0116	0.0112	0.0110	0.0110	0.0116	0.0116	0.0118	0.0118	0.0119	0.0119	0.0132	0.0132	0.0132
Water	18.0	0.1497	0.0329	0.0329	0.0309	0.0025	0.0057	0.1358	0.1700	0.1941	0.1941	0.0612	0.0612	0.0357	0.0357	0.0350	0.0201	0.0312	0.0628	0.0811	0.0811	0.0290	0.0290	0.0153	0.0153	0.0086	0.0086	0.0077	0.0048	0.0048
Sulfur Dioxide	64.1	3.70E-05	5.00E-06	5.00E-06	4.86E-06	2.95E-06	9.02E-07	2.14E-05	2.05E-05	1.99E-05	1.99E-05	2.32E-05	2.32E-05	2.38E-05	2.38E-05	2.34E-05	2.37E-05	3.67E-05	3.55E-05	3.48E-05	3.48E-05	3.68E-05	3.68E-05	3.73E-05	3.73E-05	3.75E-05	3.75E-05	3.35E-05	3.36E-05	3.36E-05
Nitrogen Dioxide	46.0	4.36E-05	4.88E-05	4.88E-05	4.74E-05	2.84E-05	8.81E-06	2.09E-04	2.00E-04	1.95E-04	1.95E-04	2.25E-04	2.25E-04	2.30E-04	2.30E-04	2.26E-04	2.29E-04	3.54E-04	3.42E-04	3.36E-04	3.36E-04	3.52E-04	3.52E-04	3.56E-04	3.56E-04	3.58E-04	3.58E-04	3.18E-04	3.19E-04	3.19E-04
Nitrogen Oxide	30.0	2.30E-06	2.61E-06	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Components		mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow
Carbon Dioxide		1,350,761	1,350,675	1,350,675	1,453,694	103,019	399,620	1,054,073	1,054,073	1,054,073	1,054,073	1,054,038	1,054,038	1,054,028	1,054,028	1,076,485	1,076,475	973,456	973,456	973,456	973,456	973,432	973,432	973,421	973,421	973,411	973,411	1,097,887	1,097,878	1,097,878
Nitrogen		4,700,627	4,700,622	4,700,622	5,030,111	329,488	4,663,416	366,695	366,695	366,695	366,695	366,695	366,695	366,695	366,695	371,716	371,716	42,227	42,227	42,227	42,227	42,227	42,227	42,227	42,227	42,227	42,227	47,585	47,585	47,585
Argon		79,707	79,707	79,707	89,982	10,276	74,559	15,423	15,423	15,423	15,423	15,423	15,423	15,423	15,423	15,445	15,445	5,170	5,170	5,170	5,170	5,170	5,170	5,169	5,169	5,169	5,169	5,191	5,191	5,191
Oxygen		286,912	286,912	286,912	322,217	35,305	279,717	42,500	42,500	42,500	42,500	42,500	42,500	42,500	42,500	44,515	44,515	9,210	9,210	9,210	9,210	9,210	9,210	9,210	9,210	9,210	9,210	11,547	11,547	11,547
Water		664,319	128,430	128,435	129,133	698	19,344	109,789	143,081	168,172	168,172	45,547	45,547	25,859	25,859	25,859	14,633	13,935	29,060	38,231	38,231	12,957	12,957	6,745	6,745	3,775	3,775	3,775	2,340	2,340
Sulfur Dioxide		584	69	69	72	3	11	61	61	61	61	61	61	61	61	61	61	58	58	58	58	58	58	58	58	58	58	59	59	59
Nitrogen Dioxide		494	486	486	507	20	76	431	431	431	431	427	427	426	426	426	424	404	404	404	404	401	401	400	400	399	399	401	400	400
Nitrogen Oxide		17	17	17	19	2	17	3	3	3	3	3	3	3	3	3	3	1	1	1	1	1	1	1	1	1	1	1	1	1
Liquid																														
Molar Flow, lbmol/hr		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Mass Flow, lb/hr		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Standard Volumetric Flow, ft3/s		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Density, lb/ft3 @ PT		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Specific Heat, Btu/lboF		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Viscosity, cP		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Surface Tension, dynes/cm		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Thermal Conductivity, Btu/hr-ft-F		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Components	mol weight	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac
Carbon Dioxide	44.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Nitrogen	28.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Argon	40.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Oxygen	32.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Water	18.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Sulfur Dioxide	64.1	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Nitrogen Dioxide	46.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Nitrogen Oxide	30.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Components		mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow
Carbon Dioxide		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Nitrogen		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Argon		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Oxygen		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Water		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Sulfur Dioxide		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Nitrogen Dioxide		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Nitrogen Oxide		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--

MTR TCM TEA
Process Stream Table
Rev D, 7/25/2022 (650 MW Net Basis)

Flow rates are total plant flow rates. The total flow rate in the stream table should be divided by the number of trains indicated on the PFD to calculate the flow rate to each piece of equipment.

Stream Number		143	144	146	147	147A	148	149	150	151
Stream Description		**MemB Comp 5 Cooler Vapor Outlet**	**MemB Comp 6 Discharge**	**MemB Comp 6 Cooler Vapor Outlet**	**Dehy Feed Chiller Outlet**	**Dehy Feed Separator Vapor Outlet**	**Superheated Dehydration Inlet**	**Dry CO2 to Reboiler / CO2 Cross Exchanger**	**CO2 Condenser Inlet**	**CO2 Distillation Column Inlet**
PFD Reference		PFD-03	PFD-03	PFD-03	PFD-04	PFD-04	PFD-04	PFD-04	PFD-05	PFD-05
Vapor Fraction (mole basis)		1.00	1.00	1.00	0.999	1.00	1.00	1.00	1.00	0.12
Temperature, °F		69.0	199.9	69.0	50.0	50.0	60.0	60.0	19.4	-31.0
Pressure, psia		169.97	392.00	389.00	386.00	386.00	383.00	376.00	373.00	370.00
Total Molar Flow, lbmol/hr		27,206	27,206	27,176	27,176	27,160	27,160	27,144	27,144	27,144
Total Mass Flow, lb/hr		1,163,738	1,163,738	1,163,182	1,163,182	1,162,902	1,162,902	1,162,613	1,162,613	1,162,613
Actual Volumetric Flow, acfm		14,173	7,594	5,597	5,309	5,309	5,541	5,663	4,940	824
Molecular Weight		42.78	42.78	42.80	42.80	42.82	42.82	42.83	42.83	42.83
Enthalpy, Btu/hr		9.88E+07	1.27E+08	9.07E+07	8.45E+07	8.48E+07	8.79E+07	8.81E+07	7.60E+07	-6.75E+07
Vapor										
Molar Flow, lbmol/hr		27,206	27,206	27,176	27,160	27,160	27,160	27,144	27,144	3,257
Mass Flow, lb/hr		1,163,738	1,163,738	1,163,182	1,162,902	1,162,902	1,162,902	1,162,613	1,162,613	120,866
Standard Volumetric Flow, MMSCFD		247.81	247.81	247.81	247.81	247.81	247.81	246.91	246.91	29.63
Density, lb/ft3 @ PT		1.369	2.554	3.464	3.651	3.651	3.498	3.422	3.922	3.529
Specific Heat, Btu/lboF		0.221	0.240	0.254	0.258	0.258	0.255	0.253	0.268	0.257
Viscosity, cP		0.015	0.019	0.016	0.016	0.016	0.016	0.016	0.015	0.015
Thermal Conductivity, Btu/hr-ft-°F		0.011	0.015	0.012	0.011	0.011	0.012	0.011	0.011	0.011
Compressibility		0.938	0.930	0.850	0.831	0.831	0.844	0.847	0.796	0.848
Components	mol weight	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac
Carbon Dioxide	44.0	0.9169	0.9169	0.9179	0.9184	0.9184	0.9184	0.9190	0.9190	0.5344
Nitrogen	28.0	0.0624	0.0624	0.0625	0.0625	0.0625	0.0625	0.0626	0.0626	0.3775
Argon	40.0	0.0048	0.0048	0.0048	0.0048	0.0048	0.0048	0.0048	0.0048	0.0242
Oxygen	32.0	0.0133	0.0133	0.0133	0.0133	0.0133	0.0133	0.0133	0.0133	0.0639
Water	18.0	0.0022	0.0022	0.0011	0.0006	0.0006	0.0006	0.0000	0.0000	0.0000
Sulfur Dioxide	64.1	3.37E-05	3.37E-05	3.37E-05	3.37E-05	3.37E-05	3.37E-05	3.38E-05	3.38E-05	1.17E-06
Nitrogen Dioxide	46.0	3.18E-04	3.18E-04	3.17E-04	3.17E-04	3.17E-04	3.17E-04	3.17E-04	3.17E-04	5.25E-06
Nitrogen Oxide	30.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Components		mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow
Carbon Dioxide		1,097,861	1,097,861	1,097,845	1,097,834	1,097,834	1,097,834	1,097,834	1,097,834	76,611
Nitrogen		47,585	47,585	47,585	47,585	47,585	47,585	47,585	47,585	34,445
Argon		5,191	5,191	5,191	5,191	5,191	5,191	5,191	5,191	3,153
Oxygen		11,547	11,547	11,547	11,547	11,547	11,547	11,547	11,547	6,656
Water		1,096	1,096	558	289	289	289	1	1	0
Sulfur Dioxide		59	59	59	59	59	59	59	59	0
Nitrogen Dioxide		398	398	397	396	396	396	396	396	1
Nitrogen Oxide		1	1	1	1	1	1	1	1	0
Liquid										
Molar Flow, lbmol/hr		--	--	--	15	--	--	--	--	23,887
Mass Flow, lb/hr		--	--	--	280	--	--	--	--	1,041,747
Standard Volumetric Flow, ft3/s		--	--	--	0	--	--	--	--	6
Density, lb/ft3 @ PT		--	--	--	63.12	--	--	--	--	68.69
Specific Heat, Btu/lboF		--	--	--	1.010	--	--	--	--	0.463
Viscosity, cP		--	--	--	1.3500	--	--	--	--	0.1830
Surface Tension, dynes/cm		--	--	--	73.01	--	--	--	--	11.33
Thermal Conductivity, Btu/hr-ft-F		--	--	--	0.327	--	--	--	--	0.081
Components	mol weight	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac
Carbon Dioxide	44.0	--	--	--	0.0163	--	--	--	--	0.9714
Nitrogen	28.0	--	--	--	0.0000	--	--	--	--	0.0196
Argon	40.0	--	--	--	0.0000	--	--	--	--	0.0021
Oxygen	32.0	--	--	--	0.0000	--	--	--	--	0.0064
Water	18.0	--	--	--	0.9823	--	--	--	--	0.0000
Sulfur Dioxide	64.1	--	--	--	0.0000	--	--	--	--	0.0000
Nitrogen Dioxide	46.0	--	--	--	0.0014	--	--	--	--	0.0004
Nitrogen Oxide	30.0	--	--	--	0.0000	--	--	--	--	0.0000
Components		mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow
Carbon Dioxide		--	--	--	12	--	--	--	--	1,021,223
Nitrogen		--	--	--	0	--	--	--	--	13,140
Argon		--	--	--	0	--	--	--	--	2,039
Oxygen		--	--	--	0	--	--	--	--	4,891
Water		--	--	--	313	--	--	--	--	1
Sulfur Dioxide		--	--	--	0	--	--	--	--	58
Nitrogen Dioxide		--	--	--	1	--	--	--	--	395
Nitrogen Oxide		--	--	--	0	--	--	--	--	0

Stream Number	156	157	158	159	160	161	162	163	164
Stream Description	**CO2 Distillation Column Bottoms**	**CO2 Product from CO2 Booster Pump**	**CO2 Product from CO2 Product Pump**	**CO2 Product from CO2 Product Heater 1**	**CO2 Product from CO2 Product Heater 2**	**CO2 Distillation Column Overheads**	**MemC Inlet**	**MemD Inlet**	**MemD Retentate**
PFD Reference	PFD-05	PFD-05	PFD-05	PFD-05	PFD-05	PFD-05	PFD-05	PFD-05	PFD-05
Vapor Fraction (mole basis)	0.00	0.00	0.00	0.00	0.00	1.00	1.00	1.00	1.00
Temperature, °F	10.4	10.8	31.1	60.0	68.0	-24.7	81.0	81.0	80.9
Pressure, psia	362.00	391.60	2219.08	2216.08	2213.08	360.00	357.00	356.28	355.55
Total Molar Flow, lbmol/hr	21,589	21,589	21,589	21,589	21,589	5,555	5,555	2,462	1,709
Total Mass Flow, lb/hr	950,175	950,175	950,175	950,175	950,175	212,439	212,439	80,240	50,724
Actual Volumetric Flow, acfm	251	251	247	267	275	1,004	1,390	648	459
Molecular Weight	44.01	44.01	44.01	44.01	44.01	38.24	38.24	32.60	29.69
Enthalpy, Btu/hr	-5.24E+07	-5.23E+07	-4.48E+07	-2.94E+07	-2.48E+07	1.43E+07	1.98E+07	8.87E+06	6.14E+06
Vapor									
Molar Flow, lbmol/hr	--	--	--	--	--	5,555	5,555	2,462	1,709
Mass Flow, lb/hr	--	--	--	--	--	212,439	212,439	80,240	50,724
Standard Volumetric Flow, MMSCFD	--	--	--	--	--	50.55	50.55	22.45	15.53
Density, lb/ft3 @ PT	--	--	--	--	--	3.527	2.547	2.062	1.840
Specific Heat, Btu/lboF	--	--	--	--	--	0.257	0.239	0.239	0.242
Viscosity, cP	--	--	--	--	--	0.015	0.017	0.018	0.019
Thermal Conductivity, Btu/hr-ft-°F	--	--	--	--	--	0.011	0.013	0.014	0.015
Compressibility	--	--	--	--	--	0.838	0.925	0.970	0.987
Components	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac
Carbon Dioxide	--	--	--	--	--	0.6059	0.6059	0.2182	0.0157
Nitrogen	--	--	--	--	--	0.3058	0.3058	0.6124	0.7774
Argon	--	--	--	--	--	0.0234	0.0234	0.0526	0.0754
Oxygen	--	--	--	--	--	0.0649	0.0649	0.1169	0.1315
Water	--	--	--	--	--	0.0000	0.0000	0.0000	0.0000
Sulfur Dioxide	--	--	--	--	--	0.0000	0.0000	0.0000	0.0000
Nitrogen Dioxide	--	--	--	--	--	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	--	--	--	--	--	0.0000	0.0000	0.0000	0.0000
Components	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow
Carbon Dioxide	--	--	--	--	--	148,119	148,119	23,640	1,182
Nitrogen	--	--	--	--	--	47,585	47,585	42,227	37,206
Argon	--	--	--	--	--	5,191	5,191	5,169	5,147
Oxygen	--	--	--	--	--	11,541	11,541	9,204	7,189
Water	--	--	--	--	--	0	0	0	0
Sulfur Dioxide	--	--	--	--	--	1	1	0	0
Nitrogen Dioxide	--	--	--	--	--	2	2	0	0
Nitrogen Oxide	--	--	--	--	--	1	1	1	0
Liquid									
Molar Flow, lbmol/hr	21,589	21,589	21,589	21,589	21,589	--	--	--	--
Mass Flow, lb/hr	950,175	950,175	950,175	950,175	950,175	--	--	--	--
Standard Volumetric Flow, ft3/s	5	5	5	5	5	--	--	--	--
Density, lb/ft3 @ PT	63.12	63.14	64.20	59.24	57.68	--	--	--	--
Specific Heat, Btu/lboF	0.603	0.602	0.532	0.595	0.614	--	--	--	--
Viscosity, cP	0.1300	0.1310	0.1360	0.1090	0.1020	--	--	--	--
Surface Tension, dynes/cm	6.80	6.76	4.60	1.88	1.24	--	--	--	--
Thermal Conductivity, Btu/hr-ft-F	0.072	0.072	0.075	0.067	0.065	--	--	--	--
Components	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac
Carbon Dioxide	0.9996	0.9996	0.9996	0.9996	0.9996	--	--	--	--
Nitrogen	1.59E-07	1.59E-07	1.59E-07	1.59E-07	1.59E-07	--	--	--	--
Argon	8.30E-07	8.30E-07	8.30E-07	8.30E-07	8.30E-07	--	--	--	--
Oxygen	8.49E-06	8.49E-06	8.49E-06	8.49E-06	8.49E-06	--	--	--	--
Water	1.46E-06	1.46E-06	1.46E-06	1.46E-06	1.46E-06	--	--	--	--
Sulfur Dioxide	4.21E-05	4.21E-05	4.21E-05	4.21E-05	4.21E-05	--	--	--	--
Nitrogen Dioxide	3.97E-04	3.97E-04	3.97E-04	3.97E-04	3.97E-04	--	--	--	--
Nitrogen Oxide	1.95E-10	1.95E-10	1.95E-10	1.95E-10	1.95E-10	--	--	--	--
Components	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow
Carbon Dioxide	949,715	949,715	949,715	949,715	949,715	--	--	--	--
Nitrogen	0	0	0	0	0	--	--	--	--
Argon	1	1	1	1	1	--	--	--	--
Oxygen	6	6	6	6	6	--	--	--	--
Water	1	1	1	1	1	--	--	--	--
Sulfur Dioxide	58	58	58	58	58	--	--	--	--
Nitrogen Dioxide	394	394	394	394	394	--	--	--	--
Nitrogen Oxide	0	0	0	0	0	--	--	--	--

