PHILLIPS 66 / DEPARTMENT OF ENERGY

SMR Carbon Capture Design (SMRCCD)

Final Report and TEA

FINAL VERSION:
08/09/2023

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1. Executive Summary

This project sought to select a process configuration, select a commercial technology offering, and complete an initial engineering design of a carbon capture system that recovers and ultimately would store ~190,000 tonnes per year of CO_2 with 90%+ carbon capture efficiency from an existing steam methane reforming (SMR) plant at Phillips 66's Rodeo Refinery.

The goals for this project were to advance carbon capture and sequestration (CCS) technology for commercialization in a steam reforming plant application. The completed initial design provides information on the process design basis, engineering design, and technoeconomics for the subsequent deployment of CCS projects that are targeting CO_2 credits, including federal 45Q tax credits and California Low Carbon Fuel Standard credits.

Three potential process configuration options for applying carbon capture to an SMR were identified and evaluated, with one option progressing to the final evaluation. After selecting only post-combustion capture as the process configuration, a technology package from Mitsubishi Heavy Industries was selected from four bidders to a request for proposal to different technology licensors. The technology package was used to generate an initial engineering design, cost estimate, technoeconomic analysis and environmental health and safety analysis. The initial engineering design was conducted to a front-end loading level 2 quality (FEL-2) and a 15% contingency cost estimate quality (the lower end of the typical 15-25% range).

The technoeconomics for the capture plant were analyzed as a discounted cash flow with capital expenditure at the start of the project and annual cash flows from operating expenses and CO_2 credit generation discounted in future years with a discount rate of 7.5%. The cost of capture calculated from this analysis was $192/tonne CO_2 captured, of which $115/tonne accounted for the cost of capital. After including credit generation revenues of $85/tonne captured from the federal 45Q tax credit and $150/tonne avoided from the California Low Carbon Fuel Standard (LCFS) credit, the project would be expected to generate an average annual rate of return (AARR) of 9.65%. Alternatively, if carbon credits are not taken into account, implementing this project would increase the cost of hydrogen supplied to the refinery by $1.5/kg hydrogen (approximately an 150% increase). The project's economics were most sensitive to the LCFS price and the capital cost.

2. Introduction

This project completed the initial design of a commercial-scale, advanced CCS system that separates and stores ~190,000 ton/year net CO_2 with 90%+ carbon capture efficiency (actual design carbon capture efficiency is 95.0 volume percent of the total CO_2 emitted from the SMR's flue stack) from an existing steam methane reforming (SMR) plant at Phillips 66's Rodeo Refinery. The H_2 produced from natural gas by this existing unit already has a purity of greater than 99.97%.

The goals for this project were to advance carbon capture and sequestration (CCS) technology for commercialization in a steam reforming plant application. The completed initial design provides information on the engineering design, environmental considerations, and basis for the subsequent deployment of carbon capture and storage (CCS) projects that are targeting the federal 45Q tax credits.

2.1 Host Site Selection

This project designed a carbon capture system for Phillips 66's Rodeo Refinery in Rodeo, California (San Francisco metro area) at the existing hydrogen production unit (HPU). This HPU uses SMR technology for generating H_2 from natural gas and can produce up to 28 MMSCFD of H_2 (99.97%+ purity). With 95% carbon capture efficiency, it is estimated that this unit can provide an opportunity for carbon capture in the range of ~190ktonne/year. An aerial view of the existing HPU is shown in Figure 2.1.1.

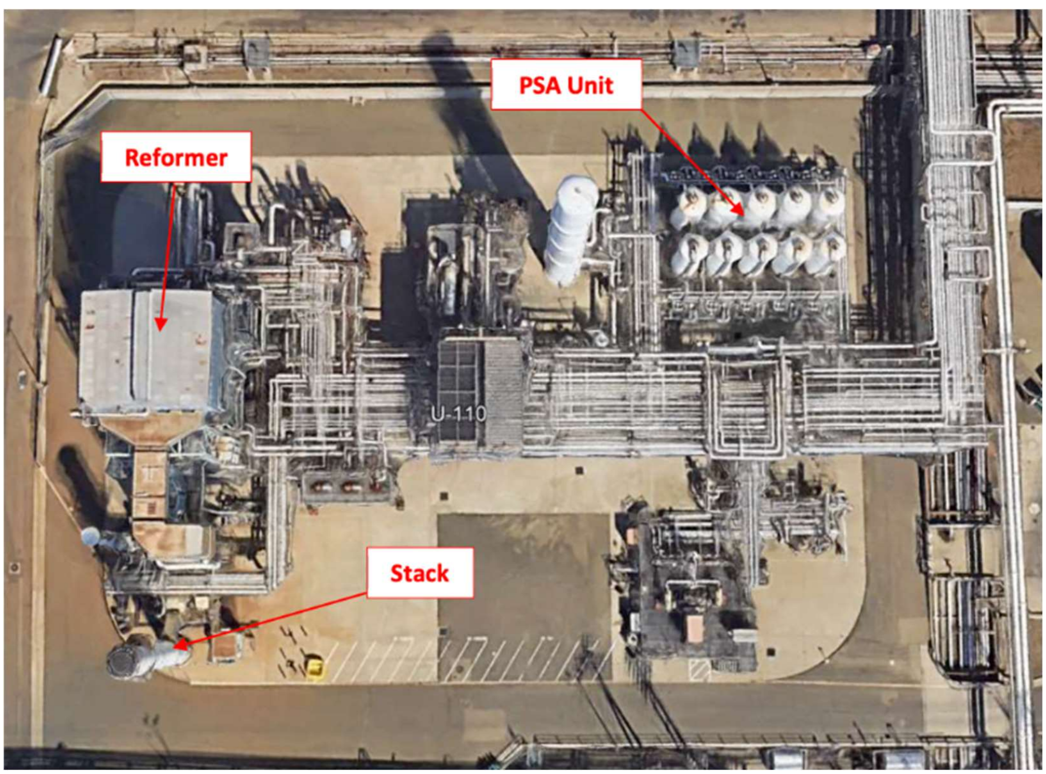


Figure 2.1.1 An Aerial View of the Existing HPU

2.2 Existing HPU

The current HPU at Rodeo Refinery is designed to process a wide range of feedstocks for producing H_2. The feed mixture can be increased to up to 2,000 barrels per day (BPD) of pentane (with the balance being natural gas) and up to 100% natural gas. For the purposes of this study 100% natural gas was utilized as the SMR feedstock. In general, the HPU can be categorized into three (3) major sections, namely:

- Feed Compression and Pretreatment
- Reforming and Steam Generation
- Hydrogen Purification

A schematic of the existing HPU with key operating parameters is shown in the following Figure 2.2.1.

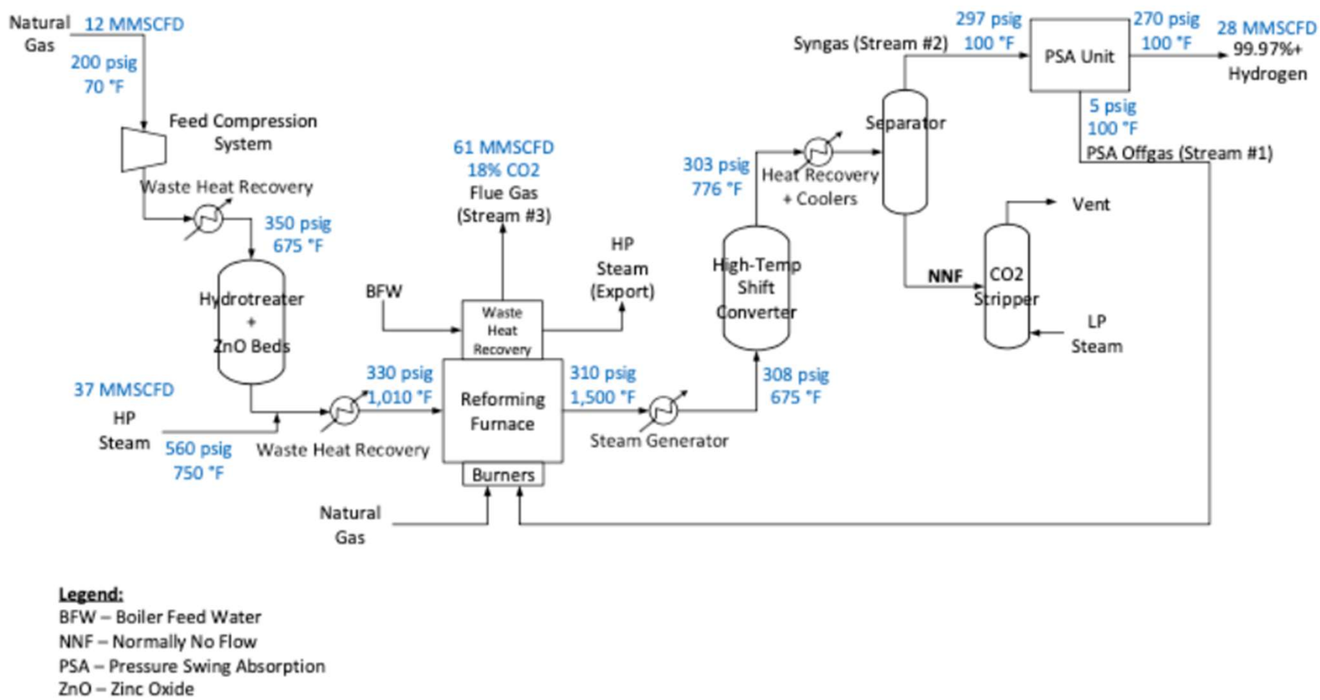


Figure 2.2.1: Block Flow Diagram of Rodeo Refinery HPU

The following paragraphs provide brief descriptions for each process section.

2.2.1 Feed Compression and Pretreatment

Natural gas is sent to the feed gas compressor for boosting the pressure and then heated by recovering waste heat from the steam reformer. To protect the reformer catalysts from sulfur poisoning, the stream is first run through a hydrotreater reactor where organic sulfur compounds will react with H_2 to form hydrogen sulfide gas (H_2S). This produced H_2S is then removed by the downstream zinc oxide guard beds.

2.2.2 Reforming

The sweetened feed stream is preheated by waste heat recovery from the steam reforming furnace before entering the reformer. In the reforming furnace, methane and water react to form syngas, which mostly comprises H_2 and carbon monoxide (CO). Syngas from the reforming furnace is then cooled before it is sent to the shift reactor. Energy efficiency is improved in the cooling step by recovering process heat for steam generation. The cooled syngas (~675 °F) passes through the High-Temperature Shift Converter where CO is reacted with steam to produce more H_2. Process heat from the effluent is recovered and further cooled by air and water cooling before arriving at a conventional gas/liquid separator. Hydrocarbon liquid condensate is not expected to be produced because of the effluent composition resulting from processing 100% natural gas as the feedstock. The separated gas stream contains mainly H_2, and CO_2, with some remaining CO, which now needs to be purified.

2.2.3 H_2 Purification

The cooled H_2-rich stream from the separator is sent to the pressure-swing adsorption (PSA) unit for final product purification. The purity of the H_2 product from the PSA is targeted at >99.97%+. The offgas (or as it's usually called, Tail Gas) from the PSA unit is then used as additional fuel for the steam reforming furnace.

2.2.4 Streams Studied for Carbon Capture

There are three configurations of carbon capture integration with the SMR that were considered for this study (see Section 3.2). The compositions and properties of the relevant input streams for the three carbon capture configurations are shown in Table 2.2.1. The feedstock to the SMR unit which results in these stream data is 100% natural gas, which is also the basis for this project. The Flue Gas 1 stream corresponds to the case where the PSA Off Gas is used to fire the SMR furnace, enriching the flue gas in CO_2 content with CO_2 from the process gas. The Flue Gas 2 stream corresponds to the case where the majority of the CO_2 in the process gas is captured upstream of the SMR furnace.

	PSA Off gas		Syngas		Flue Gas1		Flue Gas2	
	molar	lb-mol/hr	molar	lb-mol/hr	molar	lb-mol/hr	molar	lb-mol/hr
H2	28.6%	546	72.8%	3643	0.0%	0.0	0.0%	0.0
N2	0.49%	9.4	0.19%	9.5	61.4%	4112	69.8%	4112
O2	0.00%	0.0	0.00%	0.0	1.50%	100.4	1.70%	100.4
CO2	42.1%	804	16.1%	804	18.0%	1208	6.85%	403
CO	8.06%	153.9	3.08%	154.2	0.00%	0.0	0.00%	0.0
CH4	20.25%	386.8	7.72%	386.5	0.00%	0.0	0.00%	0.0
H2O	0.49%	9.4	0.19%	9.5	18.3%	1226	20.8%	1226
Ar	0.00%	0.0	0.00%	0.0	0.73%	48.9	0.83%	48.9
Total:	100.0%	1910	100.0%	5008	100.0%	6695	100.0%	5891

**There are very low ppm levels of CO, SO_x, and NO_x in the SMR's flue gas. These are respectively minimized by 1) complete combustion of the natural gas with sufficient excess O_2, 2) use of a very low sulfur content natural gas as the fuel gas, and 3) use of an SCR catalyst in the SMR's convection section and NH_3 injection into the flue gas. A CEMS analyzers are included on the current and future flue gas streams.*

Table 2.2.1: Streams Evaluated for Carbon Capture

	PSA Off gas	Syngas	Flue Gas1	Flue Gas2
Molar Flow (lb-mol/hr)	1,910	5,007	6,695	
Pressure, psig	5	297	0	0
Temperature, °F	100	100	425	425
Target CO2 Recovery, %	90 - 95	90 - 95	90 - 95	90 - 95

Table 2.2.2: Process Conditions for Streams Evaluated for Carbon Capture

2.3 Study Method

The study was divided into six tasks as described below:

Task ID	Task Description
Task 1	Project Initiation
Task 2	Technology and Scheme Selection
Task 3	Develop the Selected Technology Engineering
Task 4	Techno-economic Analysis
Task 5	Perform Environmental Health and Safety Analysis
Task 6	Allowances & Support

Table 2.3.1: The CCS Study Tasks and Descriptions

The work process and results for Task 2, Technology Selection are discussed and presented in the Technology Analysis Plan, Options Evaluated.

Development of Task 3, the Selected Technology is discussed in the Technology Analysis Plan, Option Further Developed.

The Technoeconomic Analysis (TEA) is covered by many sections in this final report with Section 5, Technology and Section 6, Economic Analysis providing the summary results.

3. Technology Analysis Plan

3.1 Goals and Desired Outcomes

The goals of this proposed project are to advance the CCS technology for commercialization in steam reforming plant application. The completed preliminary initial design provides adequate information on the design basis, engineering design, and any environmental considerations for the subsequent deployment of CCS projects that are targeting the federal 45Q tax credits.

In addition to the overall viability, design and total installed cost, also evaluated are the capture cost per tonne of CO_2 captured, capture cost per tonne of CO_2 avoided (net CO_2 emissions reduction), and the levelized cost of H_2 after carbon capture.

3.2 Cases Evaluated

Three carbon capture options were initially evaluated in the study, with one option progressing to the final evaluation. The three options are illustrated and discussed below.

3.2.1 Option 1 – Carbon Capture from SMR Flue Gas and from PSA Tail Gas

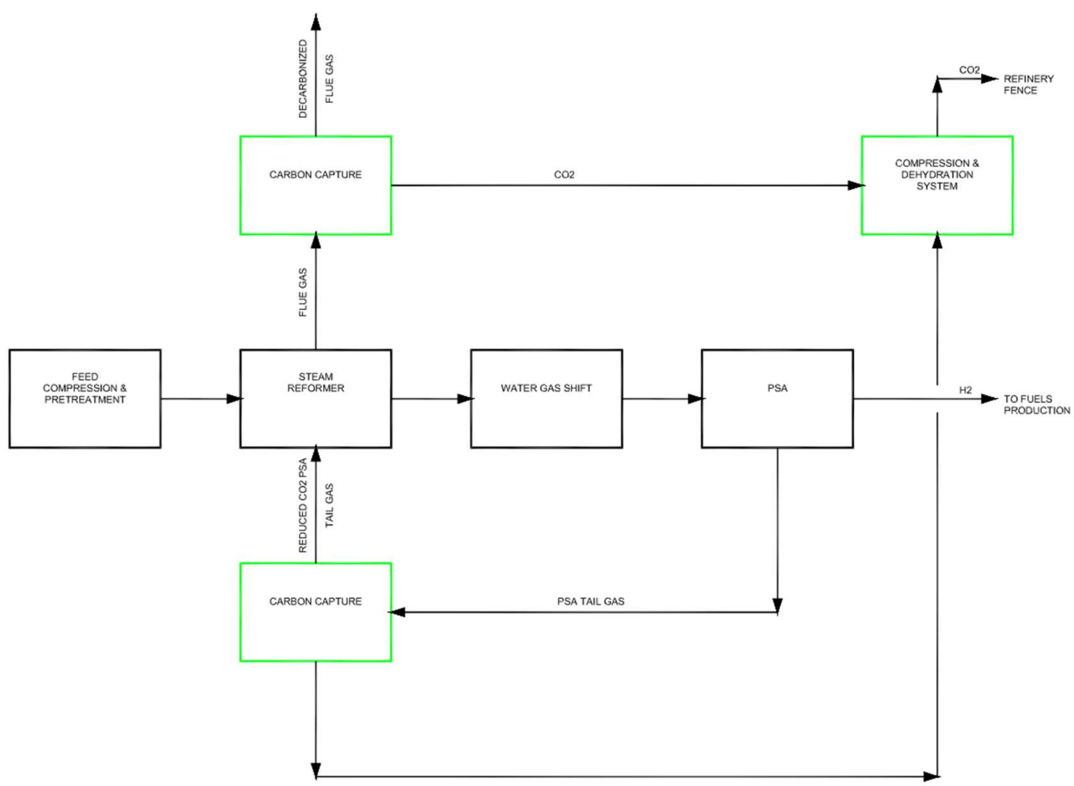


Figure 3.2.1: Block Flow Diagram for Option 1

Some of the features of this option are listed below:

- Pre-combustion carbon capture at very low pressure (~5 psig)
- Both captured CO_2 streams (from pre-combustion and post-combustion) will be sent to the same dehydration and compression system
- Two absorption towers and two solvent regeneration skids will be required due to the pre-combustion and post-combustion capture systems requiring different solvents

List of new key equipment:

- Flue gas booster blower
- Flue gas quencher
- Absorber for flue gas
- Stripper for flue gas absorption loop
- Absorber for syngas
- Stripper for syngas absorption loop
- Absorbent solution filtration and regeneration skids (2)
- CO_2 dehydration
- Multi-stage CO_2 compressor

3.2.2 Option 2 – Carbon Capture from Syngas Before PSA, and from SMR Flue Gas

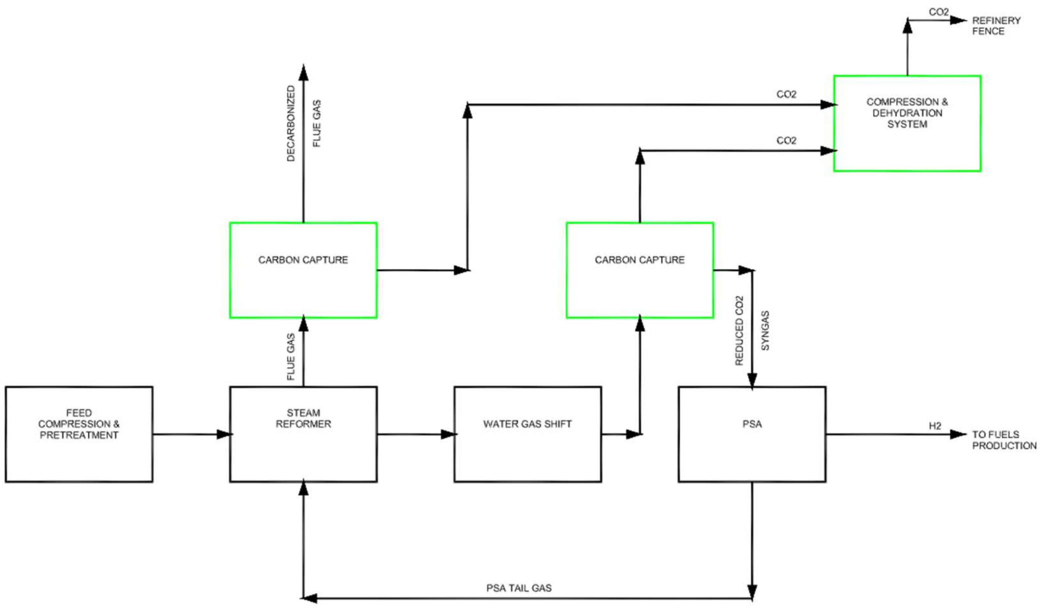


Figure 3.2.2: Block Flow Diagram for Option 2

Some of the features of this option are listed below:

- Pre-combustion carbon capture at medium pressure (~300 psig)
- Due to higher operating pressure, diameter of the absorption tower will be smaller when comparing to Option 1
- Both captured CO_2 streams (from pre-combustion and post-combustion) will be sent to the same dehydration and compression system
- Two absorption towers and two solvent regeneration skids will be required due to the pre-combustion and post-combustion captures systems requiring different solvents

List of new key equipment

- Flue gas booster blower
- Flue gas quencher
- Absorber for flue gas
- Stripper for flue gas absorption loop
- High pressure absorber for syngas
- Stripper for syngas absorption loop

- Absorbent solution filtration and regeneration skids (2)
- CO_2 dehydration
- Multi-stage CO_2 compressor

3.2.3 Option 3 – Carbon Capture from SMR Flue Gas

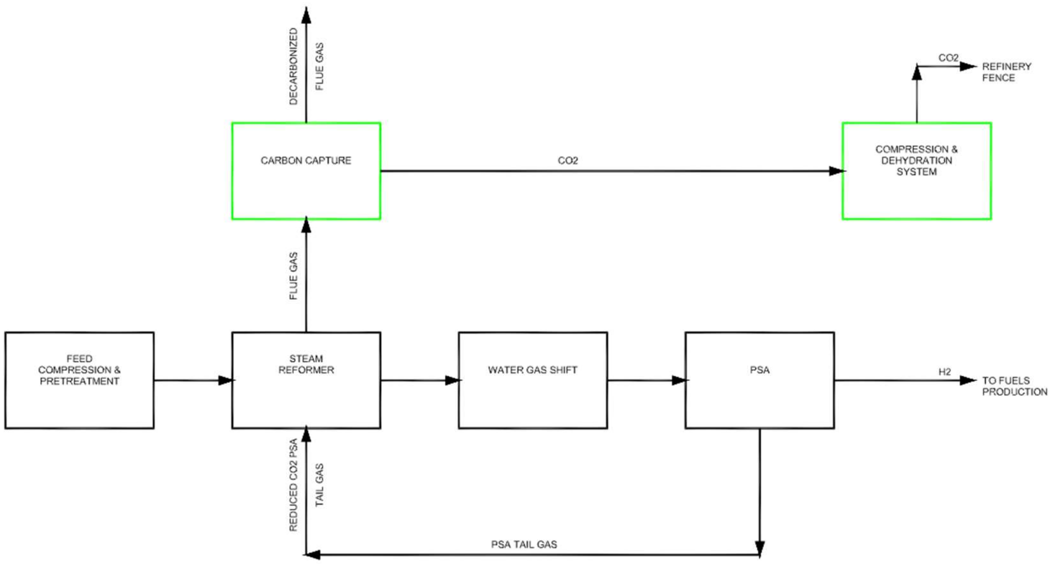


Figure 3.2.3: Block Flow Diagram for Option 3

Some of the features of this option are listed below:

- Post-combustion carbon capture only
- One absorption tower and one solvent regeneration skid will be required

List of new key equipment:

- Flue gas booster blower
- Flue gas quencher
- Absorber for flue gas
- Absorbent solution regenerator
- CO_2 dehydration
- Multi-stage CO_2 compressor

The CO_2 dehydration and compression systems were very similar in size and design among the three options because the amount of CO_2 captured was essentially the same for all three cases.

For all cases, only one CO_2-containing flue gas stream would be released to the atmosphere via a new stack above the final flue gas Absorber vessel after CCS implementation. The emissions profiles for current and projected emissions with CCS are shown in Table 3.2.1.

	Current Emissions	Projected Emissions with CCS
Temp. (°F)	~425	144
Pressure (psig)	ATM	ATM
Components (mol%)		
H2	0.0	0.0
N2	61.4	91.2
O2	1.5	2.2
CO2	18.1	1.3
CO	0.0	0.0
CH4	0.0	0.0
H2O	18.3	4.1
Ar	0.7	1.1
CO2 Capture Solvent	0.0	<0.01
Total:	100	100
Molar Flow (lbmole/hr)	6,695	TBD
Mass Flow (lb/hr)	195,614	TBD
MW	29.2	TBD
Vapor Flow (MMSCFD)	61.0	50

Table 3.1.1: Current and Projected Emission Profiles (see detailed HMB provided separately)

3.3 Technologies Compared (Initial Technoeconomic Analysis)

Proposals were received from multiple carbon capture technology providers. These proposals differed for the various schemes discussed in the prior section. The resulting analysis and recommendations for these proposals were reviewed in detail with DOE personnel on 08/11/22.

Each of these technologies were compared using a multi-point qualitative criterion covering the following topics: (with only incomplete data being available at this stage of the study the analysis can only be qualitative)

Costs	Technical Issues	Environmental
Capital cost intensity	Carbon capture efficiency	Emissions
O&M costs	Robustness of basic technology	Effluents
Utilities usage	Expected plant life	Waste
Catalyst and solvent cost	Technology risk/risk mitigation	Noise
Nominal captured CO_2 volumes	Availability and outages	Visual Impact
Impact on existing SMR	Catalyst life & chemicals replacement	Inherent process safety
Licensing issues	Modularization	
Licensor commitment to market	Complexity and integration	
Expected project duration to start-up	Size of operating units matching target	
Quality/completeness of bid package	On-going development	
	Number of units operating / size	

Table 3.3.1: Technology Selection Criterion

3.4 Case Selected

The responses from the technology providers were first compared to down-select between the configuration Options 1-3. After reviewing all of the data, Option 3 (post-combustion only) was chosen as the best option to move forward with for the following reasons:

1) Some vendors stated that their previous analyses indicated that post-combustion (Option 3) was more cost-effective than building a pre-combustion capture unit and a smaller post-combustion capture unit.

2) Worley (the engineering firm which we leveraged for this study) confirmed that the post-combustion configuration was chosen on a recent previous project for another client after they executed a similar study.

3) The operating expenses (OPEX) for the Option 3 cases were lower than for the Option 1 and 2 cases.

4) Maintenance costs for Option 3 would be expected to be lower than Options 1 and 2 due to fewer pieces of equipment.

5) The capital expense (CAPEX) for Option 3 is expected to be equal to or lower than Options 1 and 2, especially the inside-the-battery-limits (ISBL) and site preparation costs. Especially as feedback from the vendors indicated that it was not desired to utilize the same solvents for both pre-combustion and post-combustion units due to the different makeup of the gas to be treated, thus there would be no cost savings of only having one Stripper and one reclaimer skid.

6) The physical solvent and membrane technology offering options were not chosen due to higher expected CAPEX and upper limits on the CO_2 recovery potentials. Though outside of the scope of this study, the Rodeo Refinery is expected to be steam-long (have access to waste heat), thus reducing the costs associated with steam usage for amine systems. However, the final TEA analysis of the initial engineering design (see Section 5) does not assume that this waste heat is available for free.

After selecting the Option 3 case, the post-combustion-only responses from the technology providers were entered into a comparative evaluation form for review with Phillips 66 and the DOE. A numerical score was given to each technology for each item identified in Table 3.3.1 and a total score was calculated with a weighted sum. The major criteria of costs, technical issues, environmental, commercial and project, and developmental status were given relative weightings of 10, 7, 4, 1 and 4, respectively.

