Enchant Energy
San Juan Generating Station – Units 1 & 4

CO_2 Capture Pre-Feasibility Study

FINAL

Revision 0

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Prepared by

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Executive Summary

The San Juan Generating Station (SJGS) facility is an 847 MW coal-fired power plant located in northwest New Mexico that has been identified as a candidate for retrofitting carbon capture utilization and sequestration (CCUS) technology. The SJGS has two operating coal-fired utility boilers, Unit 1 and Unit 4, and two recently retired units, Units 2 and 3; the retired units have been left in place with much of the auxiliary equipment mothballed.

This pre-feasibility study is being conducted to evaluate the technical feasibility and cost of a CCUS retrofit project based on amine-based CO_2 capture technology at SJGS, considering the current federal and state regulatory requirements. The current study represents expected utility requirements and capital costs that correspond to the current advancement of the amine-based technology and rely on information published by both Mitsubishi Heavy Industries (MHI) and Shell on their recent installations and developments. Specifically, this study builds on the information provided from recent experience and installations of both MHI and Shell at Petra Nova and Boundary Dam, respectively.

Furthermore, this study considers the cost savings associated with using existing infrastructure from the recently retired Units 2 and 3 at SJGS to supply the CO_2 capture utility requirements. Using the existing auxiliary systems lowers the project capital costs and reduces the overall cost of capture, making this facility an attractive candidate for CCUS.

Even while including the cost of construction for the CO_2 pipeline connection from power plant to the nearby interstate Cortes CO_2 pipeline, the cost to implement CO_2 capture at SJGS is estimated to be $39-43/tonne, as shown in Table ES-1. These costs are in line with the U.S. Department of Energy's (DOE) long-term goal of $40/tonne, which does not include the capital cost of the new pipeline.

Table ES-1: Cost of CO_2 Capture

Description	**Units**	**85% Capacity Factor**	**100% Capacity Factor**
Total Project Cost	$	1,295,280,000	1,295,280,000
CCF		0.1243	0.1243
Annualized Capital Cost	$/yr	161,000,000	161,000,000
Annual O&M Cost	$/yr	99,939,000	115,389,000
Total Annual Cost	$/yr	260,939,000	276,389,000
CO_2 Captured	mmscfd	313	368
Annual CO_2 Captured	tonnes/yr	6,000,000	7,060,000
Cost of Capture	**$/tonne[1]**	**43.49**	**39.15**

Note 1. Cost of capture reported as dollars per metric ton (equivalent to 2,240 lbs).

In addition to the lower cost to implement CO_2 capture at SJGS, the facility is located nearby to a CO_2 pipeline. This will require minimal pipeline costs in comparison with many coal-fired facilities as well as a market opportunity for sale of the produced compressed CO_2.

As part of the next steps of this project, it is recommended that a more in-depth front-end engineering and design (FEED) study be conducted to advance the project definition, engage the technology providers to provide site-specific performance data, and develop a detailed cost estimate. During the future phases, it is recommended that the CO_2 capture system be competitively bid to obtain site-specific performance and design information, and competitive pricing for the subcontracted CO_2 capture system cost. CO_2 technology original equipment manufacturers (OEMs) have indicated that overall capital costs of the facilities have reduced in the last 10 years, due to modularization and optimization of the process. Depending on the advances made over the last 3-5 years, it is expected that OEMs will be able to provide optimized auxiliary power and steam requirements. As such, the overall plant derate may also be optimized and reduced in future applications of this technology.

If the FEED study demonstrates the viability of the project, it could become the first large-scale CCUS retrofit of a coal-fired power plant that has the potential to reduce 6,000,000 tonnes CO_2/year.

1 Introduction

1.1 Project Background

The San Juan Generating Station (SJGS) facility is a nominal 847 MW-net coal-fired power plant located in northwest New Mexico approximately 15 miles northwest of the City of Farmington ("Farmington"). The power plant has been identified as a candidate for retrofitting carbon capture utilization and sequestration (CCUS) technology. SJGS currently has two operating coal-fired utility boilers, Unit 1 and Unit 4, and two recently retired units, Units 2 and 3. The retired units have been left in place with much of the auxiliary equipment mothballed.

SJGS Units 1 and 4 fires western bituminous coal supplied by the adjacent mine, San Juan Coal Company, owned by Westmoreland Holdings. The current coal supply contract expires in June 30, 2022; however, San Juan Coal Company has offered SJGS a new contract for 3.2 million tons of coal per year for the years 2022 through 2033. Recently passed state legislation, (the New Mexico Energy Transition Act) requires the environmental improvement board, or local board, to adopt regulations limiting carbon dioxide (CO_2) emissions from coal-fired electric generating facilities with an originally installed capacity exceeding 300 MW to no more than 1,100 pounds CO_2 per megawatt-hour (lb/MWh) by January 1, 2023. Installation of CCUS technology on existing coal-fired generating facilities will likely be required to comply with this regulation. The majority shareholder of the facility, Public Service of New Mexico (PNM), has announced they will not renew the coal contract in 2022 and intend to retire the power plant.

SJGS is currently owned by a group of public utilities, investor owned utilities, and municipal power entities pursuant to the Amended San Juan Participation Agreement (ASJPA). Farmington is currently a 5.076% part-owner of the facility and has the right under the ASJPA to acquire interests held by all the other owners effective at the termination of the existing coal contract on June 30, 2022. Enchant Energy LLC ("Enchant") has entered into an Agency Agreement with Farmington to develop and manage the CCUS retrofit process and Enchant intends to acquire ownership of SJGS with the exception of Farmington's current plant ownership interest on June 30, 2022 through the assignment by Farmington to Enchant of Farmington's acquisition rights under the ASJPA. Enchant and Farmington expect to execute this assignment agreement in July 2019 after the conclusion of this pre-feasibility study.

This pre-feasibility study is being conducted to evaluate the technical feasibility and the cost of a CCUS retrofit project at SJGS taking into consideration current federal and state regulatory requirements.

As part of the next steps of this project, it is recommended that a more in-depth FEED study be conducted to advance the project definition, engage the technology providers to provide site-specific performance data, and develop a detailed cost estimate. If the FEED study demonstrates the viability of the project, it could become the first large-scale CCUS retrofit of a coal-fired power plant that has the potential to reduce 6,000,000 tonnes CO_2/year.

1.2 Sargent & Lundy Experience

S&L is an industry leader in CO_2 capture FEED studies and implementation. S&L has been conducting studies and performing detailed balance-of-plant (BOP) engineering and technical evaluations for carbon capture projects since 2007. S&L has completed several FEED studies for these and other clients in which S&L prepared the preliminary system engineering, project layout, cost estimating, and preliminary design. S&L has extensive experience conducting technical evaluations for CO_2 capture projects, as well as performing several FEED studies for clients including preliminary engineering, project layout, conceptual design, and cost estimates. The most notable project was the Petra Nova Carbon Capture Project.

S&L worked on the CCUS development and implementation for NRG and Petra Nova from 2011 to 2017. Notably, that project among other things included: owner's Engineer during development and design phase of the project, including design reviews and HAZOP; a detailed design of the ductwork system for the 240 MWe slipstream (646,500 scfm) of flue gas; and an evaluation of MHI's amine-based process which produced 1.6 million tons of CO_2 per year (4776 tons/day).

Beginning in 2018, S&L has been supporting the development of a commercial carbon capture design and costing study for the Nebraska Public Power District and the DOE. S&L's role includes performing studies, BOP and engineering and design, constructability review and cost estimating.

2 CO_2 Capture Technology

Several CCUS technologies are been developed to capture and utilize CO_2 from combustion sources, including coal-fired power plants. However, given the timeframe to achieve compliance with current New Mexico emission standards requirements, the retrofit of SJGS with CCUS technology must be based on commercially available capture technology for coal-fired power plants the size of SJGS. Based on the current status of capture technology development, amine-based CO_2 capture is the only commercial technology available at this scale. Amine-based absorption technologies have been demonstrated as technically feasible and amine-based technologies have been permanently installed at both the Petra Nova and Boundary Dam facilities. Petra Nova has been operating with CCUS technology since January of 2017 and Boundary Dam since the fall of 2014, both capturing 90% of CO_2 emissions.

As such, this pre-feasibility study will be conducted based on implementing a typical amine-based system capable of treating flue gas from SJGS Units 1 and 4. Suppliers of these systems are MHI, Shell, and Fluor. Amine-based capture, systems offered by all these vendors include the same general equipment/components, designed based on the use of their own proprietary solvent. This pre-feasibility study is not based on detailed engineering; thus, design considerations and costs included in this report are representative of the use of any of these vendors; and any of these three systems would be integrated in a similar approach.

2.1 Process Description

In general, amine-based CO_2 capture system consists of a quencher (or pre-scrubber), an absorber, and a stripper. Compression and dehydration are also included to produce CO_2 at pipeline requirements. In addition, the flue gas will require a booster induced draft (ID) fan to overcome the pressure loss through the CO_2 capture system. A high-level block diagram of the system is shown in Figure 2-1.