Stream Number	166	167	202	212	222	223	224	227	228	230
Stream Description	**MemD Permeate Recycle**	**MemC Permeate Recycle**	**Water Purge from SO2 Polisher**	**Water Purge from DCC**	**Water from MemA Comp 1 Cooler**	**Water from MemA Comp 2 Cooler**	**Water from MemA Comp 3 Cooler**	**MemA Fan 1 Water Injection**	**MemA Fan 2 Water Injection**	**Water from MemB Comp 1 Cooler**
PFD Reference	PFD-05	PFD-05	PFD-01	PFD-01	PFD-02	PFD-02	PFD-02	PFD-02	PFD-02	PFD-03
Vapor Fraction (mole basis)	1.00	1.00			0.00	0.00	0.00	0.00	0.00	0.00
Temperature, °F	46.0	43.9			69.0	69.0	69.0	81.2	81.2	69.0
Pressure, psia	17.27	79.77			5.58	9.59	17.07	43.51	43.51	11.82
Total Molar Flow, lbmol/hr	753	3,093			6,808	1,093	623	1,848	1,393	1,404
Total Mass Flow, lb/hr	29,515	132,196			122,665	19,700	11,237	33,293	25,091	25,301
Actual Volumetric Flow, acfm	3,923	3,375			33	5	3	9	7	7
Molecular Weight	39.20	42.74			18.02	18.02	18.03	18.02	18.02	18.03
Enthalpy, Btu/hr	2.69E+06	1.09E+07			-1.02E+08	-1.63E+07	-9.34E+06	-2.73E+07	-2.06E+07	-2.10E+07
Vapor										
Molar Flow, lbmol/hr	753	3,093			--	--	--	--	--	--
Mass Flow, lb/hr	29,515	132,196			--	--	--	--	--	--
Standard Volumetric Flow, MMSCFD	6.86	28.19			--	--	--	--	--	--
Density, lb/ft3 @ PT	0.125	0.653			--	--	--	--	--	--
Specific Heat, Btu/lboF	0.210	0.209			--	--	--	--	--	--
Viscosity, cP	0.015	0.015			--	--	--	--	--	--
Thermal Conductivity, Btu/hr-ft-°F	0.010	0.009			--	--	--	--	--	--
Compressibility	0.995	0.967			--	--	--	--	--	--
Components	mol frac	mol frac			mol frac	mol frac	mol frac	mol frac	mol frac	mol frac
Carbon Dioxide	0.6776	0.9144			--	--	--	--	--	--
Nitrogen	0.2380	0.0618			--	--	--	--	--	--
Argon	0.0007	0.0002			--	--	--	--	--	--
Oxygen	0.0836	0.0236			--	--	--	--	--	--
Water	0.0000	0.0000			--	--	--	--	--	--
Sulfur Dioxide	0.0000	0.0000			--	--	--	--	--	--
Nitrogen Dioxide	0.0000	0.0000			--	--	--	--	--	--
Nitrogen Oxide	0.0000	0.0000			--	--	--	--	--	--
Components	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow
Carbon Dioxide	22,457	124,476			--	--	--	--	--	--
Nitrogen	5,021	5,358			--	--	--	--	--	--
Argon	22	22			--	--	--	--	--	--
Oxygen	2,015	2,337			--	--	--	--	--	--
Water	0	0			--	--	--	--	--	--
Sulfur Dioxide	0	0			--	--	--	--	--	--
Nitrogen Dioxide	0	2			--	--	--	--	--	--
Nitrogen Oxide	0	0			--	--	--	--	--	--
Liquid										
Molar Flow, lbmol/hr	--	--			6,808	1,093	623	1,848	1,393	1,404
Mass Flow, lb/hr	--	--			122,665	19,700	11,237	33,293	25,091	25,301
Standard Volumetric Flow, ft3/s	--	--			1	0	0	0	0	0
Density, lb/ft3 @ PT	--	--			62.28	62.28	62.29	62.15	62.15	62.29
Specific Heat, Btu/lboF	--	--			1.010	1.010	1.010	1.010	1.010	1.010
Viscosity, cP	--	--			0.9880	0.9890	0.9890	0.8450	0.8450	0.9890
Surface Tension, dynes/cm	--	--			72.64	72.64	72.62	71.61	71.61	72.62
Thermal Conductivity, Btu/hr-ft-F	--	--			0.347	0.347	0.347	0.353	0.353	0.347
Components	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac
Carbon Dioxide	--	--			0.0001	0.0002	0.0004	0.0000	0.0000	0.0004
Nitrogen	--	--			0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Argon	--	--			0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Oxygen	--	--			0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Water	--	--			0.9999	0.9998	0.9996	1.0000	1.0000	0.9996
Sulfur Dioxide	--	--			0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Dioxide	--	--			0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Oxide	--	--			0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Components	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow
Carbon Dioxide	--	--			36	10	10	0	0	24
Nitrogen	--	--			0	0	0	0	0	0
Argon	--	--			0	0	0	0	0	0
Oxygen	--	--			0	0	0	0	0	0
Water	--	--			122,625	19,688	11,226	33,293	25,091	25,275
Sulfur Dioxide	--	--			0	0	0	0	0	0
Nitrogen Dioxide	--	--			4	1	1	0	0	3
Nitrogen Oxide	--	--			0	0	0	0	0	0

MTR TCM TEA
Process Stream Table
Rev D, 7/25/2022 (650 MW Net Basis)

Flow rates are total plant flow rates. The total flow rate in the stream table should be divided by the number of trains indicated on the PFD to calculate the flow rate to each piece of equipment.

Stream Number		231	232	233	234	235	236	240	241
Stream Description		**Water from MemB Comp 2 Cooler**	**Water from MemB Comp 3 Cooler**	**Water from MemB Comp 4 Cooler**	**Water from MemB Comp 5 Cooler**	**Water from MemB Comp 6 Cooler**	**Water from Dehy Feed Separator**	**MemB Fan 1 Water Injection**	**MemB Fan 2 Water Injection**
PFD Reference		PFD-03	PFD-03	PFD-03	PFD-03	PFD-03	PFD-04	PFD-03	PFD-03
Vapor Fraction (mole basis)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Temperature, °F		69.0	69.0	69.0	69.0	69.0	50.0	81.0	81.0
Pressure, psia		22.54	40.46	75.00	169.97	389.00	386.00	43.51	43.51
Total Molar Flow, lbmol/hr		345	165	80	69	30	15	840	509
Total Mass Flow, lb/hr		6,224	2,982	1,445	1,263	556	280	15,124	9,172
Actual Volumetric Flow, acfm		2	1	0	0	0	0	4	2
Molecular Weight		18.04	18.05	18.09	18.18	18.37	18.48	18.02	18.02
Enthalpy, Btu/hr		-5.16E+06	-2.47E+06	-1.19E+06	-1.03E+06	-4.47E+05	-2.29E+05	-1.24E+07	-7.52E+06
Vapor									
Molar Flow, lbmol/hr		--	--	--	--	--	--	--	--
Mass Flow, lb/hr		--	--	--	--	--	--	--	--
Standard Volumetric Flow, MMSCFD		--	--	--	--	--	--	--	--
Density, lb/ft3 @ PT		--	--	--	--	--	--	--	--
Specific Heat, Btu/lboF		--	--	--	--	--	--	--	--
Viscosity, cP		--	--	--	--	--	--	--	--
Thermal Conductivity, Btu/hr-ft-°F		--	--	--	--	--	--	--	--
Compressibility		--	--	--	--	--	--	--	--
Components	mol weight	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac
Carbon Dioxide	44.0	--	--	--	--	--	--	--	--
Nitrogen	28.0	--	--	--	--	--	--	--	--
Argon	40.0	--	--	--	--	--	--	--	--
Oxygen	32.0	--	--	--	--	--	--	--	--
Water	18.0	--	--	--	--	--	--	--	--
Sulfur Dioxide	64.1	--	--	--	--	--	--	--	--
Nitrogen Dioxide	46.0	--	--	--	--	--	--	--	--
Nitrogen Oxide	30.0	--	--	--	--	--	--	--	--
Components		mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow
Carbon Dioxide		--	--	--	--	--	--	--	--
Nitrogen		--	--	--	--	--	--	--	--
Argon		--	--	--	--	--	--	--	--
Oxygen		--	--	--	--	--	--	--	--
Water		--	--	--	--	--	--	--	--
Sulfur Dioxide		--	--	--	--	--	--	--	--
Nitrogen Dioxide		--	--	--	--	--	--	--	--
Nitrogen Oxide		--	--	--	--	--	--	--	--
Liquid									
Molar Flow, lbmol/hr		345	165	80	69	30	15	840	509
Mass Flow, lb/hr		6,224	2,982	1,445	1,263	556	280	15,124	9,172
Standard Volumetric Flow, ft3/s		0	0	0	0	0	0	0	0
Density, lb/ft3 @ PT		62.31	62.33	62.38	62.51	62.78	63.12	62.15	62.15
Specific Heat, Btu/lboF		1.010	1.010	1.010	1.010	1.010	1.010	1.010	1.010
Viscosity, cP		0.9900	0.9910	0.9940	1.0000	1.0200	1.3500	0.8470	0.8470
Surface Tension, dynes/cm		72.60	72.55	72.47	72.23	71.73	73.01	71.63	71.63
Thermal Conductivity, Btu/hr-ft-F		0.347	0.346	0.346	0.343	0.339	0.327	0.353	0.353
Components	mol weight	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac
Carbon Dioxide	44.0	0.0007	0.0014	0.0025	0.0056	0.0125	0.0163	0.0000	0.0000
Nitrogen	28.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Argon	40.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Oxygen	32.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Water	18.0	0.9992	0.9985	0.9973	0.9939	0.9866	0.9823	1.0000	1.0000
Sulfur Dioxide	64.1	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Dioxide	46.0	0.0001	0.0001	0.0002	0.0005	0.0009	0.0014	0.0000	0.0000
Nitrogen Oxide	30.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Components		mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow
Carbon Dioxide		11	10	9	17	17	11	0	0
Nitrogen		0	0	0	0	0	0	0	0
Argon		0	0	0	0	0	0	0	0
Oxygen		0	0	0	0	0	0	0	0
Water		6,211	2,971	1,435	1,244	538	268	15,124	9,172
Sulfur Dioxide		0	0	0	0	0	0	0	0
Nitrogen Dioxide		1	1	1	2	1	1	0	0
Nitrogen Oxide		0	0	0	0	0	0	0	0

MTR TCM TEA
Process Stream Table - Metric
Rev D, 7/25/2022 (650 MW Net Basis)

Flow rates are total plant flow rates. The total flow rate in the stream table should be divided by the number of trains indicated on the PFD to calculate the flow rate to each piece of equipment.

Stream Number		100	102	104	105	106	108	109	110	113	114	116	117	119
Stream Description		Flue Gas from Boundary	Flue Gas from DCC	Flue Gas from Booster Fan	MemA Feed	Recycle from MemB	MemA Retentate	MemA Permeate	MemA Fan 1 Discharge	MemA Fan 2 Discharge	MemA Compressor Stage 1 Discharge	MemA Comp Stage 1 Cooler Vapor Outlet	MemA Compressor Stage 2 Discharge	MemA Comp Stage 2 Cooler Vapor Outlet
PFD Reference		PFD-01	PFD-01	PFD-02	PFD-02	PFD-02	PFD-02	PFD-02	PFD-02	PFD-02	PFD-02	PFD-02	PFD-02	PFD-02
Vapor Fraction (mole basis)		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Temperature, °C		56.7	25.6	38.3	37.1	20.6	37.1	37.1	32.9	42.5	100.3	20.6	74.0	20.6
Pressure, bar(a)		1.01	0.97	1.09	1.09	1.13	1.03	0.10	0.15	0.22	0.39	0.38	0.68	0.66
Total Molar Flow, kmol/hr		111,742	98,245	98,245	105,276	7,032	84,928	20,348	21,186	21,818	21,818	18,730	18,730	18,234
Total Mass Flow, kg/hr		3,212,986	2,969,635	2,969,635	3,186,820	217,185	2,466,073	720,747	735,848	747,229	747,229	691,590	691,590	682,654
Actual Volumetric Flow, m3/hr		3,018,699	2,502,332	2,325,116	2,482,079	152,417	2,136,123	5,246,883	3,640,351	2,568,910	1,752,965	1,187,151	795,732	671,851
Molecular Weight		28.75	30.23	30.23	30.27	30.89	29.04	35.42	34.73	34.25	34.25	36.92	36.92	37.44
Enthalpy, kW		3.06E+05	2.39E+05	2.50E+05	2.67E+05	1.67E+04	2.13E+05	5.34E+04	5.50E+04	5.88E+04	7.10E+04	4.58E+04	5.54E+04	4.44E+04
Vapor														
Molar Flow, kmol/hr		111,742	98,244	98,245	105,276	7,032	84,928	20,348	21,186	21,818	21,818	18,730	18,730	18,234
Mass Flow, kg/hr		3,212,986	2,969,633	2,969,635	3,186,820	217,185	2,466,073	720,747	735,848	747,229	747,229	691,590	691,590	682,654
Standard Volumetric Flow, Nm3/hr		2,505,019	2,199,748	2,199,748	2,361,362	158,023	1,903,456	456,111	474,966	489,332	489,332	420,197	420,197	408,525
Density, kg/m3 @ PT		1.064	1.187	1.277	1.284	1.425	1.155	0.137	0.202	0.291	0.426	0.583	0.869	1.016
Specific Heat, kJ/kg-K		1.080	1.010	1.010	1.010	0.980	1.020	0.968	0.985	1.000	1.040	0.921	0.956	0.910
Viscosity, cP		0.017	0.017	0.018	0.018	0.017	0.018	0.016	0.015	0.015	0.018	0.015	0.018	0.016
Thermal Conductivity,W/m-K		0.025	0.024	0.024	0.024	0.023	0.025	0.021	0.020	0.021	0.026	0.019	0.024	0.019
Compressibility		0.999	0.999	0.999	0.999	0.999	0.999	1.000	0.999	0.999	0.999	0.999	0.999	0.998
Components	mol weight	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac
Carbon Dioxide	44.0	0.1246	0.1417	0.1417	0.1423	0.1510	0.0485	0.5339	0.5128	0.4979	0.4979	0.5800	0.5800	0.5958
Nitrogen	28.0	0.6811	0.7747	0.7747	0.7737	0.7587	0.8891	0.2918	0.2803	0.2721	0.2721	0.3170	0.3170	0.3256
Argon	40.0	0.0081	0.0092	0.0092	0.0097	0.0166	0.0100	0.0086	0.0083	0.0080	0.0080	0.0093	0.0093	0.0096
Oxygen	32.0	0.0364	0.0414	0.0414	0.0434	0.0712	0.0467	0.0296	0.0284	0.0276	0.0276	0.0322	0.0322	0.0330
Water	18.0	0.1497	0.0329	0.0329	0.0309	0.0025	0.0057	0.1358	0.1700	0.1941	0.1941	0.0612	0.0612	0.0357
Sulfur Dioxide	64.1	3.70E-05	5.00E-06	5.00E-06	4.86E-06	2.95E-06	9.02E-07	2.14E-05	2.05E-05	1.99E-05	1.99E-05	2.32E-05	2.32E-05	2.38E-05
Nitrogen Dioxide	46.0	4.36E-05	4.88E-05	4.88E-05	4.74E-05	2.84E-05	8.81E-06	2.09E-04	2.00E-04	1.95E-04	1.95E-04	2.25E-04	2.25E-04	2.30E-04
Nitrogen Oxide	30.0	2.30E-06	2.61E-06	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Components		mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow
Carbon Dioxide		612,695	612,656	612,656	659,384	46,728	181,265	478,120	478,120	478,120	478,120	478,104	478,104	478,099
Nitrogen		2,132,169	2,132,167	2,132,167	2,281,620	149,453	2,115,290	166,330	166,330	166,330	166,330	166,330	166,330	166,330
Argon		36,154	36,154	36,154	40,815	4,661	33,820	6,996	6,996	6,996	6,996	6,996	6,996	6,996
Oxygen		130,141	130,141	130,141	146,155	16,014	126,877	19,278	19,278	19,278	19,278	19,278	19,278	19,278
Water		301,330	58,255	58,257	58,574	317	8,774	49,799	64,901	76,282	76,282	20,660	20,660	11,729
Sulfur Dioxide		265	31	31	33	1	5	28	28	28	28	28	28	28
Nitrogen Dioxide		224	221	221	230	9	34	195	195	195	195	194	194	193
Nitrogen Oxide		8	8	8	9	1	8	1	1	1	1	1	1	1
Liquid														
Molar Flow, kmol/hr		--	--	--	--	--	--	--	--	--	--	--	--	--
Mass Flow, kg/hr		--	--	--	--	--	--	--	--	--	--	--	--	--
Standard Volumetric Flow, m3/hr		--	--	--	--	--	--	--	--	--	--	--	--	--
Density, kg/m3 @ PT		--	--	--	--	--	--	--	--	--	--	--	--	--
Specific Heat, kJ/kg-K		--	--	--	--	--	--	--	--	--	--	--	--	--
Viscosity, cP		--	--	--	--	--	--	--	--	--	--	--	--	--
Surface Tension, dynes/cm		--	--	--	--	--	--	--	--	--	--	--	--	--
Thermal Conductivity, W/m-K		--	--	--	--	--	--	--	--	--	--	--	--	--
Components	mol weight	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac
Carbon Dioxide	44.0	--	--	--	--	--	--	--	--	--	--	--	--	--
Nitrogen	28.0	--	--	--	--	--	--	--	--	--	--	--	--	--
Argon	40.0	--	--	--	--	--	--	--	--	--	--	--	--	--
Oxygen	32.0	--	--	--	--	--	--	--	--	--	--	--	--	--
Water	18.0	--	--	--	--	--	--	--	--	--	--	--	--	--
Sulfur Dioxide	64.1	--	--	--	--	--	--	--	--	--	--	--	--	--
Nitrogen Dioxide	46.0	--	--	--	--	--	--	--	--	--	--	--	--	--
Nitrogen Oxide	30.0	--	--	--	--	--	--	--	--	--	--	--	--	--
Components		mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow
Carbon Dioxide		--	--	--	--	--	--	--	--	--	--	--	--	--
Nitrogen		--	--	--	--	--	--	--	--	--	--	--	--	--
Argon		--	--	--	--	--	--	--	--	--	--	--	--	--
Oxygen		--	--	--	--	--	--	--	--	--	--	--	--	--
Water		--	--	--	--	--	--	--	--	--	--	--	--	--
Sulfur Dioxide		--	--	--	--	--	--	--	--	--	--	--	--	--
Nitrogen Dioxide		--	--	--	--	--	--	--	--	--	--	--	--	--
Nitrogen Oxide		--	--	--	--	--	--	--	--	--	--	--	--	--