Major Criteria	Sub-Criteria Factors
Costs	Capital Cost Intensity, $MM/k tonne per annum
Costs	O&M Costs
Costs	Utilities Usage
Costs	Catalyst and Solvent Cost
Costs	Nominal Captured CO_2 Volumes
Costs	Impact on Existing SMR
Technical Issues	Carbon Capture Efficiency
Technical Issues	Robustness of Basic Technology
Technical Issues	Expected Plant Life
Technical Issues	Technology Risk/Risk Mitigation
Technical Issues	Availability and Outages
Technical Issues	Catalyst Life and Chemicals Replacement
Technical Issues	Modularization
Technical Issues	Complexity & Integration
Environmental	Emissions

Major Criteria	Sub-Criteria Factors
Environmental	Effluents
Environmental	Waste
Environmental	Noise
Environmental	Visual Impact
Environmental	Inherent Process Safety
Commercial and Project	Licensing Issues
Commercial and Project	Licensor Commitment to Market
Commercial and Project	Expected Project Duration to Startup
Commercial and Project	Quality/Completeness of Bid Package
Development Status	Size of operating Units Matching Target
Development Status	On-Going Development
Development Status	Number of Units Operating/Size

Table 3.4.1: Summary Technical Selection Score

Upon analysis, the designs of all of the four post-combustion technology offerings were very similar (e.g. equipment count, tower packing, metallurgy, sizes of key equipment, etc.). There were some small differences in exchanger design, pump sizes, filtration and cooling, but not enough to significantly impact the CAPEX of the unit. The only significant difference was that the design of one technology offering allowed for a higher pressure CO_2 product from the regenerator, which may have enabled the elimination of one stage of CO_2 compression. However, we determined that without doing a detailed cost estimate including vendor quotes for each case, the four technology offerings were hard to differentiate from a capital cost perspective.

In the end the final scores were extremely close, but the post-combustion technology offering from Mitsubishi Heavy Industries scored the highest in our selection process and was selected to move forward for the engineering design, cost estimate and TEA phases of the project. Some key factors that influenced the decision included:

1) Lower licensing costs

2) Good commercial experience

3) Second lowest OPEX

4) Best predicted solvent loss performance

Once this decision was made, we were able to notify MHI of this decision and move forward into the next phase of engineering work.

3.5 Novel Technology Basis

3.5.1 Novel Equipment Size and Performance Basis

The equipment for technologies evaluated in this study were sized with process simulation software (HYSYS) which was adjusted to match the performance information provided by the technology licensors. Only commercially available processes were considered.

3.5.2 Novel Equipment Costing

Since the technology that was selected for this study was commercially available, no additional work was done to develop novel equipment. The cost of proprietary aspects of the technology was estimated with input from the technology licensor. The total cost of these proprietary parts of the design, such as the solvent reclaimer, were minor compared to the total overall equipment cost.

3.5.3 Sensitivities

Since the technology that was selected for this study was commercial, no additional work was done to assess the sensitivities of various performance characteristics to the overall capture technology performance. However, in Section 5.5, the sensitivities of unit performance and OPEX costs are indirectly evaluated by determining the economic sensitivities of the capture plant capacity factor, as well as steam and electricity prices.

4. Technology Analysis

4.1 Plant and Component Descriptions – Including Design Specs and Assumptions

4.1.1 Existing HPU (Hydrogen Production Unit, or SMR)

The current HPU at the Rodeo Refinery is designed to process a wide range of feedstocks for producing H_2. The feed mixture can be varied from up to 2,000 BPD of pentane (with the balance of natural gas) to up to 100% natural gas. In general, the HPU can be categorized into three (3) major sections, namely:

- Feed Compression and Pretreatment
- Reforming and Steam Generation
- Hydrogen Purification

A schematic of the existing HPU with key operation parameters is shown in the following Figure 3.2.1.

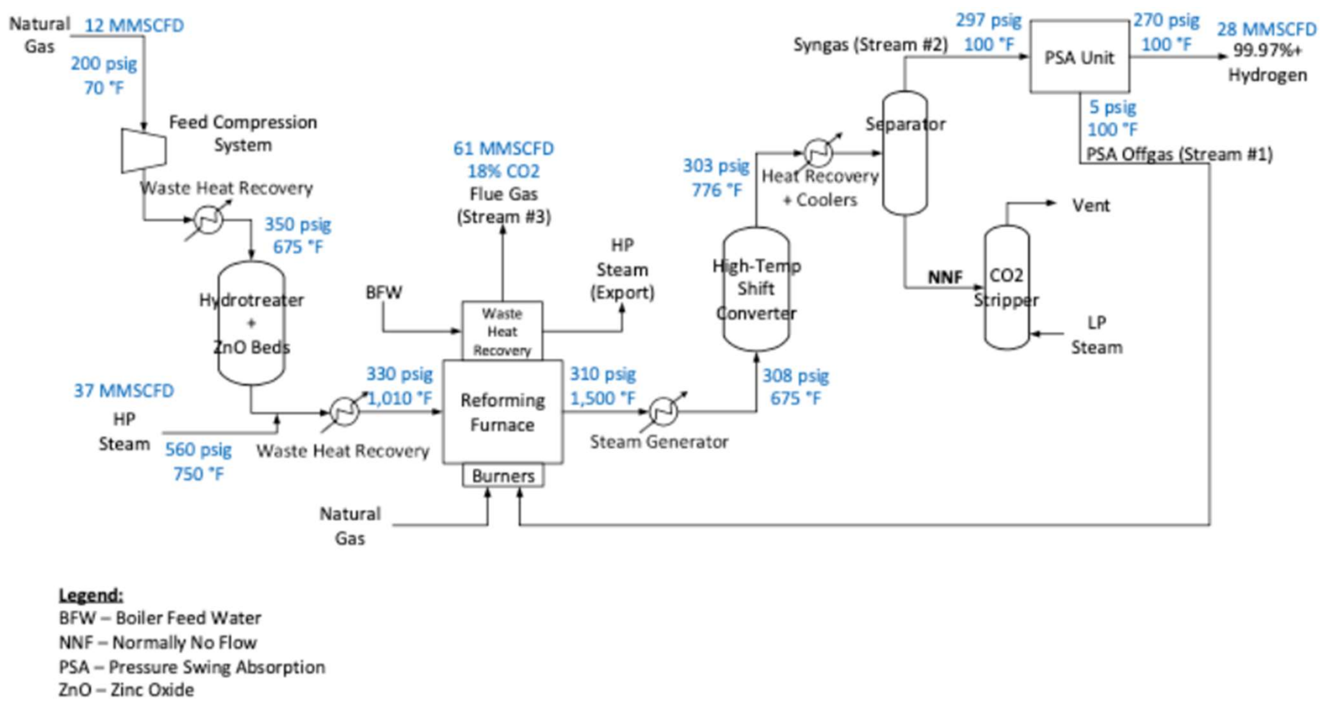


Figure 4.1.1: Block Flow Diagram of Rodeo Refinery HPU

The following paragraphs provide brief descriptions for each process section.

4.1.1.1 Feed Compression and Pretreatment

Natural gas is sent to the feed gas compressor for boosting the pressure and then heated by recovering waste heat from the steam reformer. To protect the reformer catalysts from sulfur poisoning, the stream is first run through a hydrotreater reactor where organic sulfur compounds react with H_2 to form H_2S. This produced H_2S is then removed by the downstream zeolite guard beds.

4.1.1.2 Reforming

The sweetened feed stream is preheated by waste heat recovery from the steam reforming furnace before entering the reformer. In the reforming furnace, methane and water react to form syngas, which mostly comprises H_2 and CO. Syngas from the reforming furnace is cooled before it is sent to the shift reactor. Energy efficiency is improved in the cooling step by recovering process heat for steam generation. The cooled syngas (~675 °F) passes through the High-Temperature Shift Converter where CO is reacted with steam to produce more H_2. Process heat from the effluent is recovered and further cooled by air and water cooling before arriving at a conventional gas/liquid separator. Liquid condensate is not expected to be produced because of the effluent composition resulting from processing 100% natural gas as the feedstock. The separated gas stream contains mainly H_2, which needs to be purified.

4.1.1.3 H_2 Purification

The cooled H_2-rich stream from the separator is sent to the PSA unit for final product purification. The purity of the H_2 product from the PSA is targeted at 99.97%+. The off gas (or as it's usually called tail gas) from the PSA unit is used as additional fuel for the steam reforming furnace.

4.1.2 Carbon Capture Unit

The selected case to further the study was Option 3, carbon capture from the steam methane reformer's combined flue gas. The CO_2 capture plant was then designed to capture the specified amount of CO_2. The flue gas flows from the stack and is brought to the CO_2 capture plant across the street via ducting from the existing stack through the flue gas quencher and as drawn by an induced draft flue gas blower. The flue gas shall be emitted directly to the atmosphere through the existing stack in the case of a flue gas blower trip failure. The continuous emissions monitoring system (CEMS) will remain in place for this eventuality.

The CO_2 recovery facility consists of four main sections shown in Figure 5.1.2; flue gas pretreatment, CO_2 absorption, solvent regeneration, and CO_2 compression and dehydration. The block flow diagram showing the overall plant configuration is covered below and is provided in Appendix A:

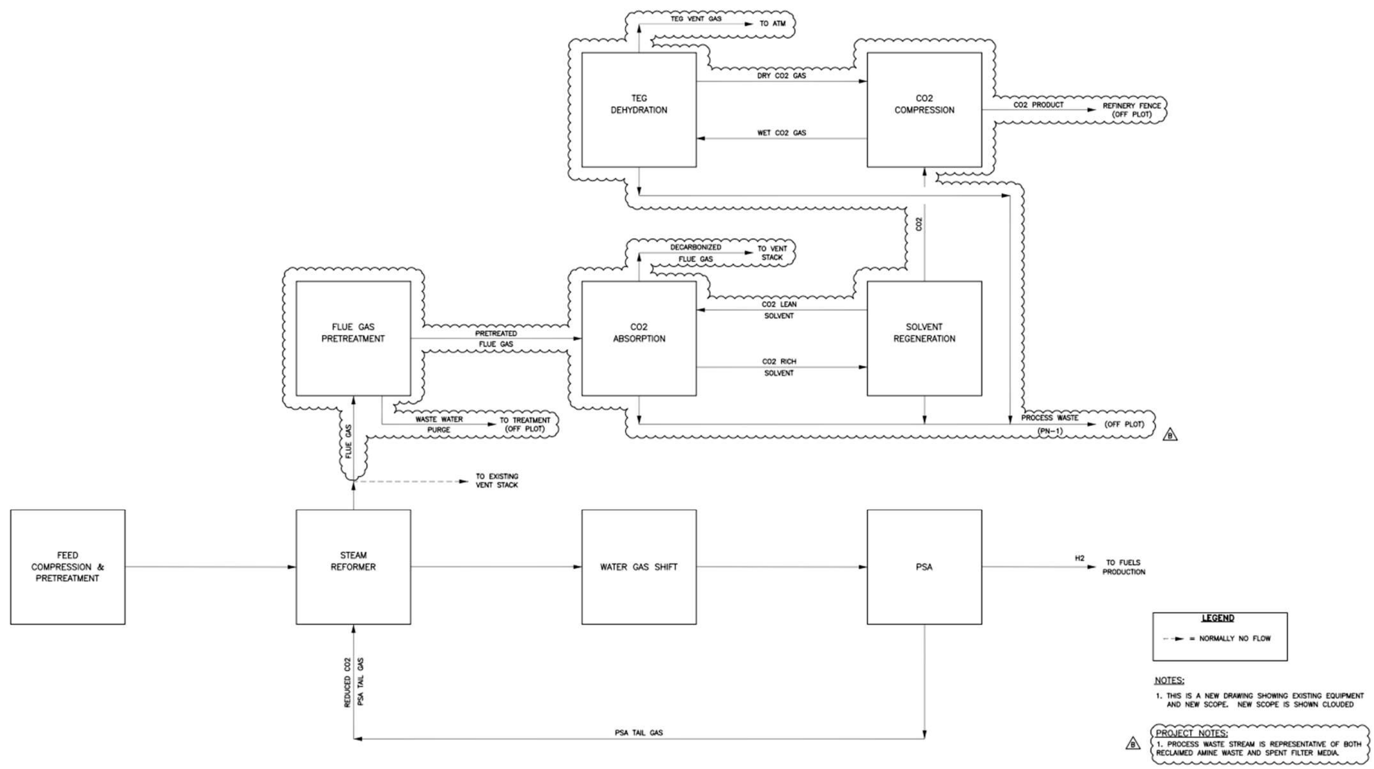


Figure 4.1.2: Block Flow Diagram of Carbon Capture Unit

A description of the unit sections is provided below.

4.1.2.1 Flue Gas Pretreatment

The temperature of the flue gas is too high to feed directly into the CO_2 Absorber (~425°F). A lower flue gas temperature is preferrable for the exothermic reaction of CO_2 absorption and solvent consumption. The hot flue gas is cooled in the flue gas quencher by direct contact with circulation water supplied from the top of the quencher. The circulation water is cooled by the flue gas water air cooler and the flue gas cooling water cooler. In addition, a small amount of caustic soda is injected into the circulation water in order to reduce the amount of SO_2 entering the amine system. The flue gas blower is installed downstream of the flue gas quencher to overcome the pressure drop across the flue gas quencher and then the CO_2 Absorber.

4.1.2.2 CO_2 Absorption

The CO_2 Absorber column has two main sections, (1) the absorption section in the lower part of the column and (2) the treated flue gas washing section in the upper part of the column. The cooled flue gas from the flue gas quencher is introduced into the bottom section of the CO_2 absorber column, where the flue gas flows upward through the internal packing. Meanwhile, lean solvent flows from the top of the absorption section and down into the packing. The flue gas comes into contact with the solvent on the packing surface(s) and the CO_2 is absorbed into the amine-based solvent. The CO_2-rich solvent from the bottom of the absorber is then pumped to the amine regenerator column via the rich solution pump and through the upstream solution heat exchanger(s). The flue gas from the absorption section continues upward through the CO_2 absorber column and into the treated gas wash water section. The treated gas comes into contact with wash water to clean any entrained solvent out of the gas. The wash water section contains a combination of packing and several demisters, one of which is a proprietary design by MHI. The treated gas is exhausted from the top section of the CO_2 absorber column into the atmosphere via a stack which has CEMS analyzers.

4.1.2.3 Solvent Regeneration

The solvent regenerator is a cylindrical packed column, where the CO_2 rich solvent is stripped via usage of a steam heated reboiler in order to remove the CO_2 from the amine solvent. The rich solvent is heated by the lean solvent from the bottom of the regenerator in the solution heat exchanger(s). The heated CO_2 rich solvent is introduced into the upper section of the regenerator, where it comes into contact with vaporized solvent from lower in the column. This vapor is produced by the regenerator reboiler, which uses low pressure (desuperheated 50 psig) steam. The overhead vapor is cooled by the regenerator air condenser and the CO_2 gas condensing unit. The CO_2 lean solvent is cooled to the optimum reaction temperature by the solution heat exchanger, followed by the lean solution cooler, before being recycled back into the CO_2 absorber column.

SO_2, NO_2 and O_2 can react with the solvent in the CO_2 absorber and this reaction over time forms low levels of heat stable salt (HSS) products. The long term accumulation of HSS causes corrosion and/or foaming to occur in the amine unit. The reclaimer unit removes the HSS and other degradation products that accumulate in the solvent. This is operated on a semi-permanent basis by feeding a slipstream of lean solvent. The MHI solvent package has been chosen to be particularly resistant to HSS formation.

4.1.2.4 CO_2 Compression

The combined CO_2 product stream from the stripper is to be compressed with a five stage reciprocating compressor from a suction condition of 24.7 psia at 107°F to 2,250 psia at 120°F, which is the desired dense phase (supercritical liquid) condition. The CO_2 stream at the suction of the compressor is saturated with moisture. Therefore, to mitigate the risks associated with wet CO_2- and O_2-related corrosion, dehydration is also required. Most of the water is removed (via interstage knockout drums) in the first few stages of the compressor via compression and cooling, resulting in a reduced water content of 120-160 lb/MM SCFD, depending on the interstage pressure and temperature. Further reduction of moisture is then achieved via a tetraethylene glycol (TEG) dehydration unit that is fed from the compressor’s third stage discharge knockout drum and the dehydrated CO_2 gas is then fed back into the final two stages of the compressor.

The best operating pressure for dehydration is within the range of 550-750 psia. The optimum operating configuration should be determined in conjunction with the compressor and dehydration unit suppliers if a different compressor design system is eventually specified.

The rated capacity and discharge pressure of the compressor is 226 KTA (28.4 tph) and 2,250 psia, respectively, on a dry basis. The best efficiency point of the compressor should be close to the rated capacity and pressure. To minimize energy consumption during turndown conditions, maximum possible turndown, ~30% of rated, shall be achievable without the need for recycle. This can be achieved via valve unloading design of the compressor.

The following table summarizes the flow rates and conditions that shall be the basis for the design. No margin or availability factor is considered for the design case.

	Normal	Design	Turndown
Dry CO_2 Rate, MM SCFD	11.0	12.1	3.3
Dry CO_2 Rate, lb/hr	51,591	56,750	15,477
Suction Pressure, psia	24.7	24.7	24.7
Suction Temperature, °F	107	107	107
Discharge Pressure, psia	2,250	2,250	2,250
Outlet Temperature, °F	120	120	120

Table 4.1.1: CO_2 Compressor Process Specifications

The driver for the compressor should be a fixed-speed synchronous electric motor. The last stage of compression was evaluated to utilize a centrifugal pump for pumping the liquid CO_2. This configuration did not reduce CAPEX however and we stayed with the decision to specify the 5-stage reciprocating compressor. Both air cooling and water cooling were specified for each interstage cooling service in order to minimize the compressor inlet temperature and to protect the water cooled exchangers from water-side fouling due to too high of an inlet temperature into them.

4.1.2.5 CO_2 Dehydration (TEG Unit)

The wet CO_2 gas enters the bottom of the glycol gas absorber (contactor), flows upward through the trayed, or packed, tower with mist eliminator (to remove any entrained glycol droplets from the gas stream) and exits from the top of the absorber as dry gas. The dry gas then flows through a glycol cooler to cool the hot regenerated glycol before the glycol enters the absorber. The dry glycol, on the other hand, flows down the column, absorbs water from the up-flowing gas mixture and exits at the bottom of the absorber as rich glycol. The rich glycol then flows through a reflux condenser at the top of the still column (stripper) and enters a flash tank where most of the entrained, soluble and volatile components are vaporized. This small gas stream is vented to atmosphere. After leaving the flash tank, the rich glycol flows through the glycol filters and the rich-lean glycol exchanger, where heat is exchanged with the hot lean glycol. The rich glycol then enters the glycol regenerator that contains the still column (stripper) and reboiler, where the water is removed by distillation, and the glycol concentration can be increased to meet the lean glycol requirements determined by the process.

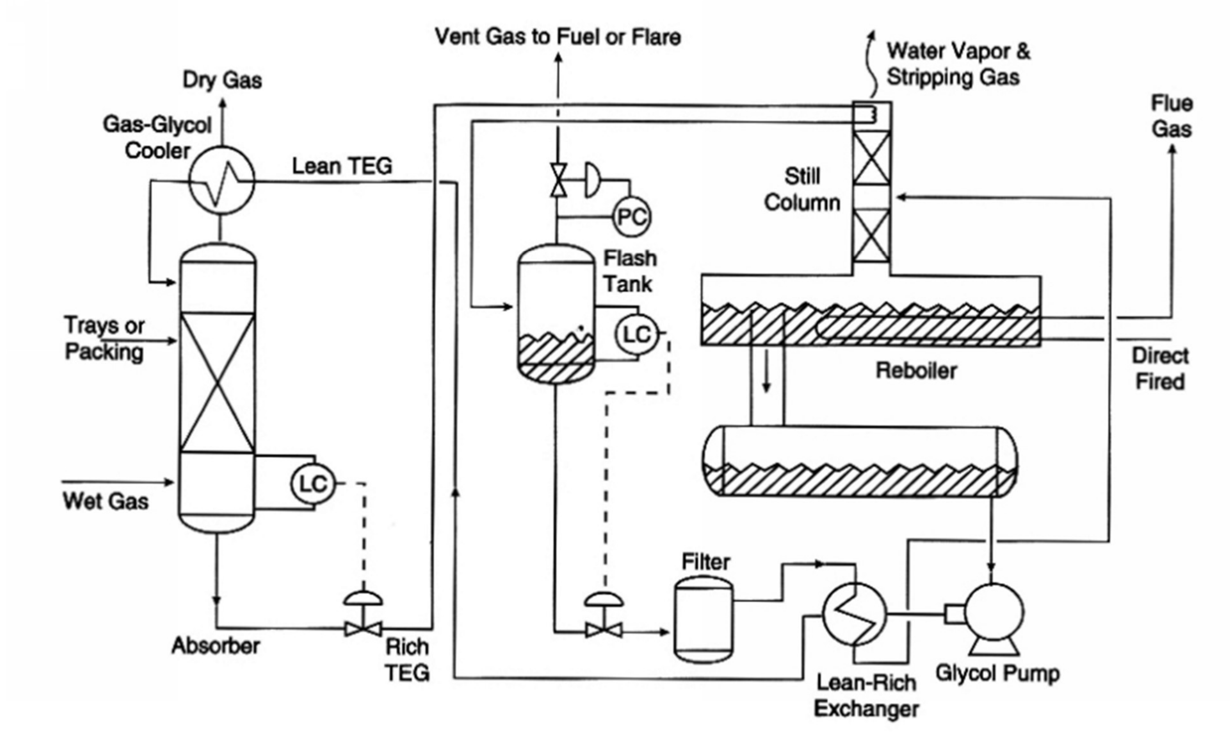


Figure 4.1.3: A PFD Sketch of a Typical Glycol Dehydration Process

4.2 Process Fluid/Materials Data

The following sections provide a summary of the potential feed streams for CO_2 capture and a brief description of the amine solvent used.

4.2.1 Feed Streams

There are three streams in this H_2 production unit that were considered for carbon capture and their compositions and properties are shown in Table 5.2.1 below. The feedstock corresponding to these stream data is 100% natural gas, which is also the basis for this project.

	PSA Off Gas	Syngas	Flue Gas
Stream No. (Figure 5)	**1**	**2**	**3**
Temperature (°F)	100	100	~425
Pressure (psig)	5	296.8	0
Components		**mol%**	
H_2	28.61%	72.77%	0.00%
N_2	0.49%	0.19%	61.42%
O_2	0.00%	0.00%	1.50%

	PSA Off Gas	Syngas	Flue Gas
Stream No. (Figure 5)	**1**	**2**	**3**
CO_2	42.10%	16.06%	18.04%
CO	8.06%	3.08%	0.00%
CH_4	20.25%	7.72%	0.00%
H_2O	0.49%	0.19%	18.31%
Ar	0.00%	0.00%	0.73%
Total:	**100.0%**	**100.0%**	**100.0%**
Molar Flow (lb-mol/hr)	1,910	5,007	6,695
Mass Flow (lb/hr)	47,439	53,682	195,614
MW	24.84	10.72	29.22
Vapor Flow, MMSCFD	17.4	45.6	60.98

Table 4.2.1: Potential Streams for Carbon Capture

Based on the chosen flow scheme and the selected licensor, the CCS unit's feed stream will be best represented by Stream No. 3 (flue gas) from the table above.

4.2.2 Specification of Solvent

The MHI KM CDR Process™ is an amine-based CO_2 capture process that uses one of MHI's proprietary solvents, KS-21™. MHI's solvent offers several advantages over conventional processes, including low steam consumption for regeneration, high CO_2 capacity, low solvent degradation, and low solvent consumption. Due to confidentiality concerns, detailed chemical composition of this material will not be noted here within the report, but it has already been permitted and utilized commercially elsewhere.

4.2.3 Product Specifications

Based on the specifications of CO_2 product for deep underground saline reservoir sequestration listed below, an integrated dehydration system in a multi-stage compression facility will be required (as described above). The CO_2 product stream from the stripper column (solvent regeneration unit) will be compressed from ~25 psia to 2,250 psia. Air coolers and water trim coolers will be utilized for compressor inter-stage cooling. To achieve the specified delivery pressure (2,250 psia), a 5-stage compression system is expected to be required. Various different compressor options were considered during this study, but ultimately a single, 100% capacity 5 stage electrically-driven reciprocating compressor was chosen. To meet the maximum water content of the CO_2 stream, dehydration by TEG absorption will be utilized. For optimum dehydration performance and also minimizing equipment footprint (e.g. TEG absorber), the dehydration process should be operated above 520 psia. The CO_2 dehydration and compression system configuration is expected to be similar among the three options as the aggregated CO_2 capture rates are in the same range for all cases. The dehydration system specified is expected to dry the CO_2 stream down to <50ppm water content, well below the required level. Dry swing (regenerable) adsorbent systems can also be specified in this service, but we chose the TEG system described above as the more typical design for this scale of operation.

Component	Unit	Value
CO_2	Vol% (Min)	95
H_2O	ppm_v	500
N_2	Vol%	4
O_2	Vol%	0.001
Ar	Vol%	4
CH_4	Vol%	4
H_2	Vol%	4
CO	ppm_v	35
H_2S	Vol%	0.01
SO_2	ppm_v	100
NO_x	ppm_v	100
NH_3	ppm_v	50
COS	ppm_v	Trace
C_2H_6	Vol%	1
C_3+	Vol%	<1
Glycol	ppb_v	46

Table 4.2.2: CO_2 Specifications for Geological Storage

4.2.4 Flue Gas Specifications

For all cases (pre-combustion and post-combustion), it is anticipated that only one CO_2-containing flue gas stream will be released to the atmosphere after CCS implementation. The emissions profiles for current and projected emissions with CCS are shown below.

	Current Emission	Projected Emission with CCS
Temperature (°F)	~425	120
Pressure (psig)	ATM	ATM
Components (mol%)		
H_2	0.00%	0.00%
N_2	61.42%	66.40%
O_2	1.50%	1.62%
CO_2	18.04%	0.97%
CO	0.00%	0.00%
CH_4	0.00%	0.00%
H_2O	18.31%	30.17%
Argon	0.73%	0.79%
CO_2 Capture Solvent	0.00%	Trace
Total:	**100.0%**	**100.0%**
Molar Flow (lb-mol/hr)	6,695	6,193

	Current Emission	Projected Emission with CCS
Mass Flow (lb/hr)	195,614	156,866
MW	29.22	25.33
Vapor Flow, MMSCFD	60.98	56.41

Table 4.2.3: Current and Projected Emission Profiles

4.3 Emissions Summary

The plant emissions summary and discussion is provided in Appendix E.

4.4 Heat (Energy) and Material Balances

The plant heat and material balances were developed for the project, but are not included here due to them containing a significant amount of MHI business confidential data. They have been visually shown to the DOE, but not issued as a deliverable. A redacted version has since been created and issued to the DOE as *a limited rights* version.

4.5 Equipment List

The equipment list for the selected Option 3 is provided in Appendix C. The equipment design was based on standard supply from MHI and applying Phillips 66 design standards in selected cases such as the compressor operating and design parameters.

4.6 Technology Evaluation of Advanced Technology Plant Impact

4.6.1 Design Basis Decision's Effect on Base Plant

Commercial post-combustion amine capture technology was chosen for this study. Since the new equipment, starting with the flue gas pre-treatment section ties into the existing SMR flue gas stack, there is essentially no effect on the SMR plant or H_2 production. This aspect was an important factor in the choice between the pre-combustion capture cases (Options 1 & 2) and the post-combustion capture case (Option 3). Inserting process equipment in between process units (i.e. between the PSA and tail gas combustion for Option 1, or between the water gas shift and PSA for Option 2) often forces downstream equipment modifications, tight equipment spacing, and operational changes. These situations are mostly avoided with the selection of Option 3.

