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Current status and technology development in implementing low carbon emission energy on underground coal gasification (UCG)

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Although coal mining has played a substantial role in world's development as a critical fuel source for at least 25 years, its value is partly offset by the massive environmental issues it presents during combustion. The shift to a net-zero CO_2 emission will open unique possibilities for new coal technological models in which progressive studies and policies, development, and modernization will play a significant role. Therefore, a collection of technologies has been proposed, one of which is cost-effective is the Underground Coal Gasification (UCG) coupled with carbon capture storage (CCS) and utilization technology (CCU) UCG-CCS/CCU. This paper reviews the current status and technology development in implementing low carbon emission energy on underground coal gasification. The study, therefore, leads to discussing the modern stage of underground coal gasification and carbon capture storage development, recent pilot operations, and current developments of the growing market. At the same time, it provides a reference for underground coal gasification combined with CCUS technology.

KEYWORDS

underground coal gasification (UCG), UCG modules, UCG CCUS, UCG-ICGCC, cost

1 Introduction

Coal is presently an essential energy source throughout the world, except for the middle east and the Former Union of Soviet Socialist Republics (USSR), which have virtually two-thirds or more of the global oil and natural gas reserves (Grimston, 1999) and will remain for many ages (EIA and International, 2003; Miller, 2005). reports a detailed estimate of coal reserves and producing nations for major states worldwide. Research by EIA (2003) also estimates energy production and consumption primarily by regions and countries. Research by EIA and International (2002) gives a projected world coal consumption by region for a forecast period to 2020. It is therefore observed that by

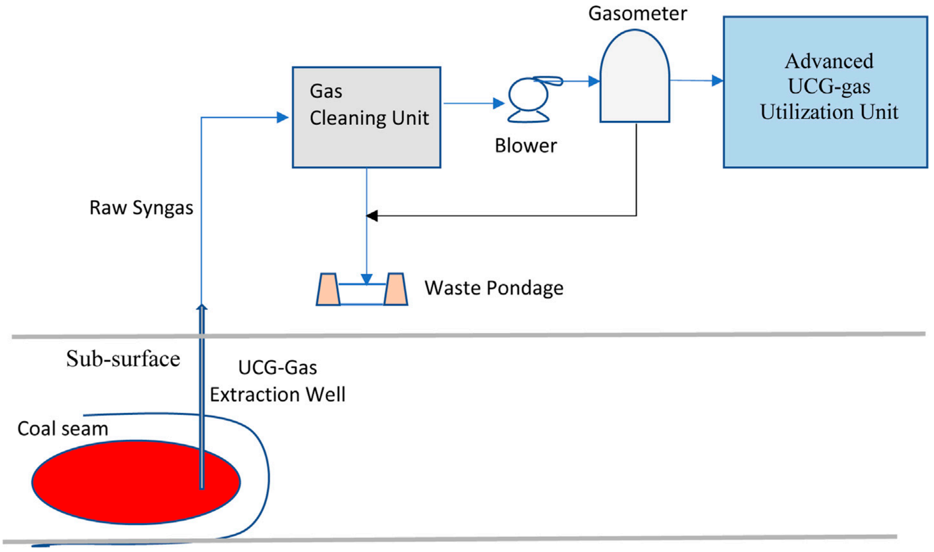

FIGURE 1
Schematic of UCG process with gas cleaning unit.

2030, future world coal consumption is expected to increase in regions like China, the United States, India, Non-OECD Asia, Japan, Russia, and others (Non-OECD Europe and Eurasia, ex Russia) (Department of Energy EIA Energy Information Administration, 2009).