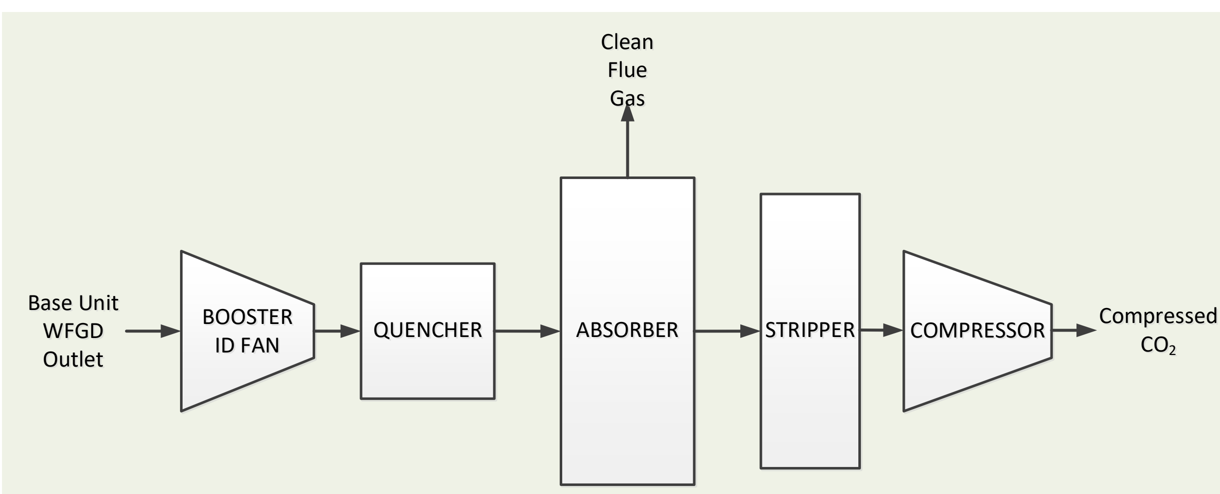


Figure 2-1: CO_2 Capture Block Diagram

Amine solvents are sensitive to impurities and will react with sulfur dioxide (SO_2) and sulfur trioxide (SO_3) molecules present in the flue gas. These reactions contaminate the solvent by forming intermediate salts, which in turn leads to higher solvent regeneration requirements and increased operational costs. SO_2 concentrations of 10 ppm or less are generally required for effective CO_2 capture. While SJGS Units 1 and 4 are equipped with recently upgraded limestone forced oxidation wet flue gas desulfurization (WFGD) systems for SO_2 control, the existing WFGDs do not provide the SO_2 and SO_3 removal efficiency required for an amine-based system. As such, additional SO_2 and SO_3 removal is required for more efficient operation of the CO_2 capture system.

2.1.1 Quencher and Pre-Scrubber

Additional SO_2 and SO_3 removal can be achieved using a caustic solution to pre-scrub the flue gas upstream of the absorber. The pre-scrubber is integrated with the quencher, which is designed to reduce flue gas temperatures to optimize CO_2 capture kinetics and efficiency in the absorber. Residual particulates, water, sulfates, and other soluble components removed from the flue gas in the quencher will build-up in the cooling contact water as it is recycled. In addition, a large volume of water will be collected in the quencher as it is condensed from the saturated flue gas. To maintain the liquid recirculation rate and limit the buildup of impurities in the recirculating solution, a blowdown stream is required to reduce the concentration of contaminants and overall liquid volume. The blowdown stream will be sent to the cooling tower as makeup water.

2.1.2 Absorber

Cooled flue gas from the quencher passes through a counter-current packed absorber column, where the amine-solvent absorbs CO_2 present in the flue gas. Several levels of packing, spray zones, and trays facilitate the required liquid-to-gas contact to ensure a high level of CO_2 absorption by the solvent Properly designed absorber columns can achieve CO_2 capture efficiencies of 90% or more. A water wash is located at the top of the absorber to remove any entrained solvent in the flue gas. The clean gas exits the absorber and is exhausted through a new stack located on top of the absorber.

2.1.3 Stripper

The CO_2–rich solvent from the absorber enters the top of a stripper column, where CO_2 is desorbed from the amine-solvent through the addition of heat to break the bond between the amine-solvent and the dissolved CO_2. The reboiler at the base of the stripper utilizes low quality steam as the source of energy to vaporize water in the dilute solvent. The hot-lean (or regenerated) solvent which is free of CO_2 is returned to the absorber.

2.1.4 Compressor

A mixture of CO_2 and steam exits the top of the stripper and is sent to the compressor system, which both dehydrates and compresses the CO_2 stream. The compressor is designed to pressurize the CO_2 product stream to pipeline quality. As part of this process, additional moisture is removed to provide a CO_2 stream with $\geq$ 99% purity at around 2,215 psia. Moisture removed from the dehydration system and during the compression process is collected and sent back to the stripper.

2.1.5 SJGS Arrangement

Figure 2-2 shows a simplified process flow diagram (PFD) of the CO_2 capture system for SJGS. Based on a preliminary review of flue gas flow rates, it is expected that the CO_2 capture system would consist of 2x50% trains, which would be sized to treat the entire flue gas volume of SJGS Units 1 and 4.

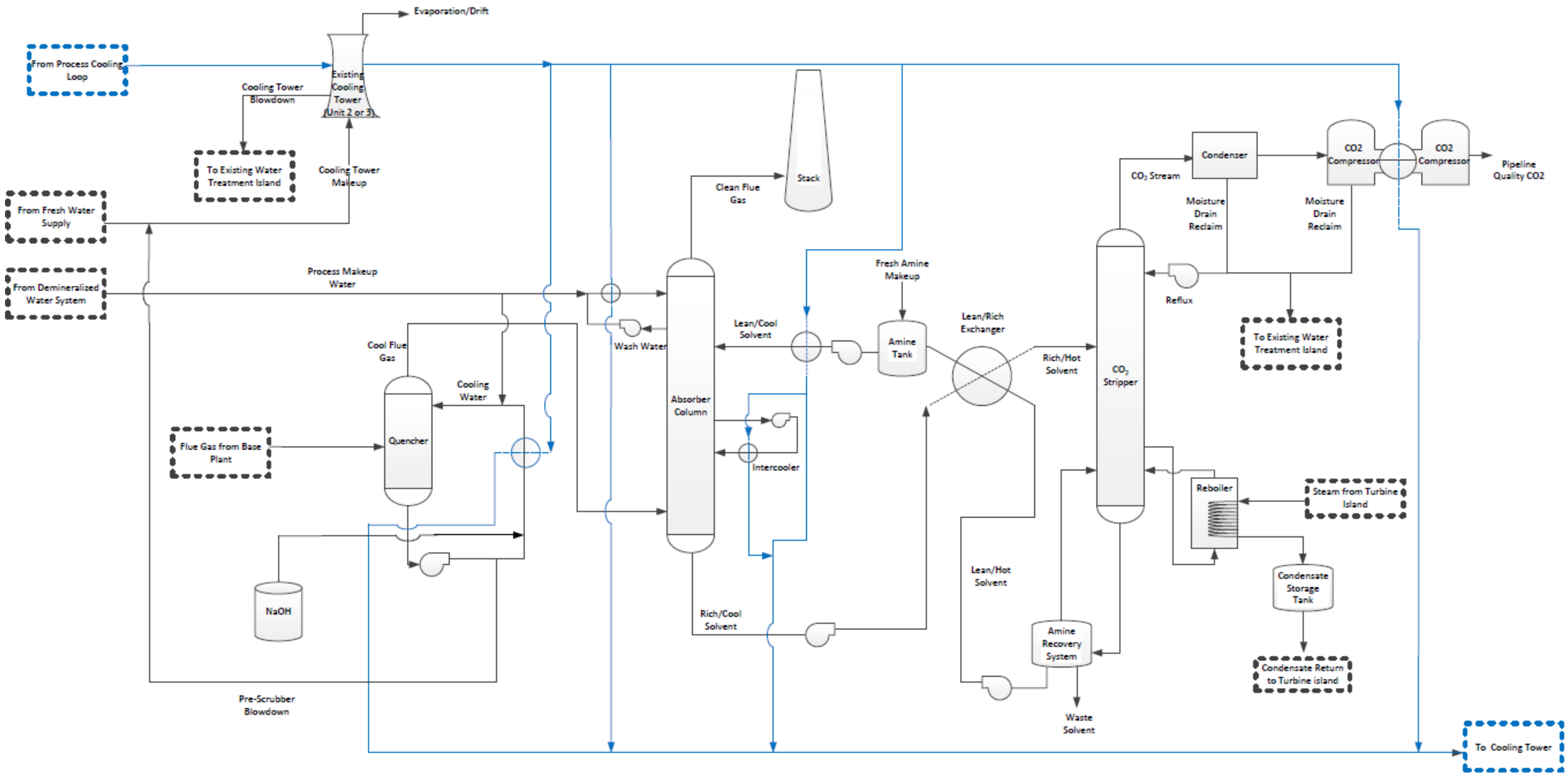


Figure 2-2: Commercial Amine Based Process Flow Diagram – 1x50% Train

2.2 Integration with SJGS Units 1 and 4

A PFD of the CO_2 capture system was developed and is included in Appendix B. Figure 2-3 highlights the tie-in locations to the CO_2 capture facility boundary limits. A visual representation of the proposed plant layout is provided in Appendix D.