Stream Number		120	121	123	124	126	127	128	130	131	133	134	136	137	138	140	141	143
Stream Description		MemA Compressor Stage 3 Discharge	MemA Comp Stage3 Cooler Inlet with MemD Recycle	MemB Feed	MemB Permeate	MemB Fan 1 Discharge	MemB Fan 2 Discharge	MemB Compressor 1 Discharge	MemB Comp 1 Cooler Vapor Outlet	MemB Comp 2 Discharge	MemB Comp 2 Cooler Vapor Outlet	MemB Comp 3 Discharge	MemB Comp 3 Cooler Vapor Outlet	MemB Comp 4 Discharge	MemB Comp 4 Cooler Inlet	MemB Comp 4 Cooler Vapor Outlet	MemB Comp 5 Discharge	MemB Comp 5 Cooler Vapor Outlet
PFD Reference		PFD-02	PFD-02	PFD-02	PFD-02	PFD-03	PFD-03	PFD-03	PFD-03	PFD-03	PFD-03	PFD-03	PFD-03	PFD-03	PFD-03	PFD-03	PFD-03	PFD-03
Vapor Fraction (mole basis)		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Temperature, °C		80.2	78.8	20.6	20.6	25.9	35.7	92.9	20.6	75.6	20.6	75.6	20.6	75.7	68.0	20.6	92.3	20.6
Pressure, bar(a)		1.19	1.19	1.18	0.20	0.29	0.44	0.83	0.81	1.57	1.55	3.00	2.79	5.38	5.38	5.17	11.93	11.72
Total Molar Flow, kmol/hr		18,234	18,576	18,293	11,261	11,642	11,873	11,873	11,236	11,236	11,080	11,080	11,005	11,005	12,408	12,372	12,372	12,340
Total Mass Flow, kg/hr		682,654	696,042	690,945	473,760	480,620	484,780	484,780	473,304	473,304	470,480	470,480	469,128	469,128	529,091	528,436	528,436	527,863
Actual Volumetric Flow, m3/hr		448,312	455,509	378,009	1,373,876	981,852	699,215	433,149	335,213	206,304	172,659	106,205	94,906	58,351	64,266	56,813	30,504	24,080
Molecular Weight		37.44	37.47	37.77	42.07	41.28	40.83	40.83	42.12	42.12	42.46	42.46	42.63	42.63	42.64	42.71	42.71	42.78
Enthalpy, kW		5.49E+04	5.57E+04	4.44E+04	2.78E+04	2.94E+04	3.12E+04	3.83E+04	2.77E+04	3.40E+04	2.72E+04	3.34E+04	2.68E+04	3.30E+04	3.62E+04	2.98E+04	3.87E+04	2.88E+04
Vapor																		
Molar Flow, kmol/hr		18,234	18,576	18,293	11,261	11,642	11,873	11,873	11,236	11,236	11,080	11,080	11,005	11,005	12,408	12,372	12,372	12,340
Mass Flow, kg/hr		682,654	696,042	690,945	473,760	480,620	484,780	484,780	473,304	473,304	470,480	470,480	469,128	469,128	529,091	528,436	528,436	527,863
Standard Volumetric Flow, Nm3/hr		408,525	416,605	410,320	252,298	261,276	265,765	265,765	252,298	252,298	248,706	248,706	246,911	246,911	278,335	277,438	277,438	276,540
Density, kg/m3 @ PT		1.523	1.528	1.828	0.345	0.490	0.693	1.119	1.412	2.294	2.725	4.430	4.943	8.040	8.233	9.301	17.323	21.921
Specific Heat, kJ/kg-K		0.948	0.947	0.904	0.864	0.884	0.901	0.947	0.867	0.914	0.865	0.913	0.869	0.919	0.914	0.881	0.950	0.924
Viscosity, cP		0.018	0.018	0.016	0.015	0.015	0.015	0.018	0.015	0.017	0.015	0.017	0.015	0.018	0.017	0.015	0.018	0.015
Thermal Conductivity,W/m-K		0.024	0.024	0.019	0.017	0.017	0.018	0.023	0.017	0.022	0.017	0.022	0.017	0.022	0.021	0.017	0.024	0.018
Compressibility		0.998	0.998	0.996	0.999	0.999	0.998	0.998	0.996	0.995	0.992	0.991	0.985	0.984	0.982	0.973	0.969	0.938
Components	mol weight	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac
Carbon Dioxide	44.0	0.5958	0.5973	0.6065	0.8909	0.8618	0.8450	0.8450	0.8929	0.8929	0.9055	0.9055	0.9116	0.9116	0.9119	0.9146	0.9146	0.9169
Nitrogen	28.0	0.3256	0.3240	0.3290	0.0607	0.0587	0.0576	0.0576	0.0608	0.0608	0.0617	0.0617	0.0621	0.0621	0.0621	0.0623	0.0623	0.0624
Argon	40.0	0.0096	0.0094	0.0096	0.0052	0.0050	0.0049	0.0049	0.0052	0.0052	0.0053	0.0053	0.0053	0.0053	0.0048	0.0048	0.0048	0.0048
Oxygen	32.0	0.0330	0.0340	0.0345	0.0116	0.0112	0.0110	0.0110	0.0116	0.0116	0.0118	0.0118	0.0119	0.0119	0.0132	0.0132	0.0132	0.0133
Water	18.0	0.0357	0.0350	0.0201	0.0312	0.0628	0.0811	0.0811	0.0290	0.0290	0.0153	0.0153	0.0086	0.0086	0.0077	0.0048	0.0048	0.0022
Sulfur Dioxide	64.1	2.38E-05	2.34E-05	2.37E-05	3.67E-05	3.55E-05	3.48E-05	3.48E-05	3.68E-05	3.68E-05	3.73E-05	3.73E-05	3.75E-05	3.75E-05	3.35E-05	3.36E-05	3.36E-05	3.37E-05
Nitrogen Dioxide	46.0	2.30E-04	2.26E-04	2.29E-04	3.54E-04	3.42E-04	3.36E-04	3.36E-04	3.52E-04	3.52E-04	3.56E-04	3.56E-04	3.58E-04	3.58E-04	3.18E-04	3.19E-04	3.19E-04	3.18E-04
Nitrogen Oxide	30.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Components		mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow
Carbon Dioxide		478,099	488,285	488,281	441,552	441,552	441,552	441,552	441,541	441,541	441,536	441,536	441,532	441,532	497,993	497,989	497,989	497,981
Nitrogen		166,330	168,607	168,607	19,154	19,154	19,154	19,154	19,154	19,154	19,154	19,154	19,154	19,154	21,584	21,584	21,584	21,584
Argon		6,996	7,006	7,006	2,345	2,345	2,345	2,345	2,345	2,345	2,345	2,345	2,345	2,345	2,355	2,355	2,355	2,355
Oxygen		19,278	20,192	20,192	4,178	4,178	4,178	4,178	4,178	4,178	4,178	4,178	4,178	4,178	5,238	5,238	5,238	5,238
Water		11,729	11,729	6,637	6,321	13,181	17,341	17,341	5,877	5,877	3,060	3,060	1,712	1,712	1,712	1,061	1,061	497
Sulfur Dioxide		28	28	28	26	26	26	26	26	26	26	26	26	26	27	27	27	27
Nitrogen Dioxide		193	193	193	183	183	183	183	182	182	182	182	181	181	182	181	181	181
Nitrogen Oxide		1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Liquid																		
Molar Flow, kmol/hr		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Mass Flow, kg/hr		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Standard Volumetric Flow, m3/hr		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Density, kg/m3 @ PT		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Specific Heat, kJ/kg-K		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Viscosity, cP		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Surface Tension, dynes/cm		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Thermal Conductivity, W/m-K		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Components	mol weight	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac
Carbon Dioxide	44.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Nitrogen	28.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Argon	40.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Oxygen	32.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Water	18.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Sulfur Dioxide	64.1	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Nitrogen Dioxide	46.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Nitrogen Oxide	30.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Components		mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow
Carbon Dioxide		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Nitrogen		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Argon		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Oxygen		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Water		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Sulfur Dioxide		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Nitrogen Dioxide		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Nitrogen Oxide		--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--

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Flow rates are total plant flow rates. The total flow rate in the stream table should be divided by the number of trains indicated on the PFD to calculate the flow rate to each piece of equipment.

Stream Number		144	146	147	147A	148	149	150	151	156	157	158	159	160	161
Stream Description		**MemB Comp 6 Discharge**	**MemB Comp 6 Cooler Vapor Outlet**	**Dehy Feed Chiller Outlet**	**Dehy Feed Separator Vapor Outlet**	**Superheated Dehydration Inlet**	**Dry CO2 to Reboiler / CO2 Cross Exchanger**	**CO2 Condenser Inlet**	**CO2 Distillation Column Inlet**	**CO2 Distillation Column Bottoms**	**CO2 Product from CO2 Booster Pump**	**CO2 Product from CO2 Product Pump**	**CO2 Product from CO2 Product Heater 1**	**CO2 Product from CO2 Product Heater 2**	**CO2 Distillation Column Overheads**
PFD Reference		PFD-03	PFD-03	PFD-04	PFD-04	PFD-04	PFD-04	PFD-05	PFD-05	PFD-05	PFD-05	PFD-05	PFD-05	PFD-05	PFD-05
Vapor Fraction (mole basis)		1.00	1.00	0.999	1.00	1.00	1.00	1.00	0.12	0.00	0.00	0.00	0.00	0.00	1.00
Temperature, °C		93.3	20.6	10.0	10.0	15.6	15.6	-7.0	-35.0	-12.0	-11.8	-0.5	15.6	20.0	-31.5
Pressure, bar(a)		27.03	26.82	26.61	26.61	26.41	25.92	25.72	25.51	24.96	27.00	153.00	152.79	152.59	24.82
Total Molar Flow, kmol/hr		12,340	12,327	12,327	12,320	12,320	12,313	12,313	12,313	9,793	9,793	9,793	9,793	9,793	2,520
Total Mass Flow, kg/hr		527,863	527,611	527,611	527,483	527,483	527,352	527,352	527,352	430,992	430,992	430,992	430,992	430,992	96,361
Actual Volumetric Flow, m3/hr		12,903	9,510	9,020	9,020	9,414	9,621	8,393	1,399	426	426	419	454	466	1,706
Molecular Weight		42.78	42.80	42.80	42.82	42.82	42.83	42.83	42.83	44.01	44.01	44.01	44.01	44.01	38.24
Enthalpy, kW		3.74E+04	2.65E+04	2.48E+04	2.49E+04	2.58E+04	2.59E+04	2.23E+04	-1.98E+04	-1.54E+04	-1.54E+04	-1.31E+04	-8.60E+03	-7.25E+03	4.19E+03
Vapor															
Molar Flow, kmol/hr		12,340	12,327	12,320	12,320	12,320	12,313	12,313	1,478	--	--	--	--	--	2,520
Mass Flow, kg/hr		527,863	527,611	527,483	527,483	527,483	527,352	527,352	54,824	--	--	--	--	--	96,361
Standard Volumetric Flow, Nm3/hr		276,540	276,540	276,540	276,540	276,540	275,642	275,642	33,131	--	--	--	--	--	56,475
Density, kg/m3 @ PT		40.911	55.481	58.483	58.483	56.034	54.813	62.831	56.526	--	--	--	--	--	56.493
Specific Heat, kJ/kg-K		1.010	1.060	1.080	1.080	1.070	1.060	1.120	1.080	--	--	--	--	--	1.070
Viscosity, cP		0.019	0.016	0.016	0.016	0.016	0.016	0.015	0.015	--	--	--	--	--	0.015
Thermal Conductivity,W/m-K		0.026	0.020	0.020	0.020	0.020	0.020	0.018	0.019	--	--	--	--	--	0.018
Compressibility		0.930	0.850	0.831	0.831	0.844	0.847	0.796	0.848	--	--	--	--	--	0.838
Components	mol weight	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac
Carbon Dioxide	44.0	0.9169	0.9179	0.9184	0.9184	0.9184	0.9190	0.9190	0.5344	--	--	--	--	--	0.6059
Nitrogen	28.0	0.0624	0.0625	0.0625	0.0625	0.0625	0.0626	0.0626	0.3775	--	--	--	--	--	0.3058
Argon	40.0	0.0048	0.0048	0.0048	0.0048	0.0048	0.0048	0.0048	0.0242	--	--	--	--	--	0.0234
Oxygen	32.0	0.0133	0.0133	0.0133	0.0133	0.0133	0.0133	0.0133	0.0639	--	--	--	--	--	0.0649
Water	18.0	0.0022	0.0011	0.0006	0.0006	0.0006	0.0000	0.0000	0.0000	--	--	--	--	--	0.0000
Sulfur Dioxide	64.1	3.37E-05	3.37E-05	3.37E-05	3.37E-05	3.37E-05	3.38E-05	3.38E-05	1.17E-06	--	--	--	--	--	0.0000
Nitrogen Dioxide	46.0	3.18E-04	3.17E-04	3.17E-04	3.17E-04	3.17E-04	3.17E-04	3.17E-04	5.25E-06	--	--	--	--	--	0.0000
Nitrogen Oxide	30.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	--	--	--	--	--	0.0000
Components		mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow
Carbon Dioxide		497,981	497,974	497,969	497,969	497,969	497,969	497,969	34,750	--	--	--	--	--	67,186
Nitrogen		21,584	21,584	21,584	21,584	21,584	21,584	21,584	15,624	--	--	--	--	--	21,584
Argon		2,355	2,355	2,355	2,355	2,355	2,355	2,355	1,430	--	--	--	--	--	2,354
Oxygen		5,238	5,238	5,238	5,238	5,238	5,238	5,238	3,019	--	--	--	--	--	5,235
Water		497	253	131	131	131	0	0	0	--	--	--	--	--	0
Sulfur Dioxide		27	27	27	27	27	27	27	0	--	--	--	--	--	0
Nitrogen Dioxide		181	180	180	180	180	180	180	0	--	--	--	--	--	1
Nitrogen Oxide		0	0	0	0	0	0	0	0	--	--	--	--	--	0
Liquid															
Molar Flow, kmol/hr		--	--	6.9	--	--	--	--	10,835	9,793	9,793	9,793	9,793	9,793	--
Mass Flow, kg/hr		--	--	127	--	--	--	--	472,528	430,992	430,992	430,992	430,992	430,992	--
Standard Volumetric Flow, m3/hr		--	--	0	--	--	--	--	593	528	528	528	528	528	--
Density, kg/m3 @ PT		--	--	1,011.10	--	--	--	--	1,100.30	1,011.12	1,011.37	1,028.43	948.88	923.96	--
Specific Heat, kJ/kg-K		--	--	4.220	--	--	--	--	1.940	2.530	2.520	2.230	2.490	2.570	--
Viscosity, cP		--	--	1.3500	--	--	--	--	0.1830	0.1300	0.1310	0.1360	0.1090	0.1020	--
Surface Tension, dynes/cm		--	--	73.01	--	--	--	--	11.33	6.80	6.76	4.60	1.88	1.24	--
Thermal Conductivity, W/m-K		--	--	0.566	--	--	--	--	0.140	0.124	0.124	0.130	0.116	0.112	--
Components	mol weight	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac
Carbon Dioxide	44.0	--	--	0.0163	--	--	--	--	0.9714	0.9996	0.9996	0.9996	0.9996	0.9996	--
Nitrogen	28.0	--	--	0.0000	--	--	--	--	0.0196	1.59E-07	1.59E-07	1.59E-07	1.59E-07	1.59E-07	--
Argon	40.0	--	--	0.0000	--	--	--	--	0.0021	8.30E-07	8.30E-07	8.30E-07	8.30E-07	8.30E-07	--
Oxygen	32.0	--	--	0.0000	--	--	--	--	0.0064	8.49E-06	8.49E-06	8.49E-06	8.49E-06	8.49E-06	--
Water	18.0	--	--	0.9823	--	--	--	--	0.0000	1.46E-06	1.46E-06	1.46E-06	1.46E-06	1.46E-06	--
Sulfur Dioxide	64.1	--	--	0.0000	--	--	--	--	0.0000	4.21E-05	4.21E-05	4.21E-05	4.21E-05	4.21E-05	--
Nitrogen Dioxide	46.0	--	--	0.0014	--	--	--	--	0.0004	3.97E-04	3.97E-04	3.97E-04	3.97E-04	3.97E-04	--
Nitrogen Oxide	30.0	--	--	0.0000	--	--	--	--	0.0000	1.95E-10	1.95E-10	1.95E-10	1.95E-10	1.95E-10	--
Components		mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow
Carbon Dioxide		--	--	4.9	--	--	--	--	463,219	430,784	430,784	430,784	430,784	430,784	--
Nitrogen		--	--	0	--	--	--	--	5,960	0	0	0	0	0	--
Argon		--	--	0	--	--	--	--	925	0	0	0	0	0	--
Oxygen		--	--	0	--	--	--	--	2,219	3	3	3	3	3	--
Water		--	--	122	--	--	--	--	0	0	0	0	0	0	--
Sulfur Dioxide		--	--	0	--	--	--	--	27	26	26	26	26	26	--
Nitrogen Dioxide		--	--	0	--	--	--	--	179	179	179	179	179	179	--
Nitrogen Oxide		--	--	0	--	--	--	--	0	0	0	0	0	0	--

