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Low-Emission CO_2-Rich Natural Gas Processing Plant with Hybrid Decarbonization: Techno-Economic and Marginal Abatement Cost Analyses

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Abstract

Natural gas processing plants (NGPP) contribute considerably to greenhouse-gas emissions, especially when processing carbon dioxide rich (CO_2-rich) natural gas. Therefore, it is urgent and of general interest to study the decarbonization of such plants through new combined technologies and to estimate its economic–environmental performance through up-to-date metrics like the Marginal Abatement Cost (MAC). Comprehensive techno-economic and MAC analyses were conducted in the decarbonization of a NGPP through hybrid membrane permeation plus aqueous-monoethanolamine post-combustion capture. The NGPP processes 6.6 $MMSm^3/d$ of 44%mol CO_2-rich gas. Hybrid decarbonization captured 94.05% of carbon dioxide abating carbon emissions from 2.69 t to 0.11 t per ton of treated gas, while power demand, investment, and manufacturing costs increased from 31.7 MW to 69.5 MW, 177.2 MMUSD to 325.4 MMUSD, and 238.8 MMUSD/y to 327.3 MMUSD/y, respectively. Simultaneously, revenues increased from 255.82 MMUSD/y to 421.78 MMUSD/y when 100% of carbon dioxide is utilized in enhanced oil recovery (EOR), leading to a 25-year net value increase from −1097 MMUSD to +441 MMUSD. For 80% carbon dioxide to EOR, the 25-year net value surpasses the counterpart of the carbon-emitting plant by 96.56 MMUSD with the same payback time (12 years). MAC decreased from 20.9 USD/t^{CO2} to −12.4 USD/t^{CO2} as carbon dioxide utilization changed from 0% EOR to 100% EOR. Since better net values and MACs were obtained for hybrid decarbonization with EOR, these retrofitted alternatives are more recommendable as they effectively reduce the carbon footprint by 54.53 MMt^{CO2} for 25 years of a profitable campaign.

Keywords: CO_2-rich natural gas; natural gas processing; hybrid carbon capture; membrane permeation; marginal abatement cost analysis; techno-economic analysis

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1. Introduction

Natural gas (NG) consumption has increased considerably over the past decades, driven by its lower carbon intensity and operational flexibility compared to coal and other fossil fuels [1]. According to the 74th edition of *Statistical Review of World Energy* [2], NG production in 2024 was 4.1× higher than in 1970, accounting for 25% of global primary energy demand (4.125×10^9 m^3). Nevertheless, NG processing and combustion still represent ≈20% of 37.8 Gt^{CO2} emissions worldwide at 1.94 kg^{CO2}/m^3 [3,4].

The Brazilian offshore Pre-Salt basin is a major recently discovered hydrocarbon province. Raw NG from deep-water oil-and-gas fields of the Pre-Salt basin usually contains high CO_2 contents above 10%mol, in addition to a high gas-to-oil ratio, constituting challenges for offshore projects [5,6]. NG market/environmental regulation typically requires CO_2 between 2.0%mol and 3.0%mol, while H_2S, water, and heavy hydrocarbons must also be removed from NG due to corrosion potential, solid gas-hydrate formation and dew-point concerns [7–9].

1.1. Onshore Processing Plant for CO_2-Rich NG

An onshore natural gas processing plant (NGPP) processes CO_2-rich raw gas exported by offshore rigs through a subsea pipeline. The NGPP comprises several units. Its first unit simultaneously performs water dew-point adjustment (WDPA) and hydrocarbon dew-point adjustment (HDPA) through Joule–Thomson expansion of raw gas mixed with monoethylene-glycol (MEG) to avoid the water freezing by keeping it in liquid form in the MEG phase as the temperature falls through the expansion. WDPA+HDPA produces three phases at lower pressure: (i) dew-point adjusted NG; (ii) hydrocarbon condensate or natural gas liquids (NGL); and (iii) aqueous-MEG phase. NG then follows to the Acid Gas Removal Unit (AGRU) for removing CO_2 (the H_2S was previously removed in the offshore rig via chemical conversion) [10]. After the AGRU, the NG is ready for exportation. NGL is also exported.

In the AGRU, NG sweetening can be done by Chemical Absorption, Physical Absorption, Pressure-Swing Adsorption (PSA), Temperature-Swing Adsorption (TSA), Membrane Permeation (MP), and Cryogenic Separation [11]. PSA and TSA involve surface interaction between acid gases and a solid adsorbent, and are more adequate for lower capacity plants or finishing operations [12,13]. Cryogenic Separation relies on low-temperature distillation, which, despite its effectiveness for decarbonizing CO_2-rich NG, demands refrigeration and high power that curbs its utilization [14]. MP separates CO_2 based on different diffusion rates through a dense polymeric membrane, wherein CO_2 leaves the MP unit as the low-pressure permeate, while the purified NG leaves as the high-pressure retentate. MP is widely applied in offshore NG processing as a pre-treatment for NG purification. Some MP advantages include its modularity, absence of solvents, and low energy demand, while its drawbacks include multi-stage requirements, gas recompression, and methane loss in the permeate [12,13,15]. Chemical Absorption, in turn, remains the most mature AGRU technology, due to its efficiency, reliability, solvent flexibility, scale-up capability, and economic competitiveness, despite higher energy requirements [11,16].

Recently, great improvements were achieved for NG purification through energy and cost-effectiveness optimizations. These innovations comprise hybrid technology, e.g., MP+Chemical Absorption, Physical–Chemical Absorption and Dual Chemical Absorption, focusing on trade-offs between separation efficiency, energy demand, and economic performance [13,17].

Dwiyantoro et al. [18] reported superior exergy efficiency and long-term profitability for the supersonic separator compared to conventional aqueous-methyl-diethanolamine absorption, wherein the latter remains more attractive for lower CO_2 concentrations. Dai et al. [19] introduced a two-stage flashing for aqueous-monoethanolamine (aqueous-MEA) regeneration, reducing the regeneration heat ratio and NG sweetening costs. On the other hand, Pauzi et al. [20] indicate conventional packed columns as the most economically attractive option against more compact systems such as membrane contactors and ultrasonic-assisted regeneration. Chu and He [21] achieved pipeline-quality NG using a two-stage carbon molecular sieve, reporting methane losses below 2% and a 15.6 USD/t sweetening cost. Recently, Wang et al. [22] proposed a hybrid AGRU employing aqueous-

K_2CO_3 absorption followed by aqueous-MEA absorption, obtaining CO_2 capture efficiencies above 99% at a 65 USD/t^{CO2} levelized capture cost.

Hybrid MP+aqueous-MEA absorption for NGPP decarbonization has been recognized as an effective solution for CO_2-rich NG. Araújo et al. [6] and Sclierf and Rufford [23] demonstrated that upstream MP applied to CO_2-rich NG reduces the CO_2 load entering the aqueous-MEA absorption, thereby decreasing regeneration costs, unit size, and investment.

1.2. Carbon Capture and Storage (CCS) Versus Carbon Capture and Utilization (CCU)

NGPPs with CO_2-rich NG emit considerable CO_2 flowrates to the atmosphere, which is a major environmental concern. Conventional NGPP carbon emission for CO_2-rich NG is usually responsible for ≈15% of NG lifecycle greenhouse-gas (GHG) emissions, while the other 85% corresponds to NG combustion [24]. For developing decarbonized NGPPs, CCS/CCU methods have to be taken into account.

Notably, NG processing represents the largest share of the global carbon capture operation, representing ≈65% of the installed capacity worldwide, mainly because CO_2 removal is already an integral part of gas sweetening. Due to Pre-Salt basin NG operations, Brazil has the second-largest carbon capture capacity, 10.6 Mt^{CO2}/y, corresponding to 21% of the total share [25]. From an economic perspective, the main CCS/CCU costs are associated with CO_2 capture, compression/liquefaction, dehydration, pipeline transport, and injection at destination [26]. According to Bagheri et al. [27], carbon transport and storage costs range from 2 USD/t^{CO2} to 40 USD/t^{CO2} in NG processing facilities.

Aqueous-MEA carbon capture was developed in the 1930s for CO_2 separation from NG and is a well-established technology for industrial applications, while MP applications were only developed after the 1970s [26]. These technologies are the most used for NG decarbonization. They are coupled with CO_2 transport for geological storage and enhanced oil recovery (EOR), or with CO_2 utilization for producing chemicals.

Considering CCS alternatives, Grande et al. [28] compared PSA with conventional aqueous-methyl-diethanolamine-piperazine (aqueous-MDEA-PZ) absorption for CO_2 removal, reporting a higher techno-economic performance for the latter. In contrast, Sukor et al. [29] compared different CO_2 capture technologies for an offshore NGPP, finding that Selexol physical absorption was the most economically attractive. In the context of aqueous-MEA absorption, Patel et al. [30] showed that the regeneration section can be optimized to reduce both manufacturing costs and global warming potential. In the context of CO_2 dehydration for pipeline transport, Sakheta and Zahid [31] reported that performing triethyleneglycol (TEG) regeneration with stripping CO_2 injection can reduce campaign costs compared with conventional dehydration.

Some studies have investigated carbon capture and utilization (CCU) strategies to improve the economics of decarbonized processes. Araújo et al. [6] and Li et al. [32] concluded that aqueous-MEA CO_2 capture coupled with CO_2-to-EOR can substantially improve the net present value (*NPV*) while reducing lifecycle cost and CO_2 emissions.

Teixeira et al. [33] evaluated the supersonic separator for MEG recovery which was integrated with aqueous-MEA post-combustion capture (PCC-MEA) aboard an offshore NGPP, wherein the PCC-MEA was designed for decarbonization of gas-turbine flue-gas. The authors concluded that this integration improved the economic performance through higher liquefied petroleum gas (LPG) recovery, lower MEG losses, and lower power consumption, while achieving ≈50% less CO_2 emissions. In addition, Kim et al. [34] demonstrated that the cryogenic CCUS for CO_2-rich NG can reduce energy consumption and GHG emissions, while maintaining economic competitiveness.

Overall, the literature indicates that hybrid MP+aqueous-MEA absorption is particularly suitable for CO_2-rich NG with CO_2 contents above 10%mol [6,23]. The present

work considers decarbonization of NGPP with CO_2-rich NG via hybrid MP+aqueous-MEA absorption for CO_2 capture.

1.3. Marginal Abatement Cost for CCS/CCUS Technologies

Since GHG reduction and economic objectives are not always aligned, cost-effectiveness and performance indicators are important to orient the design of process decarbonization. In this context, the Marginal Abatement Cost (*MAC*) analysis is an effective way to measure and compare both the environmental and economic performances of decarbonization technologies [35,36].

The majority of studies in the literature measure decarbonization costs through the CO_2 avoidance cost; i.e., an average cost of avoiding emissions for a specific CCS, CCU, or CCUS technology, wherein CCS, CCU, and CCUS effects are not distinguished on economic grounds [37]. On the other hand, *MAC* analysis seems to convey a similar but more comprehensive and better-defined concept, as it can handle CCS, CCU, and CCUS technologies while distinguishing between them (i.e., the numerical value of *MAC* can inform whether the technology is a pure CCS, a pure CCU, a partial CCS, or a partial CCU technology). *MAC* analysis also allows for the assessment of multiple mitigation scenarios for the same CCS/CCU technology. Moreover, *MAC* can rank technology options in terms of their CCS and CCU economic and environmental potentials. Therefore, *MAC* analysis is a more adequate framework for comparing (hybrid or not) decarbonization strategies to support investment decisions [38].