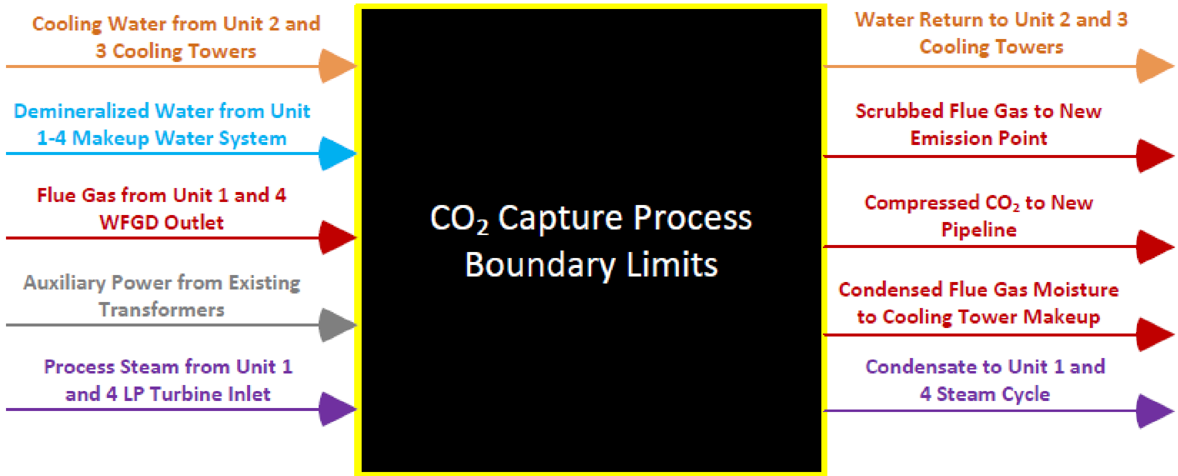


Figure 2-3: Integration Block Flow Diagram

Circulating cooling water to and from the CO_2 capture facility will be cooled via cooling towers in the Units 2 and 3 areas and will require new underground piping The Unit 3 cooling tower has remained intact, and will be repurposed for this service, with some repair work expected. The Unit 2 cooling tower has been demolished, leaving the infrastructure such as the piping and foundation in place. A new cooling tower will be constructed in place of the old Unit 2 tower. It is assumed that due to the proximity to the Unit 3 cooling tower, new circulating water pumps would not be needed. However, for integration with the new cooling tower in the Unit 2 area, the existing pumps will be replaced to overcome the additional distance and pressure drop of the system. A new piperack will be installed from the Unit 1-4 boiler buildings to the CO_2 capture facility; the pipe rack will include demineralized water for makeup to the wash water and process steam from Unit 1 and 4 steam turbines.

New ductwork to the San Juan CO_2 capture facility would be tied into Units 1 and 4, downstream of the existing WFGD systems, prior to the stack breaching. Two new booster ID fans will be located in the CO_2 capture facility to overcome the pressure drop associated with the new equipment. Flue gas would be routed from the tie-in to the CO_2 capture facility via elevated ductwork. The ductwork would combine with the piperack from the boiler building and the duct bank or cable tray from the existing auxiliary power transformers; this would become the utility rack once combined and would enter the CO_2 capture facility from the southwest corner.

Scrubbed flue gas would exit the absorber vessel through a new stack located on top of the absorber.

Energy for the stripper would be provided by low quality steam, from the units' existing steam cycle. Low quality steam would be extracted from the crossover between the intermediate (IP) and low pressure (LP) sections of the steam turbines. After the steam condenses in the stripper reboiler, the associated condensate would be pumped back to the base plant's condensate system.

For this evaluation S&L assumed that the CO_2 capture facility would be designed with two parallel 460 MW-equivalent (MWe) trains in a 2x50% configuration for the facility. Two trains allow more flexibility at more optimal performance. A single large train of 915 MWe could be installed but is not preferred due to turndown capabilities associated with feeding this equipment from multiple units. Unit 4 is the larger of the two units, at 544 MW-gross train, and should it be offline, the turndown through the CO_2 capture facility would fall below the 50% typical turndown rate.

San Juan recently retired two of four units, leaving auxiliary equipment that could be utilized for the new CO_2 capture facility. For example, as previously discussed, the cooling water demand for each CO_2 capture train is expected to be similar to the original circulating water rate for the retired units (Units 2 & 3). Therefore, the existing Unit 3 cooling tower could be repurposed, to provide cooling for the CO_2 system. Unit 2 cooling tower has since been demolished, leaving the foundation. A new tower will be built in its place, sized for the original water demands. Through such repurposing, the cost for new cooling towers to provide cooling to the CO_2 capture facility is reduced through reuse of the existing equipment and infrastructure.

Cooling towers consume significant quantities of water; however, the makeup water does not require high quality. The retirement of Units 2 and 3 is expected to provide sufficient margin in the makeup water capacity to the facility. To minimize the amount of makeup water required for the cooling tower, water generated in the process could be used as makeup to the maximum extent possible.

Cooling tower blowdown would be treated in the existing wastewater treatment system, which is sized to treat cooling tower blowdown from all four units. Since the circulating water streams are expected to operate at similar temperatures at the inlet to the cooling towers and are approximately the same flow rates, it is expected that the blowdown rates would be similar enough to be accommodated by the existing system with Units 2 and 3 offline.

A small quantity of high-quality process water would be required for operation of the CO_2 equipment for solvent regeneration or absorber water balance purposes. The water would be sourced from the plant's existing demineralized water makeup system. Based on the fact that SJGS was designed to operate with four units and now only runs two units, it is expected that there is sufficient margin in the demineralizer system to accommodate the CO_2 capture facility.

The CO_2 capture and balance of plant (BOP) systems include a significant number of pumps, compressors, fans, and other components which would result in significant auxiliary power consumption. The primary power consumer is the compressor, which pressurizes the CO_2 stream to the required pipeline pressure. For the purposes of this study, it is assumed that power would be supplied by the existing facility's auxiliary power system from the Units 2 and 3, which are no longer in operation and an additional new auxiliary power transformer.

There is additional integration with the facility based on disposal or treatment of wastes generated by the degradation products of the amine-based solvent. As part of amine solvent-based systems, the degraded solvent will be filtered out occasionally and disposed of separately off-site.

3 Project Design Basis

3.1 Flue Gas Conditions

Table 3-1 summarizes the major inputs and assumptions used as the basis for the design of the SJGS CO_2 capture system. These inputs were based on publicly available information. Assumptions based on typical industry standards and engineering judgment were also used, where appropriate.

Table 3-1: Flue Gas Properties

Stream Characteristics		Existing FGD Outlet Unit 1		Existing FGD Outlet Unit 4	
Temperature	°F	129		129	
Pressure	psia	12.241		12.241	
N_2	lb/hr-vol%	2,784,625	68.17	4,502,289	68.38
O_2	lb/hr-vol%	177,619	3.80	349,124	4.64
H_2O	lb/hr-vol%	415,475	15.82	654,005	15.45
CO_2	lb/hr-vol%	781,916	12.18	1,190,946	11.51
SO_2	lb/hr-ppmv	147.06	15.8	313.83	20.9
SO_3	lb/hr-ppmv	12.72	1.1	19.37	1.0
NOx	lb/hr-ppmv	843.47	125.7	1,244.11	115.0
NH_3	lb/hr-ppmv	24.84	10.0	40.05	10.0
Hg	lb/TBtu	1.20		1.20	
Total Flow	lb/hr-acfm	4,160,664	1,254,165	6,697,983	2,021,601
MW - Moist.	g/mol-lb/lb	28.52	0.111	28.48	0.108

3.2 Utility Usage Rates

Table 3-2 summarizes the expected SJGS CO_2 capture facility requirements and estimated utility consumption for each unit and the total plant. This information is based on S&L's experience with the commercial amine-based processes. The values used below are a ratio or factored from past studies. Project specific values will be calculated and validated with a selected OEM during the FEED study or detailed design.

Table 3-2: CO_2 Capture Facility Requirements and CO_2 Quality

CCS Data for SJGS	Unit 1	Unit 4	Total Plant	Source
Existing Plant Data				
Plant Gross Output, (MW_{gross})	370	544	914	Farmington
Total Plant Heat Input, (mmBtu/hr)	3,667	5,409	9,076	2017 IRP[1]
Existing Aux Power, (MW)	30	37	67	Farmington
Existing Net Power, (MW_{net})	340	507	847	Calculation
Existing Heat Rate, (Btu/kW_{net}, HHV)	10,786	10,669	10,716	2017 IRP[1]
Stack SO_2, (lb/MMBtu)	0.039	0.054	0.048	CAMD[2,3]
Stack CO_2, vol %	12.2	11.5	12	Calculation
CCS Requirements				
Demineralized Water, (gpm)	23	64	87	Internal Database
Steam to CO_2 System, (lb/hr)	816,000	1,262,000	2,078,000	Internal Database
Steam Extracted for IP/LP, (lb/hr)	705,840	1,091,630	1,797,470	Estimated
LP Steam to CO_2 System, %	36	37	36	Calculation
Additional Cooling Water Flow for CO_2, (gpm)	131,000	200,000	331,000	Internal Database
Plant Derating due to Extraction, (MW)	48	74	122	Estimated
Plant Gross Power Derating, %	13	14	13	Calculation
Revised Gross Output, (MW_{gross})	322	470	792	Calculation
Total Aux Load for CCS Plant, (MW)	49	75	124	Internal Database
Total Aux Load for CCS Plant, %	13	14	14	Calculation
Net Change w/ CCS				
Total New Net Power, (MW)	243	358	601	Calculation
Total Plant Power Net Reduction, %	29	29	29	Calculation

Note 1. Extracted from PNM 2017-2036 Integrated Resource Plan (IRP). July 3, 2017.
Note 2. Data from Air Markets Program Database (AMPD) 12/1/2017 to 3/31/2019.
Note 3. An average of all the SO_2 data points from the top 10% of the full load.