4.6.2 Advanced Technology Operating Parameter's Effect on Base Plant

Commercial post-combustion amine capture technology was chosen for this study. Since the new equipment, starting with the flue gas pre-treatment section ties into the existing SMR flue gas stack, there is essentially no effect on the SMR plant or H_2 production. In the event of a flue gas blower trip failure or capture plant unplanned shutdown, the SMR flue gas shall be emitted directly to the atmosphere through the existing SMR stack, maintaining SMR operation. However, to be able to continue to meet emissions monitoring requirements, a new continuous emissions monitoring system (CEMS) shall be installed on the new stack downstream of the CO_2 capture unit absorber with the existing SMR's stack CEMS continuing to be kept operational for the times when bypassing of the CCS unit may be required.

4.7 Advanced Technology Details

While the MHI technology chosen has certain proprietary design aspects to reduce energy consumption and maintain water balance, these design aspects are not significantly differentiating compared to other advanced CCS amine treating technologies to justify description here. They also are business confidential to MHI.

5. Economic Analysis

5.1 Overview

The economic analysis for this study included developing a capital cost estimate based on the engineered scope for the study, developing utilities and chemical costs, and developing operations and maintenance costs, as derived from current P66 Rodeo refinery operations.

5.2 Capital Cost Estimating

The capital cost estimate was developed jointly between Phillips 66 and Worley. As part of the estimating process, an estimate plan was developed as a roadmap for the team. The estimate plan was reviewed with Phillips 66 and then converted into the estimate basis (see Appendix D). Site Plan attached here in Appendix B.

5.2.1 Direct Costs

The engineering team developed material to takeoff quantities from scope and drawings developed during the engineering study. These qualities were reviewed and validated with Phillips 66 personnel experienced with the execution of refinery projects. In summary, the quantities were developed using the following methods:

- Overall process scope was depicted on Process Flow Diagrams (PFD) and Piping and Instrumentation diagrams (P&ID). Redacted versions of the PFDs are provided in the attachments. For a normal project at this stage, P&IDs are normally not produced, and are an enhancement to the estimate development, but they were developed and also issued to the DOE in a redacted format. This allowed more certainty to the piping sizes/lengths, instrumentation, and valve counts.
- Mechanical equipment scope was summarized in the sized equipment list. Vendor budgetary quotes were developed from data sheets and specifications for the major items, including the quench tower, blower, absorber, regenerator, TEG unit and CO_2 compressor. The balance of equipment on the equipment list was then priced from Worley internal data available for refinery projects and as built up utilizing Aspen Capital Cost Estimator (ACCE) software (the industry standard) adapted to the actual project site. Budgetary vendor quotes comprised over 80% of the equipment cost account value (versus 20% of cost account value based on in-house data). A normal target for this stage of estimate is only 50%.
- For piping quantities, standard equipment assemblies were used from ACCE and Worley's internal data and extended from the equipment list and site plan. Pipe quantities not associated with equipment for piping in the rack, pipe runs from remote tie-ins and the CO_2 transfer line to the refinery fence were developed from pipe sketches, and/or plot transpositions. To validate the overall pipe quantities, comparisons were made to projects of similar size and scope previously conducted by Worley. The results from the study matched well with expectations and no adjustments were made. Other piping items included:
  - Insulation was quantified from the requirements on the P&IDs.
  - Valve counts were developed from the equipment assemblies and from the P&IDs.

- Piping specialty items were counted from the P&IDs and listed.
- Civil and structural quantities and scopes have multiple components:
  - For site development scope, a site visit was performed, and a report was written with a narrative outline covering demolition, remediation and any relocation required to accommodate the project scope. These narratives were reviewed by the estimator and rough costs were developed.
  - For soil movements and grading, a calculation was performed on the plot area and depths for site leveling were estimated.
  - For existing foundation demolition, historic photos were reviewed for underground obstructions and a factor was applied to the new installed foundation volume to account for this scope.
  - Steel quantities were derived using internal algorithms based on the volumes and types of steel structures. To validate these quantities, comparisons were made to past projects of similar size and scope conducted by Worley. The results from this study matched well with expectations and no adjustments were made.
  - Foundations were developed from in-house assembly data derived from the equipment list and sketches for the large equipment.
  - Constructability was considered during all aspects of the site selection work and cost estimating.
- For electrical, costs were developed for the equipment and bulk wiring/supports/tray accounts.
  - For the equipment covering the power distribution center (PDC), remote instrument enclosure (RIE) and transformers, a specification and budgetary quote were obtained from the refinery approved vendor.
  - The electrical power cable was defined by the single line, plot plan and electrical load list.
  - The Instrument field, fiber optic and home runs were developed from the plot plan, P&ID's and instrument list.
- The instrumentation and controls costs were derived from the following components:
  - An overall controls system architecture sketch to identify the distributed control system (DCS) components needed to support the new installation.
  - A count of instruments categorized by type and size was taken from the P&IDs, and this list was then priced using internal data.
  - Instruments on skids provided by vendors were included in the budgetary quotes.
  - An allowance was included to cover the new CEMS (continuous emissions monitoring system).
  - The instrument list identified the installation type, which was extended in the assembly data to generate bulk installation materials such as stands, wire, fittings and tubing.
  - The RIE (remote instrument enclosure) building price was obtained by the electrical design team, and the instrumentation design team obtained pricing for panels inside the RIE.
  - The RIE was designed to be connected into the refinery DCS via fiber optic cable into the refinery backbone communication system.

- Painting was taken as a factor from the overall pipe length.
- Scaffolding and fire/hole-watch were developed as an experience factor from the direct labor hour estimate.
- Freight was taken as an experience factor from the major equipment cost account.

5.2.2 Indirect Costs

After the direct costs were developed, costs to support the project, but not directly related to quantities, were estimated. Indirect costs cover:

- Construction labor (delivery and transportation drivers, general housekeeping and clean up, and support services).
- Temporary facilities such as construction office trailers.
- Craft labor fringe benefits and taxes.
- Small tools and consumables such as drills, grinders, grinding wheels and weld rod.
- Construction equipment such as small cranes, forklifts and trucks.
- Field supervision labor costs.
- Construction contractor company overhead and profit.
- Labor per diem to cover traveling construction crews.
- Estimated large crane account for larger than 15-ton cranes.

5.2.3 Other Costs

Engineering services for all phases of the project were captured in the other costs account. Escalation, client costs and contingency were calculated from the subtotal.

5.2.4 Contingency and Sensitivity Analysis

Contingency for this level of engineering is normally set between 15% and 25%. Due to the level of engineering definition with the development of P&ID's, Worley's recent familiarity with projects at Rodeo, and having a scope for the site development and demolition, the contingency was set to the low side of the range at 15%.

Design development accounts were set up for each engineering discipline and sensitivities and risks to the project were developed and captured in the table below:

Discipline	Risk	MTO Hi	MTO Low
Mechanical	One significant lower bidder on the vessels	10%	-20%
	No specs provided with bid package	30%	-10%
	Internals separated by factor of 2 - used high bidder	10%	-30%
	SS lined stack not done before - used high bid	20%	-20%
	Dampers - dissimilar metals will be an issue	30%	-10%

Discipline	Risk	MTO Hi	MTO Low
	Compressor - no specs included	30%	-10%
	Cooling tower - only 1 quote	30%	-10%
	TEG Unit - only one bid	30%	-10%
	Blower - discrepancies in bids, included instrumentation	20%	-20%
Mechanical (Cont.)	Balance of equipment	30%	-15%
Piping	Piping Cost Estimate for lines inside the pipe rack was based on IFE P&IDs. Line details (size, material spec, quantities) may change during next phase.	20%	-10%
	Piping Cost Estimate for lines inside the pipe rack was based on IFE P&IDs. Line details (size, material spec, quantities) may change during next phase.	10%	-10%
	High level estimate for steam traps, utility stations, safety shower/eyewash stations.	20%	-10%
	Tie-in piping estimates based on preliminary routing. Need detailed tie-in locations and field investigations to confirm routing.	30%	-20%
Structural	Underground obstructions. Needs to be verified by future GPR and Potholing.	20%	-15%
	Drilled Pier foundations. Need to be confirmed by Geotech Report.	20%	-15%
	Tie in locations for UG Firewater and Oil Water Sewer may require additional piping	20%	-15%
	Earthwork needs to be verified with TOPO map of project areas	20%	-15%
I&C	Instruments - pricing from vendors on valves. Balance based on recent projects	30%	-15%
	Honeywell from recent quote	30%	-15%
	Junction Box's based on quote	20%	-20%
	Triconex safety shutdown system based on recent quote	30%	-15%
	RIE - price from Marathon with escalation. Compared to quote from Eaton	20%	-20%
Electrical	Power cable	20%	-10%
	Instrument cable	20%	-10%
	Cable tray	20%	-10%
	PDC, transformers and RIE quote from Eaton	30%	-10%

Table 5.2.1: Risks and Sensitivities

The basis of estimate is provided in Appendix D.

5.3 Operation and Maintenance Costs

5.3.1 Utility Costs

The utility costs were developed by using the utility consumption provided in the technology licensor bid package, subsequent engineering work, and using the actual site utility costs provided by Phillips 66 (Table 5.3.1).

Utility Description	Price	Consumption	Cost per Year
Electricity	$135.00 per MWh	4.014 MW per hour	$4,486,849
Fuel Gas	$21.93 per MMBTU	0 MM BTU per hour	$0.00
Steam (MP)	$6.5 per 1000 lbs	58,000 lbs. per hour	$3,121,560
Boiler Feed Water	$6.12 per 1000 gal	240 gal per hour	$12,156
Cooling Water Make-up	$1 per 1000 gal	4,200 gal per hour	$34,682
Total Cost per Year			$7,655,247

Table 5.3.1: Utility Consumption and Costs

5.3.2 Operations and Maintenance Costs

The operation and maintenance costs were developed by using estimates provided by Phillips 66 for the Rodeo Refinery (Table 5.3.2) and the expected consumables for the new unit. The labor costs were derived from typical area rates. Maintenance costs were estimated as the sum of equipment maintenance (including periodic turnarounds), plant overhead, material cost, material maintenance cost and property tax and insurance. Consumables (primarily annual solvent consumption, the volumes and pricing of which is known, but is not separated out here due to its business confidential nature) and waste disposal (which was fairly small), were all included within this category. Plant overhead, which includes supervision and laboratory costs, was estimated as 100% of the labor costs. Insurance and property taxes were estimated as 0.5% of fixed capital, and materials and maintenance costs were estimated as 0.73% of fixed capital.

Description	Basis	Cost per Year
Labor		$535,448
Overhead	100% of Labor	$534,448
Insurance and Property Tax	0.5% of Fixed Capital	$1,315,000
Materials and Maintenance	0.73% of Fixed Capital	$1,916,507
Total Cost per Year		4,302,403

Table 5.3.2: Operations and Maintenance Costs

5.4 Costs Metrics

A discounted cash flow (DCF) analysis was performed to assess the profitability of this CO_2 capture process. The assumptions of the DCF analysis (Table 5.4.1) were derived based on a typical hydrocarbon related process in a petroleum refinery.

Investment Appraisal Factors	Assumptions
Number of Operating Days per Year	345
Annual Inflation	2%
Discount Rate	7.5%
Income Tax	25%
Years of Operation	30
Years of Construction	3
CO_2 Transportation and Sequestration Cost ($/tonne)	10
Depreciation Schedule	US Fed 10-Year with Bonus

Table 5.4.1: Investment Appraisal Assumptions

The profitability of the CO_2 capture process relies significantly on the two following credits.

1. California Low Carbon Fuel Standard (LCFS), Refinery Investment Credit Program
2. US Federal 45Q tax credit

5.4.1 California LCFS

California was the first state to adopt an LCFS system and its credit market is relatively mature compared to the nascent markets in Oregon and Washington. A detailed description of LCFS is available on the website of California Air Resources Board (https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/about). As it can be seen in Figure 5.4.1, the LCFS credit price varies depending on the supply and demand of the LCFS credit.

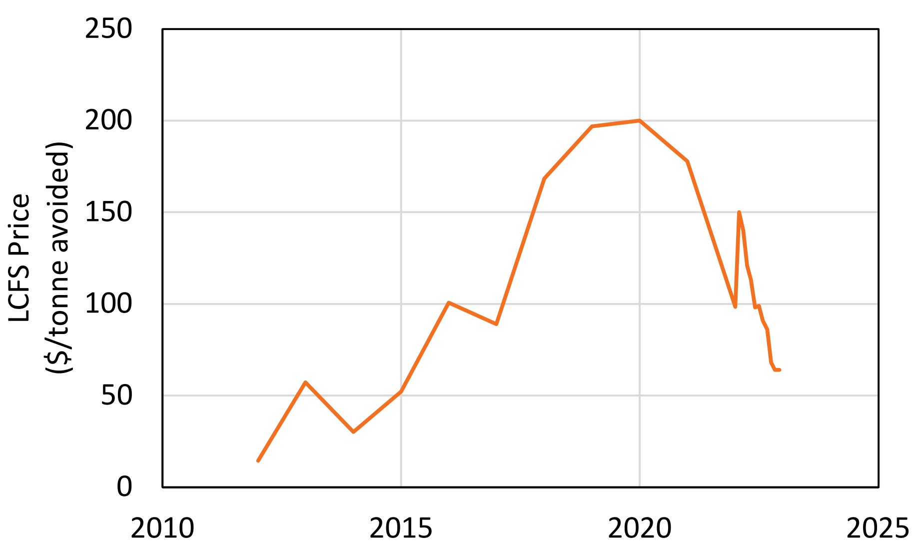


Figure 5.4.1: Variation of Low Carbon Fuel Standard Credit Price (https://ww2.arb.ca.gov/resources/documents/lcfs-data-dashboard)

Prediction of the future LCFS credit prices is beyond the scope of this work. Based on the recent past few years, an LCFS credit price of \$150/tonne of CO_2 avoided was assumed for the economic analysis. A sensitivity analysis was also performed to study what the effect of LCFS credit would be on this project's profitability. It should be noted that LCFS credit price is based on the amount of CO_2 avoidance (the net CO_2 removed from the environment), not the amount of CO_2 captured.

Figure 5.4.2 defines the difference between CO_2 capture and CO_2 avoidance. CO_2 avoidance is also referred as CO_2 abatement and net CO_2 capture in the literature.

$$CO_2\ Avoidance = \frac{CO_2\ Captured - CO_2\ Emitted\ from\ CO_2\ Capture\ Plant}{CO_2\ Captured}$$

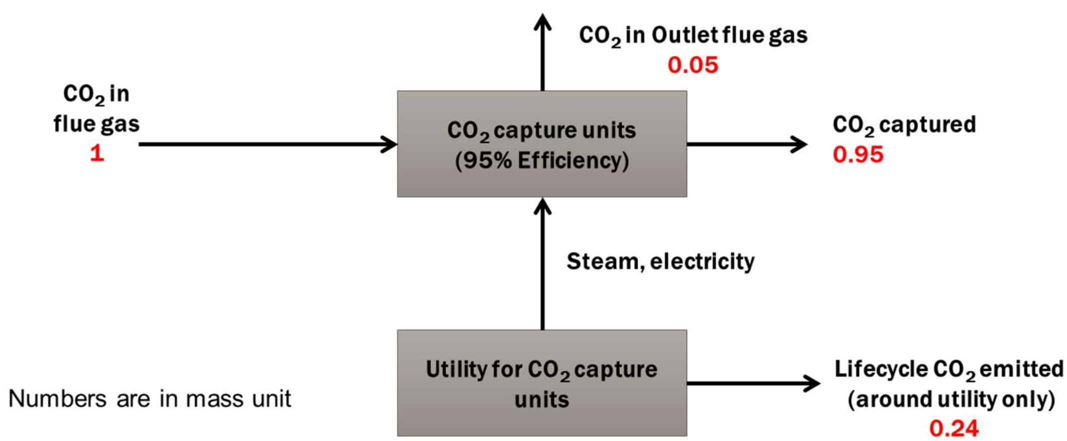
Figure 5.4.2: Equation for CO_2 Avoidance.

CO_2 emitted from the CO_2 capture plant was calculated based on the utilities CO_2 emission factors shown in Table 5.4.2, which include Scope 1, Scope 2 and Scope 3 emissions.

Utility Streams	Emission Factors	Units
50 psig Steam	0.0795	tonne CO_2 eq/1000 lb
Electricity	2.26E-04	tonne CO_2 eq/kWh

Table 5.4.2: CO_2 Emission Factors for Utilities

Based on the above emission factors, the ratio of CO_2 avoided to CO_2 captured was estimated to be 74.5%. Figure 5.4.3 illustrates that per 100 tonnes of CO_2 captured, 74.5 tonnes of CO_2 is avoided. The LCFS credit cash flow depends only on the CO_2 avoided metrics.



$$R_{CO_2} = \frac{CO_2\ Avoided}{CO_2\ Captured} = \frac{0.95 - 0.24}{0.95} = 0.745$$

Figure 5.4.3: Explanation of the Difference Between CO_2 Captured vs. CO_2 Avoided Basis. R_{CO2} is the Ratio of CO_2 Avoided to CO_2 Captured

5.4.2 45Q Tax Credit

The Federal 45Q tax credit was first introduced in 2008 to incentivize CO_2 capture and sequestration. In 2022, the value of this tax credit was revised to a current value of $85 per tonne of CO_2 permanently stored (https://www.iea.org/policies/4986-section-45q-credit-for-carbon-oxide-sequestration). It should be noted that unlike the California LCFS credit, this credit is on CO_2 captured basis, and it is not taxed. Even though currently the 45Q credit is applicable only for 12 years of plant operation, as a best-case scenario it was assumed that it would be available for the entire 30 year life of this plant (https://www.irs.gov/instructions/i8933). However, a sensitivity analysis was performed for the case of only 12 years of applicability of 45Q tax credit.

5.4.3 Economics Value Metrics

The following economic value metrics were calculated.

1. **Average Annual Rate of Return**

   The net present value (NPV) is typically used to assess the profitability of capital projects. It is a measure of the present value of the cash flows generated by an investment using a specified discount rate. The NPV should be greater than or equal to zero for a profitable project. The NPV often does not show the capital efficiency of a project, and therefore, it would not be straightforward to compare CO_2 capture units of different sizes. Therefore, in this study, the average annual rate of return (AARR), which is also commonly referred as the internal rate of return (IRR), was used. The AARR is the discount rate at which the NPV is equal to zero. Projects with AARR greater than the discount rate will have, by definition, NPV greater than zero. AARR provides a measure of the return on the investment, regardless of the size of investment.

2. **Cost of CO_2 Capture**

   The cost of CO_2 capture can be calculated by subtracting the sum of the annual credits and costs from an annualized cost of capital (Figure 5.4.4).

$$Cost\ of\ CO_2\ Capture = CRF \times CAPEX - (Credit - Utility\ Cost - \ Labor\ Cost - Fixed\ Cost - Trans\ \&\ Seques\ cost)$$

Figure 5.4.4: Equation for cost of CO_2 capture

In the equation above, CRF is a capital recovery factor, which can be calculated using a discounted cash flow analysis. It varies based on discount rate, number of years of construction and operation, inflation, depreciation schedule, income tax, etc. For the assumptions mentioned in Table 5.4, the CRF was calculated to be 0.0787. It should be noted that all the cash flow values (CAPEX, credit, utility cost, labor cost, fixed cost and transportation and sequestration cost) should be positive numbers in the above equation. Beyond the LCFS and 45Q credits, the cost of CO_2 capture is the price for which CO_2 should be sold to achieve the desired rate of return. In other words, if this is positive, it means the credits alone are not sufficient to generate the desired rate of return. On the other hand, if it is zero or negative, the credits are sufficient to provide or exceed the desired return. The above equation provides the annual cost of CO_2 capture. Typically, the cost of CO_2 capture is expressed in a normalized basis. Therefore, the cost of CO_2

capture from the above Equation should be divided by the total amount of CO_2 captured annually to express the cost in $/tonne captured units.

3. **<u>Cost of CO_2 Avoided</u>**

The CO_2 avoided cost is the ratio of the CO_2 capture cost to fraction of CO_2 avoided (in this case 74.5%).

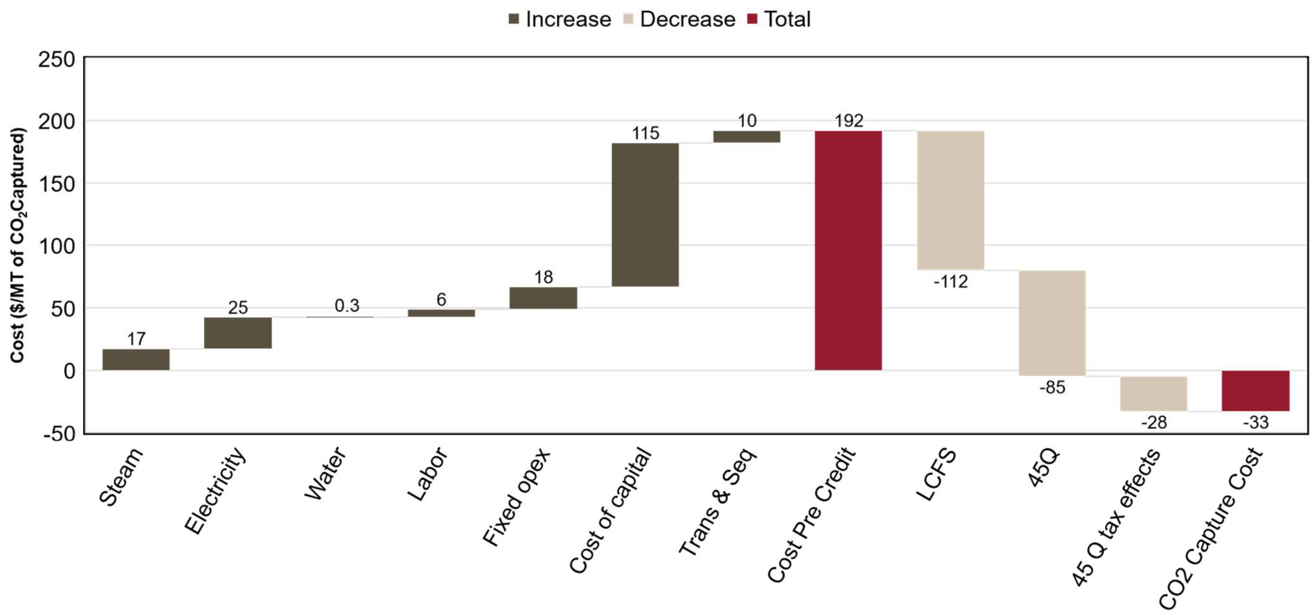
5.5 Techno Economic Results

Table 5.5.1 provides the annual cash flow (2022 US$) and EBITDA (earnings before interest, taxes, depreciation and amortization).

Cost Categories	Annual Cost ($)
Utility Cost	7,655,247
Total Labor Cost Including Overhead	1,070,896
Fixed Operating Cost	3,231,507
Transportation and Sequestration	1,795,890
Total Expenditure	13,753,541
LCFS Credits	20,083,792
45Q Credits	15,265,068
Total CO_2 Credits	35,348,861
Net Cash Flow (EBITDA)	21,595,320

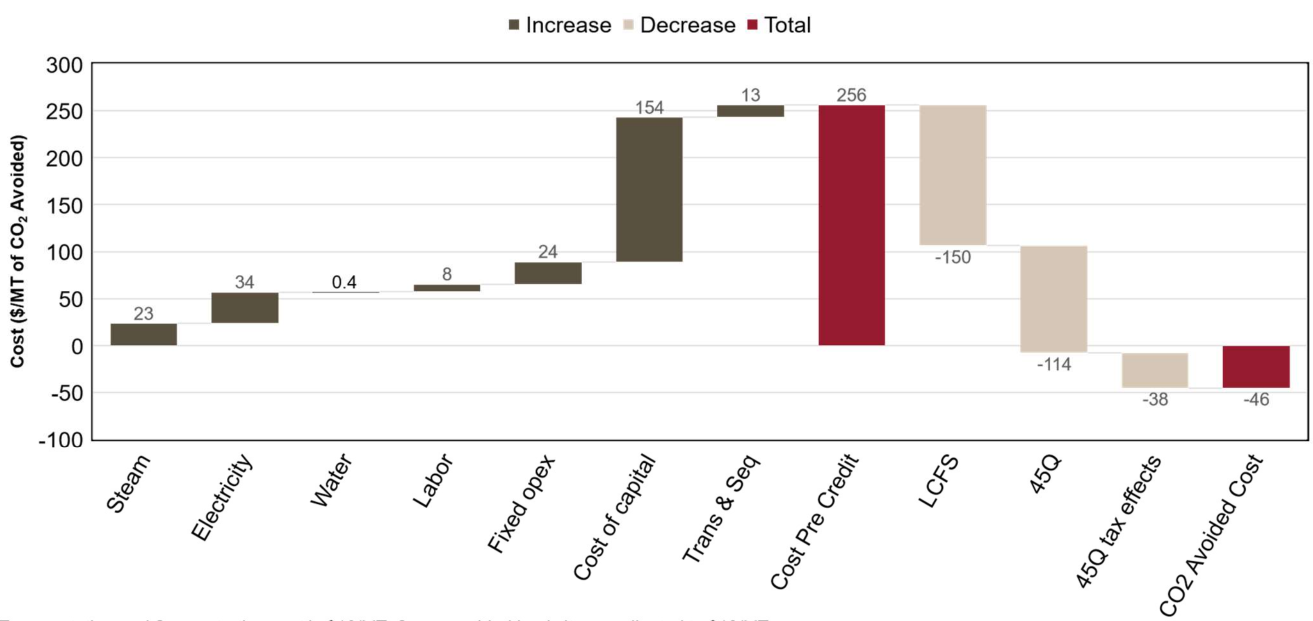
Table 5.5.1: Annual Cash Flow of the Rodeo CO_2 Capture Process

Figure 5.5.2 illustrates the cost of CO_2 capture on a per tonne basis. The total cost of CO_2 capture including the transportation and sequestration, but before application of the LCFS and 45Q credits, was estimated to be $192/tonne captured. CAPEX is the major contributor to the CO_2 capture cost (64%). Electricity contributes to 13% and steam contributes to 9% of the total capture cost. CO_2 transportation and sequestration contributes to 5%. Labor cost and other fixed operating cost such as cost of maintenance, consumables, material, insurance and property tax contribute to the remaining 12% of the cost. The assumed tax credits contribute to $225/tonne of CO_2 captured. It should be noted that the LCFS credit was corrected from an avoided basis to a captured basis and the income tax effects on 45Q was included. Since the combined value of the credits are higher than the cost, the cost of CO_2 capture is negative at a 7.5% discount rate, giving a corresponding AARR of 9.65%. Figure 5.5.3 shows the above discussed result on a CO_2 avoided basis.



LCFS Credit is $150/MT on avoided basis. On a captured basis it was adjusted to $112/MT

Figure 5.5.2: Itemized Contributions to CO_2 Capture Cost



Transportation and Sequestration cost is $10/MT. On an avoided basis it was adjusted to $13/MT
45 Q Credit is $85/MT on captured basis. On an avoided basis it was adjusted to $114/MT

Figure 5.5.3: Itemized Contributions to CO_2 Avoided Cost

Impact on H_2 Price

In the absence of LCFS and 45Q credits, the entire cost of CO_2 capture would be assigned to the SMR's produced hydrogen price. For the CO_2 capture cost of $192/tonne of CO_2 captured, the cost incurred to produce the hydrogen would therefore increase by $1.5/kg. In other words, the difference between blue and grey hydrogen price would be $1.5/kg.

Sensitivity Analysis

A sensitivity analysis was performed by varying some of the key variables that are mentioned in Table 5.5.4. AARR was used as the output variable for this sensitivity analysis. The results are shown as a tornado chart in Figure 5.5.5. The economics were found to be sensitive to the LCFS credit. If the LCFS credit falls to $50/tonne of CO_2 avoided, then the AARR decreases from 9.65% to 4%. A high LCFS price (~$150/tonne of CO_2 avoided) for the entire life of the plant (30 years) is required for profitability. All other calculated variables changed the AARR within a range of +/- 3.5%.