Stream Number	162	163	164	166	167	202	212	222	223	224	227	228	230	231	232
Stream Description	**MemC Inlet**	**MemD Inlet**	**MemD Retentate**	**MemD Permeate Recycle**	**MemC Permeate Recycle**	**Water Purge from SO2 Polisher**	**Water Purge from DCC**	**Water from MemA Comp 1 Cooler**	**Water from MemA Comp 2 Cooler**	**Water from MemA Comp 3 Cooler**	**MemA Fan 1 Water Injection**	**MemA Fan 2 Water Injection**	**Water from MemB Comp 1 Cooler**	**Water from MemB Comp 2 Cooler**	**Water from MemB Comp 3 Cooler**
PFD Reference	PFD-05	PFD-05	PFD-05	PFD-05	PFD-05	PFD-01	PFD-01	PFD-02	PFD-02	PFD-02	PFD-02	PFD-02	PFD-03	PFD-03	PFD-03
Vapor Fraction (mole basis)	1.00	1.00	1.00	1.00	1.00			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Temperature, °C	27.2	27.2	27.2	7.8	6.6			20.6	20.6	20.6	27.3	27.3	20.6	20.6	20.6
Pressure, bar(a)	24.61	24.56	24.51	1.19	5.50			0.38	0.66	1.18	3.00	3.00	0.81	1.55	2.79
Total Molar Flow, kmol/hr	2,520	1,117	775	342	1,403			3,088	496	283	838	632	637	157	75
Total Mass Flow, kg/hr	96,361	36,396	23,008	13,388	59,963			55,640	8,936	5,097	15,101	11,381	11,476	2,823	1,352
Actual Volumetric Flow, m3/hr	2,362	1,102	780	6,666	5,733			56	9	5	15	11	12	3	1
Molecular Weight	38.24	32.60	29.69	39.20	42.74			18.02	18.02	18.03	18.02	18.02	18.03	18.04	18.05
Enthalpy, kW	5.81E+03	2.60E+03	1.80E+03	7.89E+02	3.18E+03			-2.99E+04	-4.79E+03	-2.74E+03	-7.99E+03	-6.02E+03	-6.16E+03	-1.52E+03	-7.24E+02
Vapor															
Molar Flow, kmol/hr	2,520	1,117	775	342	1,403			--	--	--	--	--	--	--	--
Mass Flow, kg/hr	96,361	36,396	23,008	13,388	59,963			--	--	--	--	--	--	--	--
Standard Volumetric Flow, Nm3/hr	56,475	25,050	17,329	7,659	31,425			--	--	--	--	--	--	--	--
Density, kg/m3 @ PT	40.799	33.037	29.479	2.009	10.459			--	--	--	--	--	--	--	--
Specific Heat, kJ/kg-K	1.000	1.000	1.010	0.877	0.874			--	--	--	--	--	--	--	--
Viscosity, cP	0.017	0.018	0.019	0.015	0.015			--	--	--	--	--	--	--	--
Thermal Conductivity,W/m-K	0.022	0.025	0.026	0.018	0.016			--	--	--	--	--	--	--	--
Compressibility	0.925	0.970	0.987	0.995	0.967			--	--	--	--	--	--	--	--
Components	mol frac	mol frac	mol frac	mol frac	mol frac			mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac
Carbon Dioxide	0.6059	0.2182	0.0157	0.6776	0.9144			--	--	--	--	--	--	--	--
Nitrogen	0.3058	0.6124	0.7774	0.2380	0.0618			--	--	--	--	--	--	--	--
Argon	0.0234	0.0526	0.0754	0.0007	0.0002			--	--	--	--	--	--	--	--
Oxygen	0.0649	0.1169	0.1315	0.0836	0.0236			--	--	--	--	--	--	--	--
Water	0.0000	0.0000	0.0000	0.0000	0.0000			--	--	--	--	--	--	--	--
Sulfur Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000			--	--	--	--	--	--	--	--
Nitrogen Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000			--	--	--	--	--	--	--	--
Nitrogen Oxide	0.0000	0.0000	0.0000	0.0000	0.0000			--	--	--	--	--	--	--	--
Components	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow
Carbon Dioxide	67,186	10,723	536	10,186	56,462			--	--	--	--	--	--	--	--
Nitrogen	21,584	19,154	16,876	2,277	2,430			--	--	--	--	--	--	--	--
Argon	2,354	2,345	2,334	10	10			--	--	--	--	--	--	--	--
Oxygen	5,235	4,175	3,261	914	1,060			--	--	--	--	--	--	--	--
Water	0	0	0	0	0			--	--	--	--	--	--	--	--
Sulfur Dioxide	0	0	0	0	0			--	--	--	--	--	--	--	--
Nitrogen Dioxide	1	0	0	0	1			--	--	--	--	--	--	--	--
Nitrogen Oxide	0	0	0	0	0			--	--	--	--	--	--	--	--
Liquid															
Molar Flow, kmol/hr	--	--	--	--	--			3,088	496	283	838	632	637	157	75
Mass Flow, kg/hr	--	--	--	--	--			55,640	8,936	5,097	15,101	11,381	11,476	2,823	1,352
Standard Volumetric Flow, m3/hr	--	--	--	--	--			56	9	5	15	11	11	3	1
Density, kg/m3 @ PT	--	--	--	--	--			997.61	997.67	997.79	995.55	995.55	997.79	998.04	998.46
Specific Heat, kJ/kg-K	--	--	--	--	--			4.220	4.220	4.220	4.220	4.220	4.220	4.220	4.220
Viscosity, cP	--	--	--	--	--			0.9880	0.9890	0.9890	0.8450	0.8450	0.9890	0.9900	0.9910
Surface Tension, dynes/cm	--	--	--	--	--			72.64	72.64	72.62	71.61	71.61	72.62	72.60	72.55
Thermal Conductivity, W/m-K	--	--	--	--	--			0.601	0.601	0.601	0.611	0.611	0.601	0.600	0.599
Components	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac
Carbon Dioxide	--	--	--	--	--			0.0001	0.0002	0.0004	0.0000	0.0000	0.0004	0.0007	0.0014
Nitrogen	--	--	--	--	--			0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Argon	--	--	--	--	--			0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Oxygen	--	--	--	--	--			0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Water	--	--	--	--	--			0.9999	0.9998	0.9996	1.0000	1.0000	0.9996	0.9992	0.9985
Sulfur Dioxide	--	--	--	--	--			0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen Dioxide	--	--	--	--	--			0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001
Nitrogen Oxide	--	--	--	--	--			0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Components	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	mass flow
Carbon Dioxide	--	--	--	--	--			16	5	5	0	0	11	5	4
Nitrogen	--	--	--	--	--			0	0	0	0	0	0	0	0
Argon	--	--	--	--	--			0	0	0	0	0	0	0	0
Oxygen	--	--	--	--	--			0	0	0	0	0	0	0	0
Water	--	--	--	--	--			55,622	8,931	5,092	15,101	11,381	11,464	2,817	1,347
Sulfur Dioxide	--	--	--	--	--			0	0	0	0	0	0	0	0
Nitrogen Dioxide	--	--	--	--	--			2	1	1	0	0	1	1	1
Nitrogen Oxide	--	--	--	--	--			0	0	0	0	0	0	0	0

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Flow rates are total plant flow rates. The total flow rate in the stream table should be divided by the number of trains indicated on the PFD to calculate the flow rate to each piece of equipment.

Stream Number		233	234	235	236	240	241	
Stream Description		**Water from MemB Comp 4 Cooler**	**Water from MemB Comp 5 Cooler**	**Water from MemB Comp 6 Cooler**	**Water from Dehy Feed Separator**	**MemB Fan 1 Water Injection**	**MemB Fan 2 Water Injection**	
PFD Reference		PFD-03	PFD-03	PFD-03	PFD-04	PFD-03	PFD-03	
Vapor Fraction (mole basis)		0.00	0.00	0.00	0.00	0.00	0.00	
Temperature, °C		20.6	20.6	20.6	10.0	27.2	27.2	
Pressure, bar(a)		5.17	11.72	26.82	26.61	3.00	3.00	
Total Molar Flow, kmol/hr		36	32	14	7	381	231	
Total Mass Flow, kg/hr		655	573	252	127	6,860	4,160	
Actual Volumetric Flow, m3/hr		1	1	0	0	7	4	
Molecular Weight		18.09	18.18	18.37	18.48	18.02	18.02	
Enthalpy, kW		-3.49E+02	-3.03E+02	-1.31E+02	-6.71E+01	-3.63E+03	-2.20E+03	
Vapor								
Molar Flow, kmol/hr		--	--	--	--	--	--	
Mass Flow, kg/hr		--	--	--	--	--	--	
Standard Volumetric Flow, Nm3/hr		--	--	--	--	--	--	
Density, kg/m3 @ PT		--	--	--	--	--	--	
Specific Heat, kJ/kg-K		--	--	--	--	--	--	
Viscosity, cP		--	--	--	--	--	--	
Thermal Conductivity,W/m-K		--	--	--	--	--	--	
Compressibility		--	--	--	--	--	--	
Components	mol weight	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	
Carbon Dioxide	44.0	--	--	--	--	--	--	
Nitrogen	28.0	--	--	--	--	--	--	
Argon	40.0	--	--	--	--	--		
Oxygen	32.0	--	--	--	--	--	--	
Water	18.0	--	--	--	--	--	--	
Sulfur Dioxide	64.1	--	--	--	--	--	--	
Nitrogen Dioxide	46.0	--	--	--	--	--	--	
Nitrogen Oxide	30.0	--	--	--	--	--	--	
Components		mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	
Carbon Dioxide		--	--	--	--	--	--	
Nitrogen		--	--	--	--	--	--	
Argon		--	--	--	--	--	--	
Oxygen		--	--	--	--	--	--	
Water		--	--	--	--	--	--	
Sulfur Dioxide		--	--	--	--	--	--	
Nitrogen Dioxide		--	--	--	--	--	--	
Nitrogen Oxide		--	--	--	--	--	--	
Liquid								
Molar Flow, kmol/hr		36	32	14	7	381	231	
Mass Flow, kg/hr		655	573	252	127	6,860	4,160	
Standard Volumetric Flow, m3/hr		1	1	0	0	7	4	
Density, kg/m3 @ PT		999.22	1,001.29	1,005.67	1,011.10	995.59	995.59	
Specific Heat, kJ/kg-K		4.220	4.220	4.230	4.220	4.220	4.220	
Viscosity, cP		0.9940	1.0000	1.0200	1.3500	0.8470	0.8470	
Surface Tension, dynes/cm		72.47	72.23	71.73	73.01	71.63	71.63	
Thermal Conductivity, W/m-K		0.598	0.594	0.587	0.566	0.611	0.611	
Components	mol weight	mol frac	mol frac	mol frac	mol frac	mol frac	mol frac	
Carbon Dioxide	44.0	0.0025	0.0056	0.0125	0.0163	0.0000	0.0000	
Nitrogen	28.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
Argon	40.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
Oxygen	32.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
Water	18.0	0.9973	0.9939	0.9866	0.9823	1.0000	1.0000	
Sulfur Dioxide	64.1	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
Nitrogen Dioxide	46.0	0.0002	0.0005	0.0009	0.0014	0.0000	0.0000	
Nitrogen Oxide	30.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
Components		mass flow	mass flow	mass flow	mass flow	mass flow	mass flow	
Carbon Dioxide		4	8	8	5	0	0	
Nitrogen		0	0	0	0	0	0	
Argon		0	0	0	0	0	0	
Oxygen		0	0	0	0	0	0	
Water		651	564	244	122	6,860	4,160	
Sulfur Dioxide		0	0	0	0	0	0	
Nitrogen Dioxide		0	1	1	0	0	0	
Nitrogen Oxide		0	0	0	0	0	0	

APPENDIX D: MTR EQUIPMENT LIST

Tag	Equipment Type	Category	Description	Quantity	PFD No.
C-111A-B	Fan	Compressors/Turbines/Fans	FLUE GAS BOOSTER FAN	2	PFD-02
C-115A-F	Compressor	Compressors/Turbines/Fans	MEMA Compressor Stage 1	6	PFD-02
C-117A-F	Compressor	Compressors/Turbines/Fans	MEMA Compressor Stage 2		PFD-02
C-119A-F	Compressor	Compressors/Turbines/Fans	MEMA Compressor Stage 3		PFD-02
C-133A-B	Compressor	Compressors/Turbines/Fans	Membrane B Compressor 1	2	PFD-03
C-135A-B	Compressor	Compressors/Turbines/Fans	Membrane B Compressor 2		PFD-03
C-140A-B	Compressor	Compressors/Turbines/Fans	Membrane B Compressor 3		PFD-03
C-142A-B	Compressor	Compressors/Turbines/Fans	Membrane B Compressor 4		PFD-03
C-144A-B	Compressor	Compressors/Turbines/Fans	Membrane B Compressor 5		PFD-03
C-146A-B	Compressor	Compressors/Turbines/Fans	Membrane B Compressor 6		PFD-03
C-113A-N	Fan	Compressors/Turbines/Fans	Membrane A Fan 1	14	PFD-02
C-114A-N	Fan	Compressors/Turbines/Fans	Membrane A Fan 2	14	PFD-02
C-131A-C	Fan	Compressors/Turbines/Fans	Membrane B Fan 1	3	PFD-03
C-132A-C	Fan	Compressors/Turbines/Fans	Membrane B Fan 2	3	PFD-03
P-103A-B	Pump	Pumps	DCC Pump	4	PFD-01
P-104A-B	Pump	Pumps	SO2 Polisher Pump	4	PFD-01
P-173A-B	Pump	Pumps	CO2 Booster Pump	4	PFD-05
P-174A-B	Pump	Pumps	CO2 Product Pump	3	PFD-05
E-102A-D	Exchanger	Exchangers	DCC WSAC	4	PFD-01
E-116A-F	Exchanger	Exchangers	MEMA Compressor Stage 1 Cooler	6	PFD-02
E-118A-F	Exchanger	Exchangers	MEMA Compressor Stage 2 Cooler	6	PFD-02
E-120A-D	Exchanger	Exchangers	MEMA Compressor Stage 3 Cooler	4	PFD-02
E-134A-B	Exchanger	Exchangers	Membrane B Compressor 1 Cooler	2	PFD-03
E-136A-B	Exchanger	Exchangers	membrane B Compressor 2 Cooler	2	PFD-03
E-141A-B	Exchanger	Exchangers	Membrane B Compressor 3 Cooler	2	PFD-03
E-143A-B	Exchanger	Exchangers	Membrane B Compressor 4 Cooler	2	PFD-03
E-145A-B	Exchanger	Exchangers	Membrane B Compressor 5 Cooler	2	PFD-03
E-147A-B	Exchanger	Exchangers	Membrane B Compressor 6 Cooler	2	PFD-03
E-150A-B	Exchanger	Exchangers	Dehydration Feed Chiller	2	PFD-04
E-152A-B	Exchanger	Exchangers	Dehydration Feed Heater (Refrigerant Subcooler)	2	PFD-04
E-154A-B	Exchanger	Exchangers	Regen Heater (Electric)	2	PFD-04
E-161A-D	Exchanger	Exchangers	CO2 Condenser	4	PFD-05
E-163A-B	Exchanger	Exchangers	Column Overhead Heater 1 (Refrigerant Subcooler)	2	PFD-05
E-164	Exchanger	Exchangers	Column Overhead Heater 2 (Refrigerant Subcooler)	1	PFD-05
E-170A-B	Exchanger	Exchangers	Reboiler (CO2 Cross Exchanger)	2	PFD-05
E-171A-B	Exchanger	Exchangers	Auxiliary Reboiler 1 (Refrigerant Subcooler)	2	PFD-05
E-172A-B	Exchanger	Exchangers	Auxiliary Reboiler 2 (Refrigerant Subcooler)	2	PFD-05
E-175A-B	Exchanger	Exchangers	CO2 Product Heater 1 (Refrigerant Subcooler)	2	PFD-05
E-176A-B	Exchanger	Exchangers	CO2 Product Heater 2 (Refrigerant Subcooler)	2	PFD-05
T-101A-B	Column	Contactors	Direct Contact Cooler / SO2 Polisher	2	PFD-01
T-162A-B	Column	Contactors	CO2 Distillation Column	2	PFD-05
MEM-112	Membrane	Contactors	Membrane A	TBD	PFD-02
MEM-121	Membrane	Contactors	Membrane B	TBD	PFD-02
MEM-165	Membrane	Contactors	Membrane C	TBD	PFD-05
MEM-166	Membrane	Contactors	Membrane D	TBD	PFD-05
V-151A-B	Drum	Vessels	Dehydration Feed Separator	2	PFD-04
V-153A-D	Drum	Vessels	Dehydration Bed	4	PFD-04
V-154A-D	Drum	Vessels	Dehydration Bed	4	PFD-04
V-100	Tank	Tanks	Recycled Water Storage Tank	1	N/A
V-200	Tank	Tanks	Wastewater Storage Tank	1	N/A
V-300	Tank	Tanks	Caustic Storage Tank	1	N/A
N/A	CPU System	N/A	CPU Package	1	N/A

APPENDIX B

TECHNOLOGY GAP ANALYSIS

APPENDIX B

TECHNOLOGY GAP ANALYSIS

DE-FE0031591

Scale-Up Testing of Advanced Polaris Membrane CO_2 Capture Technology

The objective of this Technology Gap Analysis is to review the current state of development of all major process components of Membrane Technology and Research, Inc.'s (MTR) post-combustion CO_2 capture process and to provide a realistic review of all research needs required to fully develop the technology to commercialization. This report will guide the focus of future research and development (R&D) efforts related to the MTR CO_2 capture process.