1.4. The Present Work

The review evinced that the literature lacks a comprehensive and conclusive assessment of decarbonization via combined technologies of natural gas processing plants running with CO_2-rich gas. The NGPP comprises WDPA+HDPA with MEG injection and CO_2 removal via hybrid MP+PCC-MEA capture. In this sense, NGPP decarbonization comprehends three categories of CO_2 removal: (i) the CO_2 already in the CO_2-rich raw NG coming from offshore rigs through a pipeline; (ii) the CO_2 produced for generation of heating utilities—i.e., low-pressure steam (LPS)—for the PCC-MEA that removes CO_2 from item (i); (iii) the extra CO_2 produced for extra heating generation for cleaning the entire NGPP flue-gas via PCC-MEA. Moreover, *MAC* analysis of the decarbonized NGPP has not appeared yet in the literature and is also an objective. These literature gaps are addressed in the present work.

2. Methods

A hybrid MP+PCC-MEA NGPP operating with CO_2-rich NG is decarbonized via CCS/CCU. The Base Case is a standard NGPP removing CO_2 from CO_2-rich NG with aqueous-MEA absorption (AGRU) without carbon capture. Techno-economic and MAC analyses were developed to assess the decarbonized NGPP considering different CO_2 management scenarios after capture.

2.1. NGPP Base Case

The NGPP Base Case was designed to treat 6.6 $MMSm^3/d$ of raw NG (≈44%mol CO_2) from offshore deep-water oil-and-gas fields [39,40]. Figure 1 summarizes the NGPP Base Case. NG feeds the WDPA+HDPA/Joule–Thomson unit at P = 70 bar, T = 40 °C. MEG is injected in the expansion to inhibit gas-hydrate and ice formations. Aqueous-MEG is sent to Water-MEG distillation for MEG reconcentration as Lean-MEG. Dew-point adjusted NG goes to AGRU-MEA for CO_2 removal. Final NG is compressed and dehydrated to achieve NG exportation specifications.

A fraction of raw NG is burned in the Steam Generation unit producing LPS for AGRU and TEG units. Cooling water (CW) is cooled in the CW System (CW Tower) and pressurized hot water (PHW) is also reheated with flue-gas in Steam Generation. The Base Case emits Emission#1 from AGRU (CO_2 ≈ 90%mol) and Emission#2, a flue-gas from Steam Generation (CO_2 ≈ 10%mol). The residual hydrocarbons dissolved in the aqueous-MEG stream are vented from Water-MEG distillation and burned in Steam Generation.

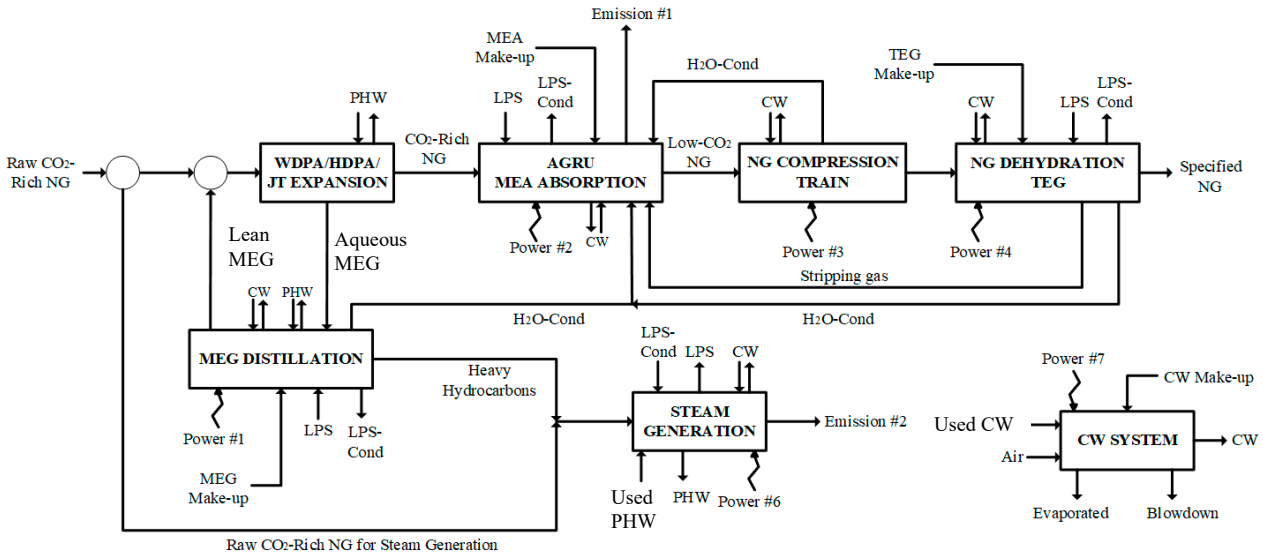


Figure 1. NGPP Base Case.

Figure 2 depicts WDPA+HDPA/Joule–Thomson and Water-MEG distillation. NG+MEG is sequentially cooled to T = −10 °C by Liquid#1, Liquid#2, and NG+CO_2 in exchangers HX#1, HX#2, and HX#3. Liquid#2 is a hydrocarbon liquid (NGL), Liquid#1 is aqueous-MEG, and NG+CO_2 is the dew-point adjusted NG stream still with CO_2.

The cold NG+MEG expands through the Joule–Thomson valve from P = 70 bar to P = 5 bar, becoming three-phase (T = −75 °C), and is flashed in the three-phase separator. Liquid#1 flashes in Flash#1 whereas Liquid#2 flashes in Flash#2, both for degassing, reducing methane losses to liquids.

Flash#1 and Flash#2 vapors are added to NG+CO_2 and follow to HX#4 where they are heated to T = 40 °C with PHW. The liquids are heated to T = 80 °C (HX#5) by PHW and expanded from P = 4 bar to P = 0.3 bar to feed the Water-MEG vacuum distillation. The distillation column vents hydrocarbon vapor (HC) and produces liquid H_2O distillate (P = 0.2 bar, T = 40 °C) at its top condenser (HX#6). From its reboiler (HX#7), a lean-MEG stream results (H_2O ≈ 10%mol). The HC vent is compressed to P = 1.25 bar and burns in Steam Generation. The water distillate is pumped to AGRU as water make-up. Lean-MEG receives MEG make-up, is pumped (Pump#2) and cooled to T = 40 °C with CW (HX#8) prior to recirculation to WDPA+HDPA/JT.

Figure 3 depicts AGRU, NG Compression Train (NG-CMP), and NG Dehydration for the Base Case. CO_2-rich NG is fed into the aqueous-MEA absorber (P = 4 bar, T = 40 °C), wherein the aqueous-MEA flows in a countercurrent absorbing CO_2 from NG. CO_2-rich aqueous-MEA from the absorber expands to P ≈ 1 bar and is heated to T = 80 °C (HX#9) by the lean solvent (T ≈ 100 °C) from the CO_2 stripper reboiler (HX#11). The lean solvent receives MEA make-up, passes through Pump#6, cooler HX#12, and returns to absorption.

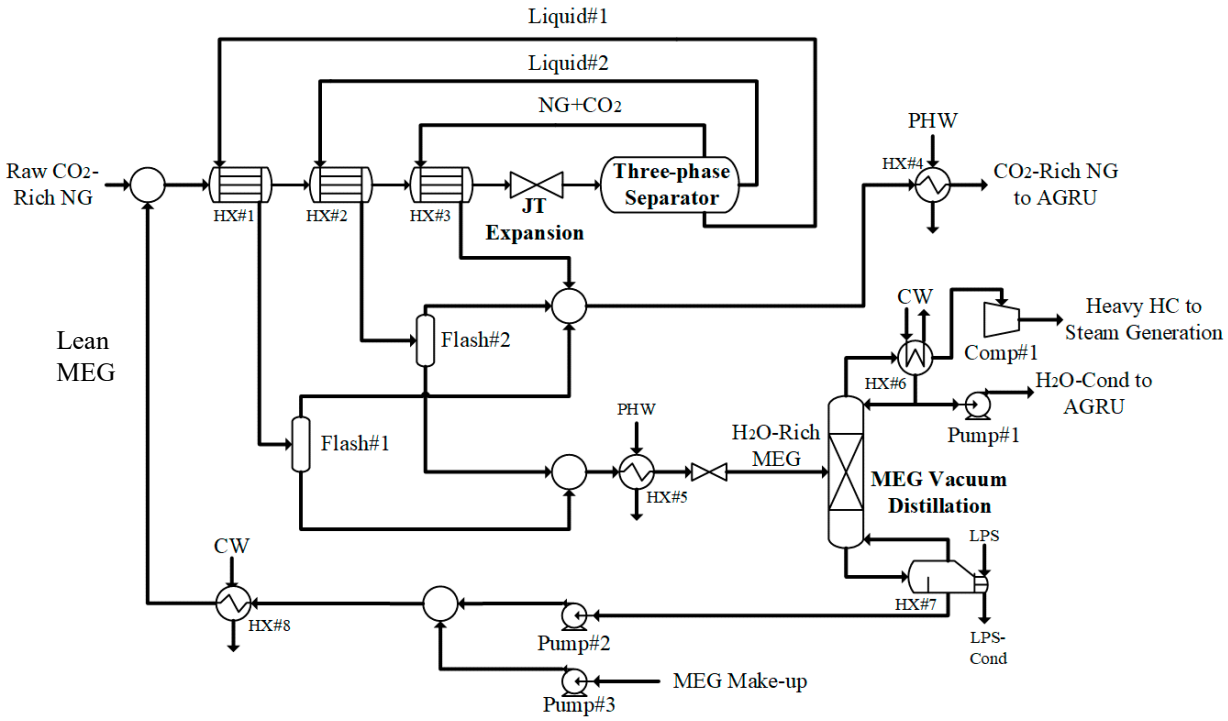


Figure 2. WDPA+HDPA/Joule–Thomson and Water-MEG distillation: NGPP Base Case.

The CO_2 vent is emitted—Emission#1—from the total reflux condenser (HX#10) of the CO_2 stripper. In turn, decarbonized NG from the top of the aqueous-MEA absorber goes to NG-CMP, where it feeds a three-staged intercooled compression train (compressors Comp#2, Comp#3, Comp#4; intercoolers HX#13, HX#14, HX#15; knockout vessels Flash#3, Flash#4, Flash#5). Aqueous liquids (T = 40 °C) from the knockout vessels return to stage#1 of the CO_2 stripper, lowering the condenser duty and water make-up. Compressed NG (P = 67.3 bar, T = 40 °C) from NG-CMP is dehydrated in the TEG absorber with the countercurrent TEG solvent.

The TEG absorber produces H_2O-rich TEG and dry NG. Rich-TEG expands to P = 1.12 bar and is heated to T = 90 °C (HX#16) with hot Lean-TEG from the reboiler of the TEG stripper. At the top condenser (HX#18) of the TEG stripper, residual water-saturated NG is vented to flare and liquid water is the distillate product. The water distillate returns to stage#1 of the aqueous-MEA stripper to reduce the water make-up. Lean-TEG (T = 140 °C) from the stripper reboiler (HX#19) has its temperature and pressure re-adjusted to absorption conditions and recycles to the absorber. A small fraction of dry NG (≈1%) is deviated and injected as stripping gas to lower the TEG reboiler temperature, preserving TEG.

