

Performance and Cost Analysis of Natural Gas Combined Cycle Plants with Chemical Looping Combustion

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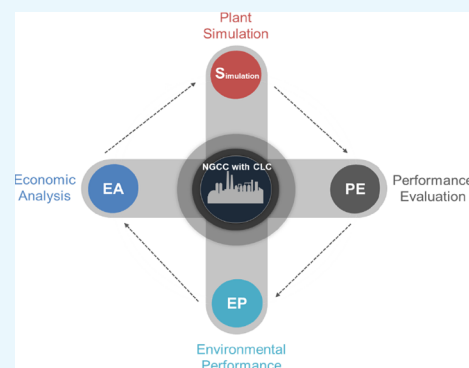
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ABSTRACT: The natural gas combined cycle (NGCC) is the most popular and efficient fossil fuel power plant; however, integrating a carbon capture system reduces its performance efficiency. The demand to reduce the carbon capture cost and improve eco-friendliness drives the development of alternatives. In this study, four alternative NGCC-based process schemes were designed: NGCC with amine carbon capture as a base configuration and NGCCs with three different chemical looping combustion (CLC) configurations. Detailed heat and material balances were evaluated for all four cases using the PRO/II simulation package. A comparative analysis of the gross and net power, plant efficiency, and carbon capture efficiency, which are imperative to optimizing the process configuration, was conducted for all of the proposed cases. All NGCC-CLC processes could produce higher net power than NGCC-MEA because the amine regenerator consumes a high amount of power in its operation. In the condition using an equal amount of natural gas supply, NGCC-CLC configurations using excess air could produce a net power of 510.1 MW with a plant efficiency of 44.35%. The excess air fed in both cases enabled the turbine to generate more power. NGCC-CLC using excess air with steam turbine integration has an investment cost of 132.9 \$/net MWh, an operating cost of 56.7 \$/net MWh year, and a levelized cost of electricity of 90.9 \$/MWh. In addition, NGCC-CLC with excess air resulted in a carbon capture efficiency of 99.93% under 59.2 \$/ton of CO₂, which was higher than that of NGCC-MEA with a carbon efficiency of 95.1%. NGCC-CLC using excess air with steam turbine integration is considered as the most efficient process scheme for generating power from natural gas with regard to efficiency, cost, and environmental impact.



1. INTRODUCTION

Natural gas (NG) is abundant and flexible and continues to serve as a primary source of energy for power generation worldwide. As NG utilization is currently growing at a constant rate of 2.4% annually, the International Energy Agency has predicted that its share of the global energy mix will continue to increase.¹ The Energy Information Administration predicts that NG consumption will increase from 26.9 quadrillion Btu to 30.5 quadrillion Btu over the next 30 years.²

Natural gas combined cycle (NGCC) power plants are rapidly expanding worldwide to produce electricity due to various advantages compared with other types of gas power plants.³ The efficiency of NGCC plants ranges from 45 to 57%.⁴ Furthermore, carbon dioxide gas emissions from NGCC power plants are lower than those from coal-fired power plants. The construction period of NGCC plants is shorter than those of other power plants, and they entail lower capital requirements.⁵ Since carbon dioxide (CO₂) emissions are a global environmental issue, the application of carbon capture technologies to NGCC power plants is essential to reduce CO₂ emission.⁶ NGCC has been regarded as an efficient fossil fuel plant in recent times; however, its performance efficiency decreases when a carbon capture system is installed. The cost

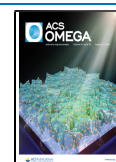
and efficiency penalty associated with integrating carbon capture and storage poses a major challenge.⁷

The amine-based capture process is widely studied as a postcombustion capture process, and various process configurations are feasible to enhance the capture efficiency.^{8,9} The demands to reduce the capture cost and to improve eco-friendliness drive the development of alternatives. One of the strong candidates is the cyclic capture process using chemical dry sorbents.^{10,11} Three different Ca-based sorbents (natural CaCO₃, natural dolomite, and synthetic CaO) have been evaluated for carbon capture from NGCC; since the sorbents are operated at a high CO₂ recycle temperature, the capacity and stability of sorbents and heat recovery have been investigated.¹² Chemical absorption/adsorption for postcombustion carbon capture was evaluated with respect to the technoeconomic

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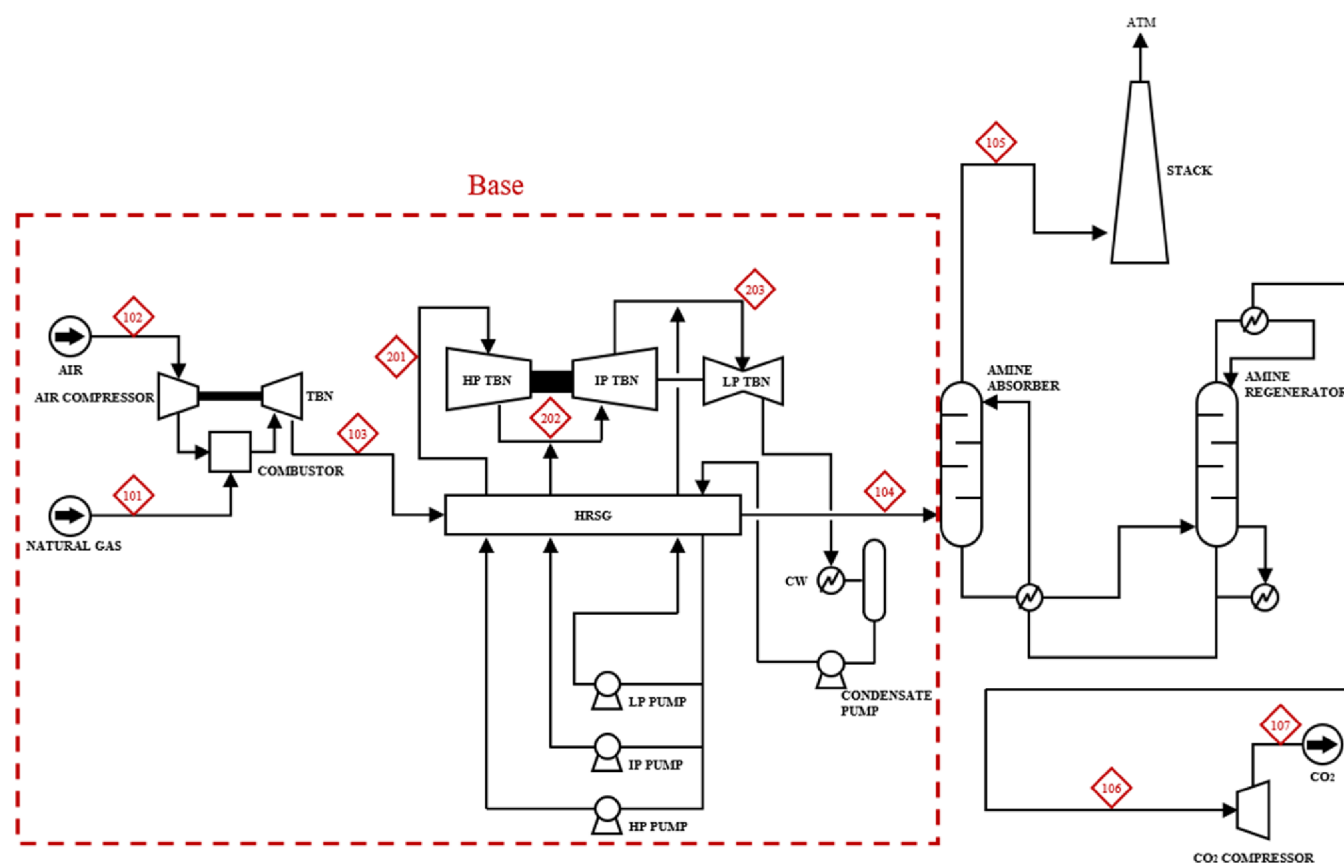


Figure 1. NGCC with MEA carbon capture (Base case and Case-1).