1. Review of the MTR Membrane Post-Combustion CO_2 Capture Process

MTR has been developing the Polaris™ membrane and associated CO_2 capture process with the U.S. Department of Energy (DOE) for over a decade. A timeline showing program development from the first feasibility program in 2007 to recently completed full-scale power and industrial front-end engineering design (FEED) studies is shown in Figure 1. During this time, the first generation (Gen-1) of our Polaris CO_2 capture technology advanced through progressively larger field demonstrations, including operation of a small pilot system in slipstream tests at the National Carbon Capture Center (NCCC) and in an integrated test at the Babcock & Wilcock (B&W) Research Center. These activities advanced our membrane capture technology through TRL-6 (prototype validated in relevant environment). In a currently DOE-funded program, a large pilot system is in the procurement phase with commissioning on coal-fired flue gas expected during the summer of 2024. This work will bring the Polaris technology to near commercial status (TRL-8).

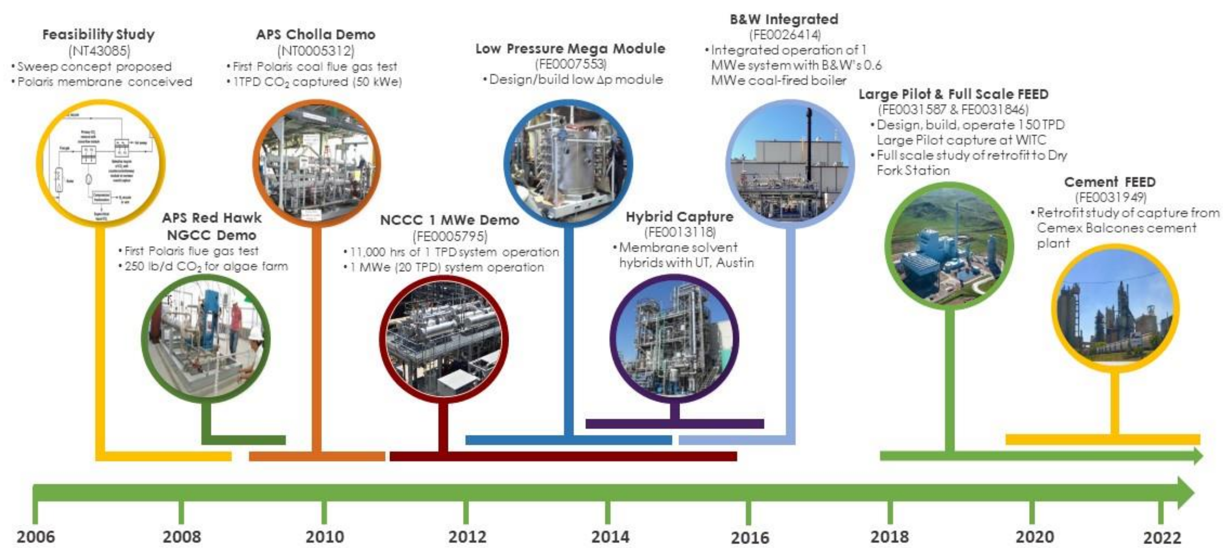

Figure 1. MTR/DOE CO_2 capture development timeline.

Developments over the past 15 years, summarized in Figure 1, include the creation of the high-performance Polaris membrane, fabrication of new low-pressure-drop membrane modules, and recently, completion of a FEED study to produce an engineering package for full-scale commercial installation. Earlier work has shown that the MTR process has the potential to capture CO_2 from coal-fired flue gas at the DOE capture cost target of <$40/tonne CO_2 (2018 USD). This promise has been verified in multiple pilot tests starting with NCCC, where commercial-sized Polaris membrane modules accumulated >11,000 hours of operation on coal-derived flue gas. This prior work included scale-up to the small pilot stage (1 MW_e or 20 TPD) that operated in slipstream tests at NCCC, and later in a fully integrated coal boiler test at a B&W research facility in Ohio. More recently, in this project, a second-generation (Gen-2) Polaris membrane and commercial membrane modules were successfully tested at the Technology Center Mongstad (TCM) in Norway in 2021 and 2022.

Our prior work with DOE has shown that the MTR membrane capture process offers a number of attractive features. In particular, for cases where environmental emissions or water shortage issues may preclude the use of amine absorption, membranes provide a viable clean capture option. In addition, membranes are a modular technology with simple, passive operation and a flexible footprint. Moreover, membrane systems use only electricity (no steam), so they can powered by renewables, avoiding the use of fossil fuel-fired steam boilers.

Over the years, the Polaris membrane and associated MTR capture process have been the subject of numerous comparative capture cost studies. For example, a DOE/NETL report on future technologies for post-combustion CO_2 capture (the Pathways Study) compares the MTR membrane approach favorably with various amine processes.[1] This study shows a membrane system using advanced Polaris membranes capturing 90% of the CO_2 from an ultra-supercritical coal plant, while meeting the DOE target of a 35% increase in cost of electricity (COE) with a cost of CO_2 avoided of <$40/tonne. More recently, researchers at SINTEF examined a membrane capture process modeled on the MTR design, and found a cost-of-capture for cement plant flue gas that was 9% lower than capture using the reference monoethanolamine (MEA) process.[2] Finally, in one of the recently completed MTR FEED studies, Sargent & Lundy (S&L) and the project team conducted a detailed cost estimate for a full-scale MTR capture system installed at the Dry Fork Station (DFS) coal-fired power plant located outside Gillette, WY. This analysis yielded a capture cost of $57.64/tonne CO_2 in Spring 2022 dollars. Given the large escalation (>30%) in material and labor costs in last 2+ years, we believe this value is competitive with any of the alternative capture technologies.

A simplified process flow diagram (PFD) for a full-scale retrofit of a MTR system at a large point source emitter is shown in Figure 2. After leaving the existing plant ID fans, new ducting diverts the flue gas prior to it reaching the plant stack. The flue gas is then routed to a direct contact cooler (DCC) where it is cooled to approximately 40°C. A flue gas booster fan provides sufficient pressure-drop to move the cooled gas through the membrane capture system. A first-stage membrane (Membrane A) selectively removes CO_2 from the flue gas using a permeate vacuum compressor to provide driving force. The retentate from this membrane stage is depleted in CO_2 and is recycled back to the existing stack for discharge to the atmosphere.

The CO_2-enriched permeate from Membrane A is recompressed to just above atmospheric pressure and sent to a second-stage membrane (Membrane B) where again vacuum compressors provide driving force for separation. The Membrane B permeate is enriched to >85 mol% CO_2 and routed to CO_2 dehydration, followed by liquefaction and purification. CO_2 product pumps are used to bring this high-purity liquid CO_2 to the required sequestration pressure (152.6 bar). Much smaller membrane steps (Membranes C and D) are used to improve the efficiency of the compression and purification unit (CPU). Also shown in the diagram are the refrigeration cycle, water lines and cooling tower required by the capture plant.

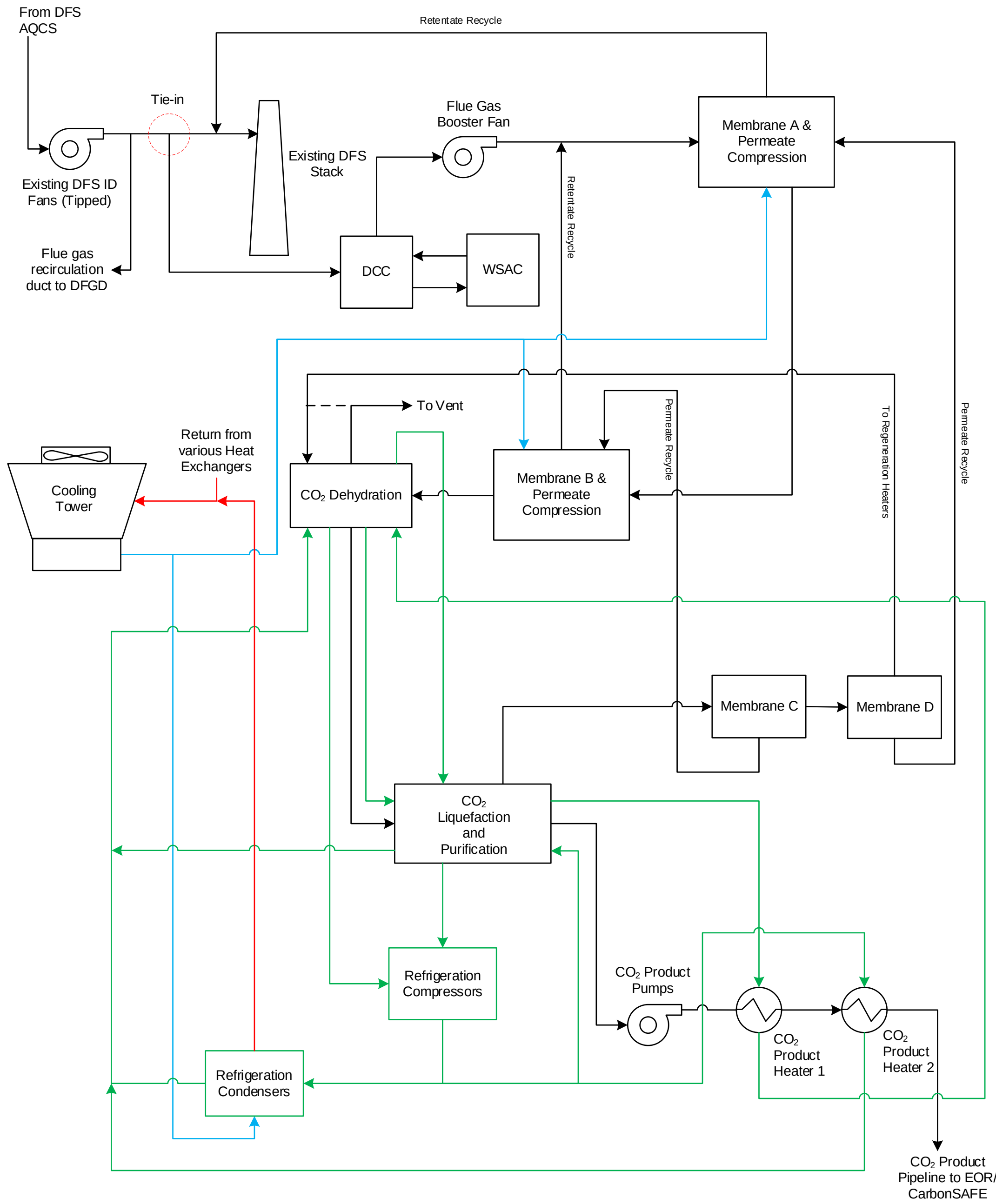

Figure 2. Simplified PFD of MTR's CO_2 capture process.

2. MTR Membrane Post-Combustion CO_2 Capture Process Key Components Technology Readiness Level and Research Summary

A summary of the important components of the MTR membrane post-combustion CO_2 capture process is given in Table 1. The MTR Polaris membrane is the only key component with currently active research. A summary of Polaris membrane research to date is provided below while the following section will detail the focus of future research efforts. The final section of this report will provide details on commercially-available components of the MTR membrane post-combustion CO_2 capture process.

Table 1. Key Components of the MTR Membrane Post-Combustion CO_2 Capture Process.

Component	Function in MTR Membrane CO_2 Capture Process	TRL	Vendor
Flue Gas Blower	Provide sufficient pressure to move flue gas through membrane capture system	9	Multiple, including Howden
Direct Contact Cooler	Cools flue gas prior to entering membrane units. Optional caustic wash provides deep removal of SO_2 in flue gas	9	Multiple, including MacroTek
Polaris Membrane (Membrane A)	Selectively removes CO_2 from flue gas	6*	MTR
Polaris Membrane (Membrane B)	Selectively removes CO_2 from the Membrane A permeate to send a high CO_2 content gas stream to CO_2 dehydration and CPU unit-operations	6*	MTR
Membranes A and B Permeate Compression	Fans and compressors create a vacuum to provide a driving force for CO_2 removal	9	Multiple, including Piller and Atlas Copco
CO_2 Purification Unit	Compresses, dries, and purifies the Membrane B permeate gas stream to produce high-purity, liquid CO_2	9	Multiple, including Salof, Linde and Pentair
Polaris Membrane (Membranes C and D)	Recover and recycle CO_2 from CPU condenser overhead gas stream	6*	MTR

***** Polaris membrane is designated TRL 6 for carbon capture based on field tests conducted at NCCC, B&W and TCM. However, MTR uses Polaris commercially (TRL 9) for other industrial applications such as natural gas treatment.

Polaris Membrane Research

MTR's Polaris membrane is a class of thin-film polymeric composite membranes that sets the standard against which other post-combustion capture membranes are now compared.[3] The proprietary Polaris selective layer is based on polar polymers that are extremely permeable to CO_2 and other polar species. Gases transport through Polaris membranes via the solution-diffusion mechanism where a partial pressure driving force is required. With an average CO_2 permeance of 1,000 gpu and a CO_2/N_2 pure-gas selectivity of 50, the Gen-1 Polaris was a step-change improvement over typical commercial CO_2-selective membranes used for natural gas treatment. This improvement is illustrated in Figure 3, where membrane performance is compared in the form of a trade-off plot of CO_2/N_2 selectivity versus CO_2 permeance. Better membranes will have properties that move up and to the right on this plot. The Gen-1 Polaris membrane has been validated in multiple field tests and is also being used by MTR in commercial natural gas and refinery membrane applications.

In addition to showcasing the benefits of Polaris over conventional membranes, Figure 3 also shows some of the more recent improvements in the performance of Polaris membranes. The Gen-2 Polaris membrane has been scaled-up to commercial production and was validated in the MTR small pilot field test conducted in this project at TCM. Recently, an advanced Polaris membrane with a CO_2 permeance of 3,000 gpu has been produced at the lab-scale. These developments demonstrate that the Polaris membrane technology continues to improve, which would reduce the capture system size and cost.

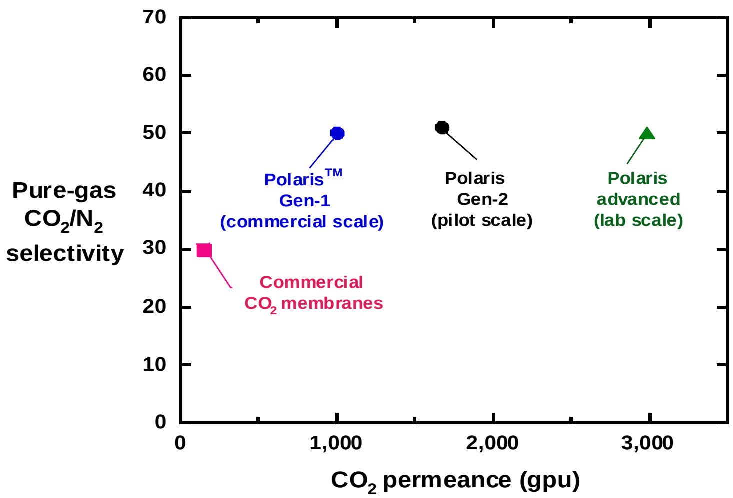

Figure 3. A CO_2/N_2 trade-off plot showing data for several generations of MTR Polaris, compared with the properties of the standard commercial natural gas membrane. Data are pure-gas values at room temperature.

Polaris Membrane Low-Pressure-Drop Module Research

An effective membrane CO_2 capture process also requires membrane module innovations because of the large volumetric flow rate and low-pressure of flue gas. These conditions result in unacceptably large-pressure-drops in conventional spiral-wound or hollow-fiber modules when used for flue gas treatment. As a consequence, MTR developed a low-pressure-drop membrane module specifically designed for flue gas CO_2 capture. The most important feature of these new planar modules is the ability for fine control of the flow path on both the feed and permeate sides of the membrane, which can be used to minimize pressure-drop. At the early development stage under equivalent laboratory conditions, new planar modules with similar packing density to spiral-wound modules achieved a pressure-drop that was less than 1/3 of the spirals.