Variable	Base	Low	High
CAPEX	263,000,000	223,550,000	328,750,000
Steam Price	6.50	0	13
Electricity Price	135	60	200
Transportation & Sequestration Cost	10	10	50
LCFS Credit	150	250	50
Capacity Factor	94.5%	80%	100%
Availability of 45Q	30 years	12 years	30 years

Table 5.5.4: Variables and Ranges Utilized for the Sensitivity Analysis

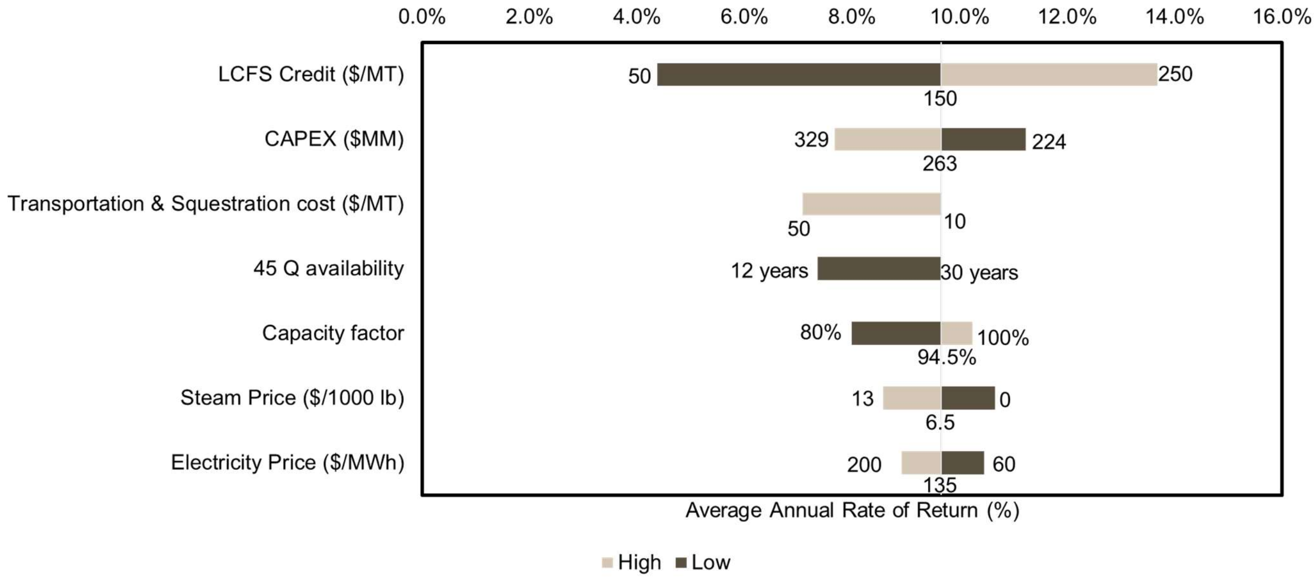
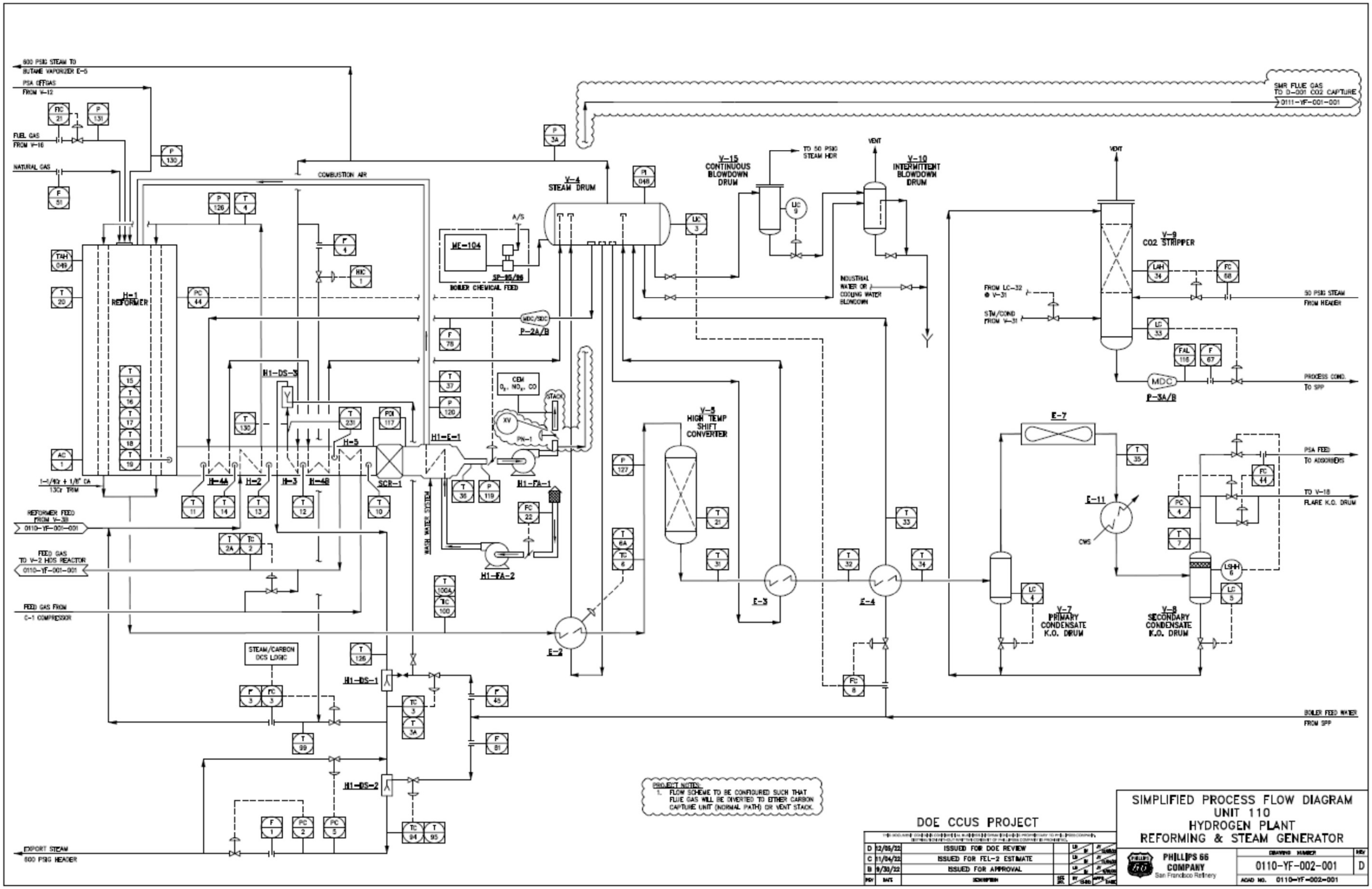


Figure 5.5.5: Tornado Chart for the AARR with Key Variables

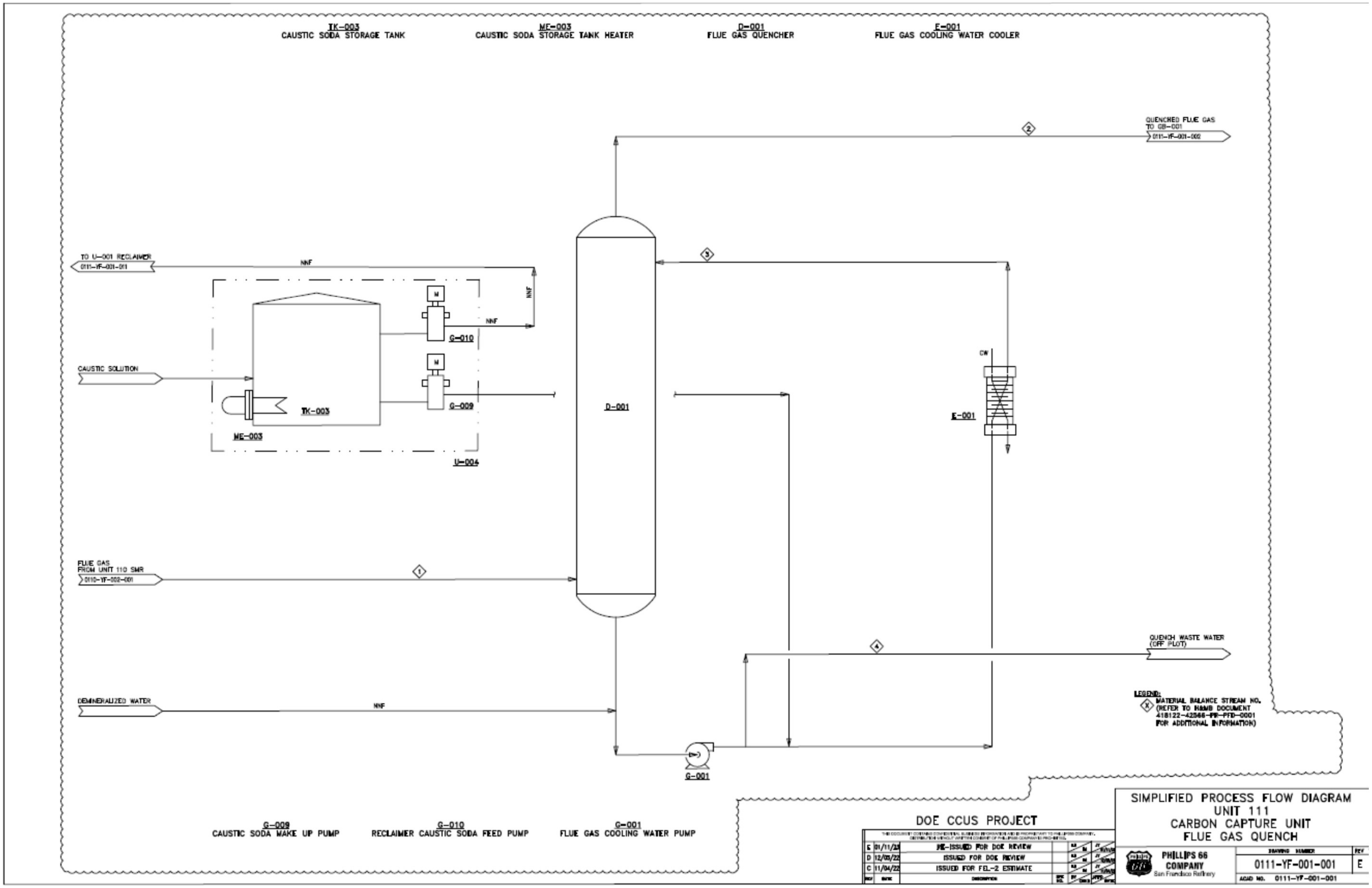
ow wi

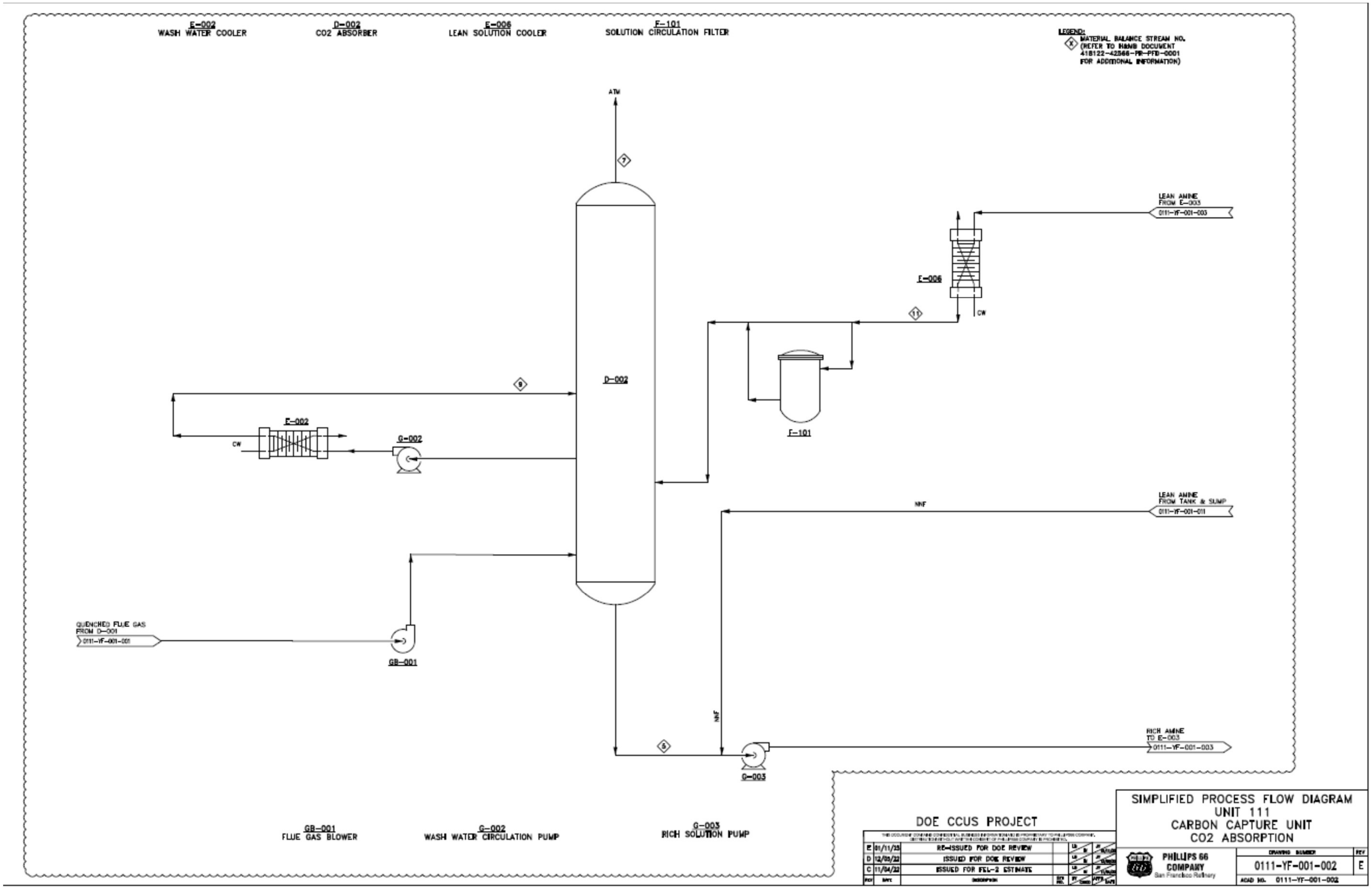
Appendix A. Process Flow Diagrams

Option 3, Existing SMR Plant and Carbon Capture from the SMR Flue Gas

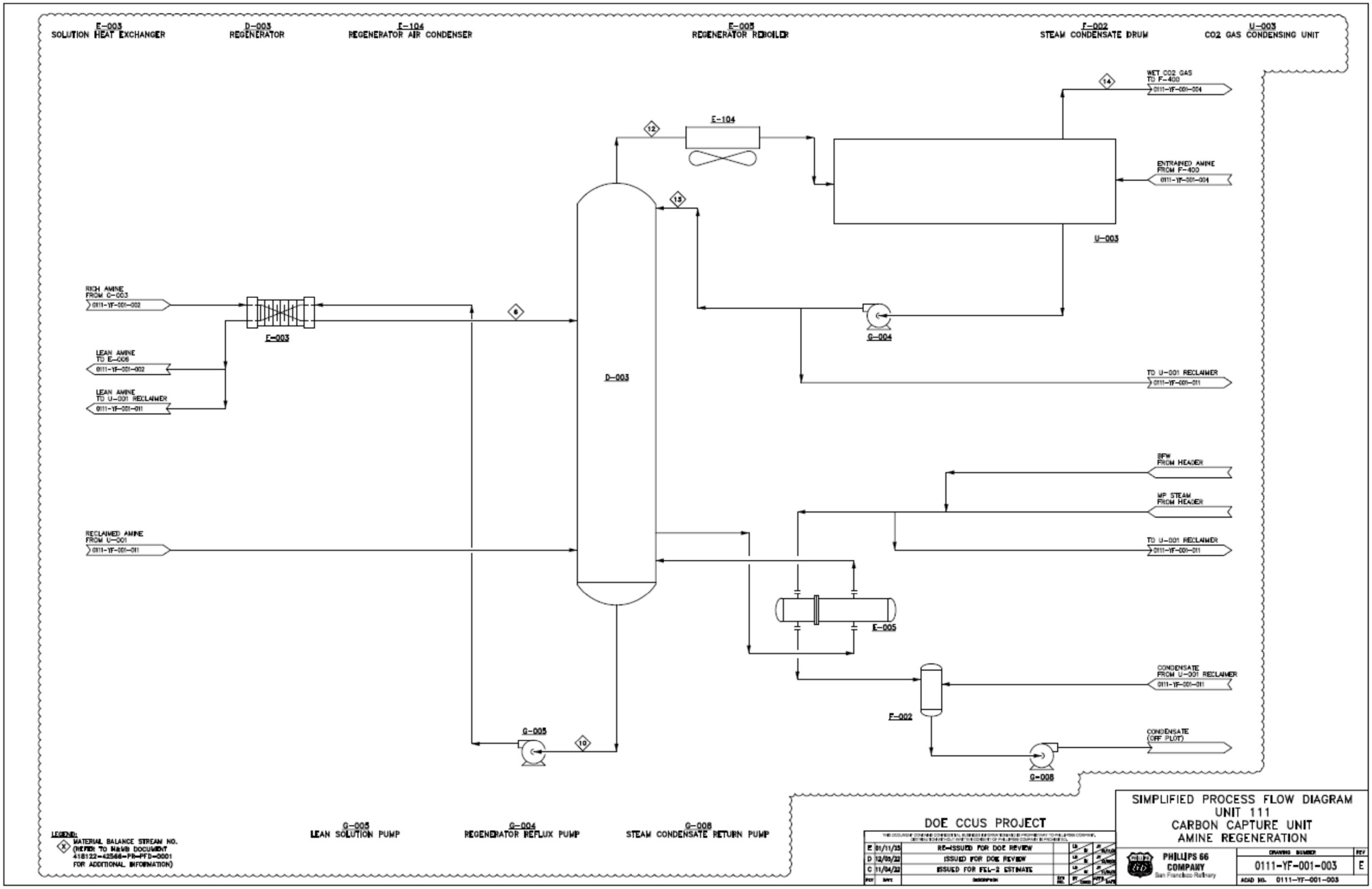


SIMPLIFIED PROCESS FLOW DIAGRAM
UNIT 110
HYDROGEN PLANT
REFORMING & STEAM GENERATOR
DOE CCUS PROJECT
PHILLIPS 66 COMPANY
San Francisco Refinery
0110-YF-002-001
H-1 REFORMER
V-4 STEAM DRUM
V-15 CONTINUOUS BLOWDOWN DRUM
V-10 INTERMITTENT BLOWDOWN DRUM
V-9 CO2 STRIPPER
V-5 HIGH TEMP SHIFT CONVERTER
V-7 PRIMARY CONDENSATE K.O. DRUM
V-8 SECONDARY CONDENSATE K.O. DRUM
SMR FLUE GAS TO D-001 CO2 CAPTURE
PROJECT NOTES:
1. FLOW SCHEME TO BE CONFIGURED SUCH THAT FLUE GAS WILL BE DIVERTED TO EITHER CARBON CAPTURE UNIT (NORMAL PATH) OR VENT STACK.
D 12/05/22 ISSUED FOR DOE REVIEW
C 11/04/22 ISSUED FOR FEL-2 ESTIMATE
B 9/30/22 ISSUED FOR APPROVAL

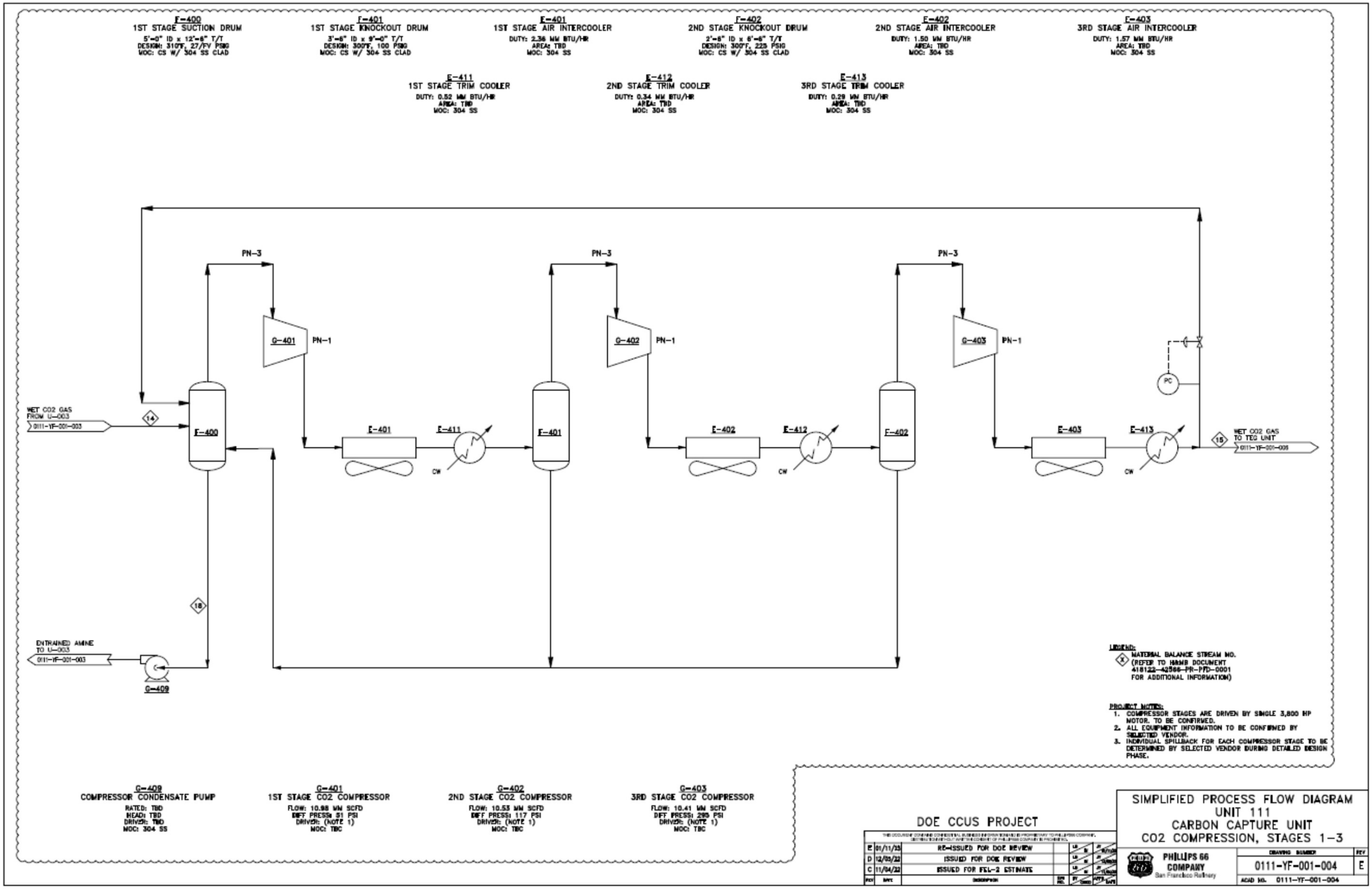

TK-003
CAUSTIC SODA STORAGE TANK
ME-003
CAUSTIC SODA STORAGE TANK HEATER
D-001
FLUE GAS QUENCHER
E-001
FLUE GAS COOLING WATER COOLER
QUENCHED FLUE GAS
TO U-001 RECLAIMER
NNF
CAUSTIC SOLUTION
G-010
G-009
TK-003
ME-003
U-004
D-001
CW
E-001
FLUE GAS
FROM UNIT 110 SMR
QUENCH WASTE WATER
(OFF PLOT)
DEMINERALIZED WATER
G-001
G-009
CAUSTIC SODA MAKE UP PUMP
G-010
RECLAIMER CAUSTIC SODA FEED PUMP
G-001
FLUE GAS COOLING WATER PUMP
DOE CCUS PROJECT
SIMPLIFIED PROCESS FLOW DIAGRAM
UNIT 111
CARBON CAPTURE UNIT
FLUE GAS QUENCH
ISSUED FOR DOE REVIEW
ISSUED FOR FEL-2 ESTIMATE
PHILLIPS 66
COMPANY
San Francisco Refinery
0111-YF-001-001
E