3.3 CO_2 Production

The CO_2 rates for SJGS are provided in Table 3-3. Based on the information provided, controlled CO_2 emissions from SJGS are approximately 249 lb/MWh-gross on a weighted average basis assuming for 90% capture.

Table 3-3: CO_2 Rates for San Juan Generating Station

SJGS CO_2 Rates		Unit 1	Unit 4	Total Plant
Baseline Plant CO_2 Emissions Rate[1]	(lb/MWh_{gross})	2,165	2,236	2,201
Post-Project CO_2 Emission Rate	(lb/MWh_{gross})	243	254	249
Max Full Load Post-Project CO_2 Capture Rate	(lb/hr)	703,724	1,071,852	1,775,576
Post-Project CO_2 Capture Rate[2]	(mmscfd)	124	189	313
	(mmscfy)	45,200	68,845	114,045

Note 1. Data from the United States Environmental Protection Agency's (EPA) Air Market Program Database (AMPD) - Annual average for 2014-2018 – Total plant is estimated based on the average of Units 1 and 4.
Note 2. Values calculated assuming an annual average facility capacity factor of 85%.

4 Project Considerations

4.1 Permitting Considerations

4.1.1 State CO_2 Requirements

New Mexico recently enacted Energy Transition Act (ETA, SB 489) requires electric generating facilities in the state with an originally installed capacity exceeding 300 MW, to comply with a CO_2 emissions standard requiring emission of under 1,100 lb/MWh by January 1, 2023. Installation of CCUS at SJGS will decrease CO_2 emissions by ≥ 90%, or approximately 6 million tons per year. More specifically, CCUS installation at SJGS would limit CO_2 emissions to 243 lb/MWh-gross and 254 lb/MWh-gross for Units 1 and 4 respectively, which is 77% below the emissions standard required by the Energy Transition Act.

There is an expected 30 to 36 month period of construction required for a project of this magnitude.

4.1.2 Water Rights

Currently, SJGS has excess infrastructure capable of handling up to 30,000 acre-feet/annum (AFA) and permits to consume up to 19,000 AFA. The operating Units 1 and 4 utilize 12,000 AFA, leaving excess capacity to process 18,000 AFA and excess water consumption rights of 7,000 AFA. The project requires an increase in the makeup water demand to the cooling towers above the current Units 1 and 4 demands. However, the blowdown flow can be treated with the existing waste water treatment system, which currently recycles up to 98% of Units 1 and 4 blowdown water. A similar water recycle/reuse rate is expected from the new blowdown stream. The net result of this will be to minimize the net fresh water makeup to only 6,000 AFA. Therefore, additional water handling facilities or water consumption rights are not expected to be needed.

4.1.3 Air Emissions

SJGS is subject to federal and state regulations on emissions. As a result of the environmental upgrade completed in 2017, the plant is currently fully compliant with all limits required under a 2013 settlement agreement with the New Mexico Environmental Department and the EPA. SJGS had selective non-catalytic reduction (SNCR) technology installed for NOx control on Units 1 and 4. The SNCR was determined to be the Best Available Retrofit Technology (BART) at the time of the settlement agreement. The installation of SNCR on the SJGS brought the plant into compliance with Section 113(g) of the Clean Air Act.

The settlement agreement also resulted in a lower SO_2 permitted emission rate for Units 1 and 4 and the retirement of Units 2 and 3 by the end of 2017. The settlement agreement does not have an expiration or renewal date.

SJGS will continue to be compliant with the terms of the 2013 settlement agreement. Installation of CCUS will not increase emissions of any controlled pollutants and, in addition to CO_2 reductions, will likely reduce facility emissions of particulate, SO_2, NOx, ammonia and mercury.

4.2 Plant Derate and Additional Auxiliary Power Demand

There are two parameters that will reduce the base facility's net power output: steam extraction and auxiliary power usage. The steam extraction from the IP/LP cross-over reduces the overall gross capacity of the turbine by removing the steam prior to passing through the LP turbine. For the purposes of this pre-feasibility study, steam demand and corresponding plant derate was estimated based on the current technology requirements and similar units. Based on the estimated steam consumption it is predicted that the gross output is derated by approximately 48 MWe on Unit 1 and 74 MWe on Unit 4.

The CO_2 capture facility also uses power to operate the mechanical equipment required to compress the CO_2. This power need is expected to be provided by the station's existing auxiliary power transformers and an additional auxiliary power transformer. This power usage requirement will reduce the net power that can be provided to the grid. Auxiliary power demands were factored from publicly available information for the current technology requirements. Based on the sizes of the facility, the total net output of the generating unit for each case is provided in Table 4-1.

Table 4-1: Plant Net Output with CO_2 Capture

	Unit 1	Unit 4	Total
Gross Boiler Size/Steam Generation	**370**	**544**	**914**
Base Plant Auxiliary Power	30	37	67
Baseline Net Boiler Output	**340**	**507**	**847**
Process Steam Equivalent Power Derate	48	74	122
CO_2 Facility Process Auxiliary Power	49	75	124
Net Power Output (MW)	**243**	**358**	**601**

During the FEED Study or detailed design, the steam consumption and power consumption will be solicited from the selected OEM, and heat balances will be developed to calculate the plant derate.

Typically, a CO_2 capture project can be adversely affected by the amounts of steam and power consumption required for the carbon capture operations resulting in lost revenues and profit. For SJGS, the overall net power output is estimated to be reduced by 246 MW due to the retrofit at 100% capacity utilization. Since SJGS will operate as a merchant plant after retrofit, the economic impact of the lost output due to auxiliary load and steam usage has been estimated at the expected cost of generation including fuel cost.

The new net power output after CCUS technology is installed will be approximately 600 MW. Currently, there is a significant amount of time in which the facility has been historically dispatched at or below 600 MWn. If this load demand were to stay the same, the SJGS would be able to operate at or near 100% boiler capacity, resulting in the maximum CO_2 production rate. It is therefore reasonable for a facility such as SJGS to evaluate the cost of the unit derate based on the cost of additional fuel and operating costs to provide the steam and auxiliary power required for CO_2 capture, rather than based exclusively or predominantly on the cost of lost generation.

4.3 CO_2 Market Opportunities

There is an opportunity for CO_2 to be sold for enhanced oil recovery (EOR) in the SJGS area. The facility is located within relatively close proximity to the Cortez compressed CO_2 pipeline, owned by Kinder-Morgan, which supplies CO_2 to the Permian Basin oil fields in southeast New Mexico and West Texas. The proximity of SJGS to the pipeline would require an additional connecting branch line of approximately 20 miles in length.[1] This proximity provides SJGS with CO_2 market opportunities, as the Permian Basin is one of the largest users of CO_2 for EOR in the world. In addition, the oil fields in the Permian Basin are also connected to EPA-certified sites for permanent storage of the captured CO_2.

For these reasons, SJGS can capture and compress CO_2 for EOR and permanent storage. The market for CO_2 can provide the facility $15-20/tonne in revenue for the sale of the compressed and purified CO_2. In combination with the U.S. EPA's 45Q tax credits, this provides SJGS the opportunity to continue operation of the facility with 90% CO_2 reduction, without a significant financial burden as is typical with most pollution control equipment.

4.4 Conceptual Site Arrangement

The major process equipment and BOP systems needed for a complete CO_2 capture facility require a significant footprint, on the order of 800'x750'. The San Juan property includes a relatively large open area directly north of the station.

Due to the retirement of two units, it is estimated that the entire CO_2 capture facility could be installed in an area of unused property to the north of the Unit 3 cooling tower. The location of the project on the north end of the facility provides a good location for routing the CO_2 pipeline, since the tie-in to the Cortez pipeline will likely be to the northeast of the SJGS facility.

Integrating the CO_2 capture facility in this location will provide close proximity to the process steam from the boiler building to the south and existing waste water treatment facility to the east of the proposed location. Furthermore, the proposed location will be directly adjacent to the Unit 3 cooling tower that will provide a significant source of the cooling demand for the facility. There are some drawbacks to the proposed location, with flue gas routing being the main concern. The flue gas tie-in would be located downstream of the existing WFGD systems and would need to be routed approximately 3,000 feet to the CO_2 capture facility. This will incur a significant cost for ductwork and support steel that will be offset by a relatively minor benefit of needing slightly less cooling water in the quencher due to thermal loss over the length of ductwork.

[1] The Petra Nova project built near Houston, Texas, required approximately 80 miles of pipeline to be built to connect the project to an EOR field.

The arrangement also will require newly routed underground circulating water pipes from the Unit 2 cooling tower area located south of the boiler building. The piping would be installed directly below power lines and will have to be routed with care to avoid existing underground circulating water piping.

A proposed plant integration layout is included in Appendix C.