Solvent regeneration (MEG, aqueous-MEA, TEG) demands LPS, which, in turn, is produced in Steam Generation (Figure 4). To this end, part of the raw CO_2-rich NG is burned in Steam Generation along with hydrocarbons (HCs) from MEG vacuum distillation. Used PHW is also reheated by hot flue-gas (HX#22). Lastly, flue-gas is cooled by CW in a direct-contact cooler (DCC#1). DCC#1 releases to the atmosphere a cold flue-gas with $CO_2 \approx 10\%$mol (Emission#2). Table 1 presents the technical assumptions for the NGPP Base Case.

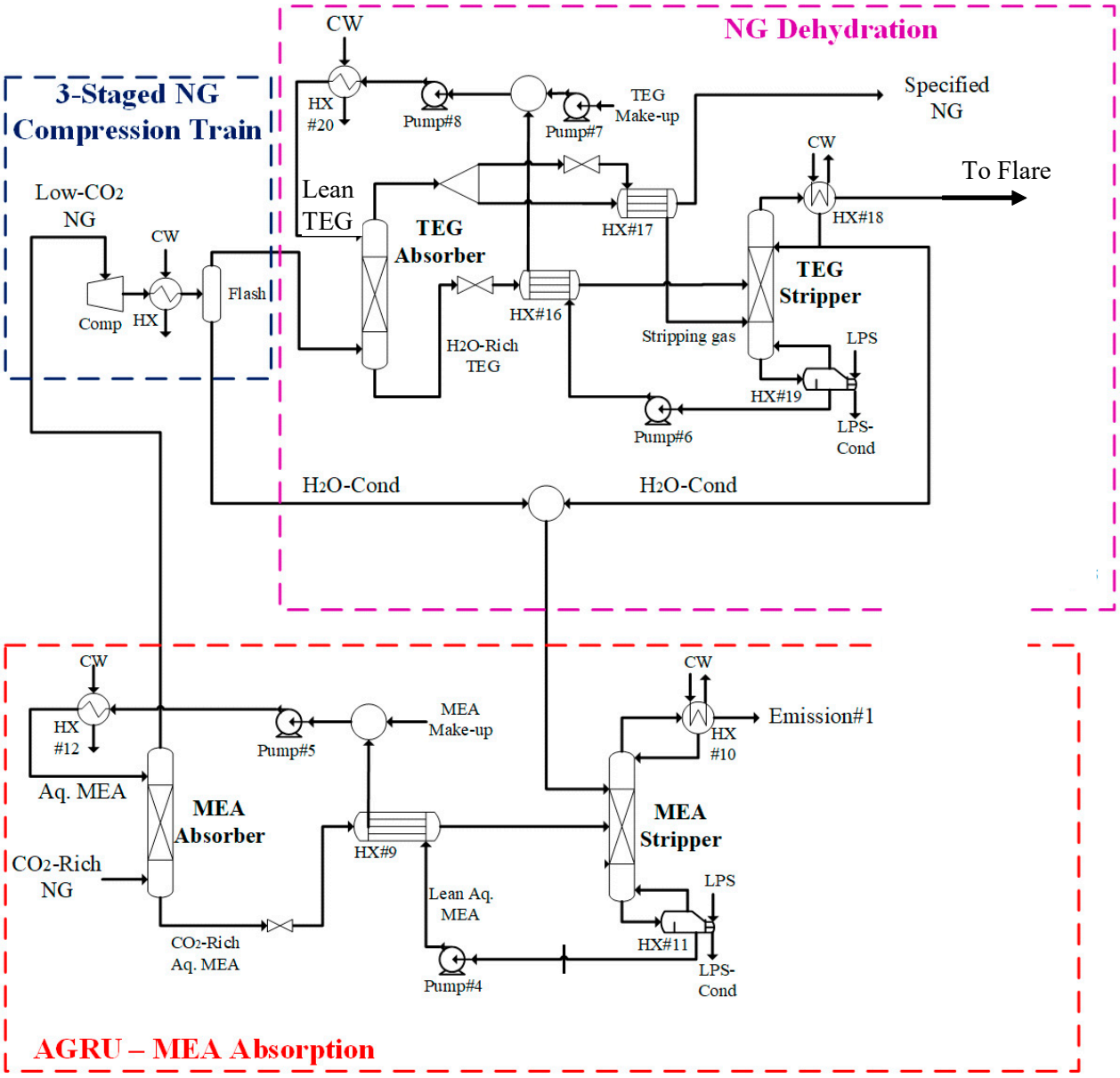


Figure 3. AGRU, NG compression, and NG dehydration: NGPP Base Case.

Table 1. Base Case: technical and simulation assumptions.

Item	Assumption
Process Simulation	Aspen-HYSYS v14
Thermodynamic Models	In general (exceptions as follows): Peng-Robinson Equation-of-State; AGRU: HYSYS Acid Gas Package; WDPA+HDPA/JT, TEG Unit, MEG Distillation: HYSYS Glycol Package; CW, PHW, LPS, Steam Generation: HYSYS ASME Table;
Raw CO_2-rich NG	6.6 MMSm^3/d; T = 40 °C; P = 70 bar; CO_2 = 43.82%mol; CH_4 = 49.82%mol; C_2H_6 = 2.99%mol; C_3H_8 = 1.99%mol; iC_4H_{10} = 0.3%mol; nC_4H_{10} = 0.2%mol; C_5H_{12} = 0.3%mol; C_6H_{14} = 0.2%mol; H_2O = 0.38%mol.
Lean-MEG	T = 40 °C; P = 70 bar; MEG = 90%mol; H_2O = 10%mol. Capture Ratio = 4.08 kg^{MEG}/kg^{H2O}.
CW	T^{inlet} = 35 °C; P^{inlet} = 4 bar; T^{outlet} = 50 °C; P^{outlet} = 3.5 bar.
PHW	T^{inlet} = 190 °C; P^{inlet} = 14 bar; T^{outlet} = 50 °C; P^{outlet} = 13.5 bar.
Air	T^{inlet} = 25 °C; P^{inlet} = 1.01 bar; N_2 = 76.6%mol; O_2 = 20.55%mol; Ar = 0.91%mol; H_2O = 1.89%mol; CO_2 = 0.04%mol.

LPS	P^{LPS} = 6.18 bar; T^{LPS} = 160 °C.
Heat Exchangers	ΔP = 0.5 bar; $\Delta T^{Approach}_{Gas-CW}$ = 5 °C; $\Delta T^{Approach}_{Gas-Gas}$ = 10 °C; $\Delta T^{Approach}_{Liq-Liq}$ = 5 °C.
Adiabatic Efficiencies	$\eta^{Compressors}$ = 75%; η^{Pumps} = 75%; η^{Fan} = 95%.
Water-MEG Distillation [a]	P^{top} = 0.2 bar; P^{bottom} = 0.4 bar; T^{inlet}_{MEG} = 36 °C; P^{inlet}_{MEG} = 0.3 bar.
AGRU[a]	Lean Aqueous-MEA: MEA = 30%*w*/*w*; H_2O = 70%*w*/*w*; Absorber: $T^{Absorber-Inlet}_{Aqueous-MEA}$ = 40 °C; P^{top} = 3.7 bar; P^{Bottom} = 4 bar; Efficiency^{Capture} = 96%; Capture Ratio = 11.41 $kg^{Aqueous-MEA}/kg^{CO2}$; Stripper: $T^{Stripper-Inlet}_{Aqueous-MEA}$ = 85 °C; $P^{Condenser}$ = 1.01 bar; $T^{Condenser}$ = 40 °C; $P^{Reboiler}$ = 1.02 bar; $T^{Reboiler}$ = 102 °C; Heat Ratio: HR = 201.6 $MJ/kmol^{CO2}$.
NG Compression	Compression Ratio^{Stage} = 2.7; Stages = 3; $T^{Intercooler}$ = 40 °C.
NG Dehydration [a]	Absorber: $T^{Absorber-Inlet}_{TEG}$ = 40 °C; P^{Top} = 67.18 bar; P^{Bottom} = 67.33 bar; Capture Ratio = 5.06 kg^{TEG}/kg^{H2O}; Stripper: $P^{Condenser}$ = 1.01 bar; $T^{Condenser}$ = 40 °C; $T^{Stripper-Inlet}_{TEG}$ = 90 °C; $P^{Reboiler}$ = 1.21 bar; $T^{Reboiler}$ = 140 °C; Heat Ratio = 83.85 $MJ/kmol^{H2O}$; Make-up: TEG = 99%*w*/*w*; H_2O = 1%*w*/*w*; T^{Inlet} = 25 °C; P^{Inlet} = 1.01 bar.
NG Pipeline [b]	$T^{Pipeline}$ = 40 °C; $P^{Pipeline}$ = 66.7 bar; $CH_4 \geq$ 85%mol; $CO_2 \leq$ 3%mol; $C_2H_6 \leq$ 12%mol; $C_3H_8 \leq$ 6%mol; $H_2O \leq$ 100 ppm-mol; $H_2S \leq$ 10 ppm-mol.
Steam Generation	P = 1.25 bar; Heat Loss = 10%; Air Excess = 66.10%; ΔP = 0.03 bar; $\Delta T^{Approach}$ = 40 °C; DCC: 3-Staged; P^{Top} = 1.16 bar; P^{Bottom} = 1.19 bar; Flue-gas: T^{Outlet} = 36 °C.
CW Tower	Blowdown = Evaporation; ΔP^{Fan} = 0.03 bar; Make-up = Evaporation + Blowdown; P = 1.01 bar; T = 30 °C.

[a] Heating via LPS; [b] ANP [9].

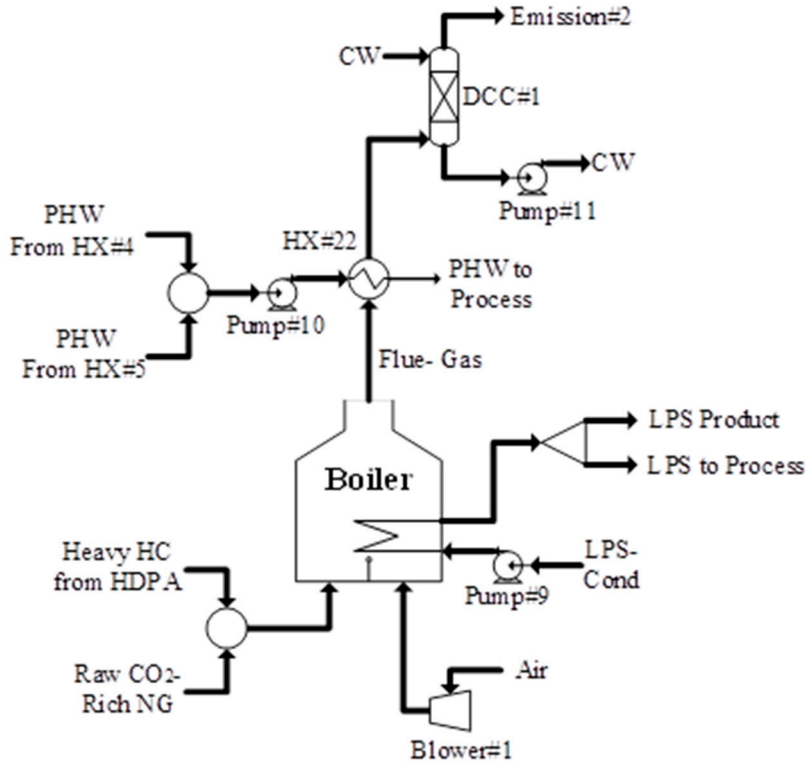


Figure 4. Steam Generation: NGPP Base Case.