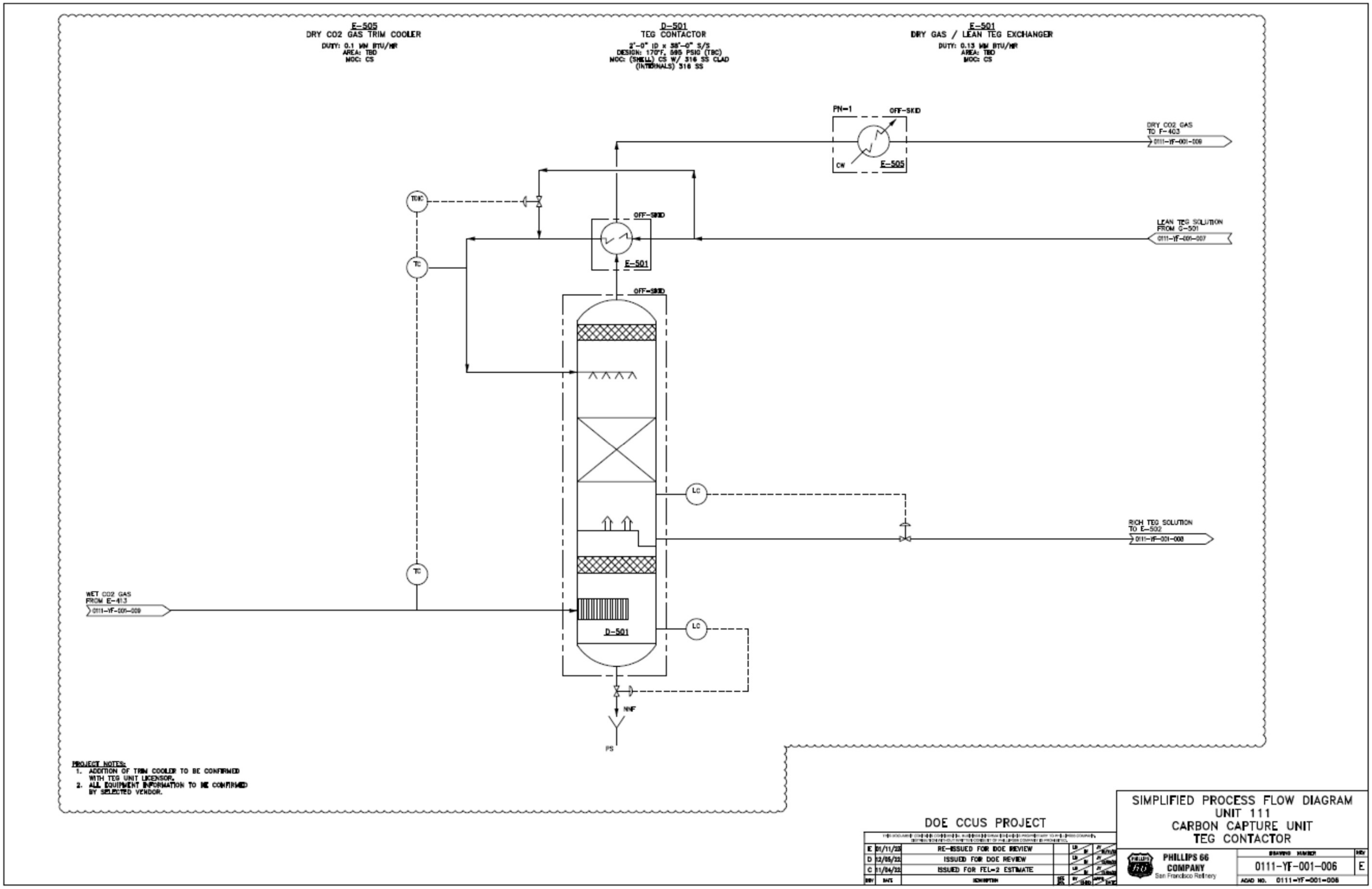


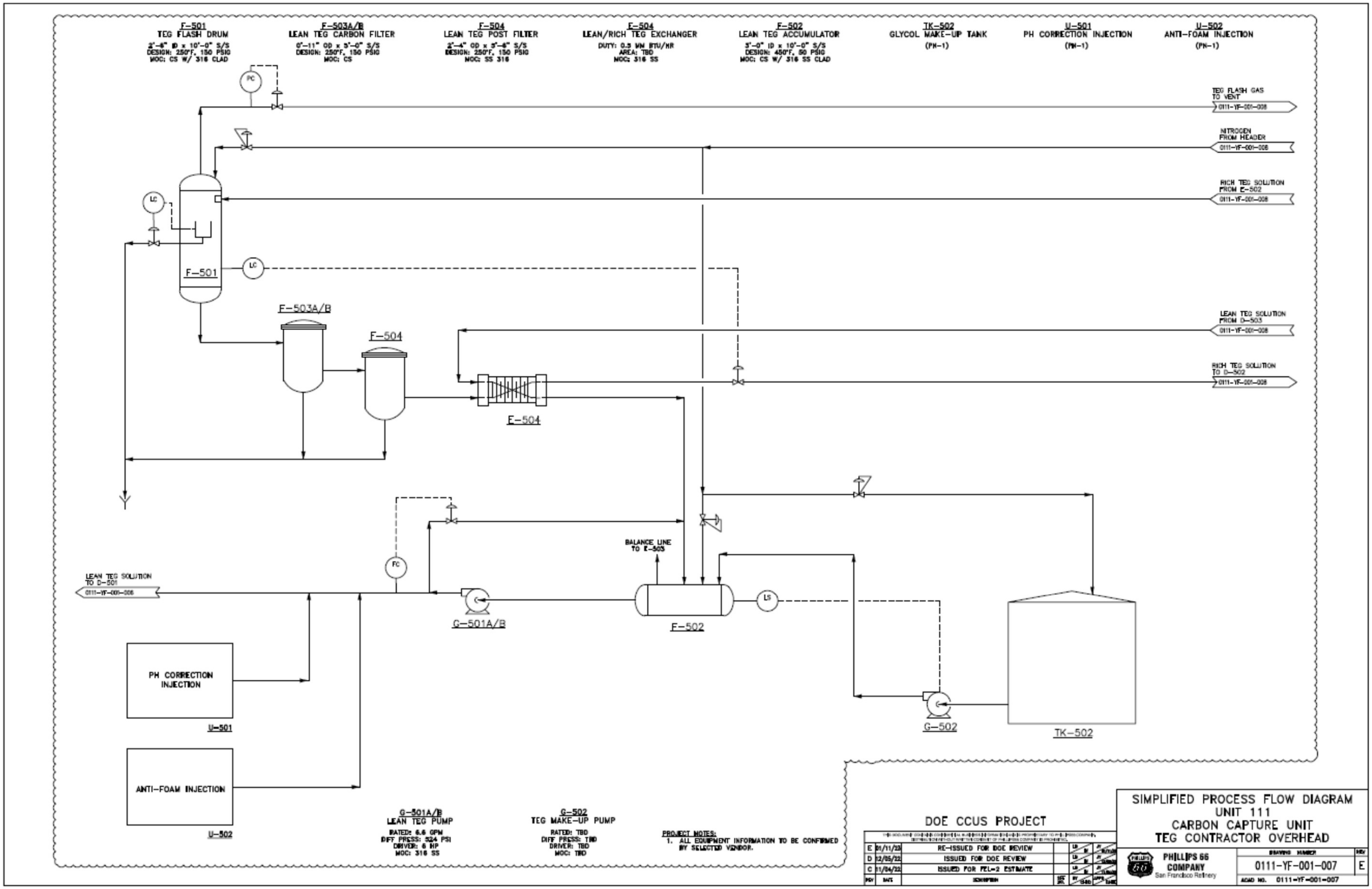
E-002
WASH WATER COOLER
D-002
CO2 ABSORBER
E-006
LEAN SOLUTION COOLER
F-101
SOLUTION CIRCULATION FILTER
LEGEND:
MATERIAL BALANCE STREAM NO.
(REFER TO H&MB DOCUMENT
418122-42566-PR-PFD-0001
FOR ADDITIONAL INFORMATION)
ATM
LEAN AMINE
FROM E-003
0111-YF-001-003
E-006
CW
F-101
D-002
E-002
CW
G-002
LEAN AMINE
FROM TANK & SUMP
0111-YF-001-011
NNF
QUENCHED FLUE GAS
FROM D-001
0111-YF-001-001
GB-001
RICH AMINE
TO E-003
0111-YF-001-003
G-003
GB-001
FLUE GAS BLOWER
G-002
WASH WATER CIRCULATION PUMP
G-003
RICH SOLUTION PUMP
DOE CCUS PROJECT
E 01/11/23 RE-ISSUED FOR DOE REVIEW
D 12/05/22 ISSUED FOR DOE REVIEW
C 11/04/22 ISSUED FOR FEL-2 ESTIMATE
SIMPLIFIED PROCESS FLOW DIAGRAM
UNIT 111
CARBON CAPTURE UNIT
CO2 ABSORPTION
PHILLIPS 66
COMPANY
San Francisco Refinery
0111-YF-001-002
E
0111-YF-001-002

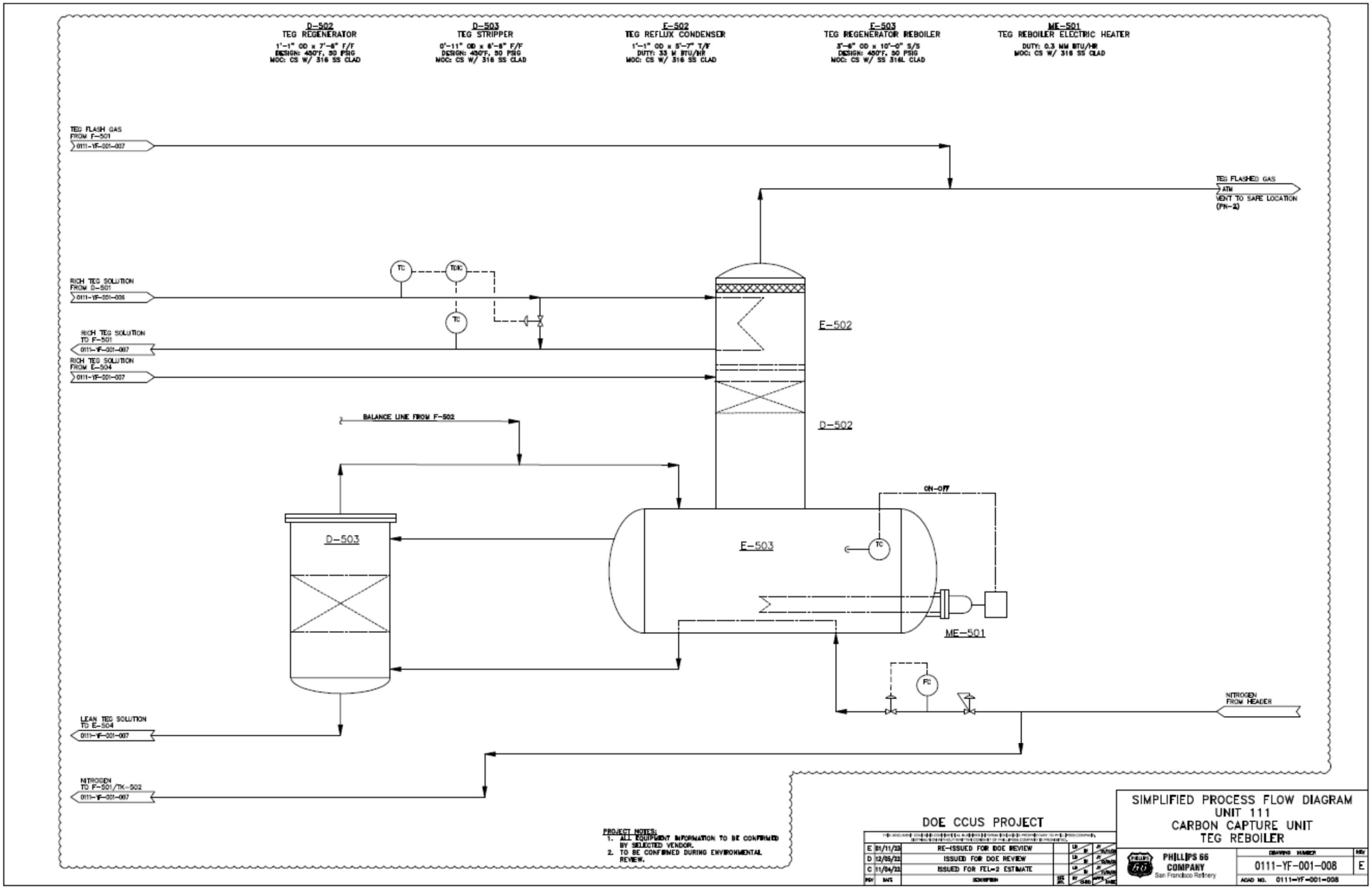


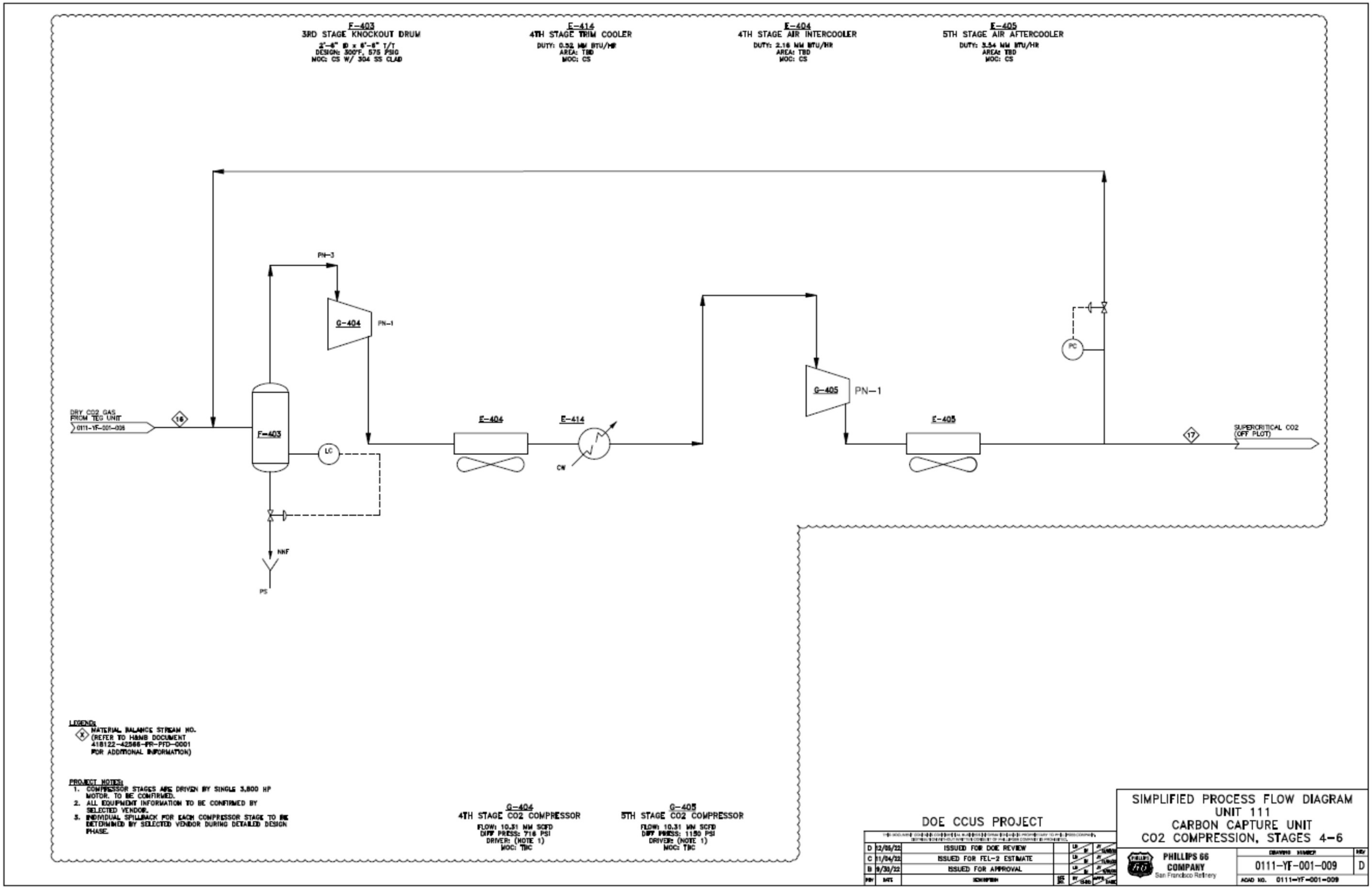
E-003
SOLUTION HEAT EXCHANGER
D-003
REGENERATOR
E-104
REGENERATOR AIR CONDENSER
E-005
REGENERATOR REBOILER
F-002
STEAM CONDENSATE DRUM
U-003
CO2 GAS CONDENSING UNIT
WET CO2 GAS TO F-400
0111-YF-001-004
ENTRAINED AMINE FROM F-400
0111-YF-001-004
U-003
RICH AMINE FROM C-003
0111-YF-001-002
LEAN AMINE TO E-006
0111-YF-001-002
LEAN AMINE TO U-001 RECLAIMER
0111-YF-001-011
D-003
G-004
TO U-001 RECLAIMER
0111-YF-001-011
BFW FROM HEADER
MP STEAM FROM HEADER
TO U-001 RECLAIMER
0111-YF-001-011
RECLAIMED AMINE FROM U-001
0111-YF-001-011
E-005
CONDENSATE FROM U-001 RECLAIMER
0111-YF-001-011
F-002
G-005
CONDENSATE (OFF PLOT)
G-008
G-005
LEAN SOLUTION PUMP
G-004
REGENERATOR REFLUX PUMP
G-008
STEAM CONDENSATE RETURN PUMP
LEGEND:
MATERIAL BALANCE STREAM NO. (REFER TO M&MB DOCUMENT 418122-42566-PR-PFD-0001 FOR ADDITIONAL INFORMATION)
DOE CCUS PROJECT
E 01/11/23 RE-ISSUED FOR DOE REVIEW
D 12/09/22 ISSUED FOR DOE REVIEW
C 11/04/22 ISSUED FOR FEL-2 ESTIMATE
SIMPLIFIED PROCESS FLOW DIAGRAM
UNIT 111
CARBON CAPTURE UNIT
AMINE REGENERATION
PHILLIPS 66 COMPANY
San Francisco Refinery
0111-YF-001-003
E
0111-YF-001-003


F-400
1ST STAGE SUCTION DRUM
5'-0" ID x 12'-6" T/T
DESIGN: 310°F, 27/FV PSIG
MOC: CS W/ 304 SS CLAD
F-401
1ST STAGE KNOCKOUT DRUM
3'-6" ID x 9'-0" T/T
DESIGN: 300°F, 100 PSIG
MOC: CS W/ 304 SS CLAD
E-401
1ST STAGE AIR INTERCOOLER
DUTY: 2.36 MM BTU/HR
AREA: TBD
MOC: 304 SS
F-402
2ND STAGE KNOCKOUT DRUM
2'-6" ID x 6'-6" T/T
DESIGN: 300°F, 225 PSIG
MOC: CS W/ 304 SS CLAD
E-402
2ND STAGE AIR INTERCOOLER
DUTY: 1.50 MM BTU/HR
AREA: TBD
MOC: 304 SS
E-403
3RD STAGE AIR INTERCOOLER
DUTY: 1.57 MM BTU/HR
AREA: TBD
MOC: 304 SS
E-411
1ST STAGE TRIM COOLER
DUTY: 0.52 MM BTU/HR
AREA: TBD
MOC: 304 SS
E-412
2ND STAGE TRIM COOLER
DUTY: 0.34 MM BTU/HR
AREA: TBD
MOC: 304 SS
E-413
3RD STAGE TRIM COOLER
DUTY: 0.29 MM BTU/HR
AREA: TBD
MOC: 304 SS
PN-3
PN-1
G-401
G-402
G-403
WET CO2 GAS
FROM U-003
0111-YF-001-003
14
F-400
E-401
E-411
CW
F-401
E-402
E-412
F-402
E-403
E-413
PC
15
WET CO2 GAS
TO TEG UNIT
0111-YF-001-005
18
ENTRAINED AMINE
TO U-003
0111-YF-001-003
G-409
LEGEND:
X
MATERIAL BALANCE STREAM NO.
(REFER TO H&MB DOCUMENT
418122-42566-PR-PFD-0001
FOR ADDITIONAL INFORMATION)
PROJECT NOTES:
1. COMPRESSOR STAGES ARE DRIVEN BY SINGLE 3,800 HP MOTOR. TO BE CONFIRMED.
2. ALL EQUIPMENT INFORMATION TO BE CONFIRMED BY SELECTED VENDOR.
3. INDIVIDUAL SPILLBACK FOR EACH COMPRESSOR STAGE TO BE DETERMINED BY SELECTED VENDOR DURING DETAILED DESIGN PHASE.
G-409
COMPRESSOR CONDENSATE PUMP
RATED: TBD
HEAD: TBD
DRIVER: TBD
MOC: 304 SS
G-401
1ST STAGE CO2 COMPRESSOR
FLOW: 10.98 MM SCFD
DIFF PRESS: 51 PSI
DRIVER: (NOTE 1)
MOC: TBC
G-402
2ND STAGE CO2 COMPRESSOR
FLOW: 10.53 MM SCFD
DIFF PRESS: 117 PSI
DRIVER: (NOTE 1)
MOC: TBC
G-403
3RD STAGE CO2 COMPRESSOR
FLOW: 10.41 MM SCFD
DIFF PRESS: 295 PSI
DRIVER: (NOTE 1)
MOC: TBC
DOE CCUS PROJECT
E 01/11/23 RE-ISSUED FOR DOE REVIEW
D 12/05/22 ISSUED FOR DOE REVIEW
C 11/04/22 ISSUED FOR FEL-2 ESTIMATE
REV DATE DESCRIPTION
SIMPLIFIED PROCESS FLOW DIAGRAM
UNIT 111
CARBON CAPTURE UNIT
CO2 COMPRESSION, STAGES 1-3
PHILLIPS 66 COMPANY
San Francisco Refinery
DRAWING NUMBER
0111-YF-001-004
REV
E
ACAD NO. 0111-YF-001-004

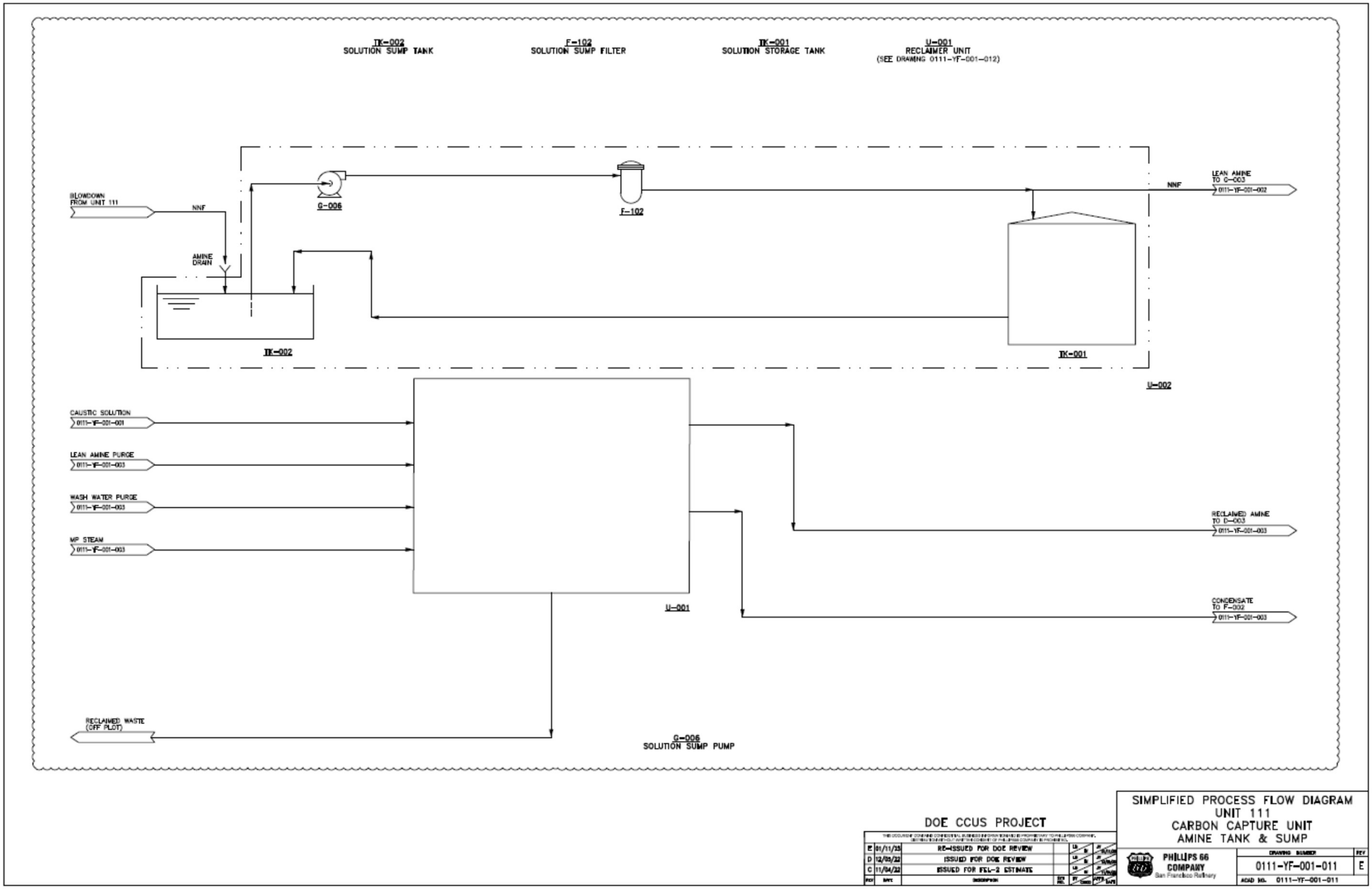

E-505
DRY CO2 GAS TRIM COOLER
DUTY: 0.1 MM BTU/HR
AREA: TBD
MOC: CS
D-501
TEG CONTACTOR
2'-0" ID x 38'-0" S/S
DESIGN: 170°F, 595 PSIG (TBC)
MOC: (SHELL) CS W/ 316 SS CLAD
(INTERNALS) 316 SS
E-501
DRY GAS / LEAN TEG EXCHANGER
DUTY: 0.13 MM BTU/HR
AREA: TBD
MOC: CS
PN-1
OFF-SKID
CW
E-505
DRY CO2 GAS
TO F-403
0111-YF-001-009
TDIC
TC
OFF-SKID
E-501
LEAN TEG SOLUTION
FROM G-501
0111-YF-001-007
OFF-SKID
LC
RICH TEG SOLUTION
TO E-502
0111-YF-001-008
TC
WET CO2 GAS
FROM E-413
0111-YF-001-009
D-501
LC
NNF
PS
PROJECT NOTES:
1. ADDITION OF TRIM COOLER TO BE CONFIRMED WITH TEG UNIT LICENSOR.
2. ALL EQUIPMENT INFORMATION TO BE CONFIRMED BY SELECTED VENDOR.
DOE CCUS PROJECT
E 01/11/23 RE-ISSUED FOR DOE REVIEW
D 12/05/22 ISSUED FOR DOE REVIEW
C 11/04/22 ISSUED FOR FEL-2 ESTIMATE
SIMPLIFIED PROCESS FLOW DIAGRAM
UNIT 111
CARBON CAPTURE UNIT
TEG CONTACTOR
PHILLIPS 66
COMPANY
San Francisco Refinery
0111-YF-001-006
E
ACAD NO. 0111-YF-001-006

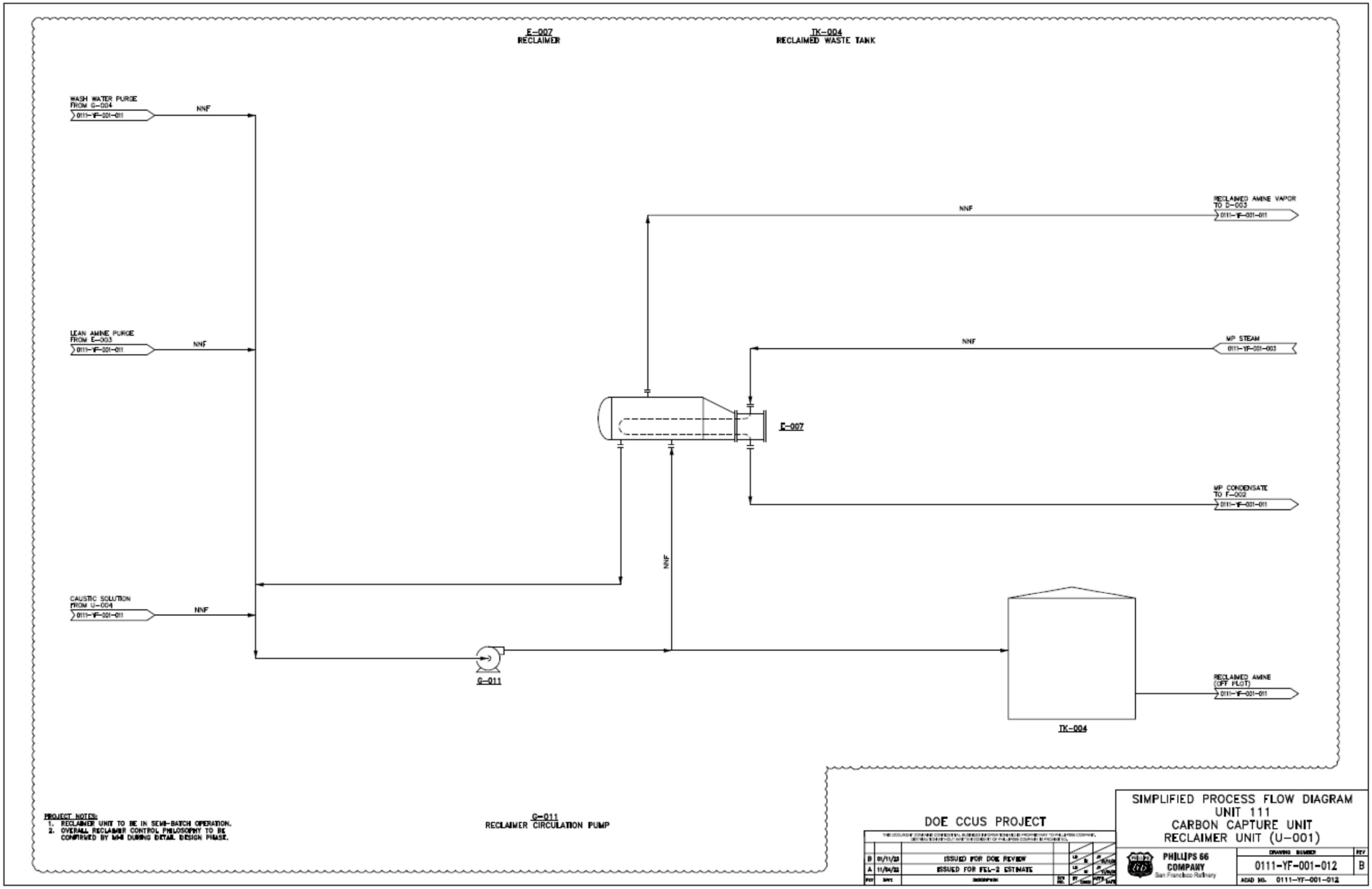

F-501
TEG FLASH DRUM
2'-6" ID x 10'-0" S/S
DESIGN: 250°F, 150 PSIG
MOC: CS W/ 316 CLAD
F-503A/B
LEAN TEG CARBON FILTER
0'-11" OD x 5'-0" S/S
DESIGN: 250°F, 150 PSIG
MOC: CS
F-504
LEAN TEG POST FILTER
2'-4" OD x 5'-6" S/S
DESIGN: 250°F, 150 PSIG
MOC: SS 316
E-504
LEAN/RICH TEG EXCHANGER
DUTY: 0.5 MM BTU/HR
AREA: TBD
MOC: 316 SS
F-502
LEAN TEG ACCUMULATOR
5'-0" ID x 10'-0" S/S
DESIGN: 450°F, 50 PSIG
MOC: CS W/ 316 SS CLAD
TK-502
GLYCOL MAKE-UP TANK
(PN-1)
U-501
PH CORRECTION INJECTION
(PN-1)
U-502
ANTI-FOAM INJECTION
(PN-1)
TEG FLASH GAS TO VENT
0111-YF-001-008
NITROGEN FROM HEADER
0111-YF-001-008
RICH TEG SOLUTION FROM E-502
0111-YF-001-008
LEAN TEG SOLUTION FROM D-503
0111-YF-001-008
RICH TEG SOLUTION TO D-502
0111-YF-001-008
LEAN TEG SOLUTION TO D-501
0111-YF-001-008
PC
LC
LC
FC
LS
F-501
F-503A/B
F-504
E-504
BALANCE LINE TO E-503
G-501A/B
F-502
G-502
TK-502
PH CORRECTION INJECTION
U-501
ANTI-FOAM INJECTION
U-502
G-501A/B
LEAN TEG PUMP
RATED: 6.6 GPM
DIFF PRESS: 524 PSI
DRIVER: 6 HP
MOC: 316 SS
G-502
TEG MAKE-UP PUMP
RATED: TBD
DIFF PRESS: TBD
DRIVER: TBD
MOC: TBD
PROJECT NOTES:
1. ALL EQUIPMENT INFORMATION TO BE CONFIRMED BY SELECTED VENDOR.
DOE CCUS PROJECT
E 01/11/23 RE-ISSUED FOR DOE REVIEW
D 12/05/22 ISSUED FOR DOE REVIEW
C 11/04/22 ISSUED FOR FEL-2 ESTIMATE
SIMPLIFIED PROCESS FLOW DIAGRAM
UNIT 111
CARBON CAPTURE UNIT
TEG CONTRACTOR OVERHEAD
PHILLIPS 66 COMPANY
San Francisco Refinery
0111-YF-001-007
E
ACAD NO. 0111-YF-001-007