5 Cost Estimate

5.1 Major Cost Inputs & Assumptions

The previous sections describe the design considerations that were made in generating capital and operating costs for the new CO_2 capture facility. The following major assumptions were made in developing the order-of-magnitude capital costs:

- Equipment previously used at the facility during Units 2 and 3 operation could be repurposed with minor allowances needed for repairs and reintegration. This includes the Unit 3 cooling tower, Units 2 and 3 dedicated auxiliary power system, and Unit 3 circulating water pump.
- New cooling tower will be built on existing Unit 2 infrastructure.
- Equipment used as part of a common system has sufficient margin to accommodate the new utility requirements of the CO_2 capture system, based on CO_2 capture demand rates similar to or lower than the previous Units 2 and 3 utility rates. This includes the cooling water, blowdown wastewater treatment system, and demineralized makeup water system.
- While all of the equipment that is expected to be reused may not be in ideal condition, it is assumed that a relatively small amount of repairs would be needed to make them operable again. Allowances are included.
- No major steam turbine redesign is required to extract process steam. An allowance is included.
- Pipeline equipment and installation costs were furnished as part of a budgetary quote.
- CO_2 compressor equipment costs were based on a budgetary quote. Labor for installation was estimated along with integration of a dehydration system.
- Costs for the amine-based capture equipment was scaled based on publicly available costs for the Petra Nova facility.
- The CO_2 capture facility will be contracted as an Engineering, Procurement, and Construction (EPC) project. As such, the appropriate risk fee is included.

The following major assumptions were made in developing the order-of-magnitude operating and maintenance (O&M) costs:

- Utility rates are expected to be similar to S&L’s previously completed CO_2 studies and publicly available information for similar amine-based systems.
- A contingency equal to 20% of the direct costs has been included.
- Electricity for auxiliary power and steam derate will be based on the current fuel cost and operating costs.
- No current operators from the existing facility will be used to operate or maintain the CO_2 capture facility. 18 new personnel are included, which includes four personnel per shift (two auxiliary operators and two maintenance personnel). There will be four shifts per week - Day, Evening, Graveyard, Weekend. In addition to these 16 personnel, two lab technicians and process support personnel will be on staff. This staffing plan is based on assuming the CO_2 process will not be staffed by anyone at the base facility.

- Maintenance costs are based on 2.5% of the equipment and materials for the complete project, including pipeline.
- CO_2 island chemical and disposal costs are based on publicly available data for various amine-based solvent suppliers.

5.2 Cost Inputs

CO_2 capture order-of-magnitude costs were estimated based on S&L's experience along with site specific SJGS considerations. All costs are provided in 2019 dollars with no escalation or financing costs (i.e., allowance for funds during construction) included. This type of costs estimate is referred to as an "overnight" cost estimate. Labor costs were estimated for each individual subcontracted process or component rather than a blanket percentage over the whole project and include the associated labor indirect costs which apply to this type of work such as overtime, per diem, contractor's G&A and profit. This capital cost estimate is a factored estimate, equivalent to an AACE Class 5 estimate. During the FEED study or detailed design, a more detailed capital cost estimate will be developed based on input from a selected OEM and detailed design.

Indirect project costs, such as engineering, construction management, startup and commissioning support, construction materials and initial fills for testing were also included in the estimate to provide a total capital investment. An allowance for owner's costs, provided by Enchant Energy, has been included.

Operating costs were estimated based on a capacity factor of 85% and are provided in 2019 dollars. Unit costs for consumables were estimated by S&L, except as noted.

Fixed O&M costs are based on 18 additional operators for the combined system; however, there is the potential for some employees to be shared between current plant personnel and the new CO_2 capture facility. Maintenance material and labor costs were estimated for the project based on the cost of material and equipment for the CO_2 capture system.

5.3 Capital Costs

The overall cost for the commercially available amine-based CO_2 capture system is provided in **Table 5-1** and Appendix D.

Table 5-1: Capital Cost Summary of CO_2 Capture System ($2019)

	Material / Equipment	Labor	Total
BOP Cost	**$ 110,360,000**	**$ 79,250,000**	**$ 189,610,000**
Civil / Sitework	*$ 4,020,000*	*$ 7,150,000*	*$ 11,170,000*
Mechanical /Equipment	*$ 31,370,000*	*$ 37,500,000*	*$ 68,870,000*
Structural / Ductwork	*$ 58,560,000*	*$ 24,770,000*	*$ 83,330,000*
I&C	*$ 5,630,000*	*$ 820,000*	*$ 6,450,000*
Electrical	*$ 14,780,000*	*$ 10,010,000*	*$ 24,790,000*
CO_2 Island Cost (Including Compression Island)	**$ 253,010,000**	**$ 309,230,000**	**$ 562,240,000**
Pipeline Cost (Furnished / Installed)			**$ 40,000,000**
Total Direct Capital Cost			***$ 796,850,000***
EPC Construction Overheads[1]			$ 119,530,000
Engineering[2]			$ 39,840,000
EPC Contingency			$ 159,370,000
EPC Risk Fee			$ 79,690,000
Total Indirect Costs			***$ 398,430,000***
Total EPC Cost			**$ 1,195,280,000**
Owner's Cost			**$ 100,000,000**
Total Project Cost[3]			**$ 1,295,280,000**

Note 1. Construction Overheads Includes:
Scaffolding, Overtime, Per Diem, Consumables, Sales Tax, Contractors Administration Fee, Contractor Profit
Note 2. Engineering Includes:
Engineering services, Field Support, Start-Up/Commissioning, SU/S Parts/Initial Fills
Note 3. Costs Exclude:
Escalation, AFUDC, Right of Way & Land Purchase, Insurance, Site Security

5.4 Operating Costs

Total overall O&M cost for the commercially available amine-based CO_2 capture system is provided for the entire facility at two different capacity factors. A capacity factor of 85% is used to determine a typical annual production capacity, while 100% is used to show the maximum costs associated with the system. Table 5-2 provides a breakdown of the annual O&M cost.

Table 5-2: Annual O&M Cost Summary of CO_2 Capture Systems ($2019)

Description	85% Capacity Factor	100% Capacity Factor
Total Fixed Operating Cost	**12,360,000**	**12,360,000**
Annual Operating Labor	2,430,000	2,430,000
Maintenance Material & Labor	9,930,000	9,930,000
Total Variable Operating Cost	**87,579,000**	**103,029,000**
Demin Makeup Water	30,000	40,000
Water Treatment	830,000	970,000
CO_2 Island Chemical and Disposal Costs	28,839,000	33,919,000
Purchased Steam & Power Cost	57,880,000	68,100,000
Total Annual O&M Cost ($/yr)	**99,939,000**	**115,389,000**

5.5 Cost of Capture

To calculate the total cost per mass of CO_2 captured, all costs should be evaluated on an annual basis. In previous DOE case studies, a capital annualization factor of 0.1243 was used for other projects of equivalent risk to evaluate costs on a constant dollar basis. This methodology was used to calculate the total cost of capture for this pre-feasibility study.

Table 5-3 provides an estimate of the total quantity of CO_2 captured in a year as well as the evaluated cost for the CO_2 capture system.

Table 5-3: Cost of CO_2 Capture

Description	Units	85% Capacity Factor	100% Capacity Factor
Total Project Cost	$	1,295,280,000	1,295,280,000
CCF		0.1243	0.1243
Annualized Capital Cost	$/yr	161,000,000	161,000,000
Annual O&M Cost	$/yr	99,939,000	115,389,000
Total Annual Cost	$/yr	260,939,000	276,389,000
CO_2 Captured	mmscfd	313	368
Annual CO_2 Captured	tonnes	6,000,000	7,060,000
Cost of Capture	**$/tonne[1]**	**43.49**	**39.15**

Note 1. Cost of capture reported as dollars per metric ton (equivalent to 2,240 lb).

6 Summary and Conclusions

This study establishes the technical feasibility and costs associated with the implementation of amine-based carbon capture technology at the San Juan Generating Station site. The current study represents expected utility requirements and capital costs that correspond to the current advancement of the amine-based technology and rely on information published by both MHI and Shell on their recent installations and developments. Specifically, this study builds on the information provided from recent experience and installations of both MHI and Shell at Petra Nova and Boundary Dam, respectively. Furthermore, this study considers the cost savings associated with using existing infrastructure from the recently retired Units 2 and 3 at SJGS to supply the CO_2 capture utility requirements. Using the existing auxiliary systems lowers the project capital costs and reduces the overall cost of capture, making this facility an attractive candidate for CCUS.

The total project cost was estimated to be $1.295 B, which considers the current level of technology advancements and cost savings for application at SJGS. Even while including the cost for the CO_2 pipeline, the cost to implement CO_2 capture at SJGS is estimated to be between $39-43/tonne. This is in line with the DOE's long-term goal of $40/tonne, which does not include the capital cost of new pipeline.

In addition to the lower cost to implement CO_2 capture at SJGS, the facility is located in relatively close proximity to a CO_2 pipeline. This will require minimal pipeline costs in comparison with many coal-fired facilities as well as a market opportunity for sale of the produced compressed CO_2.