2.2. Decarbonized NGPP-CCS-CCU

Since the carbon footprint of the NGPP Base Case corresponds to Emission#1 and Emission#2, the decarbonized NGPP (NGPP-CCS-CCU) adopts a CCS-CCU technology

based on hybrid MP+PCC-MEA capture coupled to a pipeline CO_2 dispatch to geological storage (CCS) and/or to EOR. The role of the MP unit is to reduce the CO_2 load by 50% in the raw CO_2-rich NG feed (P = 70 bar). MP operates with single-stage countercurrent modules of skin-dense cellulose acetate hollow-fiber membranes and is simulated by HYSYS by means of a HYSYS Unit Operation Extension MP-UOE developed by our group [41]. The pre-treated NG from MP and the flue-gas from Steam Generation are decarbonized by PCC-MEA. The only remaining emission of NGPP-CCS-CCU is a residual Emission#CCS/CCU.

CO_2 streams from MP, AGRU, and PCC-MEA go to a four-staged intercooled compression train (CO_2-CMP). Compressed CO_2 (P ≈ 68 bar, T = 40 °C) is dehydrated in the TEG unit. Figure 5 sketches the proposed decarbonized NGPP-CCS-CCU. Four subsystems were added to the Base Case: PCC-MEA, CO_2-CMP, CO_2 Dehydration, and CO_2 Final CMP. Here, PCC-MEA, CO_2-CMP, and CO_2 Dehydration are CO_2 analogs of the Base Case AGRU, NG Compression, and NG Dehydration. Additional LPS is required for PCC-MEA and CO_2 Dehydration. Dry CO_2 from CO_2 Dehydration attains a high pressure for the pipeline dispatch in the final CO_2 compression unit (CO_2 Final CMP). Here, CO_2 is firstly compressed to P = 130 bar (Comp#11), then cooled to T = 40 °C (intercooler HX#37) becoming a high-density supercritical fluid, which is finally pumped to P = 300 bar (Pump#18) and cooled to T = 40 °C (HX#38) for the pipeline dispatch to geological storage (CCS) or EOR (Figure 6). Table 2 complements Table 1 with extra assumptions for NGPP-CCS-CCU.

In the accountability of emissions reduction due to CO_2 capture by the NGPP-CCS-CCU, this study does not count the indirect CO_2 emissions generated elsewhere with the oil that is being produced by CO_2-to-EOR using the dense CO_2 exported by the NGPP-CCS-CCU.

Table 2. Complement to Table 1: NGPP-CCS-CCU extra assumptions.

Item	Assumption
MP Simulation and Design [a]	HYSYS Unit Operation Extension MP-UOE [41]
Membrane Permeation Operation [a]	$Efficiency^{CO2,capt}$ = 50%; $P^{Permeate}$ = 4 bar; $P^{Retentate}$ = 66 bar; Module: Countercurrent Hollow-Fiber Skin-Dense Cellulose Acetate Membrane; Permeances (MMSm³/d.m².bar): $\Pi_{CO2} = 2.77 \times 10^{-6}$; $\Pi_{H2O} = 9.57 \times 10^{-8}$; $\Pi_{N2} = 9.57 \times 10^{-8}$; $\Pi_{H2S} = 2.7 \times 10^{-6}$; $\Pi_{C1} = 9.57 \times 10^{-8}$; $\Pi_{C2} = 9.57 \times 10^{-9}$; $\Pi_{C3} = 9.57 \times 10^{-10}$; $\Pi_{C4} = 9.57 \times 10^{-10}$.
MEG	T = 40 °C; P = 70 bar; MEG = 90%mol; H_2O = 10%mol. Capture Ratio = 4.20 kg^{MEG}/kg^{H2O}.
Water-MEG Distillation [b]	P^{Top} = 0.2 bar; P^{Bottom} = 0.4 bar; T_{MEG}^{Inlet} = 36 °C; P_{MEG}^{Inlet} = 0.3 bar.
AGRU [a]	Absorber: $T_{Aqueous-NEA}^{Absorber-Inlet}$ = 40 °C; P^{Top} = 3.7 bar; P^{Bottom} = 4 bar; Aqueous-MEA: MEA = 30%*w*/*w*; H_2O = 70%*w*/*w*; Capture Ratio = 11.41 $kg^{Aqueous-MEA}/kg^{CO2}$; $Efficiency^{Capture}$ = 96%; Stripper: $T_{Aqueous-NEA}^{Stripper-Inlet}$ = 85 °C; $P^{Condenser}$ = 1.01 bar; $T^{Condenser}$ = 40 °C; $P^{Reboiler}$ = 1.02 bar; $T^{Reboiler}$ = 102 °C; Heat Ratio = 194.3 $MJ/kmol^{CO2}$.
NG Dehydration [a]	Absorber: $T_{TEG}^{Absober-Inlet}$ = 40 °C; P^{Top} = 67.2 bar; P^{Bottom} = 67.3 bar; Capture Ratio = 5.06 kg^{solv}/kg^{H2O}; Stripper: $P^{Condenser}$ = 1.01 bar; $T^{Condenser}$ = 40 °C; $P^{Reboiler}$ = 1.21 bar; $T_{TEG}^{Stripper-Inlet}$ = 90 °C; $T^{Reboiler}$ = 140 °C; Heat Ratio = 84.11 $MJ/kmol^{H2O}$; Make-up: TEG = 99%*w*/*w*; H_2O = 1%*w*/*w*; T^{Inlet} = 25 °C; P^{Inlet} = 1 bar.
PCC-MEA [b]	Absorber: $T_{Aqueous-MEA}^{Inlet} = 40^{o}C$; P^{Top} = 1 bar; P^{Bottom} = 1.2 bar; Aqueous-MEA: MEA = 30%*w*/*w*; H_2O = 70%*w*/*w*; $Efficiency^{Capture}$ = 90%; Capture Ratio = 12 $kg^{Aqueous-MEA}/kg^{CO2}$;

	Stripper: $P^{Condenser}$ = 1 bar; $T^{Condenser}$ = 40 °C; $P^{Reboiler}$ = 1.02 bar; $T^{Reboiler}$ = 102 °C; $T_{Aqueous-NEA}^{Stripper-Inlet}$ = 83 °C; Heat Ratio = 211.7 MJ/kmol^{CO2}.
CO_2 Compression	Compression Ratio^{Stage} = 3; Stages = 4; $T^{Intercooler}$ = 40 °C.
CO_2 Dehydration [b]	Absorber: $T_{TEG}^{Absorber-Inlet} = 40^{o}C$; P^{Top} = 61.9 bar; P^{Bottom} = 62.1 bar; Capture Ratio = 4.59 kg^{TEG}/kg^{H2O}; Dry CO_2: H_2O = 50 ppm-mol; Stripper: $P^{Condenser}$ = 1.01 bar; $T^{Condenser}$ = 40 °C; $P^{Reboiler}$ = 1.21 bar; Heat Ratio = 100.7 MJ/kmolH_2O. $T_{TEG}^{Stripper-Inlet}$ = 80 °C; $T^{Reboiler}$ = 140 °C.
CO_2-to-EOR and CO_2-to-CCS	Pipeline^{Length} = 275 km; $P^{Dispatch}$ = 300 bar; $T^{Dispatch}$ = 40 °C; Fluid: CO_2 = 97.2%mol; Hydrocarbons = 2.8%mol;

[a] Arinelli et al. [41]; [b] Heating via LPS.

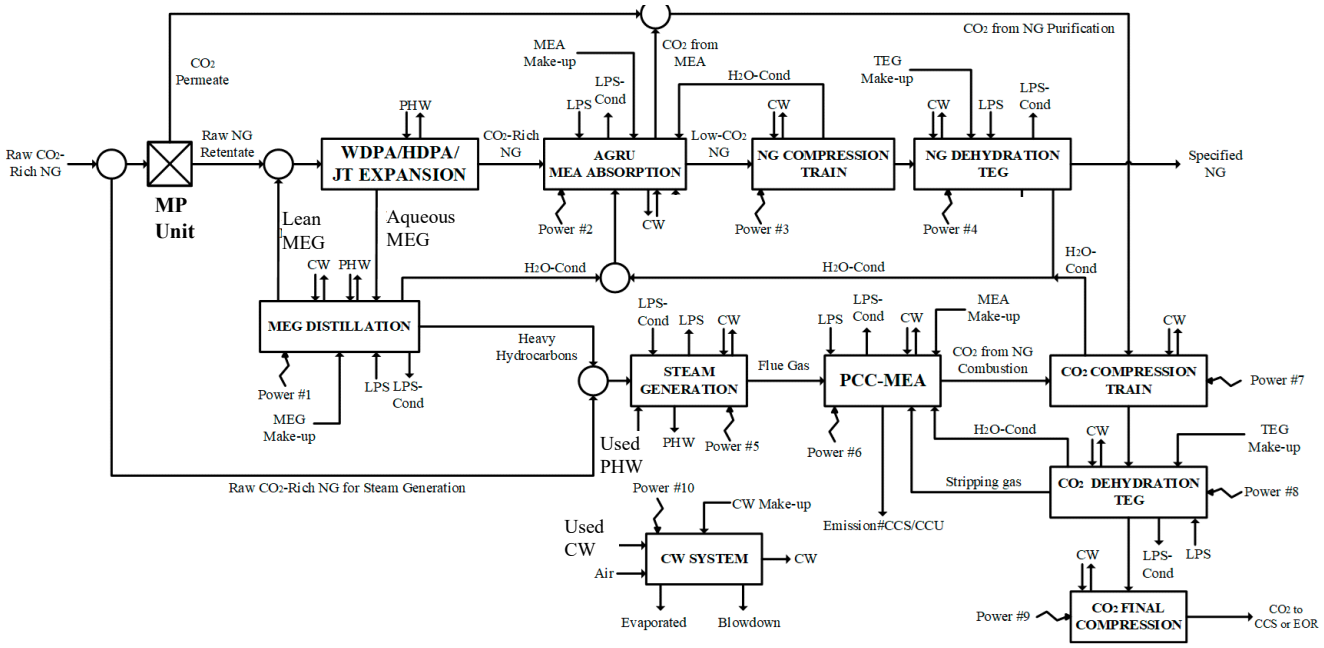


Figure 5. NGPP-CCS-CCU: Decarbonization via hybrid MP+PCC-MEA.

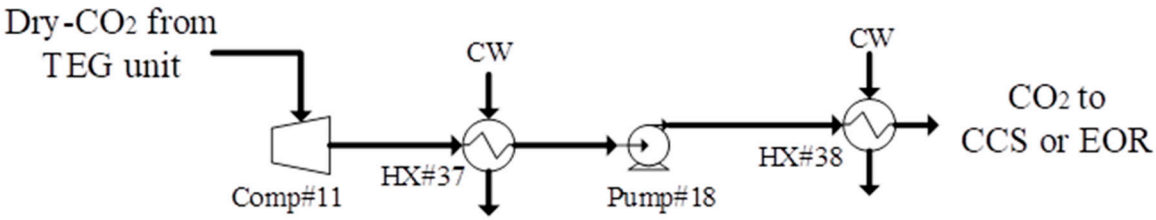


Figure 6. NGPP-CCS-CCU: CO_2-to-CCS and CO_2-to-EOR Final Compression.