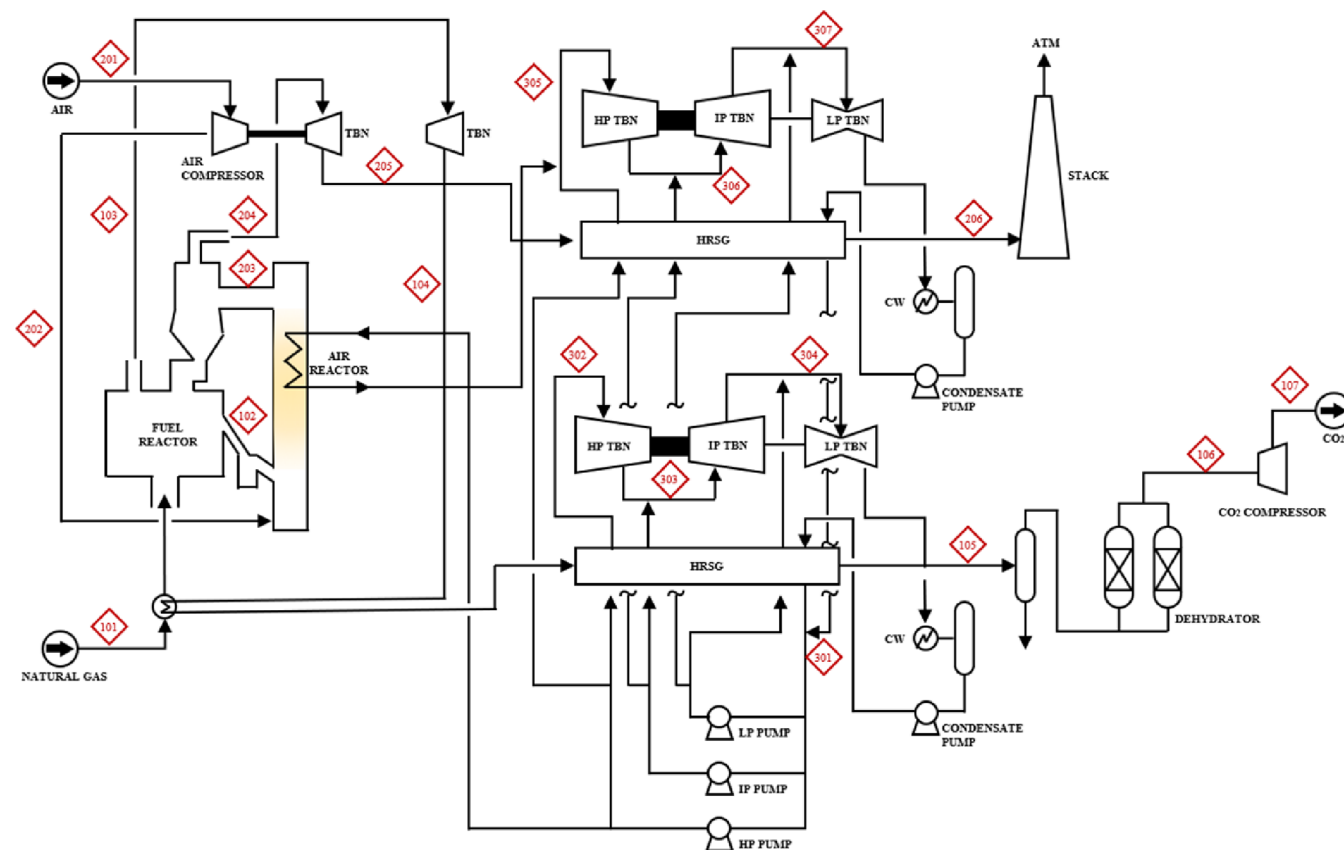


Figure 2. NGCC-CLC with an air reactor cooler (Case-2).

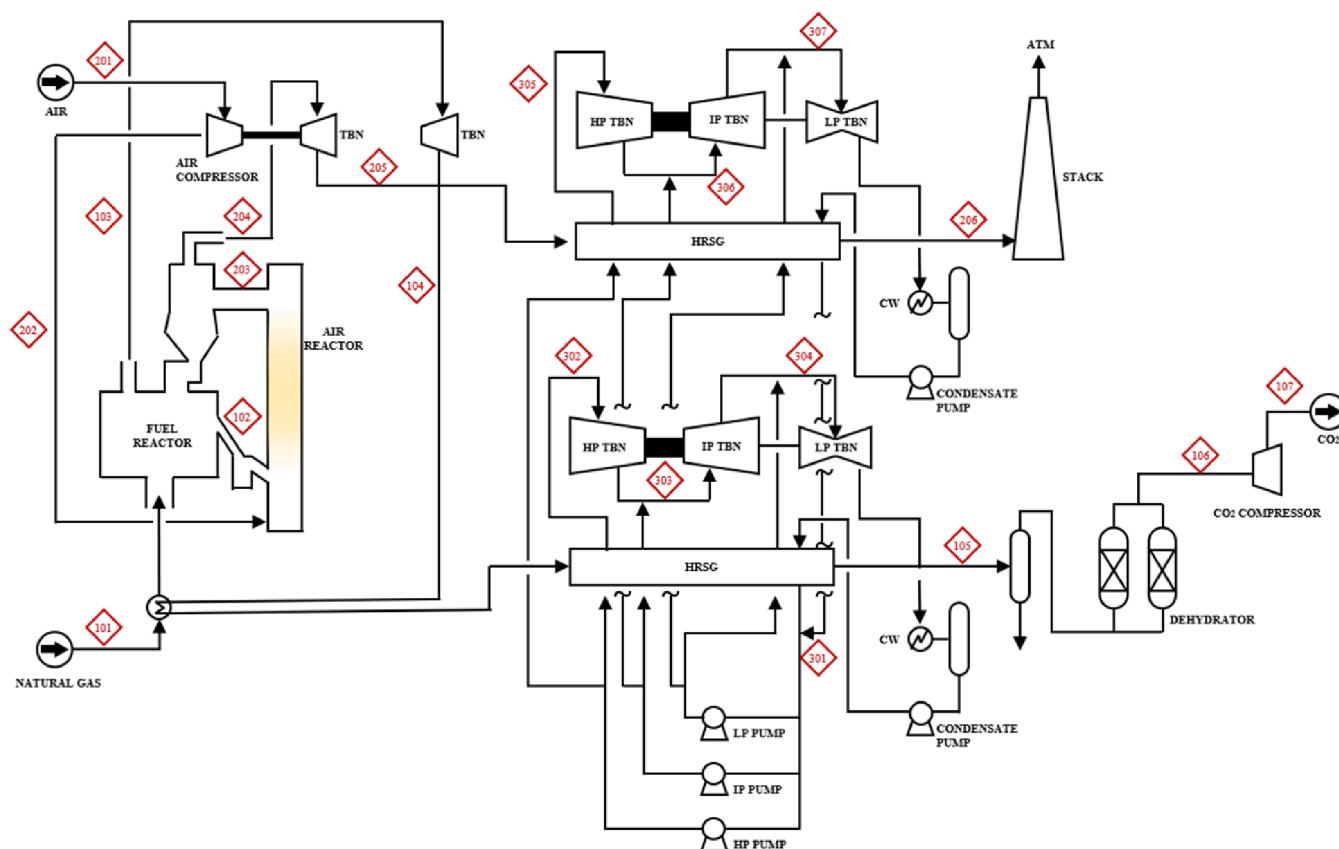


Figure 3. NGCC with CLC including an excess air inlet (Case-3).

performance of NGCCs.¹³ It was concluded that the environmental performance of NGCC power plants with carbon capture could be improved.

Among carbon capture technologies, chemical looping combustion (CLC) is widely considered as a highly promising technology for carbon capture. CLC was originally proposed to improve thermal efficiency in power plants and later identified as having inherent advantages for carbon capture.¹⁴ CLC can prevent the mixing of nitrogen in the air and carbon dioxide generated by combustion and does not require a separate facility to separate oxygen. It exhibits high power generation efficiency without generating thermal NO_x and captures higher-purity CO_2 from flue.^{15,16} In addition to no direct contact with air in CLC, the transport of oxygen between air and fuel creates a very high-purity CO_2 stream with the help of an oxygen carrier (OC) material.¹⁷ It uses CLC OCs based on iron, nickel, copper, and manganese.^{18,19} Nickel-based OCs are highly reactive and mechanically robust and perform well at high temperatures. Despite their high oxygen transport capacity, it was pointed out that Co-based OCs have to overcome their low durability and incomplete fuel conversion. Mn-based OCs have a high mechanical strength and a long service life and can completely or nearly completely burn fuels. The magnetic properties of Mn-based OCs, on the other hand, make it difficult for solids to sinter and contaminate metal parts of reactors. Iron-based OCs are both natural and cost-effective. These characteristics of CLC are vital for carbon capture because no additional energy is required to separate CO_2 from nitrogen (N_2) as in other postcombustion carbon capture processes.²⁰

A detailed simulation study of the CLC process was typically performed under three conditions: NGCC with precombustion

decarburization (PRE), NGCC-PRE with calcium looping, and NGCC with CLC (NGCC-CLC).² The results showed that the highest system efficiencies and lowest exergy destruction are achieved in the NGCC-CLC. A performance model using three different OC materials (Ni-OC, Fe-OC, and Cu-OC) was developed for NGCC-CLC. It was found that the power output and efficiency of the NGCC-CLC were higher than those of conventional NGCC without carbon capture and storage. Among the three OC materials, Ni-OC systems gave the best performance. A new inverse synthesis approach was also developed to evaluate the technology and design of a system based on the system's requirements.

All three processes utilizing CLC (NGCC-CLC, IGCC-CLC, and in situ gasification-CLC) could provide enormous value by reducing the necessary investment and operating costs of future power systems.²¹ Minimization of capital costs over other factors, such as high efficiency or low OC cost, is a crucial point in favor of the CLC process. A strategy for controlling the temperature in the Ni-based (CLC) process using methane was proposed with the aim of exploiting the inherent advantages of the Ni/NiO redox system.²² Technoeconomic analysis is useful to investigate the possibility of deploying present technologies to new markets. Technoeconomic analysis requires investigation of various closely intertwined elements, including technology, project design, project capital costs, operational and maintenance expenses, and operational cash flows.²³ Different skill sets and tools are required for each stage of the analysis.²⁴ Therefore, a simulation study should be executed to examine the energy efficiency and economic effects on carbon capture based on CLC technology. From the analysis of the pressure response and turbine inlet temperature, a high plant efficiency of 54% can