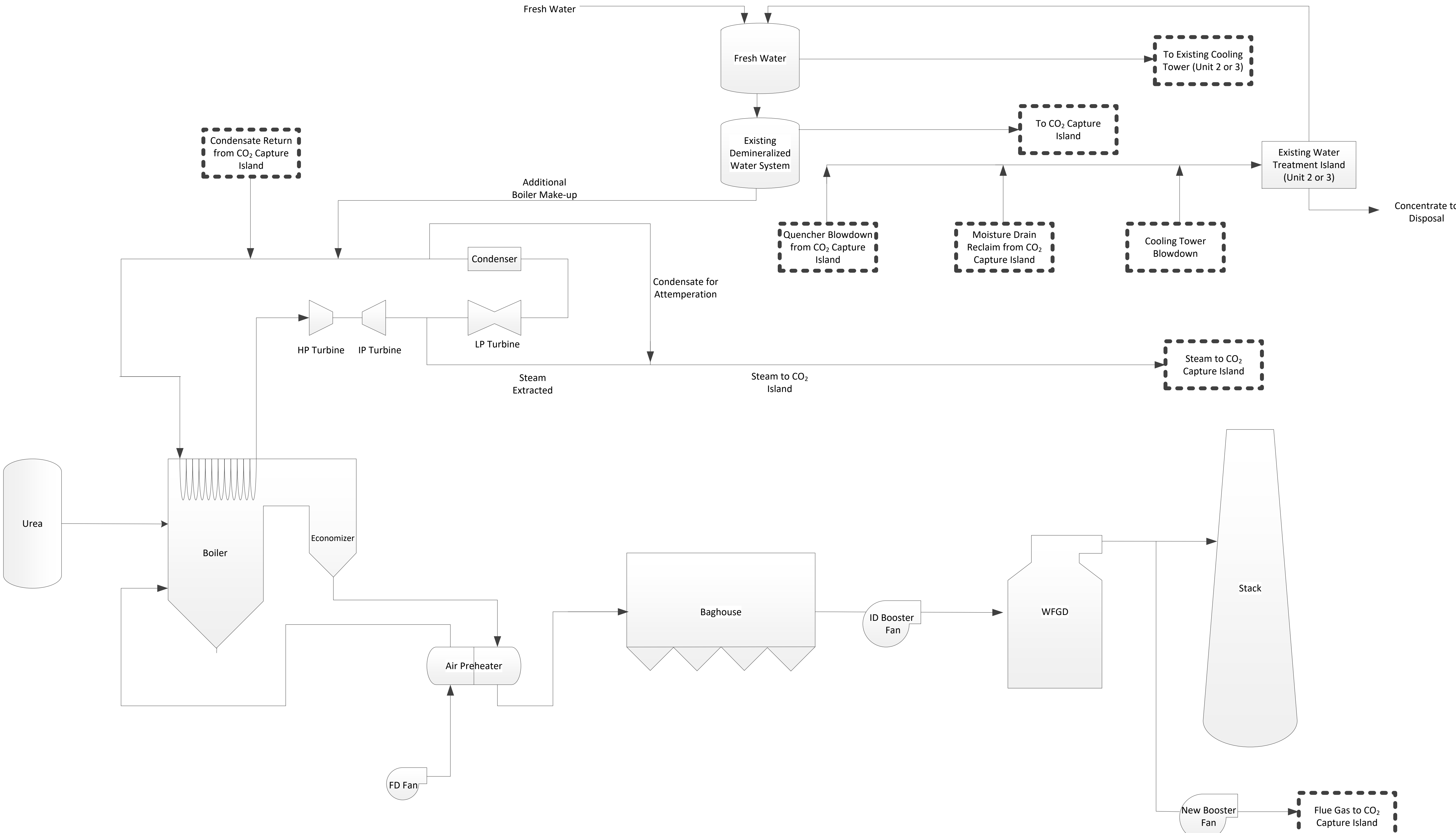
As part of the next steps of this project, it is recommended that a more in-depth FEED study be conducted to advance the project definition, engage the technology providers to provide site-specific performance data, and develop a detailed cost estimate. At this time, minimal engineering has been conducted for the design of the CO_2 capture system integration to develop an order of magnitude cost.

During the future phases, it is recommended that the CO_2 capture system be competitively bid to obtain site-specific performance and design information, and competitive pricing for the subcontracted island cost. CO_2 technology OEMs have indicated that overall capital costs of the facilities have reduced in the last 10 years, due to modularization and optimization of the process. Depending on the advances made over the last 3-5 years, it is expected that OEMs will be able to provide optimized auxiliary power and steam requirements. As such, the overall plant derate may also be optimized and reduced in future applications of this technology.

APPENDIX A:

BASE PLANT PROCESS FLOW DIAGRAM

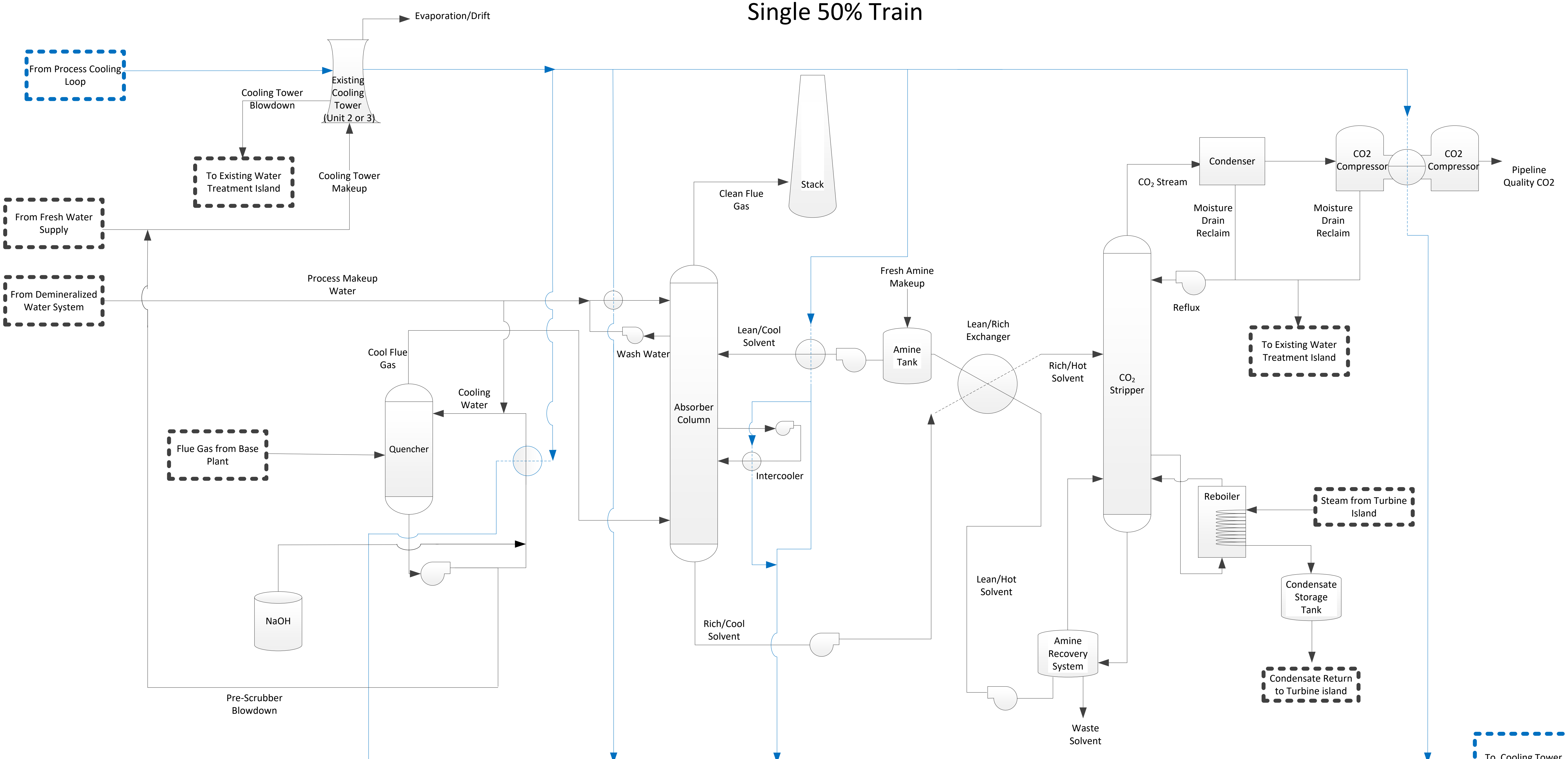
Base Plant PFD (Unit 1 or 4)