2.3. Economic Analysis

Economic analysis follows Turton et al. [42] for estimating economic variables, namely, the following: Fixed Capital Investment of installed equipment *FCI*(MMUSD); Cost of Labor *COL*(MMUSD/y); Cost of CO_2 Transport *CCT*(MMUSD/y); Cost of Raw Materials *CRM*(MMUSD/y); Cost of Utilities *CUT*(MMUSD/y); Cost of Manufacture *COM*(MMUSD/y); Revenues *REV*(MMUSD/y); Gross Annual Profit *GAP*(*MMUSD/y*); Annual Depreciation *DEPR*(MMUSD/y); Annual Profit *AP*(MMUSD/y); Net Present Value *NPV*(MMUSD); and Payback Time *PB Time*(years). Equipment *FCI* was corrected via the annual average value of Chemical Engineering Plant Cost Index (*CEPCI*) for 2025 [43], the reference year for analysis. Startup inventories (MEA, TEG, CW, PHW, process water, etc.) are included in *FCI*. A 25-year project lifetime (N = 25 y) is assumed with 2 years of

construction and 23 years of operation (from k = 3 to k = N = 25). Key economic parameters are the following: Income Tax Rate *ITR*(%); Annual Interest Rate *i*(%); Mean Annual Operator Cost Op_{Cost}(MMUSD/y); Number of Operators N_{OL}; and the Number of Equipment Items N_{EQ}. Economic relationships [42] follow in Equations (1)–(8) where *j* represents equipment item *j*; $C_{BM}(j)$ is the bare module cost (MMUSD) of *j* corrected by material/design/pressure factors [42] from a reference condition $C_{BM}^{ref}(j)$, which is corrected by *CEPCI* to the reference year; and *CF*(*j*) is the capacity factor of *j* for capacity corrections. In Equation (8) AP_k is the *AP* value for year *k* and 40%FCI is invested in year#1 and 60%FCI in year#2.

$$C_{BM}(j) = C_{BM}^{ref}(j) * \left(\frac{CF(j)}{CF^{ref}(j)} \right)^{0.6} \quad (1)$$

$$FCI = 1.18 * \sum_{j=1}^{N_{EQ}} C_{BM}(j) \quad (2)$$

$$N_{OL} = 4.5 * \left[6.29 + 0.23 N_{EQ} \right]^{0.5} \quad (3)$$

$$COL = N_{OL} Op_{Cost} \quad (4)$$

$$COM = 0.18 FCI + 2.73 COL + 1.23(CUT + CRM + CCT) \quad (5)$$

$$GAP = REV - COM \quad (6)$$

$$AP = \begin{cases} GAP - \left[(GAP - DEPR) * (ITR / 100) \right], & if\ GAP > DEPR \\ GAP, & if\ GAP \le DEPR \end{cases} \quad (7)$$

$$NPV = \left(\sum_{k=3}^{N} AP_k / q^k \right) - \left[0.4 + 0.6 / q \right] * FCI, \quad q = (1 + i / 100) \quad (8)$$

For NGPP-CCS-CCU, the *FCI* of the MP unit was estimated with the module area (m^2), the required number of modules, and the membrane unitary cost (USD/m^2) [6]. For the Base Case and NGPP-CCS-CCU, *CRM* comprises the annual costs of raw CO_2-rich NG and make-ups of aqueous-MEA, TEG, MEG, demineralized water and CW. The annual replacement rate of the MP modules generates an additional *CRM* component for NGPP-CCS-CCU. Raw NG cost was found elsewhere [44]. *CCT* was estimated from typical CO_2 unitary transport cost (USD/ton^{CO2}.100 km) imposed by pipeline operators. *CUT* corresponds to electricity consumption. The sweetened NG price was estimated from the average USA distribution price [45]. The sweetened NG is the main revenue of the Base Case and NGPP-CCS-CCU operating within the CCS-Only scenario (i.e., no EOR). Meanwhile, CO_2-to-EOR generates additional revenue for NGPP-CCS-CCU operating with Partial CO_2-to-EOR or Total CO_2-to-EOR scenarios. EOR was given by the average 2025 oil price (70USD/bbl) [46] assuming 1 bbl^{Oil}/ton$^{CO2\text{-}Injected}$. Table 3 presents economic assumptions.

Table 3. Base Case and NGPP-CCS-CCU: economic assumptions.

Item	Assumption	Reference
Project Lifetime	25 y	
Construction	2 y (40%FCI + 60%FCI)	
Operation	8400 h/y	[42]

i	6%	[42]
DEPR(MMUSD/y)	10%FCI for first 10 operational years	[42]
ITR	34%	[42]
Op_{Cost}	66,910 USD/Operator.y	[42]
Operator Shifts	3	[42]
CEPCI (Reference Dec-2025)	800	[43]
MP FCI	50 USD/m^2	[6]
MP Annual Replacement Cost	12.5 USD/m^2.y	[6]
Raw CO_2-rich NG	2.94 USD/MMBTU	[44]
$NG^{Sweetened}$	7 USD/MMBTU	[45]
CO_2-to-EOR Revenue	1 $bbl^{oil}/t^{CO2\text{-}Injected}$	[46]
Pipeline CO_2 Transport	3 USD/t^{CO2}.100 km	[47]
MEA	1270 USD/t	[48]
TEG, MEG	1685 USD/t	[49]
Demineralized Water	0.5 USD/t	[50]
Electricity	85 USD/MWh	[51]

2.4. MAC Analysis

MAC(USD/t^{CO2}) estimates the profitability loss (or profitability increase) per ton of captured CO_2 after the Base Case is retrofitted to the decarbonized NGPP-CCS-CCU [38,52–54]. *MAC* is calculated by Equation (9) using the difference in *AGAP*(MMUSD) between the Base Case and NGPP-CCS-CCU, where *AGAP*(MMUSD) measures the profitability as the accumulated discounted *GAP*(MMUSD/y) for the project lifetime. The denominator of Equation (9) represents the total carbon capture (MMt^{CO2}) via CCS and via CCU for the project lifetime. *AGAP*(MMUSD) values for the Base Case and for NGPP-CCS-CCU are calculated by Equations (10) and (11), wherein GAP_k(MMUSD/y), CCS_k(MMt^{CO2}/y) and CCU_k(MMt^{CO2}/y) represent the annual values of *GAP*, *CCS*, and *CCU* for year *k*. These values are assumed to vary during the project lifetime due to market changes, plant management decisions, and process performance variations. The total carbon capture via CCS and via CCU of NGPP-CCS-CCU are calculated via Equations (12) and (13). A positive *MAC*(USD/t^{CO2}) reflects profitability loss (the usual case) due to decarbonization, while a negative *MAC*(USD/t^{CO2}) translates into gains of profitability with the decarbonization (usually due to very lucrative CCU).

$$MAC(USD/t^{CO2}) = \frac{AGAP^{Base-Case}(MMUSD) - AGAP^{NGPP-CCS-CCU}(MMUS}{CCS^{Total}(MMt^{CO2}) + CCU^{Total}(MMt^{CO2})} \quad (9)$$

$$AGAP^{Base-Case}(MMUSD) = \sum_{k=3}^{N} \frac{GAP_k^{Base-Case}}{(1+i/100)^k} \quad (10)$$

$$AGAP^{Base-Case}(MMUSD) = \sum_{k=3}^{N} \frac{GAP_k^{Base-Case}}{(1+i/100)^k} \quad (11)$$

$$CCS^{Total}(MMt^{CO2}) = \sum_{k=3}^{N} CCS_k(MMt^{CO2}/y) \quad (12)$$

$$CCU^{Total}(MMt^{CO2}) = \sum_{k=3}^{N} CCU_k(MMt^{CO2}/y) \quad (13)$$

In the *MAC* Analysis, six CO_2 destinations were evaluated for NGPP-CCS-CCU: (i) CO_2-*to*-*CCS* = 100%, CO_2-*to*-*EOR* = 0%; (ii) CO_2-*to*-*CCS* = 50%, CO_2-*to*-*EOR* = 50%; (iii) CO_2-*to*-*CCS* = 40%, CO_2-*to*-*EOR* = 60%; (iv) CO_2-*to*-*CCS* = 30%, CO_2-*to*-*EOR* = 70%; (v) CO_2-*to*-*CCS* = 20%, CO_2-*to*-*EOR* = 80%; and (vi) CO_2-*to*-*CCS* = 0%, CO_2-*to*-*EOR* = 100%. Therefore,

six *MAC* values were obtained for NGPP-CCS-CCU to assess its economic–environmental performance. In parallel, for reasons of comparison with the literature, the CO_2 Avoidance Cost *CAC*(USD/t^{CO2}) was obtained through Equations (14)–(17), wherein *CRF*, *N*(y), *ACC*(MMUSD/y), and *TAC*(MMUSD/y) stand, respectively, for Capital Recovery Factor, Project Lifetime, Annualized *FCI*, and Total Annualized Cost [37]. In Equation (17), $Emission^{Base\text{-}Case}$ and $Emission^{NGPP\text{-}CCS\text{-}CCU}$ represent annual CO_2 emissions (MMt^{CO2}/y) of the Base Case and NGPP-CCS-CCU [52].

$$CRF = \frac{i(1+i)^N}{(1+i)^N - 1} \quad (14)$$

$$ACC(MMUSD/y) = CRF * FCI(MMUSD) \quad (15)$$

$$TAC(MMUSD/y) = COM(MMUSD/y) + ACC(MMUSD/y) \quad (16)$$

$$CAC(USD/t^{CO_2}) = \frac{TAC^{NGPP-CCS-CCU}(MMUSD/y) - TAC^{Base-Case}(MMUSD/y)}{Emission^{Base-Case}(MMt^{CO2}/y) - Emission^{NGPP-CCS-CCU}(MMt^{CO2}} \quad (17)$$

3. Results and Discussion

Techno-environmental–economic results are reported for the Base Case and NGPP-CCS-CCU.

3.1. Techno-Environmental Performance

Table 4 presents the main streams for the Base Case and NGPP-CCS-CCU. The Base Case produced 5545 kmol/h of sweetened NG from 11,631 kmol/h of raw NG, emitting 4232.55 kmol/h of CO_2 from AGRU (Emission#1, after flare) and 2197.78 kmol/h from NG combustion in the Steam Generator (Emission#2). The decarbonized NGPP-CCS-CCU had extra thermal demands, having to fire extra raw NG at 75 kmol/h, with a total reduction of 241 kmol/h of $NG^{Sweetened}$ relatively to the Base Case. On the other hand, NGPP-CCS-CCU reduced CO_2 emissions to 249.25 kmol/h. MP reduced almost half of the CO_2 outlet from AGRU (4232 kmol/h versus 2235 kmol/h), therefore lowering the AGRU thermal duty for CO_2 separation.

Table 5 depicts the results regarding the raw materials, utilities consumptions, products, and CO_2 issues for the Base Case and NGPP-CCS-CCU. Sweetened NG production from NGPP-CCS-CCU decreased by 5.78% compared to the Base Case. Additionally, the methane recoveries for the Base Case and NGPP-CCS-CCU were around 84% and 81%, respectively. The reason is that methane losses from MP, NG decarbonization, and Steam Generation correspond to 2.15%, 1.28%, and 15.91% for NGPP-CCS-CCU, while the Base Case methane losses from AGRU and Steam Generation correspond to 0.92% and 15.26%.