D-502
TEG REGENERATOR
1'-1" OD x 7'-6" F/F
DESIGN: 450°F, 50 PSIG
MOC: CS W/ 316 SS CLAD
D-503
TEG STRIPPER
0'-11" OD x 6'-6" F/F
DESIGN: 450°F, 50 PSIG
MOC: CS W/ 316 SS CLAD
E-502
TEG REFLUX CONDENSER
1'-1" OD x 5'-7" T/F
DUTY: 33 M BTU/HR
MOC: CS W/ 316 SS CLAD
E-503
TEG REGENERATOR REBOILER
3'-6" OD x 10'-0" S/S
DESIGN: 450°F, 50 PSIG
MOC: CS W/ SS 316L CLAD
ME-501
TEG REBOILER ELECTRIC HEATER
DUTY: 0.3 MM BTU/HR
MOC: CS W/ 316 SS CLAD
TEG FLASH GAS FROM F-501
0111-YF-001-007
TEG FLASHED GAS
ATM
VENT TO SAFE LOCATION (PN-2)
RICH TEG SOLUTION FROM D-501
0111-YF-001-006
RICH TEG SOLUTION TO F-501
0111-YF-001-007
RICH TEG SOLUTION FROM E-504
0111-YF-001-007
TC
TDIC
TC
E-502
D-502
BALANCE LINE FROM F-502
ON-OFF
D-503
E-503
TC
ME-501
FC
NITROGEN FROM HEADER
LEAN TEG SOLUTION TO E-504
0111-YF-001-007
NITROGEN TO F-501/TK-502
0111-YF-001-007
PROJECT NOTES:
1. ALL EQUIPMENT INFORMATION TO BE CONFIRMED BY SELECTED VENDOR.
2. TO BE CONFIRMED DURING ENVIRONMENTAL REVIEW.
DOE CCUS PROJECT
E 01/11/23 RE-ISSUED FOR DOE REVIEW
D 12/05/22 ISSUED FOR DOE REVIEW
C 11/04/22 ISSUED FOR FEL-2 ESTIMATE
SIMPLIFIED PROCESS FLOW DIAGRAM
UNIT 111
CARBON CAPTURE UNIT
TEG REBOILER
PHILLIPS 66 COMPANY
San Francisco Refinery
0111-YF-001-008
E
ACAD NO. 0111-YF-001-008



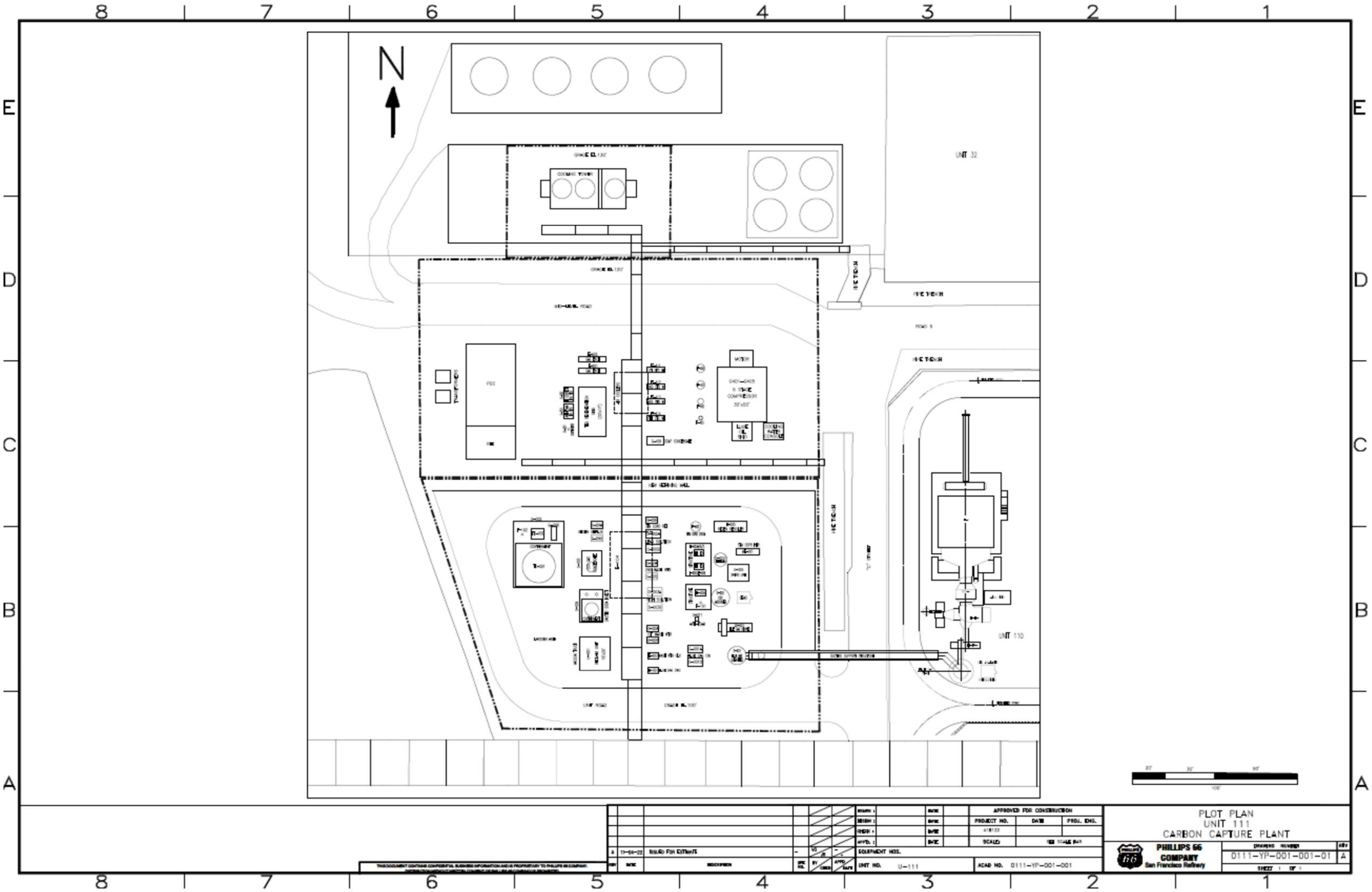
F-403
3RD STAGE KNOCKOUT DRUM
DESIGN: 300°F, 575 PSIG
MOC: CS W/ 304 SS CLAD
E-414
4TH STAGE TRIM COOLER
DUTY: 0.52 MM BTU/HR
AREA: TBD
MOC: CS
E-404
4TH STAGE AIR INTERCOOLER
DUTY: 2.16 MM BTU/HR
AREA: TBD
MOC: CS
E-405
5TH STAGE AIR AFTERCOOLER
DUTY: 3.54 MM BTU/HR
AREA: TBD
MOC: CS
DRY CO2 GAS
FROM TEG UNIT
0111-YF-001-008
16
G-404
PN-1
F-403
LC
E-404
E-414
CW
NNF
PS
G-405
PN-1
E-405
PC
17
SUPERCRITICAL CO2
(OFF PLOT)
LEGEND:
MATERIAL BALANCE STREAM NO.
(REFER TO H&MB DOCUMENT
418122-42566-PR-PFD-0001
FOR ADDITIONAL INFORMATION)
PROJECT NOTES:
1. COMPRESSOR STAGES ARE DRIVEN BY SINGLE 3,800 HP MOTOR. TO BE CONFIRMED.
2. ALL EQUIPMENT INFORMATION TO BE CONFIRMED BY SELECTED VENDOR.
3. INDIVIDUAL SPILLBACK FOR EACH COMPRESSOR STAGE TO BE DETERMINED BY SELECTED VENDOR DURING DETAILED DESIGN PHASE.
G-404
4TH STAGE CO2 COMPRESSOR
FLOW: 10.31 MM SCFD
DIFF PRESS: 716 PSI
DRIVER: (NOTE 1)
MOC: TBC
G-405
5TH STAGE CO2 COMPRESSOR
FLOW: 10.31 MM SCFD
DIFF PRESS: 1150 PSI
DRIVER: (NOTE 1)
MOC: TBC
DOE CCUS PROJECT
D 12/05/22 ISSUED FOR DOE REVIEW
C 11/04/22 ISSUED FOR FEL-2 ESTIMATE
B 9/30/22 ISSUED FOR APPROVAL
SIMPLIFIED PROCESS FLOW DIAGRAM
UNIT 111
CARBON CAPTURE UNIT
CO2 COMPRESSION, STAGES 4-6
PHILLIPS 66 COMPANY
San Francisco Refinery
0111-YF-001-009
D


TK-002
SOLUTION SUMP TANK
F-102
SOLUTION SUMP FILTER
TK-001
SOLUTION STORAGE TANK
U-001
RECLAIMER UNIT
(SEE DRAWING 0111-YF-001-012)
BLOWDOWN FROM UNIT 111
NNF
AMINE DRAIN
G-006
F-102
TK-002
TK-001
LEAN AMINE TO G-003
0111-YF-001-002
U-002
CAUSTIC SOLUTION
0111-YF-001-001
LEAN AMINE PURGE
0111-YF-001-003
WASH WATER PURGE
0111-YF-001-003
MP STEAM
0111-YF-001-003
RECLAIMED AMINE TO D-003
0111-YF-001-003
CONDENSATE TO F-002
0111-YF-001-003
U-001
RECLAIMED WASTE (OFF PLOT)
G-006
SOLUTION SUMP PUMP
DOE CCUS PROJECT
E 01/11/23 RE-ISSUED FOR DOE REVIEW
D 12/05/22 ISSUED FOR DOE REVIEW
C 11/04/22 ISSUED FOR FEL-2 ESTIMATE
SIMPLIFIED PROCESS FLOW DIAGRAM
UNIT 111
CARBON CAPTURE UNIT
AMINE TANK & SUMP
PHILLIPS 66 COMPANY
San Francisco Refinery
0111-YF-001-011
E



E-007
RECLAIMER
TK-004
RECLAIMED WASTE TANK
WASH WATER PURGE
FROM G-004
0111-YF-001-011
NNF
LEAN AMINE PURGE
FROM E-003
0111-YF-001-011
NNF
CAUSTIC SOLUTION
FROM U-004
0111-YF-001-011
NNF
RECLAIMED AMINE VAPOR
TO D-003
0111-YF-001-011
NNF
MP STEAM
0111-YF-001-003
NNF
E-007
MP CONDENSATE
TO F-002
0111-YF-001-011
NNF
G-011
TK-004
RECLAIMED AMINE
(OFF PLOT)
0111-YF-001-011
PROJECT NOTES:
1. RECLAIMER UNIT TO BE IN SEMI-BATCH OPERATION.
2. OVERALL RECLAIMER CONTROL PHILOSOPHY TO BE CONFIRMED BY MHI DURING DETAIL DESIGN PHASE.
G-011
RECLAIMER CIRCULATION PUMP
DOE CCUS PROJECT
B 01/11/23 ISSUED FOR DOE REVIEW
A 11/04/22 ISSUED FOR FEL-2 ESTIMATE
SIMPLIFIED PROCESS FLOW DIAGRAM
UNIT 111
CARBON CAPTURE UNIT
RECLAIMER UNIT (U-001)
PHILLIPS 66
COMPANY
San Francisco Refinery
0111-YF-001-012
B
ACAD NO. 0111-YF-001-012

Appendix B. Site Plan



Appendix C. Sized Equipment List

	Tag	Description	Type	Qty.	Size	Design Conditions psig / °F	Volume / Duty	Materials	Comments	Revision
					PRELIMINARY EQUIPMENT LIST - 95% CO2 Capture					
					COLUMNS					
1	D-001	Flue Gas Quencher	Packed Column	1	10'-6" ID x 39'-4" T/T	50/FV psig / 480°F	Packing volume: 1,564 ft³	CS w/ 304 SS cladding	Insulated for PP Structured packing Internals to be supplied by Koch-Glitsch or Sulzer, to be confirmed later	
2	D-002	CO2 Absorber	Packed Column	1	10'-6" ID x 153'-9" T/T	50 psig / 285°F	Packing volume: 1,564 ft³ (Washing Section) 5,506 ft³ (Absorbing Section)	CS w/ 304 SS cladding (whole vessel)	Insulated for PP Structured packing Internals to be supplied by Koch-Glitsch or Sulzer, to be confirmed later	
3	D-003	Regenerator	Packed Column	1	8'-0" ID x 114'-0" T/T	50 psig / 310°F	Packing volume: 3,016 ft³	CS w/ 304/316 SS cladding (top/bottom)	Insulate for Heat Conservation Structured packing Internals to be supplied by Koch-Glitsch or Sulzer, to be confirmed later	
4	D-501	TEG Contactor	Packed Column	1	24 in. ID x 38 ft S/S	595/FV psig / 170 °F		CS w/ 316 SS cladding 316 SS internals	(Note 1)	
5	D-502	TEG Regenerator	Packed Column	1	13 in. OD x 7.5 ft F/F	50/FV psig / 450 °F		CS w/ 316 SS cladding	(Note 1)	
6	D-503	TEG Stripper	Packed Column	1	11 in. OD x 6.5 ft F/F	50/FV psig / 450 °F		CS w/ 316 SS cladding	(Note 1)	
					VESSELS					
7	F-002	Steam Condensate Drum	Vertical	1	5'-3" ID x 6'-9" ft Height	185/FV psig / 450°F		CS		
8	F-400	1st Stage Suction Drum	Vertical	1	5.0 ft ID x 12.5 ft T/T	27/FV psig / 310 °F		CS w/ 304 SS cladding	(Note 1)	
9	F-401	1st Stage KO Drum	Vertical	1	3.5 ft ID x 9.0 ft T/T	100 psig / 300 °F		CS w/ 304 SS cladding	(Note 1)	
10	F-402	2nd Stage KO Drum	Vertical	1	2.5 ft ID x 6.5 ft T/T	225 psig / 300 °F		CS w/ 304 SS cladding	(Note 1)	
11	F-403	3rd Stage KO Drum	Vertical	1	2.5 ft ID x 6.5 ft T/T	575 psig / 300 °F		CS w/ 304 SS cladding	(Note 1)	
12	F-501	TEG Flash Drum	Vertical	1	30" ID x 10' S/S	150/FV psig / 250 °F		CS w/ 316 SS cladding	(Note 1)	
13	F-502	Lean TEG Accumulator	Horizontal	1	36" ID x 10' S/S	50/FV psig / 450 °F		CS w/ 316 SS cladding	(Note 1)	
					EXCHANGERS					
14	E-001	Flue Gas Cooling Water Cooler	Plate & Frame	1	Area = 2,900 ft² (Note 2)	Hot: 95 psig / 200 °F Cold: 100 psig / 160 °F	35.5 MM BTU/hr	304 SS		
15	E-002	Wash Water Cooler	Plate & Frame	1	Area = 450 ft² (Note 2)	Hot: 110 psig / 200 °F Cold: 100 psig / 160 °F	0.8 MM BTU/hr	304 SS		
16	E-003A/B/C	Solution Heat Exchanger	Plate & Frame	3	Area = 3,200 ft² each (Note 2)	Hot: 215 psig / 310 °F Cold: 175 psig / 310 °F	32.2 MM BTU/hr	316 SS		
17	E-005	Regenerator Reboiler	Shell & Tube	1	Area = 23,600 ft²/shell	Shell: 27/FV psig / 310 °F Tube: 185/FV psig / 450 °F	55.8 MM BTU/hr	Shell: CS w/ 304L SS cladding Tube: 304L SS	Reboiler design by MHI.	
18	E-006	Lean Solution Cooler	Plate & Frame	1	Area = 1,800 ft² (Note 2)	Hot: 215 psig / 195 °F Cold: 100 psig / 160 °F	18.7 MM BTU/hr	CS		
19	E-104A/B	Regenerator Air Condenser	Air Cooler	2	Area = 2,700 ft² each (bare) 50 hp (Note 2)	Tube: 27/FV psig / 310 °F	7.0 MM BTU/hr	304 SS		
20	E-401	1st Stage Air Intercooler	Air Cooler	1		Tube: 100 psig / 300 °F	2.36 MM BTU/hr	304 SS	(Note 1)	
21	E-411	1st Stage Trim Cooler	Shell & Tube	1		Hot: 100 psig / 300 °F Cold: 100 psig / 160 °F	0.52 MM BTU/hr	304 SS	(Note 1)	
22	E-402	2nd Stage Air Intercooler	Air Cooler	1		Tube: 225 psig / 300 °F	1.50 MMBTU/hr	304 SS	(Note 1)	
23	E-412	2nd Stage Trim Cooler	Shell & Tube	1		Hot: 225 psig / 300 °F Cold: 200 psig / 160 °F	0.34 MM BTU/hr	304 SS	(Note 1)	
24	E-403	3rd Stage Air Intercooler	Air Cooler	1		Tube: 575 psig / 300 °F	1.57 MM BTU/hr	304 SS	(Note 1)	
25	E-413	3rd Stage Trim Cooler	Shell & Tube	1		Hot: 575 psig / 300 °F Cold: 490 psig / 160 °F	0.29 MM BTU/hr	304 SS	(Note 1)	

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PRELIMINARY EQUIPMENT LIST - 95% CO2 Capture										
	Tag	Description	Type	Qty.	Size	Design Conditions psig / °F	Volume / Duty	Materials	Comments	Revision
26	E-404	4th Stage Air Intercooler	Air Cooler	1		Tube: 1300 psig / 300 °F	2.16 MM BTU/hr	CS	(Note 1)	
27	E-414	4th Stage Trim Cooler	Shell & Tube	1		Hot: 1300 psig / 300 °F Cold: 1100 psig / 160 °F	0.52 MM BTU/hr	CS	(Note 1)	
28	E-405	5th Stage Air Aftercooler	Air Cooler	1		Tube: 2500 psig / 300 °F	3.54 MM BTU/hr	CS	(Note 1)	
29	E-501	Dry Gas / Lean TEG Exchanger	Shell & Tube	1	TBD	Shell: 595 psig / 250 °F Tube: 595 psig / 250 °F	0.13 MM BTU/hr	CS	(Note 1)	
30	E-502	TEG Reflux Condenser	Tube bundle	1	13" OD x 5'-6.6" T/F	Shell: 50/FV psig / 450 °F Coil: 595/FV psig / 450 °F	33 M BTU/hr	CS w/ 316 SS cladding	(Note 1)	
31	E-503	TEG Regenerator Reboiler	Electric heater	1	42" OD x 10' S/S	50/FV psig / 450 °F	0.3 MM BTU/hr	CS w/ 316L SS cladding	(Note 1)	
32	E-504	Lean/Rich TEG Exchanger	Plate & Frame	1	TBD	150 psig / 450 °F	0.5 MM BTU/hr	316 SS	(Note 1)	
33	E-505	Dry CO2 Gas Trim Cooler	Shell & Tube	1	TBD	Shell: 595 psig / 250 °F Tube: 595 psig / 250 °F	0.1 MM BTU/hr	CS	(Note 1)	
						FILTERS				
34	F-101	Solution Circulation Filter	Vertical	1	18" ID x 5'-7" T/T	215 psig / 140 °F		CS	Cartridge type	
35	F-503A/B	Lean TEG Carbon Filter	Vertical	1	11" OD x 5' S/S	150/FV psig / 250 °F		CS	(Note 1)	
36	F-504	Lean TEG Post Filter	Vertical	1	28" OD x 5'-6" S/S	150/FV psig / 250 °F		316 SS	(Note 1)	
						ROTATING EQUIPMENT				
37	G-001A/B	Flue Gas Cooling Water Pump	Centrifugal	2x100%	110 ft Head @ 1,360 GPM		60 hp	316 SS		
38	G-002A/B	1st Wash Water Circulation Pump	Centrifugal	2x100%	80 ft Head @ 240 GPM		10 hp	316 SS		
39	G-003A/B	Rich Solution Pump	Centrifugal	2x100%	205 ft Head @ 1,210 GPM		100 hp	316 SS		
40	G-004A/B	Regenerator Reflux Pump	Centrifugal	2x100%	220 ft Head @ 16 GPM		7.5 hp	304 SS	Min flow to be included in rated capacity (to be confirmed by MHI).	
41	G-005A/B	Lean Solution Pump	Centrifugal	2x100%	255 ft Head @ 1,270 GPM		125 hp	316 SS		
42	G-007A/B	2nd Wash Water Circulation Pump	Centrifugal	2x100%	50 ft Head @ 240 GPM		7.5 hp	304 SS		
43	G-008	Steam Condensate Return Pump	Centrifugal	1	220 ft Head @ 140 GPM		25 hp	304 SS	Min flow to be included in rated capacity (to be confirmed by MHI).	
44	G-409	Compressor Condensate Pump	Centrifugal	1				304 SS	(Note 2)	
45	G-401	1st Stage CO2 Compressor		1	10.98 MM SCFD Suction: 21.7 psia Discharge: 73.3 psia		1,037 hp			
46	G-402	2nd Stage CO2 Compressor		1	10.53 MM SCFD Suction: 69.9 psia Discharge: 187.2 psia		771 hp			
47	G-403	3rd Stage CO2 Compressor	Reciprocating	1	10.41 MM SCFD Suction: 180.7 psia Discharge: 476.3 psia		721 hp		Compressor stages to be driven by single 3800 hp motor (to be confirmed).	
48	G-404	4th Stage CO2 Compressor		1	10.31 MM SCFD Suction: 450.8 psia Discharge: 1,167 psia		634 hp			
49	G-405	5th Stage CO2 Compressor		1	10.31 MM SCFD Suction: 1,125 psia Discharge: 2,275 psia		313 hp			
50	G-501A/B	Lean TEG Pump	Centrifugal	2x100%	524 psi diff @ 6.6 gpm		6 hp	316 SS	(Note 1)	
51	G-502	TEG Make-up Pump	Centrifugal	Intermittent				CS	(Note 1)	
52	GB-001	Flue Gas Blower	Centrifugal	1	35 inH2O Head @ 43,500 ACFM		350 hp	304 SS		
						STORAGE TANKS				
53	TK-502	Glycol Make-up Tank	Tote	1				CS	(Note 1)	

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PRELIMINARY EQUIPMENT LIST - 95% CO2 Capture										Revision
	Tag	Description	Type	Qty.	Size	Design Conditions psig / °F	Volume / Duty	Materials	Comments	
	MISCELLANEOUS									
54		Cooling Tower	Crossflow	1	42'-3 1/4"L x 22'-5" W x 27'-1 1/4" H (3 total cells)		95.3 MM BTU/hr		Based on budgetary estimate documents received from vendor. To be confirmed.	
55		Duct (U110 Stack to Flue Gas Quencher)				0.14/-0.7 psig / 480 °F	1201 ft^{3}/s	CS w/ 304 SS cladding	Total Estimated Linear Length: 200'-0" - Section 1: Duct Size = 2'-11" W x 8'-0" T (ID) Duct Length = 166'-0" - Section 2 (Transition Piece): Duct Size = 2'-11" W x 8'-0" T (ID) to Ø42" ID Duct Length = 24'-0" - Section 3: Duct Size = Ø42" ID Duct Length = 10'-0"	
56		Rectangular Expansion Joint for Duct	Fabric	3	2'-11" W x 8'-0" T (ID)	0.14/-0.7 psig / 480 °F	1201 ft^{3}/s	304 SS		
57		Round Expansion Joint for Duct	Fabric	1	Ø42" ID	0.14/-0.7 psig / 480 °F	1201 ft^{3}/s	304 SS		
58	ME-001	Steam Desuperheater		1				CS	(Note 2)	
59	ME-501	TEG Reboiler Electric Heater	Electric	1	10" x 10'	50 psig / 450 °F	88.6 kW	CS w/ 316L SS cladding	(Note 1)	
	U-001	**Reclaimer Unit**	Semi-Continuous					CS/PWHT	(Note 2)	
60	E-007	Reclaimer	Shell & Tube	1	Area = 450 ft^{2}/shell	Shell: 27/FV psig / 310 °F Tube: 185/FV psig / 450 °F	1.3 x 1.4 MM BTU/hr			
61	E-011	Reclaimed Waste Cooler	Plate & Frame	1	Area = 6 ft^{2}	Hot: 27/FV psig / 310 °F Cold: 100 psig / 160 °F	0.2 MM BTU/hr		Intermittent operation.	
62	G-102	Reclaimer Vapor Compressor	Turbo Fan	1	5,100 gpm Suction: 15 psia Discharge: 28 psia		50 hp			
63	G-011	Reclaimer Circulation Pump	Progressive Cavity	1	100 ft Head @ 40 GPM		3 hp			
64	G-012	Reclaimer Vapor Knockout Pump	Rotary	1	35 ft Head @ 20 GPM		1 hp		Intermittent operation.	
65	F-003	Reclaimer Drum	Vertical	1	2' ID x 8'-6" T/T	27/FV psig / 310 °F				
66	TK-004	Reclaimed Waste Tank		1	7' ID x 8'-4" T/T	Full Liquid @ 310°F				
67	ME-002	Reclaimed Waste Tank Heater	Electric	1			10.3 M BTU/hr			
	U-002	**Tank & Sump Unit**					4,000 ft^{3} capacity	CS/PWHT	(Note 2)	
68	TK-001	Solution Storage Tank		1	19'-9" ID x 16'-6" Height	Full Liquid @ 150°F				
69	TK-002	Solution Sump Tank		1	8'-3" ID x 5'-9" Height	Full Liquid @ 150°F		CS	Underground storage tank.	
70	F-102	Solution Sump Filter	Vertical	1	1'-6" ID x 4'-5" Height	95 psig / 160 °F				
71	G-006	Solution Sump Pump	Centrifugal	1	95 ft Head @ 200 GPM		11 hp	PWHT CS	Intermittent operation.	
	U-003	**CO2 Gas Condensing Unit**							(Note 2)	
72	E-004	Regenerator Condenser	Plate & Frame	1	Area = 30 ft^{2}	Hot: 27/FV psig / 310 °F Cold: 100 psig / 160 °F	1.2 MM BTU/hr	304 SS		
73	F-001	Regenerator Reflux Drum	Vertical	1	5'-9" ID x 10'-3" T/T	27/FV psig / 310 °F		CS w/ 304 SS cladding		
	U-004	**Caustic Soda Injection Unit**						PWHT CS	(Note 2)	
74	TK-003	Caustic Soda Storage Tank		1	6'-9" ID x 8'-3" Height	Full Liquid @ 125°F				
75	ME-003	Caustic Soda Storage Tank Heater	Electric	1			4.5 M BTU/hr			
76	G-009	Caustic Soda Make Up Pump	Diaphragm	1	95 ft Head @ 0.1 gpm		1 hp			
77	G-010	Reclaimed Caustic Soda Feed Pump	Diaphragm	1	20 ft Head @ 0.1 gpm		1 hp			
	U-005	**Energy Saving Unit**						304 SS	Intermittent operation. (Note 2)	
78	E-008	Semi-Lean/Lean Upper Exchanger	Plate & Frame	1	Area = 2,800 ft^{2}	Hot: 215 psig / 310 °F Cold: 45/FV psig / 310 °F	7.5 MM BTU/hr	304L SS		
79	E-009	Semi-Lean/Lean Bottom Exchanger	Plate & Frame	2	Area = 5,300 ft^{2} each	Hot: 215 psig / 310 °F Cold: 45/FV psig / 310 °F	20.5 MM BTU/hr	304L SS		
80	**U-011**	**Anti-Foam Injection Unit**		1	1.5 ft L x 1.5 ft W x 2.0 ft H			SS (tubing)	(Note 2)	