Figure 4 shows a photo of an early prototype of this planar module during testing at NCCC. Also shown in this figure is the pressure-drop measured for this planar module compared to an earlier spiral-wound membrane module under the same field test conditions. The simple, straight flow path of the new module results in a pressure-drop that is almost four times lower than that measured for the spiral module. At full-scale, this reduced pressure-drop represents ~10 MW_e savings in fan power. In addition to testing at NCCC, the performance benefits of the planar module were verified in field tests at B&W and the University of Texas, Austin in separate DOE programs.

a) b)

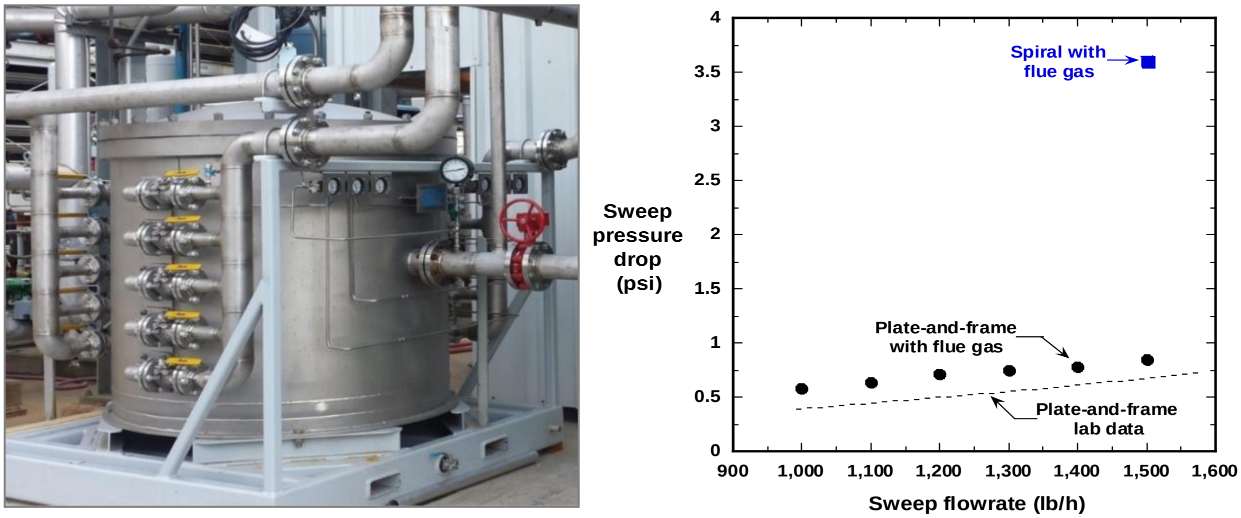

Figure 4. a) Photo of the prototype planar module vessel during testing at NCCC, and (b) measured pressure-drop in the module compared to a spiral-wound module.

More recently, MTR transitioned to a planar module form that is capable of achieving our membrane cost reduction targets and will be used for our commercial capture system. This new planar module in based on injection-molded, fiber-reinforced thermoplastics to form a stackable membrane module complete with integrated internal gas distribution. This approach cuts the fabrication cost of the membrane modules significantly. A photograph of a stack of three prototype one-sixth scale modules made by 3D printing illustrating gas flow paths is shown in Figure 5a (actual stacks will use more modules). Figure 5b shows a single, full-size injection-molded planar module. This low-cost planar module design was validated in this project during the recent small pilot field test at TCM in Norway.

(a) (b)

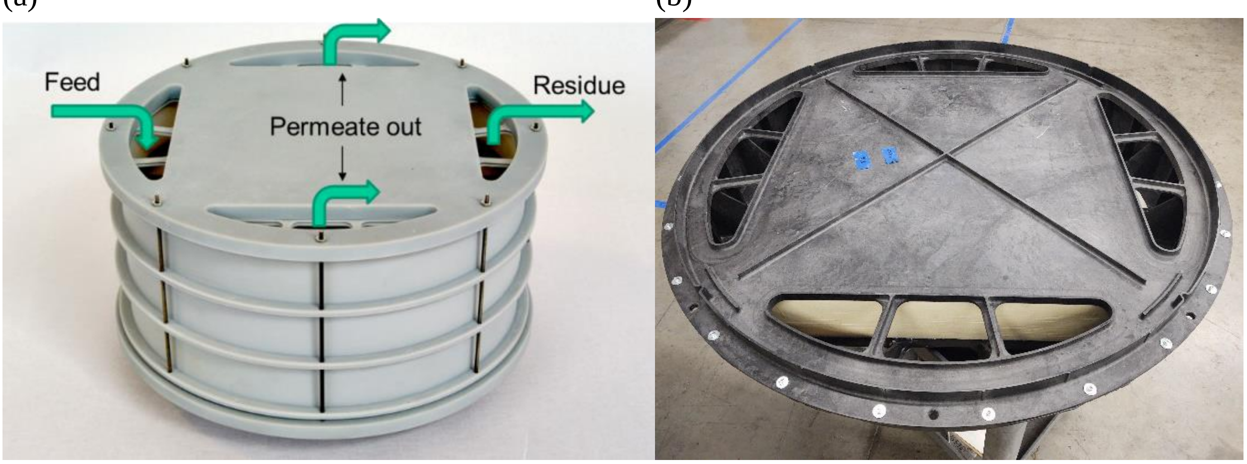

Figure 5. (a) A photograph of one-sixth-scale 3D printed mock-up of three injection-molded modules assembled as part of a stack. (b) Picture of a single, full-size injection-molded planar module (diameter = 1.4 m).

The planar modules are designed to fit one on top of the other to create a module stack. The module stack will have a pressure rating, which eliminates the need for a stainless-steel pressure vessel and further reduces skid costs. A drawing of a container-sized skid housing eight stacks is shown in Figure 6. This container-sized skid will be pre-assembled in the fabrication shop with all the required gas piping. In the field, several skids can be stacked on top of one another to minimize capture plant footprint. The containerized skid is the final form of the final modular building block for the MTR CO_2 capture membrane process.

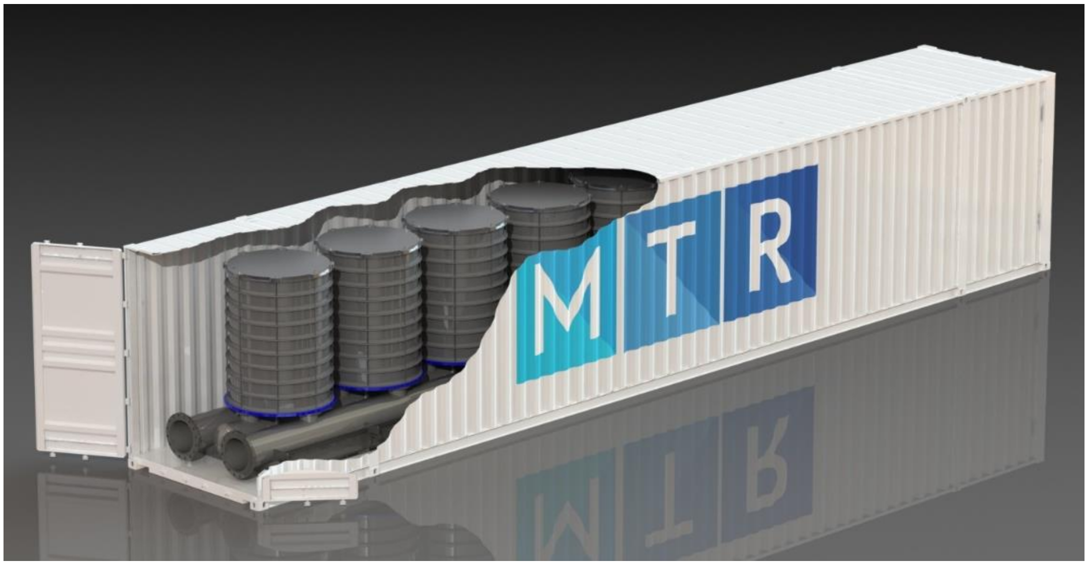

Figure 6. Rendering of MTR's commercial containerized membrane product.

Throughout the development of the Polaris membrane and low-pressure-drop planar modules, MTR, with the support of DOE, have successfully executed a number of bench-scale and small pilot field tests. These efforts include the first test of membrane modules with coal-fired flue gas at the Arizona Public Services (APS) Cholla plant in 2010; the accumulation of >11,000 hours of flue gas operation for Polaris modules on a bench-scale 1 TPD system at NCCC (TRL-5); scale-up of Gen-1 Polaris to a 20 TPD small pilot system (TRL-6), and successful operation of this system on a flue gas slipstream at NCCC and in integrated boiler testing at B&W.

In this project, MTR designed, built, and operated a small pilot system at TCM in Norway that proved Gen-2 Polaris membranes and advanced planar membrane modules in a post-combustion field test environment. Figure 7a shows the MTR test system at the TCM Site for Emerging Technologies. Over the field test duration of ~2,200 hours, the MTR test system demonstrated operation over a range of CO_2 capture rates including $\geq 90\%$. An example of data from the MTR TCM system during parametric testing is shown in Figure 7b. Further details on the successful small pilot field test at TCM can be found in the body of the Final Report.

a)

b)

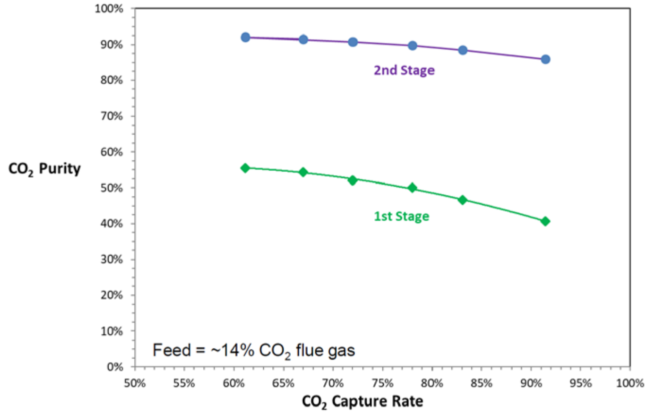

Figure 7. (a) A picture of the MTR test system at TCM, Norway, and (b) an example of test data showing CO_2 purity produced by membrane stages (no CPU) as a function of capture rate up to 93%.

3. Future R&D Efforts Related to the MTR Membrane Post-Combustion CO_2 Capture Process

All of the key components of the MTR membrane post-combustion CO_2 capture process are at a sufficient maturity level that the next logical research effort for the technology is an integrated field test. A current MTR project (DE-FE0031587) is in the build-and-operate stage (Phase III) after two down-select rounds where project feasibility, site selection, team creation, FEED study, and required permitting tasks were completed. This large pilot membrane CO_2 capture system at the Wyoming Integrated Test Center (WITC) will use multiple containers of the advanced membrane module stacks proven at TCM to capture 150 TPD of CO_2 from a 10 MW_e flue gas slipstream from DFS, which is adjacent to WITC.

The MTR Large Pilot system will be an integrated demonstration of the total CO_2 capture process including flue gas pretreatment, membrane CO_2 capture, and CO_2 purification to produce pipeline quality, supercritical CO_2. This test system will also demonstrate blower, fan, and compressor equipment representative of a full-scale commercial system. Completion of this project will set the stage for the commercial-scale demonstration project described in this proposal. Figure 8 shows a conceptual drawing of the MTR Large Pilot test system at WITC. As noted in the drawing, the Large Pilot system will use six membrane containers of the same type as the one tested at TCM (shown in Figure 7a).

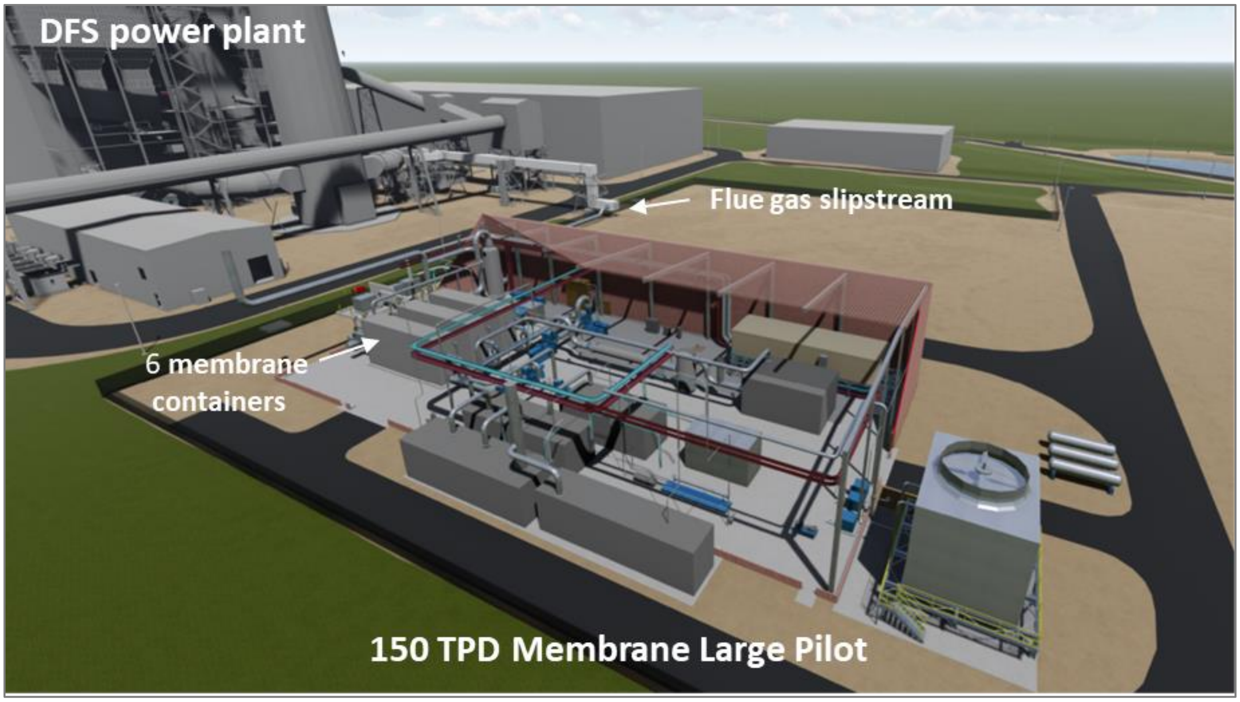

Figure 8. Conceptual drawing of MTR's 150 TPD Large Pilot capture system at WITC.

While a CO_2 capture process utilizing the Gen-2 Polaris membrane is economically competitive with advanced amine systems, future research for advanced Polaris membranes could be key to further reductions in the CO_2 capture process overall cost, energy use, and footprint. This point is underscored by DOE-NETL's continued support of MTR and other membrane-based technology developers in lower TRL-based projects (TRL 3-4) to develop advanced CO_2-selective membranes and high-performance membrane supports. In addition to membrane research, FEED studies and techno-economic analysis (TEA) would be beneficial to demonstrate the potential of a membrane process for CO_2 capture from large-point source emitters, including various industrial plants.

Recently, the DOE Office of Clean Energy Demonstration (OCED) notified MTR that a full demonstration proposal has been chosen for award negotiation. The overall goal of this new project is to produce a fully developed engineering package through an updated FEED study, commercial quality budgets, and all necessary supporting studies to prepare the integrated carbon capture and storage project at DFS for the commercial phase (Demonstration Phase II). Successfully executing this Demonstration project would complete the commercialization of this Gen-2, environmentally-friendly membrane capture technology that MTR and DOE have developed over 15 years. It would deliver community and stakeholder benefits by positioning DFS to be a low-carbon emitting, base-loaded generation asset for the Basin Electric Power Cooperative members for many decades to come, and would establish the proposed DFS storage complex to store carbon oxides from this project and from other future capture projects.

Outside of the expertise of MTR, research on large vacuum and advanced CO_2 compression equipment processes could lead to lower capital costs and energy use for all CO_2 capture processes. A summary of research gaps identified during this project can be found in Table 2.

Table 2. Future R&D Focus Areas for the MTR Membrane Post-Combustion CO_2 Capture Process.

Future R&D Focus	Benefit of R&D Effort
Large Pilot integrated demonstration of the total CO_2 capture process	Move the MTR CO_2 capture technology to TRL-7. MTR's current project (DE-FE0031587) is on track to commission a Large Pilot field test of the entire MTR CO_2 capture process at WITC by mid-2024.
Advanced Polaris membrane development with improved selectivity and permeance properties	Advanced Polaris membranes will reduce the required membrane area, system footprint, and energy use of the MTR CO_2 capture process. A current transformational capture project with DOE (DE-FE0031596) is focused on this membrane improvement.
Advanced vacuum and CO_2 compression equipment available at Large Pilot and Demonstration scales	Advanced equipment would decrease the capital and operating expenses (CAPEX/OPEX) and possibly the complexity of any point source CO_2 capture process.
Site-specific FEED and TEA studies of the MTR membrane technology for large point source CO_2 capture at power and industrial plants	Rigorous evaluation of the MTR membrane CO_2 capture approach from various large point source emitters. MTR's proposal to the OCED full demo funding opportunity (DE-FOA-0002738) is one of the seven projects that has been chosen for award negotiation. Phase I will include a FEED study at DFS for integrate carbon capture, transport, and storage.

4. Commercially Available Key Components of the MTR Membrane Post-Combustion CO_2 Capture Process

As summarized in Section 2, the MTR Polaris membrane is the only key component with currently active research. In this section, the commercially available key components used in the MTR membrane CO_2 capture process will be detailed.

The MTR CO_2 capture system is an "end of the tailpipe" technology that processes the flue gas after all other emissions control unit operations. This means the flue gas enters the MTR process relatively hot, saturated with water, and at atmospheric pressure. The function of the flue gas blower is to move flue gas through the membrane capture system and push the CO_2-depleted gas stream through the site stack. With the inlet roughly at atmospheric pressure, the blower is required to process the entire flue gas stream and discharge the gas at 1.15 bara to ensure the gas will move through the entire MTR process. Flue gas flow rates at large point source emitters are massive (roughly 1 m^3/s per MW_e at a subcritical coal-fired powerplant) so the flue gas blower size and energy use have a substantial impact on the overall CAPEX/OPEX of the MTR capture system. Blower material of construction is also critical as water saturated, hot flue gas is very acidic.

Taking all of these requirements into account, the MTR team identified multiple blower vendors in both Large Pilot (DE-FE0031587) and Full Demo (FE-DE0031846) FEED studies at the DFS coal-fired power plant. For the Large Pilot field test that will be commissioned in mid-2024, Howden was chosen as the vendor for the flue gas blower.