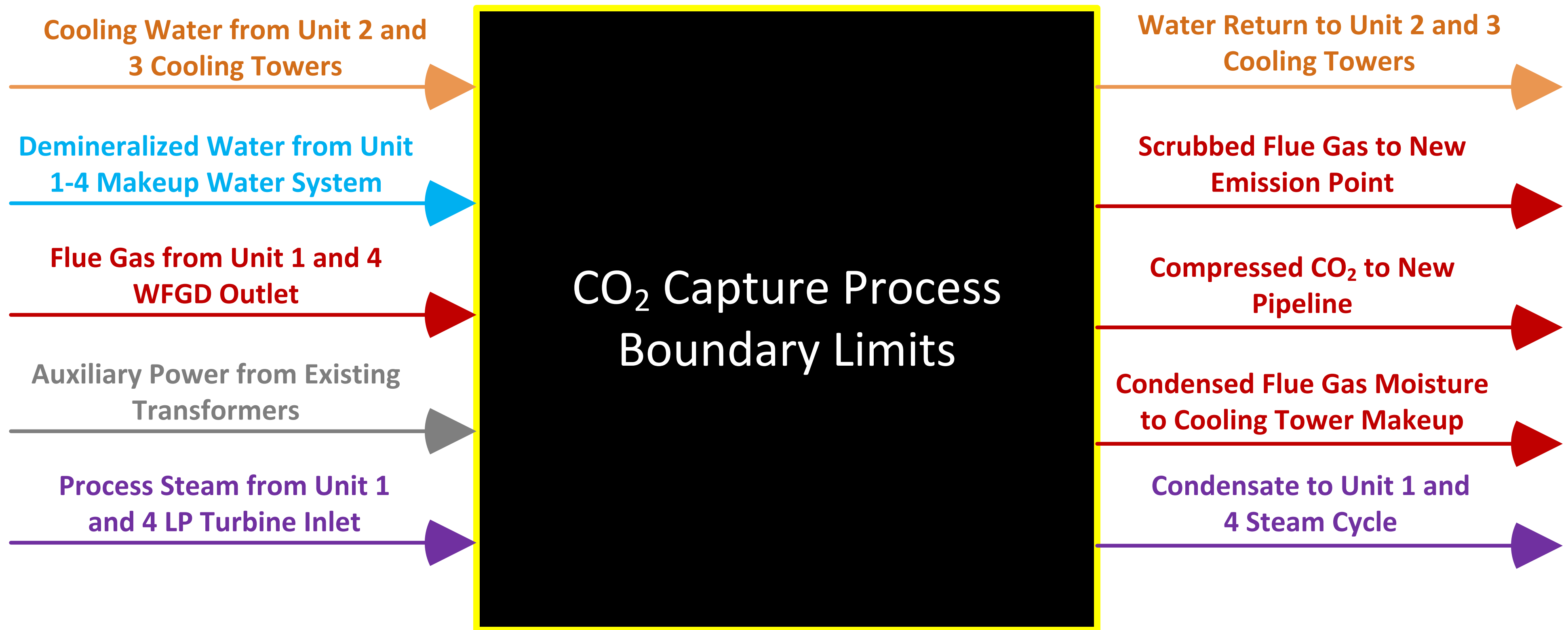
APPENDIX B:

CO_2 FACILITY PROCESS FLOW DIAGRAM

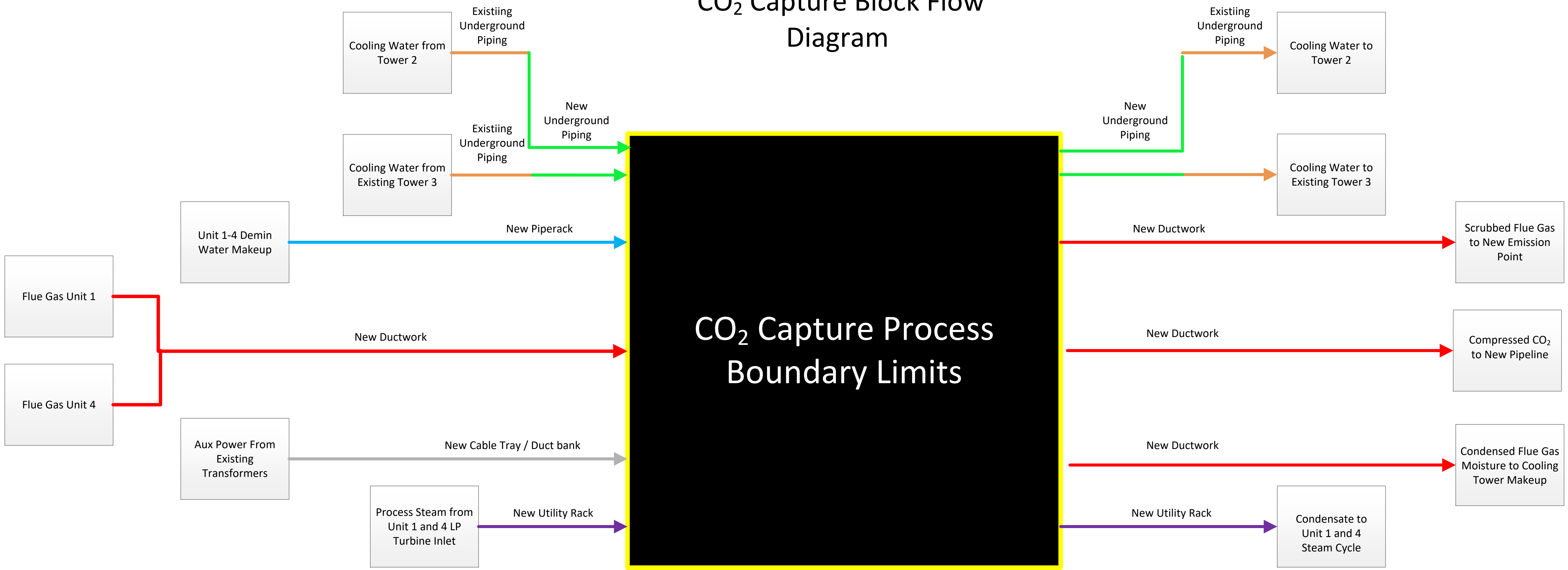
Commercial Amine Based
CO_2 PFD
Single 50% Train