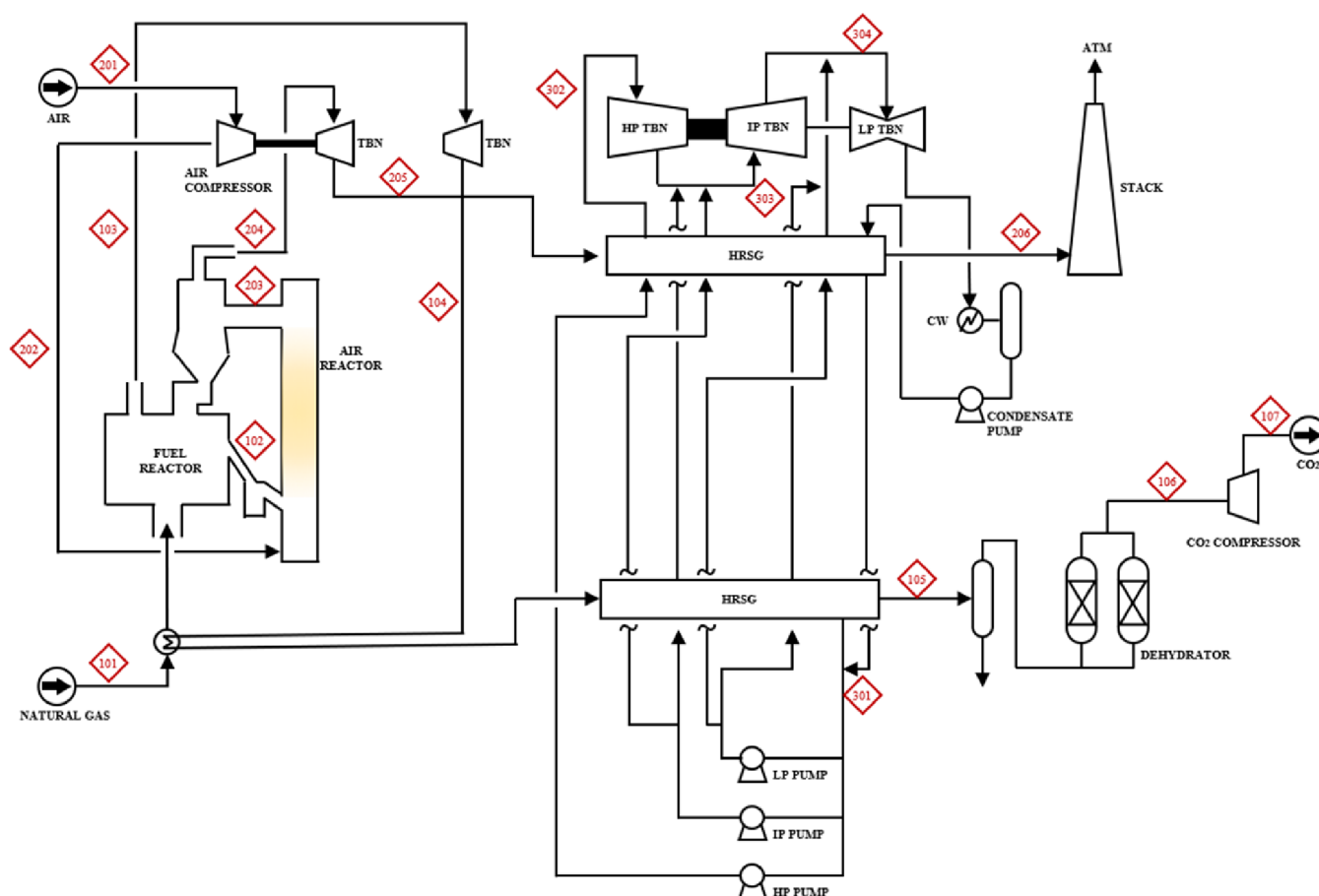


Figure 4. NGCC-CLC with the air inlet to GT and ST integration (Case-4).

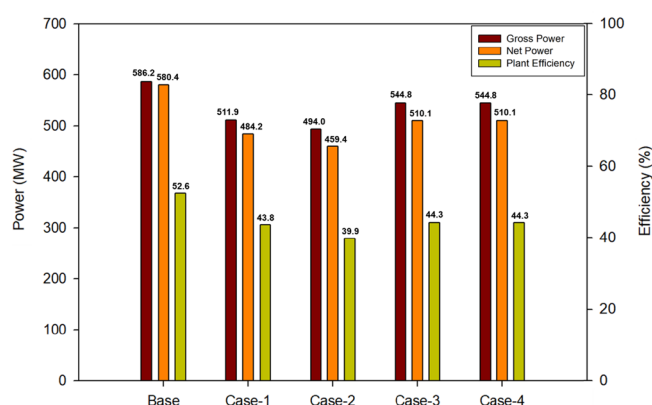


Figure 5. Gross power, net power, and plant efficiency for Base and four Cases.

be achieved at a competitive cost through a CLC.²⁵ The simulation study was conducted for the heat recovery efficiency, performance factor of the absorption cooling system, and plant efficiency of a solar-assisted NG-fired CLC power plant that utilizes waste heat for absorption cooling purposes.²⁶ According to the analysis, the multigeneration solar-assisted CLC system exhibited a plant efficiency of 63.4%, a waste heat utilization of 49%, an electricity cost of 4.9 cents/kWh, and a return on investment of 3.98 years.

NGCC with the carbon capture function becomes even more important. To evaluate the feasibility of NGCC with CLC practically, the analysis of performance efficiency, carbon

capture capability, and investment cost at the same time is required for various NGCC-CLC configurations. This study assessed the performance, economics, and environmental impact of three NGCC-CLC process schemes (Case-2: NGCC-CLC with an air reactor cooler, Case-3: NGCC-CLC with an excess air inlet, and Case-4: NGCC-CLC with excess air inlet and steam turbine integration). The NGCC-MEA scheme (Case-1) was selected as a comparative reference scheme. NG as a feed was supplied in equal amounts in all four cases, and a comparison was conducted in terms of the net power produced and plant efficiency. The investment cost, operating cost, and levelized cost of electricity (LCOE), which are considered as the key indices for economic analysis of power plants, were also evaluated. In addition, the environmental impact of each proposed case was assessed using the carbon capture efficiency and cost per ton of carbon capture.

2. PROBLEM FORMULATION

2.1. Process Configurations. The high-temperature and high-pressure gas obtained from the combustion of NG and air is used in an NGCC to generate electricity, and the pressure of the gas is decreased in the turbine. A heat recovery steam generator (HRSG) recovers heat and converts boiler feed water (BFW) into steam, and the steam turbine can generate power.⁴ Since flue gas from HRSG contains a large amount of CO₂, it should be captured in a carbon capture facility (MEA process). The other way to prevent carbon emission is to reduce the carbon before discharging it to the atmosphere.²⁷ This can be done with different process configurations, such as CLC, depending on

Table 1. Feed Conditions for Natural Gas

feed condition	
component ³⁹	
methane (mol %)	91.0
ethane (mol %)	5.6
propane (mol %)	2.1
i-butane (mol %)	0.5
n-butane (mol %)	0.5
isopentane (mol %)	0.0
nitrogen (mol %)	0.2
Feed supply pressure (bar)	31.0
Feed supply temperature (°C)	38.0

Table 2. Operating and Design Conditions for GT, ST, and Other Equipment

operating and design conditions	
GT ⁴⁰	
GT compressor adiabatic efficiency (%)	80.8
GT expander adiabatic efficiency (%)	92.2
ST ⁴⁰	
HP ST adiabatic efficiency (%)	86.7
IP ST adiabatic efficiency (%)	91.7
LP ST adiabatic efficiency (%)	92.4
HP ST expansion ratio	166.5 bar/24.8 bar
IP ST expansion ratio	24.8 bar/5.2 bar
LP ST expansion ratio	5.2 bar/0.01 bar
Equipment	
Pump adiabatic efficiency (%)	80
Dehydration efficiency (%)	99
Captured CO ₂ pressure (bar)	75.0

Table 3. Major Equipment used in This Study

variable	base	case-1	case-2	case-3	case-4
GT					
combustor	one	one	none	none	none
air compressor	one	one	one	one	one
gas expander	one	one	two	two	two
ST					
HP ST/IP ST/LP ST	one	one	two	two	one
HRSG	one	one	two	two	two
CO ₂ capture					
MEA system	none	one	none	none	none
CL combustor	none	none	one	one	one
air reactor control	none	none	one	none	none
CO ₂ compressor	none	none	one	one	one
dehydrator	none	none	one	one	one
operation					
CLC air reactor temperature	N/A	N/A	1200	1200	1200
CLC air reactor temp control	N/A	N/A	air cooler	excess air	excess air
excess air ratio	2.5	2.5	2.5	3.7	3.7

environmental regulations. Furthermore, the performance and economic viability of the system should be considered. Therefore, five different NGCC schemes including three different NGCC-CLC configurations with different operating strategies were studied:

- Base: NGCC without carbon capture.
- Case-1: NGCC with an MEA system as a comparative reference.
- Case-2: NGCC with CLC including an air reactor cooler.

Table 4. Results of the Analysis of Base and Four Cases

contents	base	case-1	case-2	case-3	case-4
process variables					
natural gas feed (kg mol/h)	4246	4246	4246	4246	4246
air feed flow rate (kg mol/h)	109,348	109,348	109,348	158,229	158,229
air feed flow rate (ton/h)	3154.7	3154.7	3154.7	4564.9	4564.9
BFW flow rate (ton/h)	509.0	509.0	788.8	627.3	627.2
CLC steam generation duty (MW)	N/A	N/A	300.314	0	0
Air reactor temperature (°C)	N/A	N/A	1200	1200	1200
process result					
CO ₂ generation (kg/h)	210,524	210,524	205,682	205,682	205,682
CO ₂ emission (kg/h)	210,524	10,279	140	140	140
CO ₂ captured (kg/h)	0	200,245	205,542	205,542	205,542
CO ₂ capture ratio (wt %)	N/A	95.1	99.93	99.93	99.93

- Case-3: NGCC with CLC including an excess air inlet.
- Case-4: NGCC with CLC including excess air inlet and ST integration.