After the flue gas blower, the entire flue gas stream needs to be cooled prior to entering the MTR membrane containers. Additionally, SO_2 readily permeates the Polaris membrane, so the SO_2 concentration in the inlet flue gas to the membranes needs to be reduced to <5 ppm to avoid concentrations in the high-purity liquid CO_2 product above 100 ppm. A direct contact cooler (DCC) can be designed to meet both requirements while also minimizing the flue gas pressure-drop through the unit. In the previously-mentioned FEED studies, DCC vendors were identified at both the Large Pilot and full-scale flue gas flow rates. For the upcoming Large Pilot field test, MacroTek was chosen as the DCC vendor.

Membranes require a partial pressure driving force for gas permeation to occur. MTR has previously shown that minimal feed-side compression (~1.05 to ~1.15 bar) along with a vacuum (0.1 to 0.2 bar) on the permeate-side is significantly more energy-efficient than compressing the full flue gas stream to even mild feed pressures (5 bar). For bench-scale and small pilot field tests, MTR utilized liquid ring vacuum pumps due to their reliability. However, even at the Large Pilot scale, liquid ring vacuum equipment is either not available at that scale or is not efficient enough. The MTR team conducted an extensive analysis to determine fan and compressor equipment that could create the required permeate vacuum and handle the highly-acidic, water-saturated permeate gas streams. For the Large Pilot, a combination of multiple Piller fans in series followed by an Atlas Copco compressor will be used to create a permeate vacuum for both the Membrane A and Membrane B unit operations. Piller and Atlas Copco have larger-sized models of their respective technology that could also be utilized at full scale.

The Membrane B permeate gas stream is water-saturated, contains ~85% CO_2, and is slightly above atmospheric pressure. The requirements of the CO_2 purification unit (CPU) are to compress, dry, and purify the Membrane B permeate gas stream to produce pipeline quality, liquid CO_2 at 152 bar. A CPU for producing a liquid CO_2 product from a CO_2-rich stream is a mature, commercial technology available from multiple OEM vendors, including Salof, Linde and Pentair. Salof was chosen as the CPU vendor for the upcoming Large Pilot field test.

A CPU includes a number of different unit operations to produce high-purity liquid CO_2 including a dehydration package that contains a regenerative mole sieve bed design for use over a wide range of inlet gas stream conditions (flow rate, pressure, temperature and inlet water content) and required exit gas water content. A typical dehydration package includes the following equipment:

- Dehydration feed chiller
- Dehydration feed knockout drum
- Dehydration mole sieve beds
- Dehydration bed regeneration heater
- Dehydration bed regeneration heater filter
- Pressure control valves

The upcoming Large Pilot field test will be the first integration of commercial CPU technology with the MTR membrane CO_2 capture process. Any balance of plant or scale-up issues identified during Large Pilot operation will be addressed in the upcoming Full Demo FEED study. The CO_2 liquefaction and purification section of a typical commercial CPU package includes the following equipment:

- CO_2 reboiler
- CO_2 condenser
- CO_2 distillation column
- CO_2 distillation column auxiliary reboiler
- Liquid CO_2 booster pumps
- CO_2 product heaters
- CO_2 product pressure reducing valve

As noted here and in Table 1, all of the key balance of plant components utilized by the MTR capture system are commercially available from multiple vendors at sizes ranging up to full scale. We don't see any technology gaps in this equipment that would hinder commercialization of the MTR membrane capture process. As mentioned in Table 2, other than ongoing membrane improvements at MTR, the biggest impact on the capture cost for the MTR process would be through cost and/or efficiency improvements in the required rotating equipment.

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APPENDIX C

ENVIRONMENTAL HEALTH & SAFETY RISK ASSESSMENT

APPENDIX C

ENVIRONMENTAL, HEALTH, & SAFETY RISK ASSESSMENT

DE-FE0031591

Scale-Up Testing of Advanced Polaris Membrane CO_2 Capture Technology

The objective of this Environmental, Health, & Safety (EH&S) Risk Assessment is to review the environmental friendliness and safety of Membrane Technology and Research, Inc's (MTR) post-combustion CO_2 capture process and identify potential deficiencies that have the potential to cause environmental harms and damages. This study characterizes the general level of risk of the membrane system and identifies opportunities for remedies at a stage of development when corrective measures can be easily implemented.

Introduction

MTR's capture process is generally considered to have low EH&S risk compared to other post-combustion capture technologies. This is mostly attributable to the inherent properties of the capture system, namely the passive nature in which membranes separate CO_2 from flue gas and the simplicity of the system itself. For this assessment, the results and knowledge gained from previous MTR post-combustion CO_2 process EH&S reports were used as the basis for risk identification and mitigation strategies. This EH&S risk assessment summarizes known risks at this stage of the membrane CO_2 capture technology development and other potential project-related health and safety risks associated with the membrane production and a full-scale post-combustion CO_2 capture system at a coal-fired power plant. A majority of the equipment in MTR's CO_2 capture plant is common, commercial devices with significant operational experience. Therefore, the likelihood of encountering large and previously unknown EH&S risks is low. As MTR produces more and larger capture plants, it is expected that new risks will be identified and appropriate mitigation strategies to address them will be developed.

Project Overview

This EH&S risk assessment considers all of the equipment included in a full-scale MTR membrane CO_2 capture system at a coal-fired power plant. The CO_2 capture system is designed to treat the flue gas from a supercritical pulverized coal power plant consistent with the basis for Case B12B from the Department of Energy (DOE) National Energy Technology Laboratory (NETL) report entitled "Cost and Performance Baseline for Fossil Energy Plants, Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity," Revision 4 and will be located adjacent to the host power plant. For further details on the design basis, see the full Techno-Economic Analysis (TEA) report produced in this project (Appendix A).

Figure 1 shows a block flow diagram of the main components and system boundaries for the MTR membrane-based CO_2 capture process. This assessment includes all of the components of the CO_2 capture system over the normal operation cycle, which includes all aspects of plant maintenance. Note: the optional high-capture rate membrane unit operation and recycle stream highlighted with dashed lines in Figure 1 were not considered in this EH&S risk assessment or the TEA report.

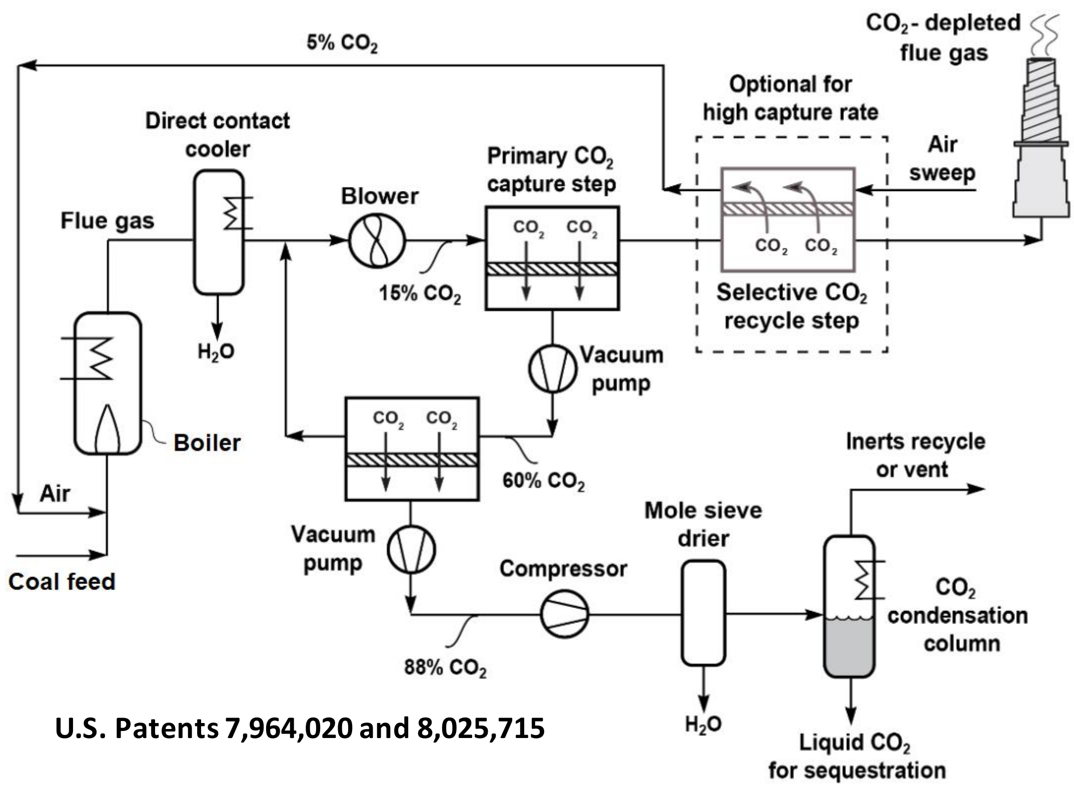

Figure 1. Block process diagram of the MTR CO_2 capture system.

EH&S Analysis

This section includes an evaluation of potential project-related health and safety risks associated with the membrane production and full-scale CO_2 capture system to be built and operated at a coal-fired power plant.

Membrane Production

To support the construction of a full-scale membrane-based CO_2 capture plant at a coal-fired power plant, MTR will use an automated, high-volume manufacturing facility to produce both Polaris™ CO_2 selective membrane and the planar membrane module elements. For this assessment, a plant sized to produce enough membrane to equip 375 containerized membrane skids per year was assumed. This is roughly three times the size that is required to supply a single full-scale CO_2 capture system, and thus corresponds to production rates to accommodate several projects per year. The type of equipment used in this operation would be similar to that found in other high-volume membrane module production operations, such as plants run by Dow (Filmtec) and Nitto (Hydranautics) to make reverse osmosis (RO) membrane modules. These plants use similar methods of construction as will be required for Polaris CO_2 capture membranes, and currently produce two to twelve million m^2 of membrane modules per year. Almost all steps in the production process are automated and robots are widely used for material handling and in production where they glue, cut and seal the membrane modules. The primary EH&S risks associated with membrane and module production are summarized below:

1. Risk of personnel exposure to harmful chemicals – The risk can be mitigated through use of proper equipment, personal protective equipment (PPE) training, and by defining exclusionary zones. Risk could further be minimized through reduction in liquid holdup and storage volume, implementation of monitors and alarms for vapor detection and spills, and through periodic checks on suitable ways to replace potential high-risk chemicals with safer substitutes. Additionally, risk can be mitigated through periodic behavioral audits to ensure compliance with safety procedures.

2. Risk of personal injury from production – The risk can be mitigated through good design practices and adherence to Occupational Safety and Health Administration (OSHA) requirements. Other measures to mitigate risk include: well-defined personnel exclusionary zones, ample space to walk-around equipment, ergonomic design of production workspaces, well-lit and well-marked hazards such as low clearances, hot areas etc., and following best practices for manufacturing line environments (e.g. Toyota Production System) for plant design, and strive for continuous improvement (Kaizen methodology) once operational.

3. Uncontrolled releases of solvent vapors – The risk applies to both the facility and to the environment as solvent vapors could pose risk to both human and environmental health. Release of solvent within the facility can be mitigated through purposeful placement of vents and fans near potential leak points and by placing new solvent inventory and spent solvent waste in designed controlled environments. Release of vapors to the environment can be mitigated through the proper design of abatement equipment.

4. Fire – This common risk can be mitigated by implementing standard industrial fire detection, suppression and prevention measures including sprinkler systems, fire containment doors/walls/ceiling, hand-held fire extinguishers, and operator fire safety training.

Membrane Production Emissions and Waste Streams

Waste generated by the membrane and module manufacturing process from the production plant and their treatment methods are summarized below:

- Air Emissions – Assuming that the manufacturing plant is located in the United States, it would be subject to similar emission limits as what is currently required at other related manufacturing processes. The air emissions from membrane manufacturing facilities are required to implement Best Available Control Technology (BACT) standards, which can achieve emissions reductions of ≥ 95%. Generally, vapors from organic solvents used in the manufacturing process are collected and sent to a thermal oxidizer. However, it may be possible to implement a vapor recovery system (membrane and/or condensation units) upstream of the thermal oxidizer to recover a portion of the organic solvent vapor and minimize emissions that must be treated by the thermal oxidizer.

- Wastewater – The production of membrane results in the generation of wastewater. The wastewater stream is generally biodegradable and is normally discharged to a local Publicly Owned Treatment Works (POTW). On-site treatment of the wastewater (for example, using an adsorption filter bed) may reduce the amount of wastewater sent to the POTW and could also offset raw water consumption by reusing the site-treated wastewater, assuming the required quality is achieved.

- Solid Waste – During the manufacturing process, excess material that cannot be reused is generated from the membrane trimming and cutting for the production of planar and spiral membrane elements. For the production of planar membrane modules, the housing elements and stack parts are made of recyclable materials. Injection molding inherently reduces the amount of waste compared to conventional cutting and machining steps indicative of subtractive membrane methods. At the end of life, containerized membrane skids are returned to MTR where the skid is partially disassembled. The reusable portions of the skids are refurbished and made ready for reuse, and the single-use components are removed and disposed of as solid waste. MTR is currently investigating reuse and recycle options. Excess material may be reduced through more efficient use of materials in production (i.e. better layouts to reduce cutting and trimming wastes). Solid waste will also be produced from destructive quality control (QC) testing of the membranes. However, improvements to the QC and manufacturing standards may result in fewer materials, components, and finished membrane elements that fail quality and assurance tests, thus reducing some waste generation. Of the total solid waste generated from the spiral membrane production, only the permeate tube can be recycled. There will likely be other non-reusable or non-recyclable packaging and crating that will also be disposed of.

Table 1 summarizes the estimated high-volume membrane/module waste streams for the MTR full-scale membrane CO_2 capture system and their treatment method.

Table 1. Waste Generated from MTR's Full-Scale Membrane and Module Production Facility (375 Membrane Containers/Year).

Waste Component (Disposal Method)	Quantity Generated (Estimate)	Comments
Waste water	725,000 gallons	• Waste components are biodegradable and typically discharged to the POTW.
Air emissions	7,700 kg	• BACT is used to mitigate emissions to allowable level. • For Polaris membranes, vapors from organic solvents used in fabrication are sent to a thermal oxidizer.
Solid waste (membrane and module materials)	77,000 kg	• Wastes from trimming and cutting of membrane in the production of membrane elements. • Wastes from discarded head-end and tail-end portions of membrane rolls. • Wastes associated with destructive QC testing. • Rejection from assembly line defects. • Non-reusable or recyclable packaging and crating.

MTR CO_2 Capture System

The major interconnection points for an MTR CO_2 capture system and a supercritical coal-fired power plant are as follows:

- Flue gas downstream of the flue gas desulfurization (FGD) unit.
- CO_2-depleted flue gas to stack.
- CO_2 product (to CO_2 transportation pipeline).
- Various condensed water streams (recycled to the FGD system).
- Cooling water supply and return for various cooling water heat exchangers.

A list of chemicals used by various components of the CO_2 capture plant equipment is summarized below.

- Direct Contact Cooler (DCC) – Caustic (membrane grade) for sulfur dioxide (SO_2) removal.
- DCC Wet Surface Air Cooler (WSAC) – Sodium hypochlorite (bleach), sodium bromide (CL 41), corrosion inhibitor (CL 5683), micro-biocide (DBNPA CL 206) and micro-biocide (isothiazolinone CL 2250).
- Closed Cooling Water System (CCWS) WSAC – Sodium hypochlorite (bleach), sodium bromide (CL 41), corrosion and scale inhibitor (CL 5694), micro-biocide (DBNPA CL 206) and micro-biocide (isothiazolinone CL 2250).
- Compression and Purification Unit (CPU) refrigeration – Ammonia.
- RO wastewater treatment system – Sodium hypochlorite (bleach), coagulant (ferric

chloride), magnesium chloride, caustic, sulfuric acid, anti-scalant, and hydrochloric acid.
- Rotating process equipment – Lubricating oil.
- Transformers – FR3 oil (vegetable oil).

Potential risks associated with the chemicals used by the MTR CO_2 capture full-scale system are discussed below:

1. Risk of personnel exposure to harmful chemicals – This can be mitigated through use of proper equipment, personal protective equipment (PPE) training, use of Safety Data Sheets (SDS) to handle spills, and training personnel for chemical handling; chemical totes will be delivered to the plant site for use in the CO_2 capture system.

2. Lubricating Oil Spill – Lubricating oil can potentially spill or leak from the on-site inventory or from the process equipment themselves. To mitigate the risk of lubricating oil spills, it is recommended to be stored in approved containers with secondary containment in a clean, dry and temperature-controlled environment. Additionally, physical protections such as barriers from vehicle traffic, and an inventory of oil spill cleanup kits shall be considered in design as part of mitigating risk solutions.

3. Ammonia Refrigerant Leak – Ammonia is considered to be mildly flammable, with a lower explosive limit (LEL) in air of 15%, and upper explosive limit (UEL) of 28%, and the lowest National Fire Protection Association (NFPA) fire rating of 1.0 (scale of 0 to 4). DOE defines three (3) levels of protective action criteria (PAC) based on 60-minute exposure to concentrations of a substance that may (PAC-1) cause mild, transient health effects; (PAC-2) irreversible or other serious health effects that could impair the ability to take protective action; and (PAC-3) life-threatening health effects. Based on this criterion, the PAC levels for ammonia have been defined to be 30 ppmv, 160 ppmv, and 1,100 ppmv for PAC-1, PAC-2, and PAC-3, respectively. Ammonia is considered severely toxic compared to other refrigerants used in industry. The NFPA health rating for ammonia is a 3 (on a scale of 0 to 4). Because ammonia is toxic and mildly flammable, any leak would have a high risk of health effects and a low risk of explosion. To mitigate these risks, installation of sensors to detect leaks (slow or sudden) in a timely manner are required to monitor for any releases to the environment and mitigate instances of personnel exposure or ignition or explosion events. Any instance of leakage can also be mitigated through use of suitable means to load and unload ammonia inventory and appropriate storage methods.