Aqueous-MEA and TEG make-ups in NGPP-CCS-CCU were 7.6× and 4.2× higher than the Base Case counterparts due to extra decarbonization and CO_2 dehydration. In contrast, NGPP-CCS-CCU has a lower MEG make-up primarily due to the lower NG throughput downstream of the MP, entailing lower MEG carry-over through the gas exit from WDPA/HDPA, a fact consistent with previous studies on NGPP glycol losses [55–57].

Table 4. Base Case and NGPP-CCS-CCU: main streams.

Base Case				
Raw NG	**Raw NG Steam Generator**	**Emission#1 (after flare)**	**Emission#2**	**$NG^{Sweetened}$**

T(°C)	40	40	293.80	36.39	40
P(bar)	70	70	1.01	1.16	66.70
kmol/h	11,631	1775	5217	21,653	5545
%mol					
CO_2	43.84	43.84	81.13	10.15	2.79
N_2	0.00	0.00	9.61	75.64	0.00
H_2O	0.38	0.38	9.15	5.24	0.01
CH_4	49.84	49.84	0.0	0.0	87.59
C_2H_6	2.99	2.99	0.0	0.0	5.26
C_3H_8	1.99	1.99	0.0	0.0	3.36

	NGPP-CCS-CCU							
	Raw NG	**Raw NG Steam Generator**	**MP Permeate**	**CO_2 AGRU**	**Flue-Gas Steam Generator**	**$NG^{Sweetened}$**	**CO_2 Capt.**	**Total Emission**
T(°C)	40	40	24.38	40	36.29	40	40	55.62
P(bar)	70	70	4.0	1.01	1.16	66.70	300	1.01
kmol/h	11,631	1850	2269	2481	25,082	5304	6526	25,177
%mol								
CO_2	43.84	43.84	94.42	90.10	9.85	2.85	97.22	0.99
N_2	0.00	0.00	0.00	0.00	75.84	0.00	0.01	75.56
H_2O	0.38	0.38	0.04	7.39	5.21	0.01	50 ppm-mol	14.35
CH_4	49.84	49.84	5.50	2.29	0.00	88.11	2.68	0.00
C_2H_6	2.99	2.99	0.03	0.13	0.00	5.41	0.06	0.00
C_3H_8	1.99	1.99	0.00	0.08	0.00	3.10	0.03	0.00

Retrofitting with PCC-MEA usually entails a large increase in LPS demand due to higher aqueous-MEA and TEG regeneration loads caused by flue-gas decarbonization [40]. However, NGPP-CCS-CCU only required 15% extra LPS relative to the Base Case, a consequence of MP pre-decarbonization of raw NG. This considerably reduced the AGRU heat load, despite the high duty of PCC-MEA for flue-gas decarbonization. This fact is consistent with the results of Araújo et al. [6] and Sclierf and Rufford [23]. Supplement S1 (Supplementary Materials) presents the Base Case and NGPP-CCS-CCU simulation results for the AGRU, PCC-MEA, and TEG plants.

NGPP-CCS-CCU air demand for Steam Generation was also higher than the Base Case counterpart, since a higher raw NG flowrate was required for the increased LPS demand. Consequently, NGPP-CCS-CCU Steam Generation produces 11% more CO_2 than the Base Case. Nevertheless, NGPP-CCS-CCU drastically reduced CO_2 emissions from ≈2.38 MMt/y (Base Case) to ≈0.09 MMt/y. This means a drop of the 25-year emissions from 54.68 MMt^{CO2} to 2.12 MMt^{CO2} and a reduction in the emission factor from 2.69 $t^{CO2}/t^{NG\text{-}Sweetened}$ to 0.11 $t^{CO2}/t^{NG\text{-}Sweetened}$. The carbon capture efficiency of NGPP-CCS-CCU is 94.05%, with a CO_2 emission ratio of 0.04 $t^{CO2}/t^{CO2\text{-}Captured}$ and a CO_2 avoidance factor of 2.74 $t^{CO2}/t^{NG\text{-}Sweetened}$.

NGPP-CCS-CCU required ≈2.2× more power than the Base Case (Table 5). In NGPP-CCS-CCU, despite the reduction in power for AGRU and NG-CMP, the entire plant required an additional 37.64 MW of power relative to the Base Case, where the higher power demand of Steam Generation and the CW System also contributed to this result. Supplements S2 and S3 (Supplementary Materials) present the Base Case and NGPP-CCS-CCU simulation results of the power demands for all units.

Table 5. Base Case and NGPP-CCS-CCU: raw materials, utilities, products, and CO_2 issues.

Item	**Base Case**	**NGPP-CCS-CCU**
Raw NG (t/y)	2,911,590	2,911,590

CW Make-up (t/y)	6,433,476	7,828,044
MEG Make-up (t/y)	2.79	0.56
MEA Make-up (t/y)	45,811	347,512
TEG Make-up (t/y)	5.12	21.50
Sweetened NG (t/y)	884,326	833,196
LPS Demand (t/y)	3,406,345	3,918,934
Air Demand (t/y)	5,322,659	5,999,037
Power Demand (MW)		
WDPA/HDPA	0.00	0.00
Water-MEG Distillation	0.19	0.30
AGRU	0.29	0.14
NG Compression	17.49	16.77
NG Dehydration	0.03	0.03
Steam Generation	4.49	5.23
PCC-MEA	-	0.06
CO_2 Compression	-	29.08
CO_2 Dehydration	-	0.13
CO_2 Final Compression	-	6.27
CW System	9.26	11.38
Total (MW)	31.74	69.38
Total (MWh/y)	266,622	582,811
CH_4 Recovery (%)	83.82	80.66
CO_2 from Raw NG (t/y)	1,884,099	1,884,099
CO_2 Produced (t/y)	549,512	609,649
CO_2 in $NG^{Sweetened}$ (t/y)	57,237	55,873
CO_2 Emissions (MMt/y)	2.38	0.092
CO_2 Emissions 25 years (MMt^{CO2})	54.68	2.12
Emission Factor ($t^{CO2}/t^{NG\text{-}Sweetened}$)	2.69	0.11
Emission Ratio ($t^{CO2}/t^{CO2\text{-}Captured}$)	-	0.04
Net CO_2 Captured (t/y)	-	2,370,842
CO_2 Captured over 25 years (MMt^{CO2})	-	54.53
CO_2 Capture Efficiency	-	94.05%
CO_2 Avoided ($t^{CO2}/t^{NG\text{-}Sweetened}$)	-	2.74 *
CO_2 Avoided	-	96.12% *

* Relative to Base Case.

3.2. Economic and MAC Performances

Table 6 presents *FCI* values for the Base Case and NGPP-CCS-CCU components. Seven subsystems of the Base Case (totaling 103 equipment items) were assessed for economic analysis. AGRU, Steam Generation, and NG compression were the most expensive units—corresponding to more than 90% of the Base Case *FCI*—which reflects the large multi-stage absorber and stripper columns, large compressors, and the high thermal load of Steam Generation. On the other hand, NGPP-CCS-CCU has 64 additional *FCI* items associated with four new CCS/CCU units, entailing an *FCI* increase of 148.28 MMUSD over the Base Case. Also, as a consequence of the large CCS/CCU units for NGPP-CCS-CCU, the inventories of Aqueous-MEA, TEG, and CW are ≈3× as large as the Base Case counterparts. Additionally, AGRU *FCI* was drastically reduced from 66.83 MMUSD (in the Base Case) to 34.93 MMUSD (in NGPP-CCS-CCU) due to NG pre-decarbonization by MP [54], a strategy endorsed by Sclierf and Rufford [23]. *FCI* discrimination for the Base Case and NGPP-CCS-CCU is approached in Supplement S4, Supplementary Materials.

Table 6. Base Case and NGPP-CCS-CCU: *FCI* (installed equipment and inventories).

	Base Case (MMUSD)	**NGPP-CCS-CCU (MMUSD)**
WDPA/HDPA	3.70	4.14
Water-MEG Distillation	2.46	3.01
AGRU	66.83	34.93
NG Compression	32.42	31.55
NG Dehydration	2.11	2.07
Steam Generation	61.02	66.37
PCC-MEA	-	93.55
CO_2 Compression	-	50.50
CO_2 Dehydration	-	4.15
CO_2 Final Compression	-	19.33
CW Tower	5.26	5.76
Solvent Inventories	3.36	10.08
TOTAL FCI	**177.16**	**325.44**

Table 7 depicts economic and *MAC* and *CAC* performances for the Base Case and NGPP-CCS-CCU, the latter considering six CO_2 final-destination scenarios. Raw NG cost is the same for the Base Case and all NGPP-CCS-CCU cases, 139.98 MMUSD/y, approximately 97.7% of the total *CRM*. The NGPP-CCS-CCU solvent make-up costs lead to ≈30× the Base Case analog due to the large PCC-MEA and TEG plants for flue-gas and CO_2 treatment, while the demineralized water cost for CW make-up in NGPP-CCS-CCU was only 20% higher than the Base Case analog. NGPP-CCS-CCU *CUT* was more than 2× higher than the Base Case counterpart, mainly due to the extra 25.22 MMUSD/y electricity cost for the CCS-CCU facilities. NGPP-CCS-CCU also exhibits ≈25% higher CW Tower *CUT* relative to the Base Case due to the higher heat input for solvent regeneration, which causes greater CW circulation and evaporation in the CW Tower. The NGPP-CCS-CCU CO_2 transportation cost (*CCT*) added 19.56 MMUSD/y more to $COM^{Base\text{-}Case}$ and all CCS-CCU facilities end up adding 88.47 MMUSD/y over $COM^{Base\text{-}Case}$.

NGPP-CCS-CCU operating at CO_2-*to-CCS* = 100% and the Base Case have only the same single source of revenue (*REV*); namely, sweetened NG sales. Meanwhile, the respective investments are very different ($FCI^{NGPP\text{-}CCS\text{-}CCU}$ = 325.44 MMUSD >> $FCI^{Base\text{-}Case}$ = 177.16 MMUSD) due to the extra *FCI* for the large CCS-CCU facilities. In the Base Case, *REV* = 271.50 MMUSD/y was sufficient to overcome its light *COM*, thereby achieving positive $NPV^{25years}$ = 104.58 MMUSD with *Payback Time* = 12 years. On the other hand, for NGPP-CCS-CCU operating at CO_2-*to-CCS* = 100%, there was no chance of achieving positive $NPV^{25years}$ due to a very high *COM* = 327.26 MMUSD/y that surpassed a relatively low *REV* = 255.82 MMUSD/y, entailing negative *GAP* = *AP* = −71.44 MMUSD/y.

Nevertheless, by adding CO_2-to-EOR revenues to NGPP-CCS-CCU, it is possible to leverage its profitability, reaching positive $NPV^{25Years}$ for CO_2-*to-EOR* ≥ 70%; i.e., NGPP-CCS-CCU $NPV^{25Years}$ increased from +81.20 MMUSD to +441.02 MMUSD as CO_2-*to-EOR* increased from 70% to 100%, automatically lowering *Payback Time* from 16 years to 8 years. Moreover, at CO_2-*to-EOR* = 80% NGPP-CCS-CCU achieves $NPV^{25Years}$ greater than the Base Case counterpart (201.14 MMUSD *versus* 104.58 MMUSD) with the same *Payback Time* = 12 years. Figure 7 illustrates *NPV* evolution over time for the Base Case and NGPP-CCS-CCU for selected values of CO_2-*to-EOR* from 0% to 100%.