2.1.1. NGCC without and with an MEA System. The conventional NGCC process without carbon capture (Base case) consists of a gas turbine, an air compressor, an HRSG, and a steam turbine. MEA carbon capture technology and a CO₂ compressor are added to the NGCC with the MEA system (Case-1), as shown in Figure 1.²⁸ The pressurized NG generates a combustion reaction with compressed air in the gas turbine combustor, where CO₂ and N₂ discharge the main high-pressure and high-temperature flue gas and then generate electricity through a pressure drop in the gas turbine. The high-temperature and low-pressure flue gas is sent to the HRSG to transfer heat to the supplied BFW to produce steam, which is then sent to the steam turbine to generate electricity. The flue gas from the HRSG contains a significant quantity of CO₂ and is processed in the carbon capture facility. The treated flue gas is consequently discharged into the atmosphere.

2.1.2. NGCC-CLC with an Air Reactor Cooler. When CLC is installed with NGCC technology, a gas turbine combustor and a separate CO₂ capture system (MEA or cryogenic unit) are not required; instead, a chemical looping combustor unit is added. In this study, two expanders were installed instead of one gas turbine because, in CLC, flue gas is emitted from the fuel reactor and O₂ and N₂ are emitted from the air reactor. Since high-temperature and high-pressure gases of different compositions are emitted by these reactors, two expanders and two HRSGs were installed to utilize these gases. The steam turbine and HRSG system were operated separately.

NGCC-CLC (Case-2) was studied at the same plant capacity at the NGCC and NGCC-MEA. In addition, the same air compressor capacity was applied to the systems. However, the capacities of the expander, steam turbine, and HRSG were different between NGCC-MEA and NGCC-CLC. Chemical looping combustion has the advantage of being able to capture

Table 5. Basis for the Economic Analysis

economic analysis basis	
plant operating hour (h/year)	8766
plant operating year (year) ⁴	30.0
plant capacity factor ⁴	0.85
capital cost factor (without CCS)	0.1
capital cost factor (with CCS)	0.1
fuel cost (\$/MMBtu)	6.3

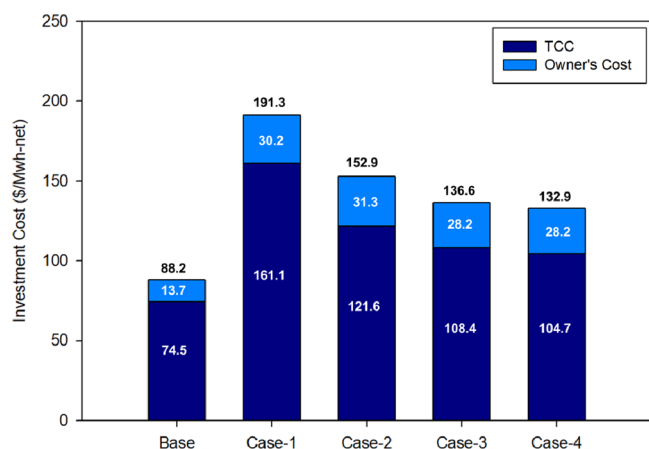


Figure 6. Investment cost per net MWh for Base and four Cases.

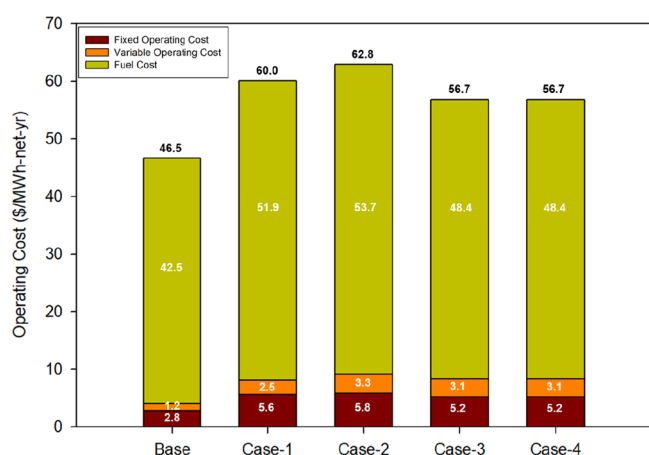


Figure 7. Operating cost per net MWh and year for Base and four cases.

CO₂ with high purity (99.9%) through oxidation and reduction reactions using metal oxides such as nickel oxide, copper oxide, and cadmium oxide as OCs, at temperatures below 1200 °C.²⁹ Since the reaction proceeds at 1371 °C,⁴ there is an advantage of suppressing the generation of NO_x.³⁰ The configurations of the various NGCC-CLC processes are illustrated in Figures 2–5.

Case-2 is based on NGCC-CLC with an air reactor cooler, as depicted in Figure 2.³¹ The temperature of the CLC reactor should be below 1200 °C, which is the maximum stable temperature of the CLC carrier. Therefore, a CLC reactor cooler was installed to control the temperature. The advantages of using CLC for carbon capture in NGCC are the small amount of NO_x and the emission of CO₂ and H₂O from the reactants. Therefore, it is highly beneficial to capture high-purity CO₂ by removing H₂O through dehydration. On the other hand, when MEA carbon capture technology using MEA or solvents is used in the NGCC process, an air separation unit (ASU) is

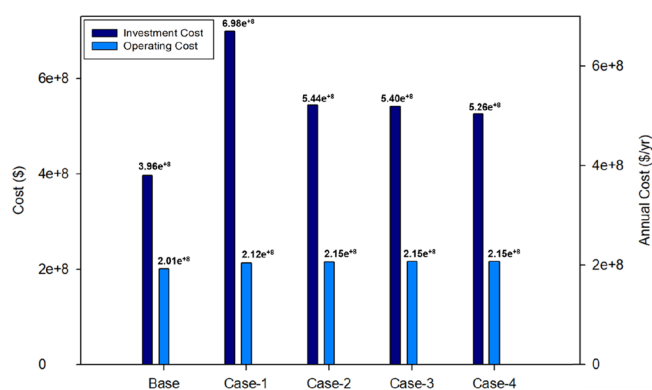


Figure 8. Total investment and operation cost of Base and four cases.

occasionally used to deliver pure oxygen to remove the quantity of NO_x in the gas turbine. Due to intensifying regulations on fine dust generation, NO_x control in power plants is more concerning. In addition, many previous studies demonstrated that the amine-based CO₂ capture systems showed the optimum efficiency at the 90–95% capture rate from power plant emission gases.^{32,33}

2.1.3. NGCC-CLC with excess air to the air compressor. In Case-3, excess air was supplied to control the reactor temperature, eliminating the need to install a reactor cooler as shown in Case-2. The process scheme in Figure 3 was set when the reactor temperature was controlled by excess air flow to the air compressor. Because the amount of excess air is greater, the capacity of the air compressor also increases, and the capacity of the steam turbine and HRSG changes. Because the temperature of the CLC reactor is controlled by the amount of excess air, a larger amount of air is supplied than the amount of air required by the conventional NGCC gas turbine in Case-1, as air acts as a coolant and an oxidant. Since a huge capacity of the air compressor is required, a high cost of machine investment is expected. In Case-2, when BFW is fed into the system through the internal cooler, generated steam can be used in a steam turbine. However, in Case-3, no steam is generated from CLC because no internal cooler is equipped. The steam turbine's capacity is reduced, and the amount of electricity generated by the steam turbine is also reduced.

2.1.4. NGCC-CLC with an Air Inlet to a Gas Turbine (GT) and Steam Turbine (ST) Integration. The motivation for Case-4 is to increase the economic efficiency of Case-3 by integrating two single STs and an HRSG. Stream-205 fed to the first HRSG

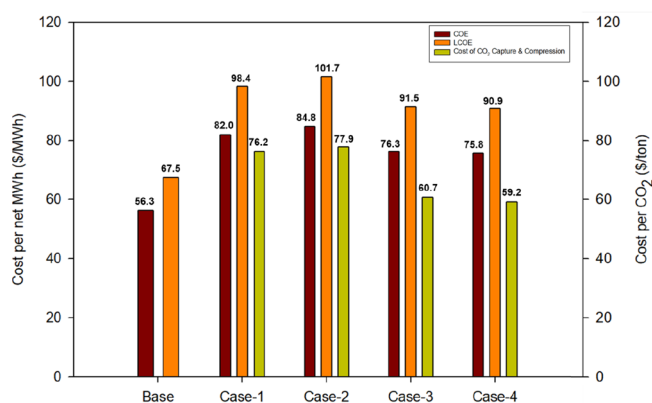
Figure 9. COE, LCOE, and CO₂ capture costs of Base and four Cases.