Although coal has played a substantial role in world development as an essential fuel source for at least the subsequent quarter-century, its value is partly offset by the massive environmental issues it presents during combustion. According to IEA (2009), CO_2 discharges worldwide raised from 1.7% in 2018 to a significant height of 33.1 $GtCO_2$. This was the maximum growth rate since 2013 and 70% more than the average increase since 2010. Coal accounts for more than 70% of fuel's total energy-related CO_2 emissions (The World bank, 2014). Overall, global coal burning is accountable for 46% of the emission of CO_2 and further records for 72% of overall greenhouse gas releases from the electricity section. The common usage of coal evidence this in generating electrical power, and the extremely high CO_2 intensity of coal-fired power. Coal emits significantly more CO_2 emissions per unit of energy produced than oil and more than twice as much as natural gas. Annually, coal burning yields over 14 billion tons of atmospheric-released CO_2, specifically from power generation. As reported by IEA (2009), coal consumption for power alone surpassed 10 $GtCO_2$, mainly in Asia. China, India, and the United States recorded an 85% increase in net CO_2 emissions, while regions like Germany, Japan, Mexico, France, and the United Kingdom accounted for decreased reductions. CO_2 Earth (2017) states that by 2,100, the levels of atmospheric CO_2 are estimated to reach about 800 ppm resulting in the rise of the earth's surface temperature to about 4°C if no immediate and effective actions are taken. Concerning the latest accessible science and the necessity to uplift global climate action, the European Council recommends attaining a climate-neutral EU by 2050, per the aims of the Paris Agreement (EU, 2020). The shift to a net-zero CO_2 emission will open unique possibilities for new technological models in which progressive research, growth, and modernization policies will have a crucial role. To achieve this aim, a collection of technologies has been projected, one of which is cost-effective (Nakaten et al., 2014) is the carbon capture (CC), utilization and storage technology (CCUS) (Dixon, 2016), coupled with Underground Coal Gasification (UCG-CCS/CCU.)

UCG is a coal technology characterized by a high resource utilization rate (Green, 2018). UCG provides both economic and enviro-friendly approaches to raising coal reserves by utilizing the un-mineable coal deposits by the conventional approach. According to Bhutto et al. (2013), UCG alters coal into gas, accompanied by eliminating sulfides and nitrogen oxides, evading the conventional coal-burning process, and has the features of minimum pollution emission, see Figure 1. UCG has numerous economic and environmental benefits (Blinderman and Anderson, 2003). The technology is much cheaper, eliminates land degradation and mining activity, and sharply permits a functioning UCG plant to increase its syngas production at minimal capital cost. UCG appears to be the leading appropriate technology to be deployed in combination with geological storing of CO_2—geological settings promising for UCG are also promising for CO_2 storing (Friedmann, 2006). Other applicable technologies can also join UCG to produce synthetic fuel and recover coal bed methane. The rising

TABLE 1 International UCG pilots operations (Prabu and Jayanti, 2012).

Dates	Place (test name)	Duration (days)	Well separation (m)	Coal gasified (tons)	System pressure (kPa)	Feed gas	Coal seam depth (m)	Auspices/comments
1982–1985	Thulin, Belgium	12	35	4	30,000 to 80,000	air; mix of N_2, O_2, CO_2	860	Institute pour le development de la gazeification souterraine, Belgium
1983–1984	Initially at Bruay en Artois, and later at La Haute Deule, France	75	60	0.3 1st phase 1.5 next phase	45,000	N_2, O_2, CO_2	880	groupe d'etude de la Gazeification souterraine, France (production well plugged by particulates and tar, terminating the tests)
1992–1999	Province of Teruel, NE Spain (El Tremedal)						550	Spain, United Kingdom, Belgium, supported by the European Commission, used CRIP
1980—present	China, 16 separate trails *							UCG centre at China Univ. Of mining and technology, Beijing
1990—present	*Chinchilla*, Queensland, Australia							
1994	Huntley, New Zealand							With US technical assistance

variability in the worldwide energy condition is bringing out shareholders in nations with primary coal deposits and present or coming energy shortfalls to recommence attention to all technologies with capabilities to raise the use of domestic coal resources (Burton et al., 2006). For virtually a century of global research and practice, many workshops, practices, and successes have been amassed in the approaches and technologies of UCG.