MTR Full-Scale CO_2 Capture System Waste at a Supercritical Coal-Fired Power Plant

The estimated waste streams generated through normal operation of the CO_2 capture system are included in Table 2. During each membrane element's time in service, the module will process a large volume of flue gas in which it is possible for some flue gas trace elements to accumulate on or within the membrane element over time in lieu of passing through with the permeate or residue streams. The composition of trace elements that might accumulate will be dependent on the types of fuel(s) fired during operation, and the environmental controls in place. Based on prior testing at NCCC, with appropriate pretreatment, the amount of trace elements in the spent membrane modules are insignificant and these modules can be landfilled as non-hazardous waste.

Table 2. MTR Full-Scale CO_2 Capture System at a Coal Power Plant Waste Generation.

Waste Component	Amount Generated (Estimate)	Description
Spent Membrane Elements – Spiral (solid waste, landfilled)	202 kg/year	• Replace 8” spiral membrane elements at 5-year interval (at 100% CF); about 20 kg waste/module replaced • Estimated based on membrane area for vent membrane unit
Spent Membrane Elements – Planar (solid waste, landfilled)	382,500 kg/year	• Membrane skids have estimated 5-year lifespan (at 100% CF); about 7,000 kg waste/containerized skid • Estimated based on membrane area of first- and second-stage membrane units
Solid Waste from Dredging Forced Evaporation Pond (wet solid waste, sent to offsite landfill)	1,560 tonnes/year	• RO reject estimated to be moderately saline with approximately 37,000 ppm total dissolved solids • Based on 3.8 gpm of wastewater sent to Forced Evaporation Pond which will be dredged approximately every 5.5 months (at 100% CF)
RO Filter Press Cake (wet solid waste, sent to offsite landfill)	905 tonnes/year	• Estimated based on Water Treatment Softening System inlet flow (at 100% CF) • Assumes generation of 250 ppm of dry solids and dewatering sludge to approximately 40 wt.% solids • Cake will be collected in small dumpster next to filter press
Lubricating Oil (liquid, hazardous waste if disposed or otherwise recycled)	To be determined later	• Lube Oil specification to be provided by equipment vendor during detailed design phase
Lube Oil Filters (hazardous waste, can be recycled)	To be determined later	• Lube Oil filters specification to be provided by equipment vendor during detailed design phase

APPENDIX D

PEER REVIEW EVALUATION

Introduction

In its first Budget Period, this project was chosen by DOE for a peer review. To aid the peer review discussion, MTR prepared a Project Technical Summary Report prior to the peer review meeting. MTR traveled to the DOE Pittsburgh site in mid-October 2018 to give a project briefing to the independent Peer Review Panel and DOE personnel. After the project presentation, MTR participated in a question-and-answer session prior to closed door discussion by the Peer Review Panel. Later that year, DOE provided MTR with the Peer Review Recommendation Form. MTR provided initial feedback on all recommendations in a January 2019 response document. Over the course of the project, MTR worked to address all of the recommendations. Feedback on the remaining actionable peer review recommendations is summarized below.

Peer Review Recommendation R3: Evaluate the optimum unit size using scaling laws (e.g., ethanol facilities all scaled to an optimum size) to leverage modularity of systems.

Recently, MTR has completed site-specific FEED studies that include equipment sizing and costing information for systems capturing:

- 150 tonnes CO_2/day (TPD) Large Pilot system (DE-FE0031587). This system processes a 10 MW_e slipstream from the Dry Fork Station coal-fired power plant outside of Gillette, WY.
- 2,000 TPD full-scale industrial capture system (DE-FE0031949). This system processes a flue gas stream containing 15% CO_2 (dry basis) at a flow rate of 2,700 TPD from Kiln #2 at the CEMEX Balcones cement plant in New Braunfels, TX.
- 8,000 TPD full-scale capture from a coal plant (DE-FE0031846). This system was designed to process the entire flue gas stream from the Dry Fork Station coal-fired power plant outside Gillette, WY.

In general, capture costs will decrease as plant size increases due to economies of scale. Typically, an exponential equation of the following form is used to related costs at different scales:

$$SC = RC * \left(\frac{SP}{RP}\right)^{Exp}$$

Where:

Exp – Exponent

RC– Reference cost

RP – Reference parameter

SC – Scaled cost

SP – Scaling parameter

For industrial equipment, a scaling exponential between 0.6 and 0.8 is often used. However, for modular systems like membranes, this factor is closer to 1. As a result, for modular membrane systems, costs will scale down better than some other capture approaches.

Figure 1 shows an example of how costs may scale for module membranes versus conventional amine capture systems. Here, costs were normalized to the full-scale capture plant at Dry Fork Station (~8,000 TPD). The curve labeled "Amine" uses a 0.7 exponential scaling factor to estimate the relative capital cost/tonne for smaller systems. The "Membrane" curve uses the same scaling factor for balance of plant equipment [(fans, pumps, CO_2 purification unit (CPU)], but a nearly linear factor for the membrane containers. As a result, the increase in capital cost for smaller capture systems is less pronounced for membranes compared to conventional amine technology.

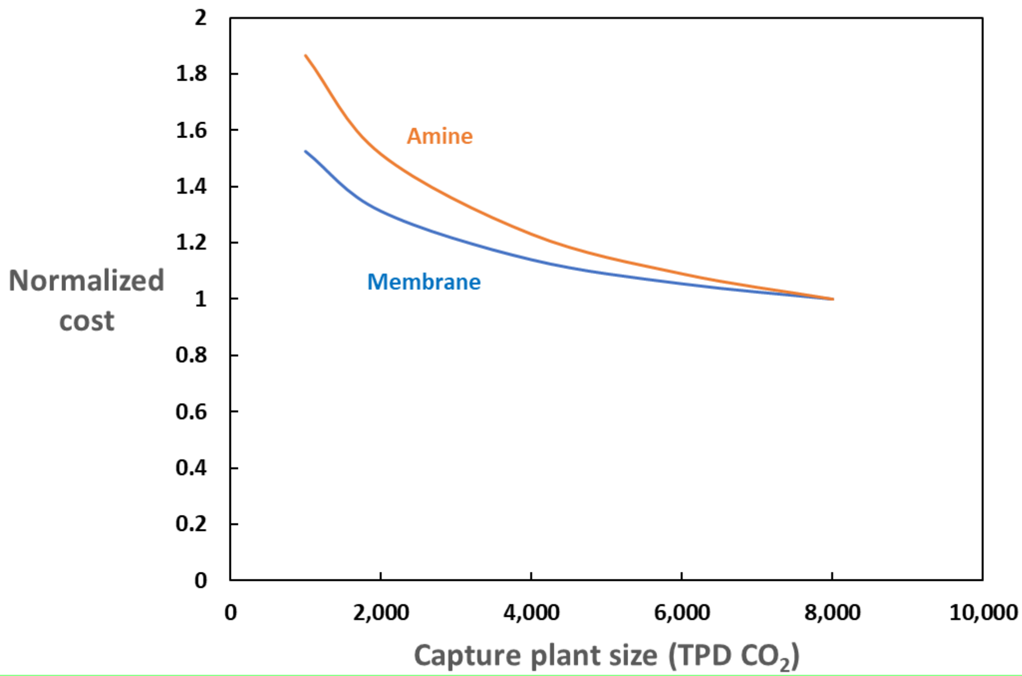

Figure 1. Normalized capture plant cost/tonne as a function of plant size. Both membrane and amine technologies are normalized to an 8,000 TPD capture plant (~ 3 million tonnes CO_2/year).

This rough analysis suggests that membrane capture systems may be particularly well-suited for smaller point-source capture opportunities of 500 to 5,000 TPD. This size range covers many of the industrial capture sources (such as the CEMEX Balcones plant) that MTR believes will be the "sweet spot" for membrane capture. Outside the scope of the current project, MTR is conducting more detailed cost analyses to fine-tune marketing targets.

Peer Review Recommendation R4: Evaluate how balance of plant performance can improve overall system flexibility and performance.

While membranes are the heart of the MTR capture process, the balance of plant equipment including fans, pumps, and CO_2 compression/purification machines contribute significantly to system performance and cost. For example, the membranes themselves make up ~30% of the total capture system equipment cost, while vacuum pumps and the CO_2 compression/purification train both contribute similar shares of the equipment cost. For this reason, various balance of plant configurations have been examined to try to minimize these associated equipment costs.

One case studied during this project was replacement of the CPU, which is used to obtain very high purity liquid CO_2 (with <10 ppm O_2 to meet strict pipeline specifications). If this stringent CO_2 product purity specification can be relaxed (for example, in CO_2 utilization or direct injection scenarios where CO_2 pipeline transport is not necessary), there would be substantial cost savings for the MTR CO_2 capture process. In this event, the CPU would be replaced by a conventional CO_2 compressor. To estimate the potential cost savings, an analysis of capture with and without a CPU was conducted by MTR and S&L for a capture system applied to the CEMEX Balcones cement plant in New Braunfels, TX. This MTR capture system was sized to capture 75% of the CO_2 from a flue gas containing 15% CO_2 (dry basis) at a flow rate of 2,700 tonnes CO_2/day (DE-FE0031949).

For the case without a CPU, MTR assumed a new conventional CO_2 compressor system would be sized for the CPU inlet conditions meaning the Membrane B compressor would remain part of the design. MTR also assumed that the CO_2 product off-taker can accept a product stream with a lower CO_2 concentration. An example of the CO_2 product composition without a CPU and its potential impacts are detailed in the table below.

Table 1. MTR CO_2 Capture Process CO_2 Product Composition without CPU

Parameter Pressure	Units (Psia)	Conventional Compressor Inlet (389)	Notes
CO_2	mole %	89.78	Assumed to be acceptable for maintaining dense phase. However, may require high alloy material of construction.
N_2	mole %	5.89	Nitrogen higher than 4 mol% can increase potential for CO_2-H_2O hydrates and can require increased transport pipe strength requirements due to ductility issues.
O_2	mole %	4.31	As O_2 increases corrosion potential, CO_2 specs typically call for concentrations < 10 ppmv. O_2 scavenger and/or high alloy material of construction will most likely be required.
H_2O	mole %	0.22	To reduce the chance of CO_2-H_2O hydrate formation and to maximize storage within geological formations, water content will most likely need to be reduced.
SO_2	mole %	0.000268	Acid gas not anticipated to be an issue at this time.
NO_2	mole %	0.00838	CO_2 specs typically require < 100 ppmv of NO_x. Combined value close to exceeding threshold.
HCl	mole %	0.000958	Acid gas not anticipated to be an issue at this time.
NO	mole %	0.0020	CO_2 specs typically require < 100 ppmv of NO_x. Combined value close to exceeding threshold.
NH_3	mole %	0.00247	Considerably lower than 50 ppmv, should not be an issue.

At a minimum, treatment of the membrane permeate would include a dehydration system to achieve 30 lb/MMSCF water in the CO_2 product. As this would only require ~70% removal, a less energy intensive dehydration system could be utilized instead of the mol-sieve technology used as part of the CPU in the TEA produced in this project. Nitrogen concentrations could potentially be manageable through increased material of construction costs of the downstream equipment. O_2 concentrations would require further evaluation and discussion with the utilization or injection well operator to determine an acceptable concentration due to the increased corrosion potential. An O_2 catalyst, higher alloy material and/or combination of the two may be required for a cost-effective solution.

Table 2 shows a high-level pricing comparison for the base case where a full CPU with CO_2 liquefaction is used, and two cases where a new CO_2 compressor is used to directly compress ~90 mol% or ~95 mol% CO_2 produced by the membrane system (after dehydration).

Table 2. Comparison of CPU and a Conventional CO_2 Compressor Costs.

CO_2 Product	**Unit**	**Base Case**	**New Case 1**	**New Case 2**
		75% Capture with CPU, 99.99% CO_2 product	**75% Capture without CPU, 90% CO_2 product**	**75% Capture without CPU, 95% CO_2 product**
Pressure	bar	152	152	152
CO_2	mole %	99.99	89.78	95.35
O_2	mole %	0.001	4.31	2.06
N_2	mole %	1.19E-07	5.89	2.58
SO_2	mole %	0.0003	0.000268	0.000293
NO_2	mole %	0.00953	0.00838	0.00914
Estimated Direct Equipment Costs Downstream of Membrane System	$	$23,593,000	$5,000,000	$6,903,000
Membrane Costs	$	$38,039,000	$38,039,000	$39,739,000
Total Capture Plant Equipment Costs	$	$122,791,700	$104,198,700	$106,101,700
Auxiliary Power Consumption	kW	4,610	4,226	4,429

The new cases without a CPU offer significant upfront capital cost savings compared to the base case as well as slightly lower power consumption. In fact, the direct equipment cost savings for the cases without CPU are equal to nearly half the cost of the membrane units themselves. Table 2 only reflects the difference in purchased equipment costs, any additional savings in installation costs are not reflected in the numbers (and would be expected to be significant). Other potential cost savings beyond the scope of this high-level study include the effect of the CPU deletion on the balance of plant design (reducing cooling demand, less wastewater, smaller building/foundation, no refrigerant handling or storage precautions, fewer sensors, simpler system controls and electrical supply, and significantly fewer connecting piping).

Overall, the capital cost savings associated with removing the CPU are significant (~15%) and warrant a detailed engineering and design study at future site-specific point-source capture plants where a relaxed CO_2 product purity can be offloaded.

Peer Review Recommendations R6: Quantify the role of additive manufacturing on the reduction of the cost of electricity (COE).

The scope of this recommendation is relatively narrow because additive manufacturing only includes 3D printing and other similar layer-by-layer processes. Currently, MTR is using a variety of techniques to make our capture product including injection molding, extrusion, roll-to-roll processing, and other "lossless" manufacturing methods. Many of these are already relatively low cost, so the cost reduction potential of using additive manufacturing is somewhat limited.

Generally, Additive Manufacturing is better than Subtractive Manufacturing (machining) because there is no wasted material. From that perspective, the MTR membrane modules do not include any Subtractive Manufacturing steps except for the final membrane stack trimming, which is cut to a precise size. However, out of 10,000 cubic inches of membrane material, MTR typically shaves off 1,000 cubic inches (10%) of the membrane material or less during that step. At this time, this step is technically necessary for the function of the product. For comparison, typical machining processes see 60%+ of the material removed from the original billet.

The individual components of the manufactured membrane product are listed below. General comments and the potential of additive manufacturing for each component are also provided.

- Polaris membrane and permeate spacer – these are full-width paper products, all of which is used in the final module (minus the 10% trim).
- Feed spacer – these components are an extruded plastic net. There is no waste or loss inherent to the process that could be lessened by 3D printing.
    - MTR has evaluated the potential of 3D printing the feed spacer on the membrane surface. This would reduce the amount of spacer material in the module and in theory could be cheaper than extruded net, but it is currently more expensive and there is a minimum 5-10 year road map for getting to parity with standard net spacers. This would require a significant investment by MTR along with one of the major spacer vendors.
- Module housings – These components are produced in high-volume by injection molding which, as mentioned above, is not a subtractive process. The housings were designed to have a certain structural strength, as stacks of these housing are not enclosed in pressure vessels.
    - During the design process and for the project field test, MTR purchased machined aluminum housings. These were relatively expensive items. In contrast, the injection-molded fiber-reinforced plastic housings are about 18 times less costly per module. As the number of injection module housings required for individual systems increases, costs will reduce further. At that point, our analysis shows that the module cost is completely associated with the raw material costs. Additive manufacturing could not improve on these economics.

- Module seals – These components are also injection-molded. They are necessary for a good seal and have a minor cost associated with them that likely could not be improved by additive manufacturing.
- Module stack base (MSB) – These are large stainless-steel components that are machined and welded. This component directs the feed, residue, and permeate gas streams in and out of membrane module stacks and containers. This component is currently not a likely candidate for additive manufacturing because of the chemicals and pressures involved. Moreover, there is no 3D technology that could print something the size of an MSB today; however, future advances in additive manufacturing technology could potentially reduce MSB costs significantly.
    - MSBs are custom components that currently relatively expensive. This price will come down at scale, but the savings is limited for such a big custom weldment. The price of steel will significantly dictate the price of the component. If it were possible in the future, additive manufacturing could reduce MSB costs by up to an estimated 50%.
- Membrane container – For the membrane containers, MTR uses standard metal shipping containers. It is less of a stretch to imagine a shipping container manufactured by 3D printing compared to the MSB. If 3D printing existed at this scale, the savings would be significant. The strength of a 3D printed shipping container would be an issue, but other constraints (leak-free, etc.) would not apply. One major issue for the 3D printed metal container would be the seismic load requirement of stacking containers three high at 50,000 lbs each.
    - Current containers are relatively expensive. Similar to the MSB component, additive manufacturing could possibly reduce the cost of a membrane container by 50%.
- Otherwise, the MTR CO_2 capture process uses a significant amount of piping which is also extruded and not machined. It is possible that a technology developer is working on 3D printing large ducting and piping, but it will be some time before this would be adopted by industry or acceptable to an end user for inclusion in a system.

In summary, additive manufacturing is unlikely to make a significant near-term impact on the cost of capture with MTR's membrane process. However, future manufacturing advances could reduce costs particularly in the module stack containers and piping (MSBs). Combined these effects would produce a maximum reduction in the cost of capture by a few dollars/tonne (less than 10% of total capture cost). This is a smaller potential benefit than developing 3rd generation Polaris membranes or eliminating the need for a CPU, which are clearly higher priority development areas. Nevertheless, it is still worthwhile to follow the ongoing advances in additive manufacturing and revisit this topic in future optimization work.