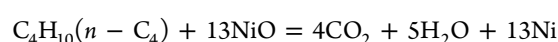
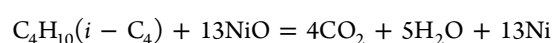
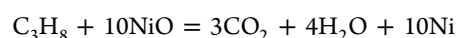
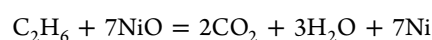
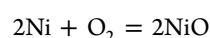
Table 6. Summary of the Performance and Cost Analysis of Five Cases and Comparison with Other Works

contents	USDOE 2011	case-1	case-2	case-3	case-4
plant description					
CCS technology	econamine FG+	MEA	CLC	CLC	CLC
net power without CCS (MW)	512	580.4	N/A	N/A	N/A
net power with CCS (MW)	435	484.2	459.4	510.1	510.1
annual operating hours (h)	8766	8766	8766	8766	8766
plant capacity factor	0.85	0.85	0.85	0.85	0.85
fuel	natural gas	natural gas	natural gas	natural gas	natural gas
power plant efficiency					
without capture (%)	50.5	52.6	N/A	N/A	N/A
with capture (%)	42.9	43.8	39.9	44.3	44.3
cost of electricity					
without capture (LCOE) (\$/MWh)	65	67.5	N/A	N/A	N/A
with capture (COE) (\$/MWh)	N/A	82	84.8	76.3	75.8
with capture (LCOE) (\$/MWh)	95.9	98.4	101.7	91.5	90.9
CO ₂ capture					
CO ₂ generation (ton/h)	N/A	210.5	205.6	205.6	205.6
CO ₂ capture (ton/h)	N/A	200.2	205.5	205.5	205.5
cost of CO ₂ capture (\$/CO ₂ ton)	80	76.2	77.9	60.7	59.2

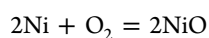
contains primarily nitrogen and is discharged to the atmosphere. Stream-104, on the other hand, is fed to the second HRSG and contains CO₂. Therefore, it is sent to the CO₂ capture unit. Combined feeding of two streams into one HRSG is not vital because the device load of the CO₂ capture unit increases. Since a method for independently placing two flue gas streams into a single HRSG is not typical in the common HRSG, it is excluded in the study. When CLC is applied to NGCC, effluents of different compositions are produced in the air reactor and fuel reactor; these products are used to produce electricity in Case-2 and Case-3 using two gas turbines, two HRSGs, and two steam turbine sets. In Case-4, a system that generates electricity by integrating two steam turbine sets into a single steam turbine set was studied. While exhibiting the same performance as Case-3, Case-4 has the advantage of reduced investment cost because of the reduction in the number of steam turbine sets as shown in Figure 4. The main design difference between Case-3 and Case-4 results from an economic aspect. However, it is expected that the operation of Case-4 may be relatively difficult because it must be operated by connecting one steam turbine set with two HRSGs.

2.2. Combustion Reactions and Thermodynamics. In this study, NiO as an OG is selected because of its outstanding physical property and reactivity at high temperatures. NG is supplied to the fuel reactor, and NiO at high temperature in the reactor generates H₂O and CO₂. Furthermore, Ni is transferred to the air reactor. The generated H₂O and CO₂ are transferred to the gas turbine. Electricity is generated through a pressure drop of 31 bar/1.2 bar, and a gas at 650 °C or higher is generated by supplying heat from the HRSG to the BFW to generate steam. When H₂O is removed from the dehydrator, the remaining CO₂ is compressed and transported.^{32,34}

In the fuel reactor,



In the air reactor,



In the air reactor, an exothermic reaction, converting Ni to NiO, occurs by combining Ni with oxygen in the supplied air. Unreacted oxygen and nitrogen at high temperature and high pressure from the air reactor generate electricity in the expander. This supplies heat to the HRSG to generate steam from the BFW, which is discharged to the atmosphere. Ni and NiO are contained with 60 wt % Al₂O₃ support to circulate through the fuel and air reactors.³⁵ To obtain Ni in the above equation, NiO is injected back into the fuel reactor through a cyclone.

In this study, the yield of reaction/reduction was predicted by modeling using a Gibbs reactor since the reactions take place at high temperatures in the gas phase, which guaranteed an equilibrium reaction. The Gibbs reactor tries to find the reaction path to minimize Gibbs free energy, which corresponds to equilibrium conditions. As a matter of fact, a similar method using the Gibbs reactor was reported from other studies.^{2,36}

The Soave–Redlich–Kwong modified (SRKM) equation is one of the most widely used model equations to examine the behavior of hydrocarbons and gases. A modified Panagiotopoulos mixing rule is introduced to the SRK equation.³⁷ The SRKM equation, used in this study, is known to simulate the behavior of a gas accurately. In addition, since the binary parameters of the feed stream in the SRKM are embedded to the simulator in this study, the calculation accuracy can be guaranteed.

Table A1. Heat and Material Balance for Case-1

stream name	101	102	103	104	105	106	107	201	202	203
stream description	NF feed	air feed	HRS feed	FG to CC	treated GAS	captured CO ₂	compressed CO ₂	HP ST inlet	IP ST inlet	LP ST inlet
phase	vapor	vapor	vapor	vapor	vapor	vapor	vapor	vapor	vapor	vapor
temperature (°C)	38.0	15.0	689.4	45.0	50.4	21.0	115.0	565.6	561.3	335.3
pressure (bar)	31.0	1.0	1.2	1.1	1.1	1.6	75.0	166.5	24.8	5.2
mass rate (kg/h)	75,901	3,154,732	3,230,633	3,230,633	3,015,043	229,202	201,722	386,876	463,184	234,088
molar rate (kg mol/h)	4246	109,348	113,867	115,940	111,520	5258	4628	21,475	25,711	12,994
molar component percentage										
CH ₄	91.0	0	0	0	0	0	0	0	0	0
C ₂ H ₆	5.6	0	0	0	0	0	0	0	0	0
C ₃ H ₈	2.1	0	0	0	0	0	0	0	0	0
IC ₄	0.5	0	0	0	0	0	0	0	0	0
NC ₄	0.5	0	0	0	0	0	0	0	0	0
IC ₅	0	0	0	0	0	0	0	0	0	0
CO	0	0	0	0	0	0	0	0	0	0
CO ₂	0	0	4.2	4.6	0	98.3	98.3	0	0	0
H ₂ O	0	0	7.9	8.8	9.9	1.5	1.5	100.0	100.0	100.0
N ₂	0.2	79.0	75.9	86.6	90.0	0.1	0.1	0	0	0
O ₂	0	21.0	12.0	0	0	0	0	0	0	0
MEA	0	0	0	0	0	4.2 × 10 ⁻⁶	0	0	0	0

3. RESULTS AND DISCUSSION

3.1. Simulation Basis. The PRO/II simulation package³⁸ was used for the process modeling and simulation of Base and the four cases discussed in the previous chapter. The feed conditions are summarized in Table 1. Methane, ethane, and propane are the main components of NG. The simulation basis for GT and ST is also shown in Table 2. Table 3 summarizes the major equipment used in this study.

3.2. Simulation Results. The same quantities of NG and feed conditions were applied for all five cases: NGCC without carbon capture (Base case), NGCC with an MEA system (Case-1), NGCC with CLC including an air reactor cooler (Case-2), NGCC with CLC including an excess air inlet (Case-3), and NGCC with CLC including excess air inlet and ST integration (Case-4). The amounts of produced power and steam were calculated and recorded using a simulation based on the process scheme. The detailed heat and material balance are given in Appendix.

The process conditions and simulation results of the Base and four cases are summarized in Table 4. The NG feed had the same pressure, temperature, and flow rate in all cases. Since Base, Case-1, and Case-2 were supplied with an equal amount of air (109,348 kg mol/h), the capacity of the installed air compressor is the same for these three cases. On the other hand, in Case-3 and Case-4, a large amount of air (158,229 kg mol/h) was supplied as excess air to control the temperature of the CLC reactor.

One advantage of NGCC-CLC schemes is that they allow for utilization of heat obtained from the CLC reactor, which can be used to produce steam from BFW and for the ST. In Case-2, an air reactor cooler is installed to supply BFW to produce steam, the total amount of which (788.8 ton/h) is 54.9% greater than those (509 ton/h) in Base and Case-1. In Case-3 and Case-4, excess air is used to control the reactor temperature, and the amount of air supplied is 44% greater than that in Case-1. The amount of CO₂ emission from NGCC-CLC is 140 kg/h, which is smaller than that of NGCC with MEA (10,279 kg/h).

Due to the interaction force between CO₂ and other components of the flue gas, it is thermodynamically impossible

to capture 100% CO₂ using an amine. As shown in Table 4, the MEA process could capture 95.1% CO₂ from flue gas. When CLC is used, CO₂ and H₂O are produced by the reaction in the fuel reactor. Since only H₂O is required to be separated from CO₂, the CLC process was able to capture about 99.93% of generated CO₂. In this study, about 5 wt % total generated CO₂ from the MEA process is emitted into the atmosphere, whereas in the case of CLC, about 0.07% is discharged into the atmosphere. Since CLC can contribute to reducing CO₂ generation and enhancing CO₂ capture efficiency, it can be described as environmentally friendly.

3.3. Power Generation and Plant Efficiency. Figure 5 shows the gross and net power produced in each case. The Base case produced a net power of 580.4 MW, whereas the amount of power generated in Case-1 was 484.2 MW, which was a 16.6% reduction. This was because the steam consumption by the regenerator of the MEA process in Case-2 reduced the amount of power produced from the steam turbine, and the power consumption of the CO₂ compressor decreased the net power. Case-2 produced 3.5% less power than Case-1, when an equal amount of air was supplied. In addition, since installing internal coils or wall piping in a FBR can change the flow patterns of the particles and fluid, the reactor efficiency should be carefully evaluated. In Case-3 and Case-4, where the temperature of the CLC reactor was adjusted with excess air, the GT produced an additional electricity of 6.4%. The net power produced was 510.1 MW, which was a 12.1% reduction from the Base case. However, with respect to carbon capture requirement, NGCC with CLC (Case-3 and Case-4) could produce an additional 5.4% of net powder compared with Case-2. In the NGCC-CLC, the GT produced more power, resulting from the greater amount of air supplied to the air compressor. In addition, a regeneration energy for carbon capture was not necessary.