High Level CO_2 Capture Block Flow Diagram

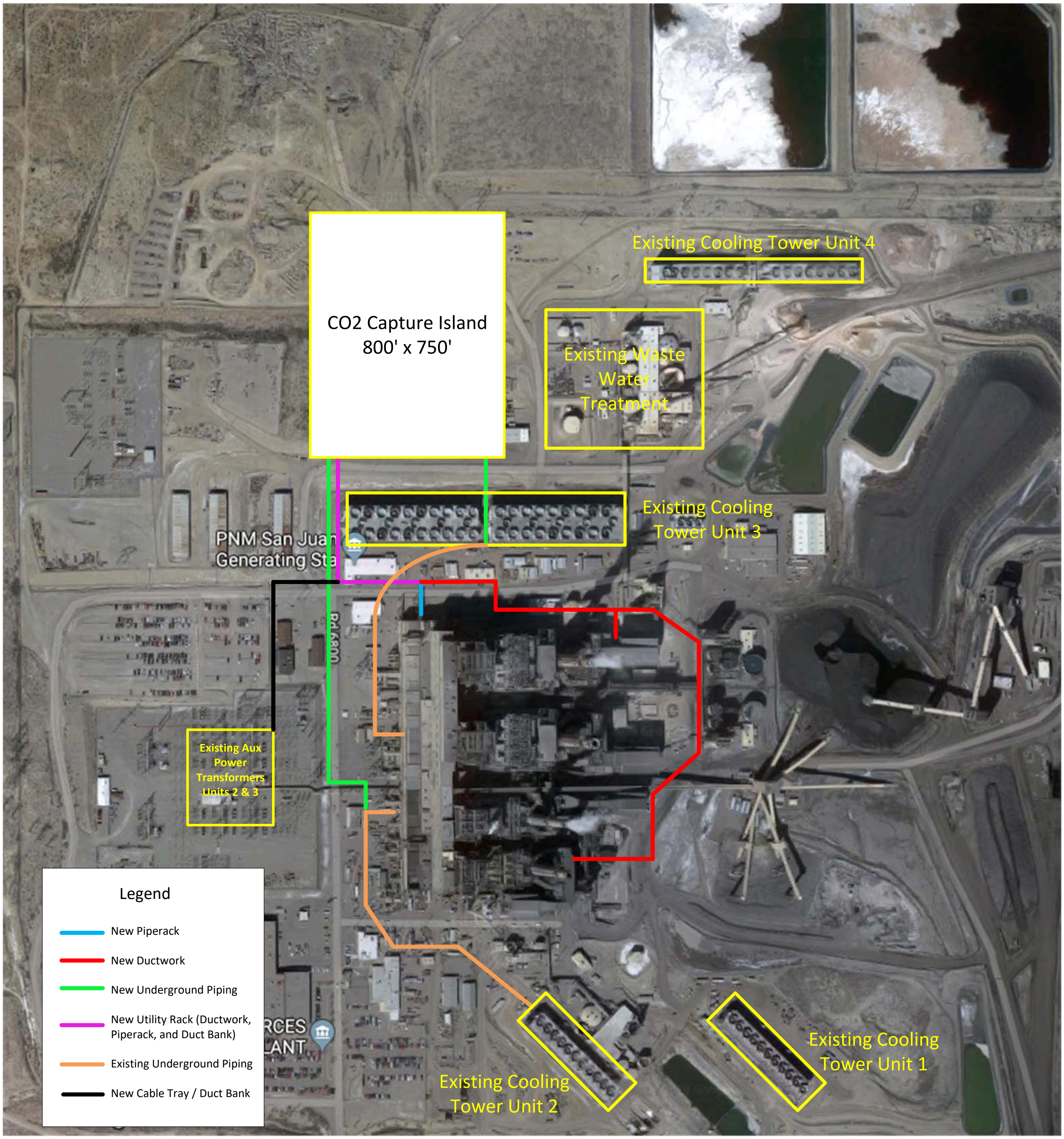


CO_2 Capture Block Flow Diagram



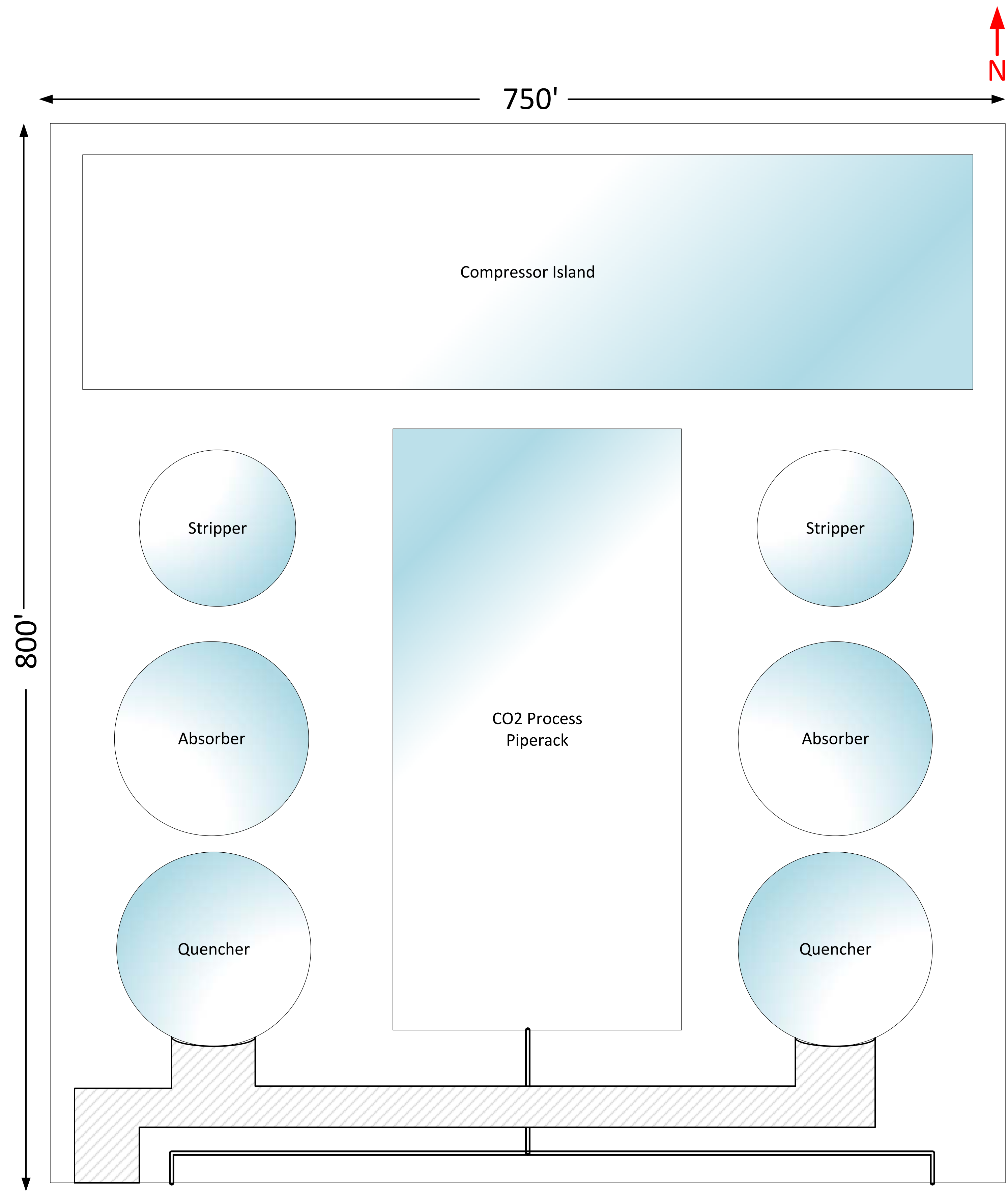
APPENDIX C:

GENERAL ARRANGEMENT AND PLANT LAYOUT


CO2 Capture Island
800' x 750'
Existing Cooling Tower Unit 4
Existing Waste Water Treatment
Existing Cooling Tower Unit 3
PNM San Juan Generating Sta
Existing Aux Power Transformers Units 2 & 3
Existing Cooling Tower Unit 2
Existing Cooling Tower Unit 1
Legend
New Piperack
New Ductwork
New Underground Piping
New Utility Rack (Ductwork, Piperack, and Duct Bank)
Existing Underground Piping
New Cable Tray / Duct Bank

Enchant Energy
San Juan Generating Station
CO_2 Capture Pre-Feasibility
General Arrangement Drawings

Project No.: 13891-001
Issue: Rev 0
Date: 7/3/2019



APPENDIX D:

DETAILED CAPITAL COSTS

Summary San Juan CO_2 Capture Capital Costs

	Material / Equipment	Labor	Total
BOP Cost	**$ 114,360,000**	**$ 80,250,000**	**$ 194,610,000**
Civil / Sitework	*$ 4,020,000*	*$ 7,150,000*	*$ 11,170,000*
Mechanical / Equipment	*$ 31,370,000*	*$ 37,500,000*	*$ 68,870,000*
Structural / Ductwork	*$ 58,560,000*	*$ 24,770,000*	*$ 83,330,000*
I&C	*$ 5,630,000*	*$ 820,000*	*$ 6,450,000*
Electrical	*$ 14,780,000*	*$ 10,010,000*	*$ 24,790,000*
CO_2 Island Cost (Including Compression Island)	**$ 253,010,000**	**$ 309,230,000**	**$ 562,240,000**
Pipeline Cost (Furnished / Installed)			**$ 40,000,000**
Total Direct Capital Cost			*$ 796,850,000*
EPC Construction Overheads[1]			$ 119,530,000
Engineering[2]			$ 39,840,000
EPC Contingency			$ 159,370,000
EPC Risk Fee			$ 79,690,000
Total Indirect Costs			***$ 398,430,000***
EPC Capital Cost [3]			**$ 1,195,280,000**
Owner's Cost			**$ 100,000,000**
Total Project Cost			**$ 1,295,280,000**

Note 1. Construction Overheads
- Scaffolding
- Overtime
- Per Diem
- Consumables
- Sales Tax
- Contractors Administration Fee
- Contractor Profit

Note 2. Engineering
- Engineering services
- Field Supoort
- Start-Up/Commissioning
- SU/S Parts/Initial Fills

Note 3. Costs Exclude:
- Escalation
- AFUDC
- Right of Way & Land Purchase
- Site Security

APPENDIX E:

DETAILED O&M COSTS

Summary San Juan Combined Cost of CO_2 Capture

Input Data:		**Unit 1**	**Unit 4**	**Total Plant**	**Total Plant**
Plant Gross Capacity (Max Normal)	MW	370	544	914	914
Base Plant Aux Power Consumption	MW	30	37	67	67
Base Plant Net Capacity @ Max Normal Load	MW	340	507	847	847
CO_2 Capture Aux Power Consumption	MW	49	75	124	124
CO_2 Island Steam Derate	MW	48	74	122	122
Post CO_2 Net Capacity @ Max Normal Load	MW	243	358	601	601
Capacity Factor	%	85%	85%	85%	100%
CO_2 Capture Design (@ 100% Capacity Factor):					
CO_2 Capture System Size	MWe	370	544	914	914
Total Unit Derate due to CO_2 Capture	MW	97	149	246	246
CO_2 Capture Rate	lb/hr	703,724	1,071,852	1,775,576	1,775,576
Carbon Capture Design @ Capacity Factor	ton CO_2/year	2,619,960	3,990,500	6,610,470	7,777,020
	mmscfd	125	189	312	368
O&M Unit Pricing:					
Water Cost	$/1000gal	1.30	1.30	1.30	1.30
Waste Water Treatment Cost	$/1000gal	1.5	1.5	1.5	1.5
CO_2 Transportation, Storage, Monitoring Cost	$/tonne	not included	not included	not included	not included
CO_2 Capture Island O&M Rates (@ Capacity Factor):					
Demin Water Makeup Rate	gpm	23	34	57	57
Waste Water Production Increase	gpm	487	744	1,232	1,232
Variable O&M Summary:					
Water Cost	$/yr	10,000	20,000	30,000	40,000
Additional Water Treatment Cost	$/yr	330,000	500,000	830,000	970,000
CO_2 Island Chemical and Disposal Costs	$/yr	11,499,000	17,340,000	28,839,000	33,919,000
Total Steam & Power Cost	$/yr	22,820,000	35,060,000	57,880,000	68,100,000
Total Variable O&M Cost (First Year)	**$/yr**	**34,659,000**	**52,920,000**	**87,579,000**	**103,029,000**
Fixed O&M Cost:					
Additional Operators [1]	#			18	18
Operator Wage [2]	$/hr			65	65
Additional Operating labor ($/hr, 40 hrs week)	$/yr			2,430,000	2,430,000
Maintenance Material and Labor	$/yr			9,930,000	9,930,000
Additional Administrative labor	$/yr			0	0
Fixed O&M Cost	**$/yr**			**12,360,000**	**12,360,000**
Total O&M Cost:	**$/yr**			**99,939,000**	**115,389,000**
Cost of Capture:					
EPC Capital Cost	$			1,195,280,000	1,195,280,000
Owners Cost	$			100,000,000	100,000,000
Total Project Cost	$			1,295,280,000	1,295,280,000
Annualization Factor [2]				0.1243	0.1243
Annualized CapEx	$/yr			161,000,000	161,000,000
Total Annual Cost	$/yr			260,939,000	276,389,000
Total Annual CO_2 Production @ Capacity Factor	tonne/yr			6,000,000	7,060,000
Cost of Capture	**$/tonne**			**43.49**	**39.15**

Note 1. 4 personnel per shift (2 auxiliary operators, 2 maintenance personnel). 4 shifts per week - Day, Evening, Graveyard, Weekend. Plus 2 lab techs/process support. Assumes no sharing with base facility staffing for operators.
Note 2. DOE annualization factor, based on a 5-year capital expenditure period for a high-risk project.