Since the 20th century, over 50 pilot-scale operations of UCG have taken place in Europe, Australia, China, the Former Union of Soviet Socialist Republics (USSR), the United States, and South Africa (see Tables 1, 2). These tests have mainly been commenced at low depths, as seen at the 140 m *Chinchilla* in Australia, Angren (110 m) in Uzbekistan, Hoe Creek (30–40 m) in the United States, and Hanna (80 m) also in the United States (Prabu and Jayanti, 2012). The USSR UCG program is believed to have used up 15 Mt of coal, and the US research effort to increase regulation and efficiency of the UCG development in about 60 separate tests is projected to have vaporized 100,000 tons of coal. However, it was halted shortly by the same minimum prices of natural gas in the 1990 s. From 1974 to 1989, scientific investigations and the expansion of UCG rose in the United States. Thirty-three pilot projects of UCG were planned and sited in Texas, Wyoming, Alabama, West Virginia, and Washington (Gem, 2021). Among them, the most effective was the Rocky Mountain 1 project in Carbon County, Wyoming (Clean Air Task Force Report, 2009). Many companies worldwide have initiated successful UCG projects that include electric generation and coal-to-liquids. In 2002 (Sasol, 2013), Eskom initiated its UCG technology development (using Ergo Energy's UCG technology) and successfully piloted it for 5 years with proven results. The same technology has been utilized in three UCG projects in the past few years, particularly Linc Energy's initial *Chinchilla* UCG project in Australia, the Huntly West UCG project in New Zealand established by Solid Energy, and Eskom's Majuba pilot project in South Africa. The Ergo Energy's UGC technology is utilized to expand commercialized UCG energy plans in Canada, China, the United States, New Zealand, India, and other nations. In 2006, under the sponsorships of the US-India Energy Dialogue Coal Working Group and the Asia Pacific Partnership, a UCG workshop took place in India Kolkata (US Department of Energy, 2006) and Houston (Burton et al., 2006) to accelerate the implementation of UCG and initiate a commercial UCG project set to deliver gas. Studies from esteemed economics have placed power production from UCG Levelized electricity rate at around €49 MWh in the absence of CCS and €72 MWh with CCS (Nakaten et al., 2014), which proposes that UCG is highly viable for power generation in both methods of operation. According to Eskom Holdings Ltd (2008), the Angren power station in Uzbekistan has generated power from UCG gas for over 50 years by co-firing the gas with coal in a boiler. Lately (DECC Report, 2015) puts the UCG power

TABLE 2 20th century UCG primary projects.

Test site	Country	Year	Seam thickness (m)	Seam depth (m)	Coal gasified (ton)	Syngas cv (mj/m^3)
Lisichansk	Russia	1934–1936	0.75	24		3–4
Lisichansk	Ukraine	1943–1963	0.4	400		3.2
Gorlovka	Russia	1935–1941	1.9	40		6–10
Podmoskova	Russia	1940–1962	2	40		6 with O_2
Bois-la-dame	Belgium	1948	1			
Newman Spinney	United Kingdom	1949–1959	1	75	180	2.6
Yuzhno-Abinsk	Russia	1955–1989	2-September	138	2×10^6	9–12.1
Angren	Uzbekistan	1965–now	4	110	$>1 \times 10^7$	3.6
Hanna 1	United States	1973–1974	9.1	120	3,130	
Hanna 2	United States of America	1975–1976	9.1	84	7,580	5.3
Hoe creek 1	United States	1976	7.5	100	112	3.6
Hanna 3	United States of America	1977	9.1	84	2,370	4.1
Hoe creek 2A	United States	1977	7.5	100	1820	3.4
Hoe creek 2B	United States	1977	7.5	100	60	9
Hanna 4	United States of America	1977–1979	9.1	100	4,700	4.1
Hoe creek 3A	United States	1979	7.5	100	290	3.9
Hoe creek 3B	United States of America	1979	7.5	100	3,190	6.9
Pricetown	United States	1979	1.8	270	350	6.1
Rawlins 1A	United States	1979	18	105	1,330	5.6
Rawlins 1B	United States	1979	18	105	169	8.1
Rawlins 2	United States	1979	18	130–180	7,760	11.8
Brauy-en-artois	France	1981	1,200			
Thulin	Belgium	1982–1984	860			
Centralia tono A	United States	1984–1985	6	75	190	9.7
Centralia tono B	United States	1984–1985	6	75	390	8.4
Haute-duete	France	1985–1986	2	880		
Thulin	Belgium	1986–1987	6	860	157	
Rocky mountain 1A	United States	1987–1988	7	110	11,200	9.5
Rocky mountain 1B	United States	1987–1988	7	110	4,440	8.8
EI tremedal	Spain	1997	2	600		

generation release of CO_2 with combined cycle gas turbine (CCGT) in the range 570–785 kg CO_2 MWh without resource to CCS, relative to natural gas at 400 kg CO_2 MWh. CCS could decrease the emissions of UCG to 100 kg CO_2 MWh less. These values are remarkable and therefore put UCG on equivalence to renewable energy sources and the finest fossil fuel discharges with CCS.

2 Status of UCG configuration modules for initiating UCG reactions

UCG involves compound physical and chemical processes, and the composition and quality of the syngas are affected by many factors. Given the high-temperature humidity and closed setting, it becomes problematic to efficiently monitor and control the overall UCG process to upgrade the quality of the syngas. Studies by Mostade (2014) confirm that the technical challenge with UCG monitoring and controlling the hot cavity to move safely and reliably along the coal seam and convert as much coal as possible into valuable, sustainable, high-quality syngas. UCG is currently noted as a composite process where engineers are proficient in forecasting the accessibility and dependability of the entire process during the construction, process control, and monitoring of UCG operations together with the post-operation shutdown program (Mojibul and Mohammad, 2015). All UCG modules (the arrangement of both linked injection and production point) are identical. Thus, they require at least two process points connected within the coal seam to inject the vaporizing agents and begin ignition (injection point) and the other for recovering the syngas that is produced (production point) (Lavis et al., 2013). Between these two process points, a higher-performance gas circuit needs to be built by increasing the permeability of coal in a process called "linking."