The net plant efficiency is defined as the ratio of the electrical power sent out of the power station to the rate at which heat is supplied to the reactor.⁴¹ The plant efficiency of the Base case was 52.6% and that of Case-1 was 43.8%. The energy consumption in the amine regenerator (Case-1) naturally led to a lower plant efficiency and net power produced when

Table A2. Heat and Material Balance for Case-2

stream name	101	102	103	104	105	106	107	201	202	203
stream description	NG feed	circulation NIO	CO ₂ to turbine	CO ₂ from second GT	CO ₂ from HRSG	captured CO ₂	compressed CO ₂	air supply	compressed air	AR effluent
temperature (°C)	38.0	1047	1047	500.2	110.0	100.9	120.0	25.0	545.4	1200
pressure (bar)	31.0	31.0	31.0	1.0	1.0	1.0	75.0	1.0	31.0	31.0
mass rate (kg/h)	75,901	5,757,096	365,127	365,127	365,127	206,223	206,223	3,154,733	3,154,733	8,911,829
molar rate (kg mol/h)	4246	74,473	13,703	13,703	13,703	4887	4887	109,348	109,348	174,741
molar component percentage										
CH ₄	91.0	0	0	0	0	0	0	0	0	0
O ₂	0	0	0	0	0	0	0	21.0	21.0	7.9
N ₂	0.2	0	0.1	0.1	0.1	0.2	0.2	79.0	79.0	49.4
CO ₂	0	0	34.1	34.1	34.1	95.6	95.6	0	0	0
H ₂ O	0	0	64.3	64.3	64.3	0.0	0.0	0	0	0
C ₂	5.6	0	0	0	0	0	0	0	0	0
C ₃	2.1	0	0	0	0	0	0	0	0	0
IC ₄	0.5	0	0	0	0	0	0	0	0	0
NC ₄	0.5	0	0	0	0	0	0	0	0	0
IC ₅	0	0	0	0	0	0	0	0	0	0
NI	0	24.4	0	0	0	0	0	0	0	0
NIO	0	51.7	4.7 × 10 ⁻¹⁴	4.7 × 10 ⁻¹⁴	4.7 × 10 ⁻¹⁴	0	0	0	0	32.4
Al ₂ O ₃	0	23.9	0	0	0	0	0	0	0	10.2
H ₂	0	0	1.5	1.5	1.5	4.2	4.2	0	0	0
C	0	0	0	0	0	0	0	0	0	0
stream name	204	205	206	301	302	303	304	305	306	307
stream description	FG	FG to HRSG	FG to stack	BFW	HP steam to HP ST	IP steam to IP ST	LP steam to LP ST	HP steam to HP ST	IP steam to IP ST	LP steam to LP ST
temperature (°C)	1200	441.8	110.0	148.0	450.0	448.1	251.5	566.0	369.4	193.6
pressure (bar)	31.0	1.0	1.0	5.1	166.5	24.8	5.2	166.5	24.8	5.2
mass rate (kg/h)	2,864,186	2,864,186	2,864,186	788,872	6.7	53,555	66,936	385,183	654,589	721,937
molar rate (kg mol/h)	100,268	100,268	100,268	43,789	0.4	2973	3716	21,381	36,335	40,074
molar component percentage										
CH ₄	0	0	0	0	0	0	0	0	0	0
O ₂	13.8	13.8	13.8	0	0	0	0	0	0	0
N ₂	86.2	86.2	86.2	0	0	0	0	0	0	0
CO ₂	0	0	0	0	0	0	0	0	0	0
H ₂ O	0	0	0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
C ₂	0	0	0	0	0	0	0	0	0	0
C ₃	0	0	0	0	0	0	0	0	0	0
IC ₄	0	0	0	0	0	0	0	0	0	0
NC ₄	0	0	0	0	0	0	0	0	0	0
IC ₅	0	0	0	0	0	0	0	0	0	0
NI	0	0	0	0	0	0	0	0	0	0
NIO	0	0	0	0	0	0	0	0	0	0
Al ₂ O ₃	0	0	0	0	0	0	0	0	0	0
H ₂	0	0	0	0	0	0	0	0	0	0
C	0	0	0	0	0	0	0	0	0	0

compared with the Base case. Case-2 and Case-3 showed plant efficiencies of 39.9% and 44.3%, respectively, since the net power generation of Case-2 (459.4 MWh) was lower than that of Case-3. Since both Case-3 and Case-4 were designed to have the same net power, they had the same plant efficiency of 44.3%.

As shown in Figure 5, NGCC-CLC with excess air demonstrated the highest performance with 510.1 MWh net power and 44.3% plant efficiency. The economic analysis will outline the reason that Case-4, which incorporated an integrated

steam turbine, is economically superior to Case-3 in terms of CO₂, COE, LCOE, and CO₂ capture cost per ton.

4. ECONOMIC ANALYSIS

4.1. Basis for the Economic Analysis. An economic analysis was carried out to measure the costs of investment and operation. Whereas the investment cost includes total capital cost and owner's cost, the operating cost consists of the fixed operating cost, variable operating cost, and fuel cost. In addition,

Table A3. Heat and Material Balance for Case-3

stream name	101	102	103	104	105	106	107	201	202	203
stream description	NG feed	circulation NIO	FR effluent	CO ₂ from second GT	CO ₂ from HRSG	captured CO ₂	compressed CO ₂	air supply	compressed air	AR effluent
temperature (°C)	38.0	1047	1047	500.2	110.0	101.1	120.0	25.0	545.4	1200
pressure (bar)	31.0	31.0	31.0	1.0	1.0	1.0	75.0	1.0	31.0	31.0
mass rate (kg/h)	75,901	5,757,100	6,122,220	365,127	365,127	206,223	206,223	4,564,960	4,564,960	10,322,100
molar rate (kg mol/h)	4246	74,473	88,177	13,703	13,703	4887	4887	158,229	158,229	223,622
molar component percentage										
CH ₄	91.0	0	0	0	0	0	0	0	0	0
O ₂	0	0	0	0	0	0	0	21.0	21.0	10.8
N ₂	0.2	0	0	0.1	0.1	0.2	0.2	79.0	79.0	55.9
CO ₂	0	0	5.3	34.1	34.1	95.6	95.6	0	0	0
H ₂ O	0	0	10.0	64.3	64.3	0	0	0	0	0
C ₂	5.6	0	0	0	0	0	0	0	0	0
C ₃	2.1	0	0	0	0	0	0	0	0	0
IC ₄	0.5	0	0	0	0	0	0	0	0	0
NC ₄	0.5	0	0	0	0	0	0	0	0	0
IC ₅	0	0	0	0	0	0	0	0	0	0
NI	0	24.4	20.6	0	0	0	0	0	0	0
NIO	0	51.7	43.7	4.7×10^{-14}	4.7×10^{-14}	0	0	0	0	25.3
Al ₂ O ₃	0	23.9	20.2	0	0	0	0	0	0	8.0
H ₂	0	0	0.2	1.5	1.5	4.2	4.2	0	0	0
C	0	0	0	0	0	0	0	0	0	0
stream name	204	205	206	301	302	303	304	305	306	307
stream description	FG	FG to HRSG	FG to stack	BFW	HP steam to HP ST	IP steam to IP ST	LP steam to LP ST	HP steam to HP ST	IP steam to IP ST	LP steam to LP ST
temperature (°C)	1200	442.5	110.0	148.0	400.0	397.9	219.9	450.0	448.1	251.5
pressure (bar)	31.0	1.0	1.0	5.1	166.5	24.8	5.2	166.5	24.8	5.2
mass rate (kg/h)	4,274,410	4,274,410	4,274,410	627,348	5.6	448,336	560,413	6.7	53,555	66,936
molar rate (kg mol/h)	149,149	149,149	149,149	34,823	0.3	24,886	31,108	0.4	2973	3716
molar component percentage										
CH ₄	0	0	0	0	0	0	0	0	0	0
O ₂	16.2	16.2	16.2	0	0	0	0	0	0	0
N ₂	83.8	83.8	83.8	0	0	0	0	0	0	0
CO ₂	0	0	0	0	0	0	0	0	0	0
H ₂ O	0	0	0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
C ₂	0	0	0	0	0	0	0	0	0	0
C ₃	0	0	0	0	0	0	0	0	0	0
IC ₄	0	0	0	0	0	0	0	0	0	0
NC ₄	0	0	0	0	0	0	0	0	0	0
IC ₅	0	0	0	0	0	0	0	0	0	0
NI	0	0	0	0	0	0	0	0	0	0
NIO	0	0	0	0	0	0	0	0	0	0
Al ₂ O ₃	0	0	0	0	0	0	0	0	0	0
H ₂	0	0	0	0	0	0	0	0	0	0
C	0	0	0	0	0	0	0	0	0	0

this study also discussed the COE, LCOE, and carbon capture cost to evaluate the economic advantages of each case.