Regarding *MAC* performances, *MAC* only makes sense for decarbonized processes (i.e., NGPP-CCS-CCU) and expresses the abatement cost of one additional CO_2 metric ton. As Table 7 shows, NGPP-CCS-CCU was not economically feasible (negative $NPV^{25years}$) for CO_2-*to-CCS* = 100%, CO_2-*to-EOR* = 50%, and CO_2-*to-EOR* = 60%. The corresponding *MACs*

reached values from 20.92 USD/t^{CO2} down to 0.92 USD/t^{CO2}. As *CO_2-to-EOR* further increases, *MAC* keeps decreasing, eventually attaining the most negative value (−12.41 USD/t^{CO2}) at *CO_2-to-EOR* = 100%. This is attributed to increasing profitability as *CO_2-to-EOR* increases above *CO_2-to-EOR* = 70%. On the other hand, the CO_2 avoidance cost *CAC*(USD/t^{CO2}) does not depend on *CO_2-to-EOR* and attains the same 43.79 USD/$t^{CO2avoided}$ for all six *CO_2-to-EOR* scenarios of NGPP-CCS-CCU. The truth is that *CAC*(USD/t^{CO2}) cannot distinguish between CCS and CCU because it is insensitive to profitability. This is why *MAC*(USD/t^{CO2}) seems to be a better process decarbonization metric than *CAC*(USD/t^{CO2}) as *MAC*(USD/t^{CO2}) distinguishes between CCS and CCU. Figure 8 presents the *MAC* curve for the six NGPP-CCS-CCU scenarios of *CO_2-to-EOR*.

Table 7. Base Case and NGPP-CCS-CCU: economic and *MAC* and *CAC* performances.

Variable	Base Case	NGPP-CCS-CCU (%CO_2-to-EOR or %CO_2-to-CCS)					
		100% CO_2-to-CCS	**50% CO_2-to-EOR**	**60% CO_2-to-EOR**	**70% CO_2-to-EOR**	**80% CO_2-to-EOR**	**100% CO_2-to-EOR**
FCI Allocated (year#1)	70.86	130.18	130.18	130.18	130.18	130.18	130.18
FCI Allocated (year#2)	90.14	195.26	195.26	195.26	195.26	195.26	195.26
CRM(MMUSD/y)	143.28	146.56	146.56	146.56	146.56	146.56	146.56
Raw CO_2-rich NG	139.98	139.98	139.98	139.98	139.98	139.98	139.98
Demineralized Water	3.22	3.91	3.91	3.91	3.91	3.91	3.91
Make-up Solvents	0.08	2.41	2.41	2.41	2.41	2.41	2.41
Membrane Replacement	-	0.25	0.25	0.25	0.25	0.25	0.25
COL(MMUSD/y)	1.07	1.34	1.34	1.34	1.34	1.34	1.34
CUT(MMUSD/y)	22.53	49.33	49.33	49.33	49.33	49.33	49.33
Bare NGPP	15.96	15.94	15.94	15.94	15.94	15.94	15.94
CCUS+CCS Section	-	25.22	25.22	25.22	25.22	25.22	25.22
CW Tower	6.57	8.17	8.17	8.17	8.17	8.17	8.17
CCT(MMUSD/y)	-	19.56	19.56	19.56	19.56	19.56	19.56
COM(MMUSD/y)	238.79	327.26	327.26	327.26	327.26	327.26	327.26
DEPR(MMUSD/y)	17.72	32.56	32.56	32.56	32.56	32.56	32.56
REV(MMUSD/y)	271.50	255.82	338.80	355.39	371.99	388.58	421.78
Sweetened NG	271.50	255.82	255.82	255.82	255.82	255.82	255.82
CO_2-to-EOR	-	-	82.98	99.57	116.17	132.76	165.96
GAP(MMUSD/y)	32.71	−71.44	11.54	28.13	44.73	61.32	94.52
Income Tax(MMUSD/y) (with DEPR)	5.09	-	-	-	4.14	9.78	21.06
Income Tax(MMUSD/y) (no DEPR)	11.12	-	3.92	9.57	15.21	20.85	32.14
AP(MMUSD/y) (with DEPR)	27.62	−71.44	11.54	28.13	40.59	51.55	73.45
AP(MMUSD/y) (no DEPR)	21.59	−71.44	7.61	18.57	29.52	40.47	62.38
$NPV^{25Years}$(MMUSD)	104.58	−1096.87	−205.50	−48.60	81.20	201.14	441.02
Payback Time(y)	12	-	-	-	16	12	8
MAC and CAC Performances							
$AGAP^{25y}$(MMUSD)	358.21	−782.29	126.33	308.05	489.78	671.50	1034.9
$CO_2^{Captured-25y}$(MMt^{CO2})	-	54.53	54.53	54.53	54.53	54.53	54.53
MAC(USD/t^{CO2})	-	20.92	4.25	0.92	−2.41	−5.75	−12.41
CAC(USD/$t^{CO2\text{-}Avoided}$)	-	43.79	43.79	43.79	43.79	43.79	43.79

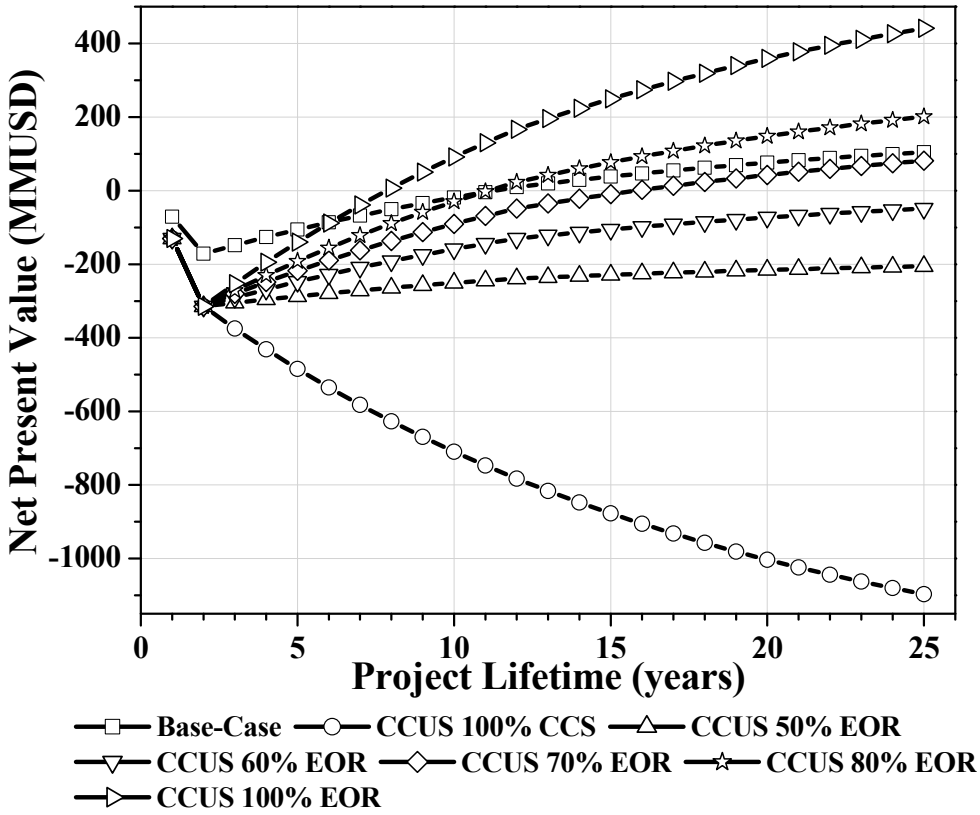


Figure 7. Base Case and NGPP-CCS-CCU: NPV(MMUSD) versus Time(year) for CO_2-to-CCS = 100% and CO_2-to-EOR from 50% to 100%.

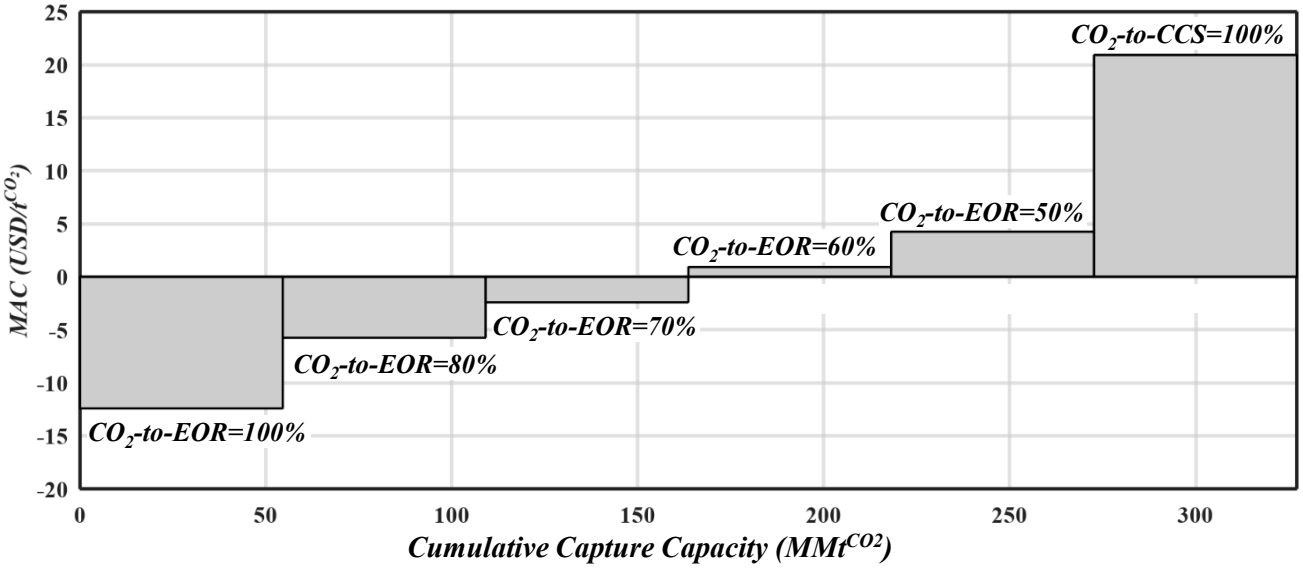


Figure 8. NGPP-CCS-CCU: *MAC*(*USD*/t^{CO2}) for CO_2-to-CCS = 100% and CO_2-to-EOR from 50% to 100%.

3.3. Literature Comparison

The proposed NGPP-CCS-CCU using hybrid capture MP-PCC-MEA exhibits trends generally consistent with previous studies on hybrid CO_2 capture for NG processing plants. Nevertheless, the present NGPP-CCS-CCU study extended the usual scope towards both extremes; i.e., including CO_2-rich NG processing and *MAC* and *CAC* in the performance analysis. In addition, the present approach contemplated rigorous process

engineering, heat and power and mass integration strategies, realistic utility production, and realistic emission accounting.

Comparing NGPP-CCS-CCU with the Base Case, one facet of the Capture Penalty was the increase in LPS consumption, which was limited to 15%; i.e., considerably lower than that typically reported for conventional post-combustion capture systems. This behavior is primarily attributed to the pre-decarbonization of raw CO_2-rich NG in the MP unit, which reduced the AGRU heat load and partially compensated the additional LPS consumption of PCC-MEA and CO_2 dehydration. This fact was corroborated by the work of Patel et al. [30], which demonstrated that process retrofitting can reduce steam requirements, although their analysis was restricted to the PCC-MEA regeneration section.