PRELIMINARY EQUIPMENT LIST - 95% CO2 Capture

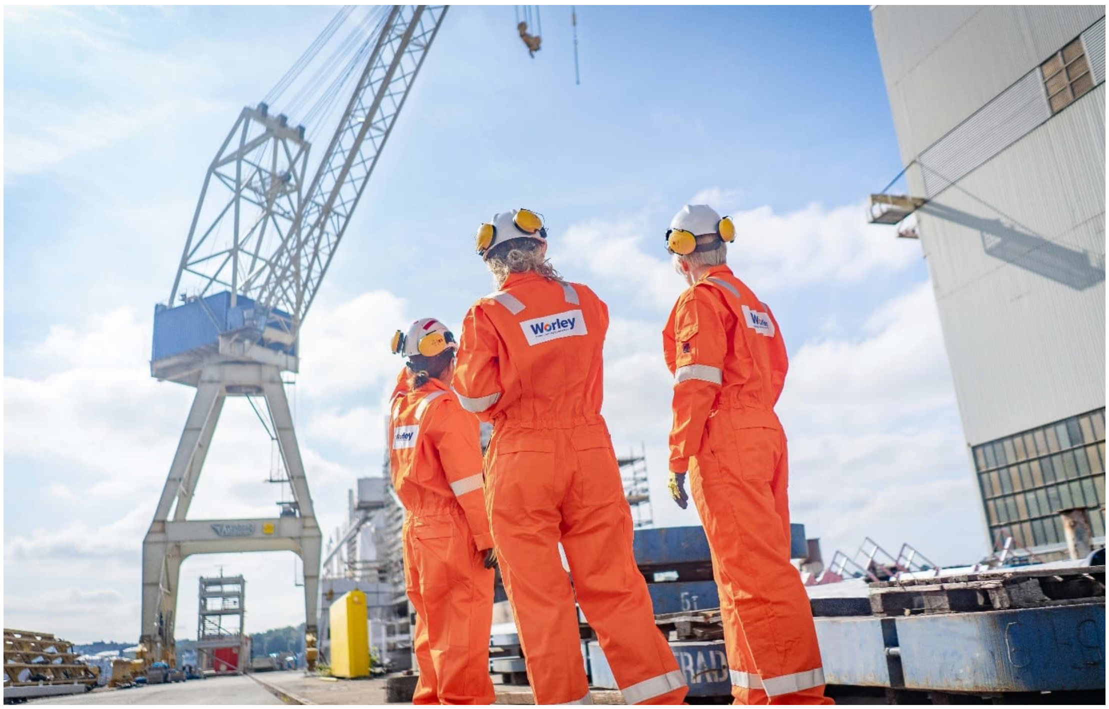
	Tag	Description	Type	Qty.	Size	Design Conditions psig / °F	Volume / Duty	Materials	Comments	Revision
	U-501	**pH Correction Injection Unit**						316 SS (tubing)	(Note 1)	
81		pH Correction Tank	see note	1		Full Liquid @ 149 °F			Atmospheric, Rectangular Tank (Dual Compartment)	
82		pH Correction Pumps	Diaphragm	2x100%	0.18 GPH					
	U-502	**Anti-Foam Injection Unit (for TEG)**						316 SS (tubing)	(Note 1)	
83		Anti-Foam Storage Tank	see note	1		Full Liquid @ 149 °F			Atmospheric, Rectangular Tank (Dual Compartment)	
84		Anti-Foam Injection Pumps	Diaphragm	2x100%	0.18 GPH					

Made by: LB/HL	Date: 10/31/2022	P66 CCUS Project - CO2 Capture Unit	Rev. Letter:	A			**REMARKS**	
			Date:	10/31/2022			1. Design details to be confirmed by selected licensor.	
Checked by: IM	Date: 10/31/2022	PLANT: P66 Rodeo SMR Post Combustion CO2 Capture Unit	Signature:				2. Additional details to be confirmed by MHI.	
			Description	Issued for Information				
Approved by:	Date:							

Appendix D. Estimate Basis

Basis of Cost Estimate Document - FEL-2

P66 DOE CCUS Project – Rodeo, CA



Document No: Rev. 0A MS-ES-TEM-0022
Dec 16, 2022

Table of contents

1. Executive Summary

This Capital Cost Estimating Plan is to be applied during the Rodeo DOE CCUS project to develop an FEL 2 Capital Cost Estimate with target accuracy +25%~-15%, per P66 standard.

See Section 4.1 for more scope details.

The basis of the estimate in terms of methodology and process in determining the capital cost value are the prime areas of focus of this estimate basis document.

2. Introduction

2.1 Project Background

To reduce future Greenhouse Gas (GHG) emissions from hydrogen production at Rodeo, Phillips 66 has proposed several carbon-capture options at their Hydrogen Production Unit (HPU). The existing HPU uses Steam Methane Reforming (SMR) technology for generating H2 from natural gas and is capable of producing 28 MMSCFD of H2 (99.97%+ purity). With ~95% carbon capture efficiency, it is estimated that this unit can provide an opportunity for carbon capture in the range of ~190 kilo-ton/year.

2.2 Purpose of the Document

This document has been prepared to support the development of the Capital Cost Estimate for the Rodeo DOE CCUS project for Rodeo Refinery at Rodeo, California. The intended accuracy for this estimate is in the range of +25/-15% per P66 Standard (Worley's "Class 4" (FEL-2) type cost estimate).

The total estimated cost of the overall project as detailed in this document is USD $ 239.4 million.

This amount is based on US dollars at a +25%/-15% probability of overrun/underrun (excludes market forces and currency hedging).

This cost estimate is summarized in Table 1 below:

Table 1: Cost Estimate Summary

Notes: All costs referenced in Table 1 have been estimated in US dollars, base date *Q4 2022*

CUSTOMER : PHILLIPS 66 | MTO BY : WORLEY

PROJECT : RODEO DOE CCUS FEL2 | FEL 2 (+25/-15%) | ESTIMATE BY : AZ

JOB NUMBER : | **ESTIMATE SUMMARY** | DATE: 15-Dec-22

LOCATION : RODEO, CA | FILE NO. : 37-22 | REVISION : 1

PRIME CODE	DESCRIPTION	QTY	UOM	MATL $/UNIT	LABOR HRS/UNIT	LABOR HOURS	S/C HOURS	LBR RATE $/HR	MATERIAL COST	LABOR COST	S/C COST	TOTAL COST
	Brief Description of Work:			**RODEO DOE CCUS FEL2**								
DIRECT COSTS												
50	MAJOR EQUIPMENT	81	EA	$319,669	232.5	18,834		$115.65	$25,893,198	$2,178,089		$28,071,287
51	DEMOLITION	1	LT		9,568	11,481		$118.39		$1,359,200		$1,359,200
52	SITE EARTHMOVING		CY									
53	SITE IMPROVEMENTS (ROAD AREA)	2,377	SY			5,221		$106.66	$273,034	$556,865		$829,898
54	PILING, CAISSONS (14"x45' Prestressed Concre		EA									
55	BUILDINGS		SF									
56	CONCRETE	1,612	CY	$433	16.0	25,818		$106.23	$698,730	$2,742,765		$3,441,495
57	MASONRY, REFRACTORY		SF									
58	STRUCTURAL STEEL	707	TON	$4,274	41.5	29,369		$111.19	$3,023,309	$3,265,549		$6,288,858
59	CORRUGATED SIDING & DECKING		SF									
60	FIREPROOFING		SF									
61	DUCTWORK	200	FT	$1,478	8.6	1,723		$107.19	$295,544	$184,683		$480,227
62	PIPING Avg. Dia.4.4"	51,042	LF	$106	2.4	119,964		$141.26	$5,407,913	$16,945,563	$2,586,116	$24,939,592
63	INSULATION	27,746	LF/SF	$12		11,510		$116.89	$341,435	$1,345,355		$1,686,790
64	INSTRUMENTATION	256	EA	$9,714	26.5	6,775	144	$126.26	$2,482,834	$855,428	$1,441,000	$4,779,263
65	ELECTRICAL (qty = CONDUIT LF)	25,911	LF	$209	0.9	24,540		$115.54	$5,425,162	$2,835,452	$100,002	$8,360,616
66	PAINTING	15,000	SF	$11.4		1,824		$101.15	171,675	$184,493		$356,168
69	SCAFFOLDING	17%	of DLH			66,341		$107.16		$7,109,064		$7,109,064
69	FIREWATCH	5%	of DLH			19,895		$108.49		$2,158,436	$911	$2,159,347
77	FREIGHT								$2,460,733			$2,460,733
	Design Allowance					50,051	24		$6,208,649	$6,333,342	$825,424	$13,367,415
A	**TOTAL DIRECT COST (TDC)**					**393,346**	**168**	**$122.17**	**$52,682,200**	**$48,054,300**	**$4,953,500**	**$105,689,954**
81	**SALES TAX**	**8.75%**							**$5,477,073**			**$5,477,073**
INDIRECT COSTS												
75	CS LABOR	6%	of DLH			23,601		$109.95		$2,883,300		$2,883,300
76	TEMPORARY FACILITIES	4%	of DLC			5,769		$109.95	$1,287,900	$634,300		$1,922,200
78	PREMIUM PAY									$2,989,313		2,989,313
79	CRAFT FRINGES		included in craft rates									
80	PAYROLL TAXES & INSURANCE		included in craft rates									
81	NON-PAYROLL TAXES & INSURANCE		included in craft rates									
83	SMALL TOOLS		included in craft rates									
84	CONSUMABLES		included in craft rates									
85A	CONSTRUCTION EQUIP	9%	of DLC					$11.00	$4,326,804			$4,326,804
87	FIELD STAFF (SUPERVISION)	20%	of DLH			78,669		$120.00		$9,440,300		$9,440,300
	CONTRACTOR OH		included in craft rates									
	PER DIEM								3,854,789			$3,854,789
	HEAVY LIFT EQUIPMENT								$3,000,000			$3,000,000
B	**TOTAL INDIRECT COST**					**108,039**			**$12,469,493**	**$15,947,213**		**$28,416,706**
C	**ACCUMULATIVE TOTALS**					**501,385**	**168**	**$177.01**	**$70,628,800**	**$64,001,500**	**$4,953,500**	**$139,583,700**
OTHER COSTS												
	PROJECT DEVELOPMENT - FEL2	0.6%	of TIC									$1,400,000
	PROJECT DEVELOPMENT - FEL3	2.5%	of TIC									$6,013,201
	PROJECT DEVELOPMENT - FEL3a	1.0%	of TIC									$2,328,291
90	ENGINEERING & PROC	9.0%	of TIC									$21,545,996
	HOME OFFICE CONSTRUCTION SUPPORT	0.5%	of TIC									$1,197,000
D	**SUBTOTAL COSTS**											**$172,068,189**
	ESCALATION								$2,969,400	$5,464,500	$371,600	$8,805,500
	CLIENT COSTS (By Phillips 66)	10.0%	of TIC									$23,939,996
	CONSTRUCTION MANAGEMENT		Incl w/ Client Costs									
98	CONTINGENCY (Of Unescalated TIC)	15.0%	of Unescalated TIC									$34,589,008
E	**TOTAL INSTALLED COST**											**$239,400,000**

3. Basis of Estimate

3.1 Estimate Classification and Estimate Accuracy

This estimate will be based on FEL-2 engineering required to complete definition phase deliverables with an average scope risk range of +25/-15%.

3.1 Extent of the Estimate

GENERAL SCOPE

The overall objective of this project is to complete the initial design of a commercial-scale, advanced CCS system that separates and stores ~190,000 ton/year net CO2 with 95% carbon capture efficiency from an existing steam methane reforming plant at Phillips 66's Rodeo Refinery. The H2 produced from natural gas by this unit is expected to have 99.97% purity. The goal of this project is to select the most technologically sound and economical CCS system design from three proposed options. All the options considered will achieve a net carbon capture efficiency of 95%.

- Option 3 – Carbon Capture from Steam Methane Reformer Flue Gas (i.e. Post-Combustion Carbon Capture only). This is the selected case and the only case being estimated for the final report.

3.1.1 Mechanical

- Installation of new equipment -- details per equipment lists
- Demolition of existing OOS (out of service) equipment to make space for new system(s)

3.1.2 Site Improvement

- Site Prep
- Back Fill mid field
- Paving, including new roads

3.1.3 Civil/Structural

- UG Piping System
- Equipment foundation
- Pipe Rack and Equipment support structure

3.1.4 Piping

- Transpositions for OSBL Interconnecting Rack Piping
- Piping Speciality Items
- Insulation/Tracing
- Safety Shower Eye Wash Stations
- Demo pipe.

3.1.5 Control System Scope

- DCS, SIS and MAC
- RIE
- Allen Bradley PLC Assembly
- Analysers
- Bentley Nevada
- Transmitters, gauges, etc

3.1.6 Electrical

- PDC
- MV/LV (4.16 KV/480V) Switchgear
- MV/LV (4.16 KV/480V) MCC
- UPS System
- Fiber optic home run cables
- 4.16 kV / 480V Power Transformer incl NGR
- Cable tray and conduit
- Instrument Cables
- Grounding
- Lights and lighting panels
- No known Demo scope

3.1.7 Insulation/Fireproof

- Insulation is based on operating temperature
- Fireproof is not required

Worley has based the capital cost estimate on the engineering details, including material take-offs, budget quotes from subcontractors, and work-hour estimates.

3.2 Key Qualifications/Assumption/Exclusions

The following qualifications were noted when preparing the Capital Cost Estimate.

- Direct labor is based generally on a 5 days 10 hours per day or 50hr week for works undertaken outside of the planned shutdown.
- Contractor parking, warehousing, lay down, and other construction related site improvements are provided by P66 on existing property within near proximity to the project site
- Bussing is not required for transport of craft
- Local Civil and Electrical Permitting costs are owner costs
- Dewatering costs are not included
- Modifications for heavy haul road not included
- Geotech and Soil Testing cost is an allowance is included in other engineering costs
- Operating manuals and operator training are an owner cost
- Tariffs are excluded
- Imported backfill
- PSE is factored per P66 direction, except for FEL-2 actual cost
- No known asbestos insulation
- As build is a part of owner's cost

EXHIBIT 1 – OWNER'S COST ITEMS

Owner Costs will be factored at 10% of TIC. Owner costs typically may include:

- Project financing and development cost
- Project Insurance – except contractor's own construction insurances
- Cost of Forward Cover of foreign content
- Exchange Rate Fluctuations – (over or below the basis rates stated in the contract)

- Third Party Inspection Authority
- Construction Management
- Catalyst Material Cost (Labor cost if applicable will be included in the direct field cost under equipment)
- Environmental Impact Studies
- Cost of land/lease
- Delays due to unknown underground obstructions
- Commissioning and Start-up costs
- Operator Training, training manuals and training facilities
- HAZOP studies and facilitator
- Start-up modifications
- Consultants appointed by Customer
- License fee and/or Royalty
- Supplier representatives after start-up
- Flushing and making the existing plant and facilities safe
- Permits (Building/Environmental/ Heavy Haul related)
- Regional Services Council levies
- Customers own staff and expenses – (salary, travelling, accommodation, subsistence, etc.)
- Contaminated material disposal – (if not specifically requested in Scope of Work)
- Any mobile equipment
- Capital and operating spares (except for what is purchased with/included with mechanical equipment) – (commissioning/start-up spares included in Direct Field Cost)
- Catalyst and Chemicals – (initial/inventory/operating).
- Lubricants – (initial/inventory/operating)
- Import duties and surcharges
- Insurances

3.3 Schedule

Project schedule/FEL2 estimate submittal to P66 – Dec 16, 2022

Plant start up – 1Q 2026

4. Scope Description

4.1 Scope by WBS

The capital cost estimate has been developed in accordance with the different areas specified in the Estimate Plan / Scope of Work.

Very minimal T/A work in Unit 110. The U110 scope during the outage is to lift off the existing stack, replace it with a taller one

The scope is summarized below:

- U111:CCPU - New Unit
  - U111:CCPU
  - TEG Pkg
  - Compressor Pkg
  - U-001 Reclaimr Pkg 20x18
  - U-002 Tank & Sump Unit
  - U-003 CO2 Gas Condensing
  - U-004 Caustic Soda Injec
  - U111 5-Piping/CSA
  - U111 6-Electrical
  - U111 7-Control Sys
- U110:SMR - Brown Field
  - U110:SMR
  - U110:SMR - TAR

Exclusions:

1. Fire detection and suppression will be reviewed during detail design.

5. Quantity Derivation and Cost Basis

5.1 Quantity Derivation

Quantities used have been based on the engineering material take-offs (MTO's) and Basis of Design (BOD) supplied by engineers.

Quantities by commodity were developed by Worley based on scope which were reviewed during the design review in the form of drawings, sketches, equipment list and MTO's.

Project design is based on Specifications and Standards in the following precedence (where applicable): P66, PIP/ Industry Standards

The following deliverables were issued to estimating for the FEL-2:

- Priced mechanical equipment list
- Priced tagged instrument list.
- Piping MTO for interconnecting pipe on rack, SP items, Demo
- Civil MTOs, including UG piping
- Structural MTOs (Pipe Rack and Equipment support structure sizes)
- Electrical bulks MTO, Electrical equipment priced.

5.2 Pricing Generally

Pricing for bulk materials and equipment are based vendor quotes.

5.2.1 Mechanical

- Mechanical obtained budgetary vendor quotes for the following equipment, account for 76% of the equipment cost
  - Compressor Package
  - Quench Tower
  - Blower
  - Absorber Tower
  - Regenerator Tower
  - TEG Unit
  - Cooling Tower
  - New Stack

The balance of equipment were estimated by ICARUS based on the equipment list.

5.2.2 Buildings

- N/A

5.2.3 Concrete

- By ACCE, indexed to Worley standards

5.2.4 Structural Steel

- Material pricing by ACCE
- Direct hours based on ACCE unit man-hours, adjusted to Worley standards

5.2.5 Fireproofing

- N/A

5.2.6 Piping

- Piping size and materials are input based on Piping MTOs
- Safety Shower Eye Wash Stations are included.
- All welded piping to be shop fabricated to maximum extent.
- Pipe shoes and miscellaneous supports are generated by ACCE.
- Material costs were modeled by ACCE then adjusted to recent quotes.
- Direct hours based on ACCE unit man-hours, adjusted to Worley standards
- Specialty Items included

5.2.7 Insulation

- Equipment and piping requiring insulation is based on MTO.
- Insulation direct hours and material costs are generated by ACCE and adjusted to quotes.

5.2.8 Instrumentation

- Instrument tagged items as well as bulk quantities are based on MTO. Direct hours are based on Worley standards. Bulk material pricing are modeled by ACCE adjusted to quotes
- Tagged instruments, RIE, SIS, analyzer, Nevada Bentley (equipment mod sys), costs are based on previous project quotes

5.2.9 Electrical

- Material costs for PDC Building are based recent project PO
- Material costs of power transformers are by electrical.
- Electrical bulk quantities are based on MTO, supplemented by ACCE. Material costs were modeled by ACCE then adjusted to Worley standards
- Direct hours based on ACCE unit man-hours, adjusted to Worley standards

5.2.10 Painting

- Painting is modeled by ACCE, and pricing is adjusted to Worley standards
- Pipe is remote shop blasted, primed and finished painted
- 10% field touch-up painting for pipe is included
- 10% field touch-up painting for equipment is included
- 10% field touch-up steel galvanizing is included
- Line labelling is included in the paint account

5.3 Craft Wage Rates

DIRECT ALL-IN WAGE RATE

- All-in Wage Rate are provided by P66 Rodeo Refinery, June 2022. The rate includes
  -Craft Fringes
  -Payroll Taxes and Insurance
  -Non-payroll Taxes and Insurance
  -Small Tools
  -Consumables
  -Contractor OH & Profit

	2022
concrete	104.82
steel	106.15
Equipment	113.56
piping	144.75
electrical	114.86
control	133.2
Painter	96.73
insulation	122.66
Firewatch (piper apprentice	108.49
scaffoler	107.16

-

- Direct Labor Costs are based on union standard rates
- Foreman and Operators included in the direct labor hours

The cost of construction labor is based on Worley standards for installation hours and modified by productivity factors.

5.4 Construction Indirects, cranes, scaffolding and firewatch

5.4.1 Scaffolding

- Estimating applied percentages of the craft hours for scaffolding hours per all direct crafts by discipline
- Pipe scaffolding is based on number of field welds and bolt up locations, percent of pipe locations needing scaffolding, and average scaffold height resulting in estimated pipe scaffolding sections. The resultant hours show the calculated percentage of pipe hours.

5.4.2 Firewatch / Holewatch/Safetywatch

- Firewatch, holewatch, and safetywatch hours are factored using a % of direct labor hours. The % varies per craft.

5.4.3 Temporary Facilities

Temporary Facilities for this project are calculated at 4% of total direct labor.

Temporary Facilities is defined as items needed on a temporary basis for construction of a project and does not become part of the permanent installation. Items in temporary facilities include:

- Field Office Expenses: telephone, reproduction, office equipment, printers, computers, software, computer and office supplies, furniture, safety supplies, safety orientation, drug tests, safety awards
- Temporary Buildings: office trailers, field trailers, set up and take down of trailers, warehouse, fabrication buildings, craft shacks/gang boxes, lunchroom tent, sanitary facilities holding tanks
- Temporary Services & Facilities: telephone & communication systems, temporary piping, road maintenance, temporary fencing, laydown area maintenance, parking lots and maintenance, warehouse improvements, portable toilets, temporary construction power, trailer hook up water and sewage, dumpsters, utility service charges, safety barricades, signs, Reproduction and Copier, Office Equipment such as Fax, PC's and Software, Furniture, Office Supplies, First Aid and Safety Equipment, Postage/Fed Ex/Freight, Office Trailers, Warehouse (Conex), Storage/Tool Room, Fabrication Table/Tool Boxes, Dunnage, Shelving for Conex.

5.4.4 Construction Services Labor

- Estimating applied a percentage of the craft work hours for construction service labor (CSL).
- Construction service labor man-hours are factored at 6% of the direct labor man-hours
- Construction service labor is defined as guard service, surveying, warehousing, tool room, truck drivers, mobilization / demobilization, fueling, drinking water, clean-up, welder qualification, drug testing, safety orientation, safety meetings, rain-outs, Traffic Control, Warehouseman, Warehouse Clerk, Receiving Office Clerk, Toolroom Attendant Cleanup, Dewatering, Mechanic, Runner, Welder Testing, Concrete Testing, Safety (Craft non-supervisor), QA/QA (Craft non-supervisor), Standby/Upset Condition, and other incidental service labor
- CSL hours are not included in the direct craft work hour installation unit rates.

5.4.5 Construction Equipment

- Construction Equipment Rentals (60 tons and below) are included at $11/Hr of Total Direct Field Hours (TDMh).
- Construction Heavy Lift allowance of $3,000,000

- Construction Equipment includes Flatbed Trucks, Pick-up Trucks, Manlifts, Dump Trucks, Air Compressors, 60 Ton Cranes and below, Carry Decks, Forklifts, Test Pumps, Hydro Pumps, Dewatering Pumps, Rig Welding Trucks, Weld Machines, Bevelling Machines, Threading Machines, Portable Generators, Conduit Benders, Cable Pullers, Radios.

5.4.6 Field Staff with Burdens

- Field staff with burdens is applied at a rate of $120/hour, x 20% of direct field hours.
- Field Staff is defined as the contractor staff supervision and management team that manages the execution of the hourly direct and indirect construction workers. Field Staff typically covers the responsibilities of the following positions: Site Manager, Construction Manager, Constructability Coordinator, Tool Room Supervisor, Field Office Supervisor, Project Superintendent, Construction Engineer, Area Superintendents, Field Engineers, QA/QC Manager, Field Purchaser, Warehouse Supervisor, Safety Manager, Project Controls Supervisor, Schedulers, Cost Engineers, Subcontract Administrators, Administrative Manager, HR Manager/Recruiter, Material Control Supervisor, Field Buyers, Craft Superintendents, Document Control, Safety Inspectors, QA/QC Inspectors, Clerks, Receptionists, Project Secretaries, Timekeepers, Accounting, Quantity Surveyors. Some staff positions may cover multiple responsibilities in the management team. The Field Staff rate includes burdens for payroll taxes, insurance and benefits.

5.4.7 Premium Time with Burdens

- Premium pay is included at 20% of direct labor hours or 10 hours per week at the overtime rate as an indirect cost.
- Premium time for Turnaround is based on 6 x 10-hour workdays double shift

5.4.8 Craft Fringe Benefits

- Craft Fringe Benefits are included in the wage rates
- Craft Fringe Benefits are defined as vacation, holiday, sick time, group health & welfare insurance, and 401k.

5.4.9 Per Diem and Travel Allowance

- Field Staff Per Diem is included at $200/Day.
- Craft Per Diem is included for union labor.
- Craft Travel Allowance of $100/day for 50% of the craft will be included

5.4.10 Craft shift differential and incentives

- N/A

5.4.11 Payroll taxes and Insurance

- Payroll Taxes and Insurance is included in the wage rates

5.4.12 Small tools and Consumables

- Small Tools are included in the wage rate
- Consumables are included in the wage rate

5.4.13 Overhead and Contract Fee

- The overhead and contract fee basis are included in the Construction wage rates

5.5 Productivity

For direct construction workforce productivity is defined below. Both are based on 5 days 10 hours per day or 50 hours per week for non-turnaround scope. 6 days 10 hours per day for turnaround scope.

Non-OUTAGE	OUTAGE
75%	65%

Additional adjustments are made to account for double handling unload and store, for piping, steel and Alfa Laval equipment.