COE is the net income per net MWh received during the plant's first year of operation under the assumption of its increase at the same nominal annual inflation rate. LCOE refers to the revenue received per net MWh during the plant's first year of operation, assuming that the COE remains constant in nominal terms over the operational period of the plant. It was calculated as the product of COE and levelized factor.⁴ The CO₂ capture cost was the revenue to capture per ton of CO₂.²⁷ The

formulas for COE, LCOE, and CO₂ capture cost are shown below:⁴

$$\text{COE} = \frac{(\text{CCF}) * (\text{TOC}) + \text{OC}_{\text{FIX}} + (\text{CF})(\text{OC}_{\text{VAR}})}{(\text{CF})(\text{MWH})}$$

$$\text{LCOE} = \text{LF} \times \text{COE}$$

$$\text{CO}_2 \text{ capture cost} \left(\frac{\$}{t\text{CO}_2} \right) = \frac{(\text{LCOE})_{\text{cc}} - (\text{LCOE})_{\text{ref}}}{(t\text{CO}_2/\text{MWH})_{\text{cc}}}$$

Table A4. Heat and Material Balance for Case-4

stream name	101	102	103	104	105	106	107	201	
stream description	NG feed	circulation NIO	CO ₂ capture	CO ₂ from second GT	CO ₂ from HRSG	captured CO ₂	compressed CO ₂	air supply	
temperature (°C)	38.0	1047	1047	500.2	110.0	101.2	120.0	25.0	
pressure (bar)	31.0	31.0	31.0	1.0	1.0	1.0	75.0	1.0	
mass rate (kg/h)	75,901	5,757,096	365,127	365,127	365,127	206,223	206,223	4,564,959	
molar rate (kg mol/h)	4246	74,473	13,703	13,703	13,703	4887	4887	158,229	
molar component percentage									
CH ₄	91.0	0	0	0	0	0	0	0	
O ₂	0	0	0	0	0	0	0	21.0	
N ₂	0.2	0	0.1	0.1	0.1	0.2	0.2	79.0	
CO ₂	0	0	34.1	34.1	34.1	95.6	95.6	0	
H ₂ O	0	0	64.3	64.3	64.3	0	0	0	
C ₂	5.6	0	0	0	0	0	0	0	
C ₃	2.1	0	0	0	0	0	0	0	
IC ₄	0.5	0	0	0	0	0	0	0	
NC ₄	0.5	0	0	0	0	0	0	0	
IC ₅	0	0	0	0	0	0	0	0	
NI	0	24.4	0	0	0	0	0	0	
NIO	0	51.7	4.7×10^{-14}	4.7×10^{-14}	4.7×10^{-14}	0	0	0	
Al ₂ O ₃	0	23.9	0	0	0	0	0	0	
H ₂	0	0	1.5	1.5	1.5	4.2	4.2	0	
C	0	0	0	0	0	0	0	0	
stream name	202	203	204	205	206	301	302	303	304
stream description	compressed air	AR effluent	FG	FG to HRSG	FG to stack	BFW	HP steam to HP ST	IP steam to IP ST	LP steam to LPST
temperature (°C)	545.4	1200	1200	442.5	110.0	148.0	400.0	403.5	223.4
pressure (bar)	31.0	31.0	31.0	1.0	1.0	5.1	166.5	24.8	5.2
mass rate (kg/h)	4,564,959	10,322,054	4,274,411	4,274,411	4,274,411	627,263	5.6	501,816	627,263
molar rate (kg mol/h)	158,229	223,622	149,149	149,149	149,149	34,818	0.3	27,855	34,818
molar component percentage									
CH ₄	0	0	0	0	0	0	0	0	0
O ₂	21.0	10.8	16.2	16.2	16.2	0	0	0	0
N ₂	79.0	55.9	83.8	83.8	83.8	0	0	0	0
CO ₂	0	0	0	0	0	0	0	0	0
H ₂ O	0	0	0	0	0	100.0	100.0	100.0	100.0
C ₂	0	0	0	0	0	0	0	0	0
C ₃	0	0	0	0	0	0	0	0	0
IC ₄	0	0	0	0	0	0	0	0	0
NC ₄	0	0	0	0	0	0	0	0	0
IC ₅	0	0	0	0	0	0	0	0	0
NI	0	0	0	0	0	0	0	0	0
NIO	0	25.3	0	0	0	0	0	0	0
Al ₂ O ₃	0	8.0	0	0	0	0	0	0	0
H ₂	0	0	0	0	0	0	0	0	0
C	0	0	0	0	0	0	0	0	0

Table 5 shows the basis for the economic analysis. AACE Class 4 for cost estimation was employed with the expected range. The accuracy range was 30–50% for the lower range and 30–100% for the upper range.⁴²

4.2. Investment and Operating Cost. The detailed breakdown of the investment and operating cost is given in Table A5. The investment cost is the ratio of the total capital cost to the new power in each case, i.e., the nominator is the total capital cost with net power being the denominator. The investment cost per net MWh of each unit was calculated by referring to the NETL report;⁴ the results are shown in Figure 6. The investment cost for CLC was calculated based on ref 36 and the amount of feed gas and operating pressure from heat and material balance. The investment cost of the Base case was 88.2 \$/net MWh, while that of Case-1 was the highest (191.3 \$/net

MWh) due to the use of MEA-based carbon capture and CO₂ compression. On the other hand, the NGCC-CLC-based schemes showed a reduction in investment costs of 8.9–13.9% compared to Case-1.

The total capital costs of Case-1, Case-2, Case-3, and Case-4 were \$698,937,189, \$544,824,279, \$540,684,744, and \$526,305,068, respectively (discussed more later in Figure 8). The net power of Case-1 was 484.2 MW, while those of Case-2, Case-3, and Case-4 were 459.4, 510.1, and 510.1 MW, respectively, in Figure 5. The investment cost per net MWh for Case-4 was the lowest, making it economically superior to the others.

Figure 7 shows the resulting operating cost, and the details are shown in Tables A5 and A6 in the Appendix. The fuel for plant operation accounts for about 90% of the total operating cost.

Table A5. Investment Cost and Operating Cost per Net MWh of Base and Each Case

contents	base	case-1	case-2	case-3	case-4
TCC (\$/MWh-net)					
feed water and MISC. BOP systems	9.72	13.08	13.53	12.18	12.19
gasifier and accessories	0.00	0.00	0.00	0.00	0.00
gas cleanup and piping	0.00	0.00	0.00	0.00	0.00
CO ₂ removal and compression	0.00	67.87	4.03	3.63	3.63
chemical looping system	0.00	0.00	19.22	17.31	17.31
combustion turbine/ accessories	22.54	26.75	27.46	26.43	25.94
HRSG, ducting, and stack	11.02	11.66	13.12	10.45	10.45
steam turbine generator	11.55	11.80	13.31	10.56	7.27
cooling water system	3.91	7.17	7.42	6.68	6.68
ash/spent sorbent handling SYS	0.00	0.00	0.00	0.00	0.00
accessory electric plant	8.03	12.96	13.41	12.07	12.07
instrumentation and control	3.12	4.33	4.48	4.03	4.03
improvements to site	2.19	2.67	2.77	2.49	2.49
buildings and structures	2.46	2.84	2.94	2.65	2.65
TCC	74.55	161.13	121.68	108.49	104.71
owner's cost (\$/MWh-net)					
preproduction costs	3.33	5.98	6.18	5.57	5.57
inventory capital	0.42	0.92	0.95	0.86	0.86
initial cost for catalyst and chemicals	0.00	0.23	0.24	0.22	0.22
initial cost for land	0.07	0.08	0.09	0.08	0.08
other owner's costs	11.25	24.60	25.45	22.92	22.92
financing cost	2.03	4.43	4.58	4.13	4.13
owner's cost	13.76	30.26	31.31	28.20	28.20
fixed operating cost (\$/MWh-net-year)					
annual operating labor cost	0.46	0.71	0.73	0.66	0.66
maintenance labor cost	0.61	1.18	1.22	1.10	1.10
administrative and support labor cost	0.27	0.47	0.49	0.44	0.44
properties taxes and insurance	1.50	3.28	3.39	3.06	3.06
fixed operating cost	2.83	5.63	5.83	5.25	5.25
variable operating cost (\$/MWh-net-year)					
annual maintenance material cost	0.91	1.76	1.82	1.64	1.64
catalysts	0.34	0.79	0.81	0.73	0.73
chemicals and others	0.00	0.00	0.74	0.74	0.74
waste disposal	0.00	0.00	0.00	0.00	0.00
byproducts and emissions	0.00	0.00	0.00	0.00	0.00
variable operating cost	1.26	2.55	3.37	3.11	3.11
fuel cost (\$/MWh-net-year)					
annual fuel cost	42.54	51.95	53.75	48.40	48.40
fuel cost	42.54	51.95	53.75	48.40	48.40
economic analysis					
(COE) capture + compression	56.3	82.0	84.8	76.3	75.8
(LCOE) capture + compression	67.5	98.4	101.7	91.5	90.9
(tCO ₂ /MWh) capture + compression	N/A	0.4	0.4	0.4	0.4
cost of CO ₂ capture and compression (\$/tCO ₂)	N/A	76.2	77.9	60.7	59.2