A similar trend was observed regarding *FCI*. Although the incorporation of MP [54] substantially reduced AGRU size, the overall investment increased due to additional capture and CO_2 compression and conditioning. MP removed ≈50% of the CO_2 in the feed, lowering AGRU *FCI* from 66.83 MMUSD in the Base Case to 34.93 MMUSD in NGPP-CCS-CCU, while the total *FCI* increased from 177.16 MMUSD to 325.44 MMUSD. These results agree with the reductions in AGRU *FCI* reported by Sclierf and Rufford [23], and with Araújo et al. [6] who reported an *FCI* increase from 210 MMUSD to 269 MMUSD after including carbon capture and CO_2-to-EOR to offshore CO_2-rich NG processing and the respective power generation system. Likewise, Sukor et al. [29] reported *FCI* = 640 MMUSD for an MP-based CCS system, achieving $NPV^{15years}$ = 292.94 MMUSD and *Payback Time* = 8 years for a NGPP-CCS.

However, unlike these previous studies, the present NGPP-CCS-CCU extended the system boundaries to include post-combustion capture of the CO_2 emitted in the Steam Generation flue-gas. Despite this additional Capture Penalty, implementing at least CO_2-*to-EOR* = 70% rendered the NGPP-CCS-CCU economically feasible with positive $NPV^{25years}$ of 441.02 MMUSD and lowering *Payback Time* down to 8 years. Additionally, the proposed retrofitted NGPP simultaneously mitigates NG sweetening emissions and utility-related emissions (e.g., Steam Generation), entailing an emission ratio of 0.04 $t^{CO2\text{-}Emitted}/t^{CO2\text{-}Captured}$, while Araújo et al. [6] achieved 0.19 $t^{CO2\text{-}Emitted}/t^{CO2\text{-}Captured}$, highlighting the importance of extending capture beyond conventional process emissions.

The economic results further reinforce the CCU importance to achieve profitability. Li et al. [32] reported an *NPV* increase from 50 MMUSD to 135 MMUSD when NG processing occurs simultaneously with EOR. Similarly, the present work showed that storage-only (i.e., CCS) scenarios remained economically unattractive, whereas implementing at least CO_2-*to-EOR* = 70% resulted in positive *NPV*.

Methane losses remain an inherent limitation of polymeric membranes, as reported elsewhere [21,23]. The present work also detected reduction in methane recovery from 83.82% to 80.66%, due to MP CH_4 losses. Nevertheless, this drawback was compensated for by the substantially reduced GHG emissions and decreased AGRU size, indicating that the environmental benefits outweigh the relatively small NG production penalty.

The overall CO_2 capture efficiency of ≈94% agrees with values commonly reported for integrated amine-based capture systems, such as that of Wang et al. [22], who achieved capture efficiencies of 99% using sequential H_2S and CO_2 absorption. Albeit its slightly lower capture efficiency, the proposed NGPP-CCS-CCU simultaneously treats raw CO_2-rich NG and flue-gas from Steam Generation, representing a more comprehensive decarbonization strategy. Consequently, atmospheric emissions were reduced from 2.38 MMt^{CO2}/y to only 0.09 MMt^{CO2}/y, or ≈96% avoided emissions. Moreover, NGPP-CCS-CCU reached *CAC* = 43.79 USD/$t^{CO2\text{-}Avoided}$, whereas Grande et al. [28] achieved only 26 USD/$t^{CO2\text{-}Avoided}$ for a typical NGPP with CO_2 removal and transportation. The higher avoidance cost of NGPP-CCS-CCU reflects the expanded capture scope adopted in this study, rather than an inferior process performance.

Unlike the PCC-MEA CCU in Teixeira et al. [33], NGPP-CCS-CCU adopted a more comprehensive decarbonization strategy by addressing both the CO_2 emissions from raw NG decarbonization and those from Steam Generation. Although Teixeira et al. [33] achieved $NPV^{25years}$ above 800 MMUSD with similar *REV* (>200 MMUSD/y), as well as lower *COM* (<50 MMUSD/y) and power demand (<10 MW), only 43% of CO_2 emissions were mitigated due to heat offer limitations. In contrast, the proposed NGPP-CCS-CCU mitigated more than 96% of CO_2 emissions, while warranting profitability for some CO_2-to-EOR scenarios, demonstrating the advantages of hybrid decarbonization for NGPP retrofitting.

Finally, the obtained *MAC* values for NGPP-CCS-CCU highlight a contribution from this study. While previous investigations on NGPP generally focused on capital costs, capture cost, or CO_2 avoidance cost, the present work demonstrated that coupling hybrid decarbonization with CO_2-to-EOR leads to *MAC* = −12.41 USD/t^{CO2} for the 100% CO_2-to-EOR scenario. This indicates that NGPP-CCS-CCU not only mitigates emissions but can reach profitability, strengthening the feasibility of hybrid decarbonization for CO_2-rich NG processing plants.

4. Conclusions

This work assessed the decarbonization of a conventional NG processing plant (the Base Case) operating with CO_2-rich NG by implementing hybrid MP-PCC-MEA carbon capture to create a decarbonized analog, NGPP-CCS-CCU. Six different CO_2-to-EOR scenarios—from *CO_2-to-EOR* = 0% to *CO_2-to-EOR* = 100%—were evaluated in terms of $NPV^{25Years}$, *MAC*, and *CAC* performances. The Base Case comprised WDPA+HDPA, AGRU, NG Compression, NG Dehydration, and Steam Generation units, while NGPP-CCS-CCU added MP, PCC-MEA, CO_2 Compression, CO_2 Dehydration units, and CO_2 pipeline transport.

Despite the reductions of 5.78% in sweetened NG exportation and 3.16% in methane recovery, NGPP-CCS-CCU achieved 94.05% of carbon capture efficiency, dispatching 54.53 MMt^{CO2} to CCS or to EOR (CCU) during 25 years of project lifetime. This performance corresponds to a reduction of 96.12% in CO_2 emissions relative to the Base Case, while achieving 2.74 $t^{CO2\text{-}Avoided}/t^{NG\text{-}Sweetened}$.

Regarding the six CO_2-to-EOR destination scenarios for NGPP-CCS-CCU, implementing *CO_2-to-CCS* = 100% did not attain feasibility due to negative $NPV^{25Years}$ = −1096.87 MMUSD, a consequence of insufficient *REV* vis-à-vis a high *COM*. On the other hand, implementing *CO_2-to-EOR* > 0% increases the profitability leverage of NGPP-CCS-CCU due to revenue increase. At *CO_2-to-EOR* = 70%, NGPP-CCS-CCU attains profitability with $NPV^{25Years}$ = +81.20 MMUSD. At *CO_2-to-EOR* = 80%, NGPP-CCS-CCU overcomes the Base Case profitability reaching $NPV^{25Years}$ = +201.14 MMUSD with same *Payback Time* = 12 years. The highest $NPV^{25Years}$ = +441.02 MMUSD and lowest *Payback Time* = 8 years were achieved at *CO_2-to-EOR* = 100%; i.e., 100% of captured CO_2 is directed to EOR. As a consequence of the progressive revenue increase by increasing *CO_2-to-EOR* from 0% to 100%, NGPP-CCS-CCU *MAC* values steadily decreased from *MAC* = +20.92 USD/t^{CO2} to *MAC* = −12.41 USD/t^{CO2}, unveiling the progressive improvement of the economic–environmental performance of NGPP-CCS-CCU.

In summary, for NGPP-CCS-CCU—the decarbonized version of a conventional CO_2-rich NG processing plant—that adopts hybrid MP-PCC-MEA decarbonization, this work showed that the progressive monetization of CO_2 via continuous increase in *CO_2-to-EOR*, gradually improves NGPP-CCS-CCU economic–environmental performance, eventually reaching a point of complete economic feasibility and more than 95% decarbonization.

5. Suggestions for Future Works

Any research paper can experience unlimited scope expansions, but at the same time, must be kept compact, concise, readable, conclusive, and self-contained for publication. Thus, several possible scope expansions applicable to the present work—no matter how interesting they are—should be analyzed with contention and moderation, and—if it is the case—be left as suggestions for future works based on the present manuscript. In the following, several possible scope expansions of the present work are listed as possible suggestions for future research.

Suggestion #1: Consider comparing the proposed hybrid MP+PCC-MEA configuration for CO_2 capture with other technologies for NGPP decarbonization. Such comparisons could encompass different hybrid capture processes, such as membrane permeation with new sodium chloride batch mineralization post-combustion capture (de Medeiros et al. [57]). This assessment would allow for the technical, environmental, economic, and MAC performances of the proposed decarbonized NGPP configuration to be compared against other decarbonization pathways under comparable operating and economic conditions.

Suggestion #2: Consider applying process optimization strategies to improve the economic, environmental, and MAC performances of the hybrid MP+PCC-MEA NGPP-CCS-CCU plant. Optimization studies should consider process operating conditions, equipment sizing, membrane area, solvent parameters, and heat integration. Such an approach could identify NGPP-CCS-CCU configurations with improved economic, environmental, and MAC performances considering different CO2 destinations (CCS or EOR).

Suggestion #3: Consider applying to NGPP-CCS-CCU a Multi-Factor and Multi-Level Sensitivity Analysis and/or a Multi-Factor Monte Carlo Analysis to assess the impacts of variations of critical economic parameters (e.g., oil price, electricity price, and discount rate) on the NPV and MAC of the decarbonized NGPP with hybrid MP+PCC-MEA. Such kinds of analyses will provide a broader assessment of the proposed decarbonization strategy under different market and financial conditions, allowing for the identification of the economic parameters that most significantly influence project performance.

Supplementary Materials: The following supporting information can be downloaded at: https://www.mdpi.com/article/10.3390/gases6040053/s1, Supplementary Materials with Supplements S1, S2, S3, and S4 are available online. (Supplement S1. Simulation Results of AGRU, PCC-MEA and TEG absorbers and strippers for NGPP Base-Case and Hybrid MP/PCC-MEA CCS/CCU. Supplement S2. Simulation Results for NG-CMP, CO2-CMP and CO2 Final CMP for Base-Case and Hybrid MP/PCC-MEA CCS/CCU. Supplement S3. Power demand for NGPP Base Case and Hybrid MP/PCC-MEA CCS/CCU. Supplement S4. Fixed Capital Investment (FCI) for the equipment simulated in NGPP Base Case and Hybrid MP/PPC-MEA CCS/CCU.)

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Nomenclature

AP	Annual profit	(MMUSD/y)
CEPCI	Chemical engineering plant cost index	----
COL, *COM*	Cost of labor and cost of manufacture	(MMUSD/y)
CRM, *CUT*	Cost of raw materials and cost of utilities	(MMUSD/y)
CCT, *DEPR*	Cost of CO_2 transport and annual depreciation	(MMUSD/y)
FCI	Fixed capital investment	(MMUSD)
GAP	Gross annual profit	(MMUSD/y)
i, *ITR*	Annual interest rate and income tax rate	(%)
LHV	Lower Heating Value	(MJ/kg)
MAC	Marginal Abatement Cost	(USD/t^{CO2})
NPV	Net present value	(MMUSD)
REV	Revenues	(MMUSD/y)

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