Separate adjustments are also made to account for manual installation of pipe spool inside the PTU building.

5.6 Design Allowance

		DESIGN ALLOWANCE
50	MAJOR EQUIPMENT	10%
51	DEMOLITION	20%
52	SITE EARTHMOVING	30%
53	SITE IMPROVEMENTS	30%
54	PILING, CAISSONS	20%
55	BUILDINGS	20%
56	CONCRETE	20%
57	MASONRY, REFRACTORY	20%
58	STRUCTURAL STEEL	20%
59	CORRUGATED SIDING & DECKING	20%
60	FIREPROOFING	20%
61	DUCTWORK	20%
62	PIPING	20%
63	INSULATION	20%
64	INSTRUMENTATION	20%
65	ELECTRICAL	20%
66	PAINTING	20%

Design allowance covers developmental cost known to occur in different classes of estimates. They cover growth in cost as engineering is further defined. In earlier phases it covers the lack of definition and in control phases it covers the variances from issued for design to issue for construction definition as well growth in purchase orders as designs are finalized.

5.7 Professional Services

The Professional Services (Engineering, Procurement and Construction) have been estimated by Worley based on the Project schedule and necessary deliverables to complete the Project.

Per P66 direction, PSEs are factored based on historical benchmark.

- FEL-2 Engineering Costs are included, actual cost
- Phase III FEED (FEL-3) Engineering costs are included based on historical benchmark factor
- Phase IV Detail Engineering costs are included based on historical benchmark factor
- Phase V Construction Support costs are included based on benchmark factors

5.8 Pre-Operational testing, Commissioning Handover and Closeout Costs

Commissioning and handover costs, Start-up costs, and first fill chemical and catalyst costs are owner costs.

5.9 Freight and Material Handling

- Freight costs are included at 5% of all material less civil material.

5.10 Sales Tax

8.75%.

5.11 Supplier Reps

Vendor representative costs are excluded

5.12 Spares and First fills

- Capital Spares are excluded and is included in owner costs if necessary. Start-up spares are owner costs.
- Chemicals and first fill costs are included in owners' costs.

5.13 Escalation Assessment

Escalation is calculated based on the major project phases schedule durations for Engineering, Procurement, and Construction to the midpoint of their duration. Annual escalation rate of 3% is applied to field direct labor, field indirect and construction management labor, process equipment, construction equipment, materials, and engineering costs. Current hyper inflation is excluded from escalation and will be considered as a separate risk item.

Start up 1Q 2026

5.14 Contingency Allowances

Contingency is 15% TIC costs. Contingency has been reviewed by the project team.

Contingency is an allowance for unforeseen conditions and is part of the estimated job cost and is based on technology unknowns, project specific unknowns, status of engineering, status of design and specifications, quality of pricing, unanticipated jobsite conditions, weather conditions, labor productivity variances, increases in costs not covered by contractual provisions, delays in equipment and materials, estimating errors and omissions; it is a provision to cover unknown elements of cost where previous experience has proven they are most likely to occur; it does not cover force majeure, unusual economic situations, labor strikes, material shortages, additional work or scope changes by the Client after the definition of the job has been frozen for the estimate; this allowance is designed to produce the most likely cost of the project.

5.15 Exchange Rates

The following exchange rates have been used:

None

No provision is made in the cost estimate to mitigate for currency risk. Currency risk should be captured in the project's risk register and will be managed by customer

5.16 Customer Costs

Owner Costs are included at 10% of TIC (Owners Costs will include Construction Management Costs). References to client/owner costs are defined throughout the estimate basis.

6. Definitions

Word / Phrase	Definition
AACEI	Association for the Advancement of Cost Engineering International.
Cost Estimate Classification System	Provides guidelines for applying the general principles of estimate classification to asset project cost estimates. Asset project cost estimates typically involve estimates for capital investment and exclude operating and lifecycle evaluations. The system maps the phases and stages of asset cost estimating together with a generic maturity and quality matrix that can be applied across a wide variety of industries (per AACEI).
Estimate Basis	A document that outlines the basis of the estimate including such items as documents used, design criteria, procurement approach, construction approach, labor surveys, wage rate development, schedule basis, work week, etc.
Estimate Plan	A document that outlines how the estimate will be developed including: schedule, responsibilities, approach, estimate classification, estimate purpose, project overview, Material Take Off (MTO) requirements, accuracy, etc.
Contingency	An amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and that experience shows will likely result, in aggregate, additional costs (per AACEI). Contingency is not to be used to address additional work or scope changes after the scope of the project has been defined.
Escalation	A provision in costs or prices for uncertain changes in economic and market conditions over time.

7. References

None

Appendix E. Environmental Review

SMR CARBON CAPTURE DESIGN (SMRCCD)

Environmental Health and Safety Assessment

Document Number: 418122-42566-ENV-REPT-0006
Revision D Date: 16 December 2022

Customer: P66 / Department of Energy

A

PROJECT 418122-42566 – SMRCCD – Environmental Assessment

Rev	Description	Originator	Reviewer	Worley Approver	Revision Date	Customer Approver	Approval Date
Rev A	Draft for Review	S. Sparks, S. Chang	P. Srinivasan	J. Yox	10 Nov 2022		
Rev B	Draft for Review	S. Sparks, S. Chang	P. Srinivasan	J. Yox	01 Dec 2022		
Rev C	Draft for Review	S. Sparks, S. Chang	P. Srinivasan	J. Yox	08 Dec 2022		
Rev D	Issued for Review	S. Sparks, S. Chang	P. Srinivasan	J. Yox	16 Dec 2022		

Table of Contents

1.0 INTRODUCTION

The advancement of Carbon Capture and Storage (CCS) technology is critically important in addressing CO_2 emissions and global climate change concerns on the pathway to net-zero emissions. The Project is designed to demonstrate commercial-scale integration of a new carbon capturing facility with an existing Hydrogen Production Unit (HPU) within Phillips 66’s existing San Francisco Refinery in Rodeo, California.

Phillips 66, in partnership with Worley Group (engineering contractor) and Mitsubishi Heavy Industries America, Inc. (MHI, technology licensor), propose this project with the objective of completing an initial engineering design study (FEL-2 class) of an amine-based carbon capture system for the post combustion capture of CO_2 from the Unit 110 Steam Methane Reformer (SMR) at the Rodeo Refinery. The Unit 110 SMR is designed to process natural gas (NG) and other light hydrocarbon gases to produce H_2. The existing HPU is capable of producing 28 MMSCFD of H_2 (99.97%+ purity). With a planned ~95% carbon capture efficiency, it is estimated that the new carbon capture unit can provide an opportunity for carbon capture in the range of ~190,000 metric tonnes/year.

2.0 AIR AND WATER EMISSIONS, AND SOLID WASTES

Proposal Instructions
All potential ancillary or incidental air and water emissions, and solid wastes produced from the proposed technology shall be identified and their magnitude estimated. In addition to solvents or sorbents used, researchers shall consider possible by-products of side reactions that might also occur in the system, accumulated waste products, and the fate of contaminants from the feed gas stream. Environmental degradation products shall be addressed. Bioaccumulation, soil mobility, and degradability shall be considered. Conditions at the point of discharge shall be examined.

The addition of an amine-based carbon capture (ACC) system on the currently operating SMR facility will minimally change the non-CO_2 emissions and waste streams that are currently generated. There are seven main waste streams associated with the ACC process that are considered for the EH&S analysis:

- Treated flue gas
- Triethylene Glycol drying unit (TEG) vents
- Cooling tower drift to the atmosphere
- Cooling tower water blowdown
- Solvent reclaiming waste
- Wastewater from flue gas pre-treatment
- Spent filter media

Exhaust / Waste Stream	Source	Estimated quantity	Environmental impact	Mitigation Strategy
Treated Flue Gas after CCS	Flue gas from the SMR - treated by the CCS and vented to the atmosphere	28,503 scfm at 60 °F	Significant net reduction in CO_2 released to atmosphere	Air pollution control equipment and comprehensive air permitting program
TEG Vents	TEG regeneration process	~ 990 SCFH	Little, mainly nitrogen with trace of TEG [1]	Air pollution control equipment and comprehensive air permitting program
Cooling Tower Drift	Water lost from cooling towers as liquid droplets are	0.55 lb PM_{10} / $PM_{2.5}$/day	Little, as cooling tower will be controlled with high-efficiency	Air pollution control equipment and comprehensive

Exhaust / Waste Stream	Source	Estimated quantity	Environmental impact	Mitigation Strategy
	entrained in the exhaust air		drift eliminator (0.0005% drift rate)	air permitting program
Concentrated Spent Solvent from the Reclaimer	Solvent reclamation process	26-30 ston/year	Little, as it will be continuously recycled in the process	Specialized recycling technology and equipment that is designed to maximize the percentage of material recovered for reuse
Wastewater	Flue gas cooling prior to absorption	7-11 ston/hr	Little, as it will be treated prior to discharge via a permitted discharge point	Wastewater treatment system and comprehensive NPDES permitting program
	Cooling tower blowdown	10 ston/hr		
Spent Filter Media	Filters for lean amine & tank and sump unit	2.2 ft^3/month	Little, as it will be disposed of in accordance with existing policies	Existing disposal procedures for amine filters as non-hazardous waste

[1] Composition and flow rate to be confirmed with selected licensor during detailed design phase.

2.1 AIR EMISSIONS

Flue Gas generated from the furnace of the SMR unit will be treated by an ACC system via contact with the proprietary MHI KS-21™ solvent. The post-abatement (SCR abatement) flue gas stream has carbon dioxide (CO_2), nitrogen oxides (NOx), carbon monoxide (CO), precursor organic compounds (POC), particulate matters (PM), sulfur dioxide (SO_2), ammonia (NH_3) and other air contaminants from the combustion of natural gas, refinery fuel gas, and pressure swing adsorption (PSA) off gas. The proposed carbon capture process will reduce CO_2 in the flue gas by 95%. Combustion emissions other than CO_2 in the flue gas, such as NO_2 and SO_2, are also expected to be reduced through the CO_2 capture process. The flue gas will be vented into the atmosphere through a new absorber stack. In the new absorber stack, VOCs and some new type of toxic pollutant emissions are expected from the use of KS-21™ solvents. A detailed assessment of the treated flue gas stream will be performed as part of the FEED study.

Previous research efforts, as well as operational data, into the use of KS-21™ to treat flue gas emissions has indicated that low levels of aldehyde compounds emissions will be generated. As aldehyde compounds are classified as a Hazardous Air Pollutant (HAP) by the USEPA and toxic air contaminant by the Bay Area Air Quality Management District (BAAQMD), additional engineering and environmental research will be conducted to better understand ways to minimize air emissions of aldehyde compounds. In addition to aldehyde compounds, ammonia is also a toxic air contaminant according to BAAQMD Regulation 2 Rule 5. Depending on the amount of VOCs, aldehyde compounds and ammonia released by the carbon capture unit, the current PSD and Title V permits may need to be modified to account for increased emissions of VOCs, toxic air contaminants and hazardous air pollutants.

Preliminary air emissions from the stack after the ACC are estimated and summarized in table below. There may be a slight increase in POC emissions due to the emissions of amines and aldehydes from the carbon capture process compared to the allowable emissions in the current permit. As previously mentioned, the composition of the treated flue gas stream will be evaluated in detail as part of the FEED study. Permit requirements for treated flue gas streams and carbon capture processes will be thoroughly explored during the permit application process.

Composition	**mol.% (w)**	**ppmv(d)**	**mol.% (d)**	**MW**	**Emissions**	
				g/mol	**lb/day**	**tpy**
N_2+Ar	92.3					
O_2	2.2			32.00	76143	13896
CO_2	1.3			44.01	61880	11293
H_2O	4.1			18.02	79909	14583
SO_2		< 1	<1.00E-04	64.07	<6.65E+00	1.21
NOx		< 7.7	<7.70E-04	46.01	<3.67E+01	6.71
CO				28.01		0.00
Amine [a]		Trace		61.08		<1
Aldehydes [b]		Trace		30.03		<1
NH_3		Trace		17.03		<1

[a] Amine is assumed to be monoethanolamine (MEA).
[b] Aldehydes are conservatively assumed to be formaldehyde.

Air emissions from other sources such as the wastewater tanks and fugitive components will be very low.

2.2 WATER EMISSIONS

Wastewater from the Flue Gas Pre-Treatment will be routed to the site's large, and already existing, wastewater treating plant which utilizes automatic tanks and pumps and is in compliance with the plant's issued water discharge permits. Any additional waste streams linked to the addition of the ACC system will be handled by the existing wastewater system.

Well-designed and well-operated wastewater treatment facilities minimize operational risk and exposure. There are no additional physical or chemical hazards associated with this stream. Permitting is covered under the Clean Water Act and National Pollution Discharge Elimination System (NPDES). If the project progresses to later stages of engineering, a study will be conducted to identify whether the current discharge permit needs to be modified.

Waste Type	Contaminant	Concentration
Flue Gas Condensate Water	SO_3	200 ppm
	SO_4	
	NO_2	5 ppm
	NO_3	
	CO_2	750 ppm
	Na	400 ppm

Additional wastewater will be generated at the new cooling tower, during blowdown operations. Blowdown is necessary to prevent buildup of dissolved solids (TDS) in the cooling tower water, which can cause scale and corrosion problems within the tower. The blowdown water, with a TDS concentration of 1140 mg/l at 6 cycles of concentration, will be routed to on-site wastewater treatment consistent with how the other cooling tower blowdown's are currently handled.

2.3 MANAGEMENT OF SOLID WASTES

Disposal of Filter Media

Filter F-101 is in lean-CO_2 amine solution service, and F-102 refers to the Tank & Sump unit's filter (which includes any entrained amine from the process as well as fresh amine). As a basis, F-101 is assumed to be changed out monthly, with F-102 changed biannually (every 6 months). Filters are flushed with water and then nitrogen prior to be unloaded to minimize the amount of amine which stays absorbed onto the elements.

Waste Type	Contaminant	Concentration
Filter media	Polypropylene or Nylon-wound material of construction	~100 wt%
	PM	Trace
	Rust	Trace

Solvent Reclaiming Related Waste

KS-21™ circulating solvent is reclaimed as needed. The material that will be reclaimed is made up of the solvent, solvent degradation products, and water with low concentrations of various by-products from the flue gas, as well as any minor concentrated piping corrosion products.

As KS-21™ is a proprietary chemical, MEA is typically used as a comparable solvent in the MHI ACC process. Previous studies using MEA were based on a maximum stack concentration of 1 ppm. It should be noted that this is a conservative estimate. Data associated with the use of KS-21™ shows emission rates greatly lower than this level. For this report, the solvent was considered as MEA. Furthermore, the two primary thermal degradation products of MEA, hydroxyethylimidazolidinone (HEIA) and Trihydroxyethyl-imidazolidinone (triHEIA) were used as surrogates for the primary thermal degradation products of KS-21™.

Waste Type	Contaminant	Volatility	Flammability	Hazardous or non-Hazardous
Reclaimed Solvent	Solvent + H_2O [1]	Vapor pressure: 0.5 hPa at 20 °C	Product is combustible at high temperatures.	Acute toxicity, skin corrosion, serious eye damage
	Na_2CO_3 (Sodium Carbonate)	Vapor pressure: 1 mmHg @ 865°C	Flammability: 0	Eye irritation, category 2A
	$NaNO_3$ (Sodium Nitrate)	Vapor pressure: Not determined	Flammability: 1	Eye irritation, category 2A
	Na_2SO_4 (Sodium Sulfate)	Vapor pressure: Not available	Flammability: 0	May cause eye, skin irritation. Ingestion or inhalation may cause irritation
	Organic Compounds [2]	Vapor pressure: No data available	Flammability: No data available	Non-hazardous

1) Properties of pure solvent, considered as MEA
2) Properties of surrogate degradation products, HEIA & triHEIA

Concentrations of KS-21™ in the solvent reclaiming process will be very low. The reclaimed solvent waste is not expected to be ignitable, corrosive or reactive. Exposure to the general public or animal species is unlikely, and worker exposure will be minimized through engineering and administrative controls and worker PPE. Engineering controls include loading reclaiming waste into trucks for transport and disposal. PPE for workers will include face shields, goggles, chemical resistant gloves and clothing to prevent dermal exposure. The site already operates some very similar amine units and is familiar with the safety and environmental responsibilities associated with this type of operation.

2.4 BIOACCUMULATION, SOIL MOBILITY, AND DEGRADABILITY

If full-strength concentrations of KS-21^{TM} are directly released into the environment, they have a high potential for soil mobility, but the biodegradation rate is also high, with a low risk of bioaccumulation. Concentrations of KS-21^{TM} in the solvent reclaiming process will be at very low concentrations. Solvent and degradation products are expected to be moderately toxic to aquatic organisms although these degrade quickly in the environment. Human toxicity is low, but direct exposure to the solvent can cause irritations or burns. Mitigation measures of these potential risks will be managed by process hazards and operability mitigation (HAZOP) studies, robust engineering design, pre-start-up safety reviews, and operation and maintenance plans.

3.0 Toxicological Effects of Emissions/Wastes

Proposal Instructions
If possible, a concise but complete and comprehensible description of the various toxicological effects of the substances identified in (1) above shall be provided. A thorough literature search shall be conducted to examine potential human health effects and ecotoxicity. Where information is lacking for a particular material, it shall be compared to similar substances or classes of substances.

KS-21™ is a proprietary product that's composition is a trade secret belonging to MHI. Revealing solvent composition, specific aspects of solvent physical property data, and/or the solvent degradation products would reveal critical information about the identity of the solvent. Therefore, for the purposes of the EH&S assessment, MEA solvent was used as a surrogate for KS-21™. KS-21™ has a lower solvent emissions and solvent degradation rates than MEA; in addition, a lower solvent circulation rate is used for KS-21™. Therefore, the use of MEA in the EH&S Assessment provides a conservative estimate of the quantity of emissions and waste produced by the ACC Process.

Comparing the Safety Data Sheet (SDS) of a variety of solvents confirms MEA to be representative of KS-21™. The acute toxicity of MEA is similar to that seen in KS-21™, both for mammals and aquatic receptors. SDS data is inadequate to compare chronic exposures and for potential carcinogenic, mutagenic, teratogenic, or developmental effects; however, there are no reasons to believe MEA would produce substantially different effects from KS-21™. Chemical components in reclaimed solvent waste from MEA- or KS-21™-based processes associated with CO_2 capture are composed primarily of the solvent and thermal degradation products of the solvent. Waste streams generated will be further characterized during the initial engineering design study to determine the appropriate waste classification, regulatory requirements, and waste disposal options.

4.0 Volatility, Flammability, Explosivity, other Chemical Reactivity

Proposal Instructions
Properties related to volatility, flammability, explosivity, other chemical reactivity, and corrosivity shall also be collected from existing databases or if necessary through direct measurement in cases where the substance is not in common use.

The main chemicals used on the proposed process include KS-21™, TEG, and Caustic Soda. If the FEED study identifies additional components, they will be addressed in the final EHS study that will be completed at the end of the project.

As KS-21™ is a proprietary blend of amines, MEA was used to represent the properties of KS-21™. MEA is stable under normal conditions and isn't considered flammable or explosive. In the presence of CO_2, MEA binds with the CO_2 to "capture" the molecule. The CO_2 molecule is then released with heat. MEA has a higher volatility than other amines. The MHI process compensates for this higher volatility with a capture capability on the top of the contactor to minimize emissions to the atmosphere. On the NFPA diamond, MEA has a 3 for health, 2 for flammability, and a 0 for reactivity.

TEG (triethylene glycol) is a stable, low volatility, flammable, low reactive compound that is commonly used as an antifreeze, but here is being leveraged for the removal of water from gas streams. TEG absorbs water, thus removing it from the process. On the NFPA diamond, TEG has a Health of 1, flammability of 0 and a reactivity of 0.

Caustic Soda (Sodium Hydroxide, NaOH) is a strong alkali agent that is very soluble in water. It isn't considered flammable or explosive, but can have strong reactions with acidic compounds. On the NFPA diamond, Sodium Hydroxide has a Health of 3, flammability of 0, and a reactivity of 1 in addition to being listed as an Alkali agent. The site currently utilizes large volumes of caustic and has done so for years.

Compound	Volatility	Flammability	Explosivity
MEA	Vapor pressure: 0.5 hPa at 20 °C	Product is combustible at high temperatures	Lower explosion limit: 3.4 %(V) at 88.3 °C Upper explosion limit: 27.0 %(V) at 133.8 °C
TEG	Vapor pressure: <0.01 mmHg at 20°C	Flammability: 1	Lower explosion limit: 0.9 Upper explosion limit: 9.2
Caustic Soda (Sodium Hydroxide)	Vapor pressure: No data available	Flammability: 0	No data available

5.0 Compliance and Regulatory Implications of the Proposed CCS Technology

Proposal Instructions
The compliance and regulatory implications of the proposed CCS technology shall be addressed with reference to applicable U.S. EH&S laws and associated standards including the Comprehensive Environmental Response and Liability Act of 1980 (CERCLA), Toxic Substances Control Act (TSCA), Clean Water Act (CWA), Clean Air Act (CAA), Superfund Amendments and Reauthorization Act (SARA) Title III, and the Occupational Safety and Health Act (OSHA).

Comprehensive Environmental Response and Liability Act of 1980 (CERCLA), Toxic Substances Control Act (TSCA), & Superfund Amendments and Reauthorization Act (SARA) Title III

CERCLA and SARA are primarily related to management and mitigation of uncontrolled contaminated sites with no apparent owner. Such is not the case for the P66 Rodeo refinery and there is no regulatory requirement for this project under these laws. Similarly, TSCA relates to producers of potentially hazardous products – that is not the case with this project either and TSCA has no regulatory requirements on it.

Clean Water Act (CWA)

The Clean Water Act (CWA) regulates discharges of pollutants into the waters of the United States and quality standards for surface waters. The facility currently operates under an NPDES permit and will seek the necessary amendments to that permit for this project. Relevant streams include (1) SMR flue gas condensate from cooling prior to the absorption column and (2) blowdown from the cooling tower. These streams will be treated on-site prior to discharge in accordance with the permit.

Clean Air Act (CAA)

The Clean Air Act (CAA) regulates air emissions from stationary sources such as this project. The facility currently operates under an air permit and will seek the necessary amendments to that permit for this project. Relevant sources include (1) the treated SMR flue gas, (2) process vents on the glycol unit, and (3) drift from the cooling tower. These sources will be operated in compliance with the facility's air permit.

Occupational Safety and Health Act (OSHA)

OSHA regulates health and safety in the workplace. The facility will continue to follow all applicable OSHA standards. Worker exposure to process chemicals will be minimized through engineering and administrative controls and worker PPE.

California Environmental Quality Act (CEQA)

The California Environmental Quality Act (CEQA) requires government agencies to consider the environmental consequences of their actions before approving plans and policies or committing to a course of action on a project. The project will have to be evaluated for whether it fits under a statutory or categorical exemption, and if not, will have to prepare an initial study into the potential environmental impacts. Depending on the results of the initial study, either a negative declaration or an Environmental Impact Report (EIR) will have to be prepared.6.0 Engineering Analysis

Proposal Instructions
An engineering analysis shall be conducted for any potentially hazardous materials identified to look for ways their use can be eliminated or minimized. Less hazardous materials should be substituted where possible. For any new materials being proposed, synthetic options shall be examined that may lead to similar, less-hazardous compounds with the required functionality. Possible engineering controls and other mitigation strategies shall be described as appropriate.

Commercially available amine-based CO_2 capture processes can typically remove greater than 90% of the CO_2 from the flue gas stream in cogeneration units. Shell *Cansolv*, Fluor *Econamine* and MHI *KM CDR* process ™ has commercial scale experience. Emerging capture processes such as UOP Advanced Solvent for Carbon Capture (*ASCC*) and Entropy Inc. Entropy23™ solvent have been/are completing pilot test and seeking the first commercial application. Of these, MHI and Shell have built large scale CO_2 capture units using flue gas from coal fired boilers, both MHI and Fluor have built smaller natural gas-based units using fired heater flue gas and Fluor has built a (small) commercial unit using NGCC flue gas. All mentioned processes can capture 90% (in some cases more than 90%) of the CO_2 from low concentration flue gas. The carbon capture process selected for this application is MHI's Advanced Kansai Mitsubishi Carbon Dioxide Recovery Process (KM CDR Process™) utilizing the new KS-21™ solvent. This CO_2 capture system will recover over 95% of the CO_2 from the low concentration flue gas resulting in a purified CO_2 stream with +99% CO_2 purity.

The process is similar at a high level to other amine-based carbon capture processes, by means of introducing flue gas to the solvent in the absorber. The solvent absorbs the CO_2, and the clean flue gas exits the top of the absorber. The CO_2 is then removed from the solvent in the regenerator through steam stripping. Lower volatility, lower energy requirement for regeneration, and greater stability against degradation are amongst the key features differentiating this solvent from other amine-based solvents. Many advantages set MHI's Advanced KM CDR Process™ apart from other amine-based post combustion technologies including the following:

- High-performing amine solvent – MHI's KS-21™ solvent offers several advantages over conventional processes, including low steam consumption for regeneration, high CO_2 capacity, low solvent degradation, and low solvent consumption.
- Solvent performance – The KS-21™'s performance was tested at Technology Test Center (TCM) in Norway from flue gas emitted by a gas turbine at TCM's test facility. The results confirmed a carbon capture rate of 95-98%, which is above the current industry standard (approximately 90%). This testing demonstrates that 99.8% capture from fossil fuel-based power generation is achievable. The results indicate 'outstanding' energy-saving performance and low amine emissions, which exceed both the benchmark amine-based solvent, Monoethanolamine (MEA), used in the chemical absorption process and MHI's own existing solvent, KS-1™. While the heat of absorption is about 85% that of KS-1™ and the overall steam consumption will be slightly less than KS-1™.

Parameters Relative to Conventional	KS-1™ (%)	KS-21™ (%)
Volatility	100	50 – 60
Thermal Degradation Rate	100	30 – 50
Oxidation Rate	100	70
Heat of Adsorption	100	85

Exhibit 1: Solvent Performance Comparison. *MHI's KS-21™ solvent offers several advantages over conventional processes.*

- Amine purification system – Impurities introduced from the flue gas can degrade CO_2 capture performance. MHI has successfully demonstrated a reclaiming process to prevent accumulation of unwanted impurities.

7.0 SAFE HANDLING AND SAFE STORAGE

Proposal Instructions
Precautions for safe handling and conditions for safe storage shall be identified, including any incompatibilities with other materials that may be used in the process. Waste treatment and offsite disposal options shall be examined. Accidental release measures shall also be discussed.

The proposed CO_2 recovery plant will be located within an active refinery that is under a complex system of permits and regulatory inspection requirements. Chemicals related to the existing site operations, as well as the proposed CO_2 Plant, will be stored and handled in a safe manner following federal, state, and local regulations, as well as generally accepted industry practices.

As the project's footprint is within an active refinery, these practices are well understood by the work force and the environmental management team supporting the plant. Safe handling and storage of chemicals is a day-to-day priority and critical to the overall safe operation of the facility. Examples of on-going safe chemical practices include separation of incompatible materials, curbed areas around pumps and storage tanks, proper labeling and recordkeeping, routine inspections of chemical storage areas as well as waste storage areas.

Any potentially incompatible chemicals and/or materials shall be identified during the FEED Study. Risk of chemical releases are mitigated by a variety of measures, including Spill Prevention, Control, and Countermeasure (SPCC) plans, Emergency Response Plans, and Hurricane Management Plans that are used to prepare the facility for potential upset conditions that may affect operations. These plans along with other similar plans are designed to minimize and respond to accidental release measures.

Any new waste streams generated by this process unit will be characterized and profiled to ensure that proper waste management practices are followed and that appropriate offsite disposal options are evaluated and selected. The Site is currently a generator of hazardous waste and is regulated under RCRA. No treatment of hazardous waste occurs on-site.

APPENDIX A – BLOCK FLOW DIAGRAM