Table A6. Total Investment and Operating Cost Reflecting the Capacity of NGCC and Each Case

	base	case-1	case-2	case-3	case-4
TOC (\$)	396,333,033	698,937,189	544,824,279	540,684,744	526,305,068
TCC (\$)					
feed water and MISC. BOP systems	42,022,000	46,313,000	46,313,000	46,313,000	46,313,000
chemicals looping system			65,789,474	65,789,474	65,789,474
CO ₂ removal and compression		240,334,000	13,798,047	13,798,102	13,798,047
combustion turbine/accessories	97,490,000	94,719,405	93,976,436	100,455,324	98,575,686
HRSG, ducting, and stack	47,667,710	41,289,466	44,902,464	39,701,577	39,701,577
steam turbine generator	49,969,323	41,794,319	45,557,858	40,140,267	27,640,284
cooling water system	16,920,000	25,402,000	25,402,000	25,402,000	25,402,000
accessory electric plant	34,737,000	45,888,000	45,888,000	45,888,000	45,888,000
instrumentation and control	13,490,000	15,318,000	15,318,000	15,318,000	15,318,000
improvements to site	9,454,000	9,467,000	9,467,000	9,467,000	9,467,000
buildings and structures	10,658,000	10,075,000	10,075,000	10,075,000	10,075,000
owner's costs (\$)					
preproduction costs	14,410,000	21,170,000	21,170,000	21,170,000	21,170,000
inventory capital	1,802,000	3,260,000	3,260,000	3,260,000	3,260,000
initial cost for catalyst and chemicals		823,000	823,000	823,000	823,000
initial cost for land	300,000	300,000	300,000	300,000	300,000
other owner's costs	48,655,000	87,105,000	87,105,000	87,105,000	87,105,000
financing cost	8,758,000	15,679,000	15,679,000	15,679,000	15,679,000
operating costs (\$/year)	201,662,760	212,935,330	215,452,134	215,730,124	215,730,043
fixed operating cost (\$/year)					
annual operating labor cost	1,972,971	2,497,781	2,497,781	2,497,781	2,497,781
maintenance labor cost	2,635,374	4,162,295	4,162,295	4,162,295	4,162,295
administrative and support labor cost	1,152,086	1,665,019	1,665,019	1,665,019	1,665,019
properties taxes and insurance	6,487,309	11,614,024	11,614,024	11,614,024	11,614,024
variable operating costs (\$/year)					
annual maintenance material cost	3,953,061	6,243,443	6,243,443	6,243,443	6,243,443
catalysts	1,488,499	2,780,677	2,780,677	2,780,677	2,780,677
chemicals and others			2,516,804	2,794,794	2,794,713
fuel cost					
annual fuel cost gas unit price: 6.55 \$/MMBtu	183,973,460	183,972,091	183,972,091	183,972,091	183,972,091

The fuel cost of 6.55 \$/MMBtu was obtained from ref 4. The total operating costs were similar (~21 million dollars) for all cases because of the fuel cost as shown in Table A6. However, the difference in operating costs (\$/net MWh year) resulted from the net power produced in each case. Case-3 and Case-4 showed a similar operating cost of 56.7 \$/net MWh year, which was lower than those of Case-1 and Case-2.

The total investment cost and the operation cost were compared among all cases in Figure 8, and a detailed summary is given in Table A6. Total costs were calculated based on the investment cost per net MWh (Figure 6 and Table A5), the operating cost per net MWh-year (Figure 7 and Table A5), and the material balances (Tables A1–A4). The investment cost of Case-1 was 22–24.6% more expensive than NGCC with CLC schemes due to the higher cost of the MEA process. The investment cost of Case-4 was 2.6% lower than that of Case-3 due to the integration of STs, thereby making it economically efficient.

4.3. COE, LCOE, and Carbon Capture Cost. COE is the actual cost to buy electricity, while LCOE is the break-even cost to generate the electricity. The LCOE is the widely accepted calculation of the total life cycle cost per unit of electricity produced in the lifetime of a project.⁴³ Figure 9 shows the economic analysis on the COE, LCOE, and CO₂ capture cost per ton. The Base case had the lowest LCOE of 67.5 \$/MWh, whereas Case-2 showed the highest LCOE of 101.7 \$/MWh, which was 34.2% higher than the Base case. Case-4 was

economically efficient since its LCOE was 2% lower than that of Case-3 and 3.8% lower than that of Case-2.

The carbon capture potential of a power plant serves as an important basis for economic analysis. Conventional NGCC (Base) is unable to capture CO₂ because any capture process was not equipped. In this study, Case-1 was used to capture about 95.1% of CO₂ and 4.9% was released into the atmosphere, while NGCC-CLC schemes captured about 99.93% of CO₂ and a small amount (about 0.07%) was discharged into the atmosphere. The CLC schemes have a higher rate of carbon capture than the MEA because the CLC fuel reactor emits only CO₂ and H₂O. In conclusion, the CO₂ capture cost of Case-4 was 13.9% lower than that of NGCC-MEA.

Table 6 summarizes the findings of the study and compares them with the relation.^{27,44,45} The reference NGCC process employs Econamine for carbon capture. NGCC-Econamine has a net capacity of 435 MW, which is less than the results of the analysis. Although Case-1 and Case-2 have LCOEs of 98.4 and 101.7 \$/MWh, respectively, NGCC-Econamine has an LCOE of 95.9 \$/MWh, which is more efficient than the other two scenarios. Case-3 and Case-4 have LCOEs of 91.5 and 90.9 \$/MWh, respectively. This means that when the NGCC-CLC configuration is correctly built, it produces better economic performance. As previously said, since the investment cost for a CO₂ absorber and regenerator in an amine-based carbon capture operation is typically very high, the LCOE increases. In addition, NGCC-Econamine has a carbon capture cost of 80 \$/ton, while

NGCC/CLC Case-4 has a CO₂ capture cost of 59.2 \$/ton, which is 25.5% cheaper.

5. CONCLUSIONS

With NGCC being a major player in the generation of electricity, this study evaluated four cases of NGCC-based process schemes: NGCC with an MEA system (Case-1), NGCC-CLC with an air reactor cooler (Case-2), NGCC-CLC with an excess air inlet (Case-3), and NGCC-CLC with excess air inlet and ST integration (Case-4). A comparative analysis of the performance, cost, and carbon capture capability was performed on all four cases in view of the feasibility study. Performance and environmental analyses included net power, plant efficiency, and carbon capture capability. Economic assessment was also performed on the investment cost, operating cost, carbon capture cost, and LCOE. The results of this study are summarized as follows:

- **Simulation:** Detailed heat and material balance results for the studied processes were obtained under the condition of an equal amount of NG feed (4264 kg mol/h). An internal cooler was installed in Case-2 to produce steam when BFW was fed through it. The BFW flow rate in Case-2 was higher than that in the other cases. One the other hand, air was fed at a flow rate of 158,229 kg mol/h in Case-3 and Case-4, which was greater than the other cases. The excess air was used to control the temperature of the CLC reactor in these cases.
- **Performance:** The performance of a power plant was described by its net power and efficiency. Case-1 produced a net power of 484.2, which represented a 16.6% reduction when compared to 580.4 MW in the Base Case. The net power of Case-1 was low because the steam consumed by the operation of the regenerator in the MEA process resulted in reduction in the amount of power produced by the steam turbine. Both Case-3 and Case-4 produced a net power of 510.1 MW, which was 5.4% more than that produced in Case-2. A plant efficiency of 44.3% made them more efficient than the other cases proposed. The excess air fed in both cases helped the turbine to generate more power.
- **Economics:** The economic analysis was conducted using the investment cost, operating cost, and LCOE as the basis. Case-1 had the highest investment cost (191.3 \$/net MWh) due to the use of MEA-based carbon capture and CO₂ compression. The investment and operating costs of Case-4 were 132.9 and 56.7 \$/net MWh year, respectively. Case-4 had a lower investment cost than Case-3 because of the ST integration. Although both Case-3 and Case-4 produced the same amount of net power, Case-4 had a lower LCOE.
- **Carbon capture capability:** The carbon capture ratio was used as the basis for the environmental impact analysis. NGCC-CLC-based schemes had a better carbon capture ratio of about 99.93%. The CLC carbon capture rate was higher than that of MEA because the fuel reactor in the CLC emitted only CO₂ and H₂O. Additionally, the carbon capture cost per ton in Case-4 (59.2 \$/CO₂-ton) was the lowest among all four cases.

With regard to the results and discussion from our study, Case-4 (NGCC-CLC with the ST integration) was considered the most efficient process scheme for generating power from NG with regard to performance, economics, and the environment

impact. The detailed results of this study were subject to change due to several factors such as investment cost, levelized factor, and operating condition. This study demonstrated that combining CLC with NGCC is a promising technology for mitigating the amount of CO₂ emitted by power plants. If commercially reliable advanced OCs can be applied, further enhancement can be achieved. In addition, it can be developed with further modification for full-scale operation. In the scaled FBR, more detailed design and operation difficulties are expected because it is operated at high pressures.

■ APPENDIX

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Notes

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■ NOMENCLATURE

ASU	air separation unit
BFW	boiler feed water
CC	carbon capture
CF	plant capacity factor
CCF	capital charge factor
CCS	carbon capture and sequestration
CCU	carbon capture and utilization
CHP	combined heat and power
CLC	chemical looping combustion
COE	cost of electricity (\$/MWh)
GT	gas turbine
HP	high pressure (kPa)
HRSG	heat recovery steam generator
IGCC	integrated gasification combined cycle
IOU	investor owned utility
IP	intermediate pressure (kPa)
LCOE	levelized COE (\$/MWh)
LP	low pressure (kPa)
MEA	monoethanolamine
MW	net plant capacity (MW)
NG	natural gas
NGCC	natural gas combined cycle
OC	oxygen carrier

OC _{FIX}	the sum of all fixed annual operating costs
P	pressure (kPa)
P _c	critical pressure (kPa)
R	gas constant (J/kmol)
SRK	Soave–Redlich–Kwong
SRKM	Soave–Redlich–Kwong modified
ST	steam turbine
T	temperature (K)
T _c	critical temperature (K)
TCC	total capital cost (\$)
TOC	total ownership cost (\$)
TS&M	transporting, storing, and monitoring
V	molar volume (m ³ /mol)
W	acentric factor
LF	levelization factor

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