Therefore, scholars in many countries have conducted meaningful studies on UCG modules. According to (Mojibul and Mohammad, 2015), there are various methods, such as hydraulic fracturing, horizontal drilling, reverse combustion, linked vertical well (LVW), electric linkage, and controlled retractable injection point (CRIP) method. Another suitable technology based on the Former Union of Soviet Socialist Republics (USSR) UCG technology is Ergo Energy's UCG technology (Burton et al., 2006). Other technology development modules are China's Long Tunnel Method (Lavis et al., 2013), "Super Daisy Shaft," and Single Well Flow Tube (SWIFT) technology. Portman Energy established SWIFT technology and uses a single vertical well for oxidant injection and syngas supply (Couch, 2009).

2.1 CRIP method

The Lawrence Livermore National Laboratory developed the CRIP method in the US in 1970 (Kumar, 2014). The production wells are drilled vertically, and the injection wells are drilled using directional drilling techniques to connect to the production wells. Once the channel is established, a burner attached to the retractable coiled tubing is used to initiate the gasification cavity, which ignites the coal as it burns the borehole casing (Hill, 1983). CRIP provides a stationary state of the vertical press-in well, but if necessary, the press-in point moves to fresh coal within the coal seam (Hill, 1983). Studies in Klimenko (2009) have confirmed that the flash point can be moved along the horizontal injection well to create a new gasification cavity when the coal near the cavity is exhausted. The second combustion begins near the injection well when the first combustion is finished. This way, the progress of gasification can be precisely controlled, and this procedure continues until the seams are burned out. Syngas, more than one-third of hydrogen in many early UCG pilots (the rest are CO_2, CO, CH_4, and higher hydrocarbons), is brought to the surface and processed to remove particles, CO_2, and H_2S. Moreover, CO is converted. From CH_4 and higher hydrocarbons to more hydrogen (Burton et al., 2006). See Figures 2A, B.

The concept of CRIP can be divided into Linear-CRIP (L-CRIP) (see Figure 2C) and Parallel-CRIP (P-CRIP) configurations. In the L-CRIP configuration, both process points are linked by one intra-seam excursion well. In a P-CRIP configuration, both process wells are drilled into the seam parallel to each other. See UGE (1999) and Nourozieh et al. (2010) for more information on the two processes.

2.1.1 CRIP commercialization developments

The CRIP method was primarily developed in the US in the 1980 s during major R & D stages (Cena et al., 1988), in Spain (1990s), Australia (late 1990s to present), and currently in Alberta, Canada (from late 2000s to the present) (Lavis et al., 2013). The L-CRIP configuration has been successfully demonstrated at shallow depth (110 m) in the Rocky Mountain 1 (RM-1), Wyoming, US, at intermediate depth (500–600 m) in the European UCG project at El Tremedal, Teruel, Spain, and is currently being used to produce high-quality syngas at great depth (1,400 m) in the Swan Hills UCG project, Alberta, Canada (Hill and Shannon, 1981). In addition, the P-CRIP configuration was first tested at the partial seam CRIP test (Tono-1) in Centralia, Washington State, US, and has since been used during the RM-1 trial (Tono-2), United States, and by Carbon Energy and LINC at their respective facilities in Queensland, Australia (Mostade, 2014).

2.2 LVW

SHS(2012) states that the LVW method is one of UCG's oldest methods and is derived from technology developed in the former Soviet Union. A vertical well is drilled at the coal seam and uses the coal's internal pathways to direct the oxidizer flow and produced gas from the inlet to the exit borehole. Internal pathways can occur naturally or be constructed *via* reverse combustion, electrical coupling, and hydraulic fracturing (Shafirovich and Varma, 2009).

The injection point is located at the complete base of the vertical injection well, and the production point is at the complete base of the vertical production well (Mostade, 2014). In the simplest form, the entry and exit drilling positions of the LVW method are stationary throughout the life of the system. However, it has been found that as the coal surface moves during operation and the distance from the coal surface to the oxidant injection point increases,

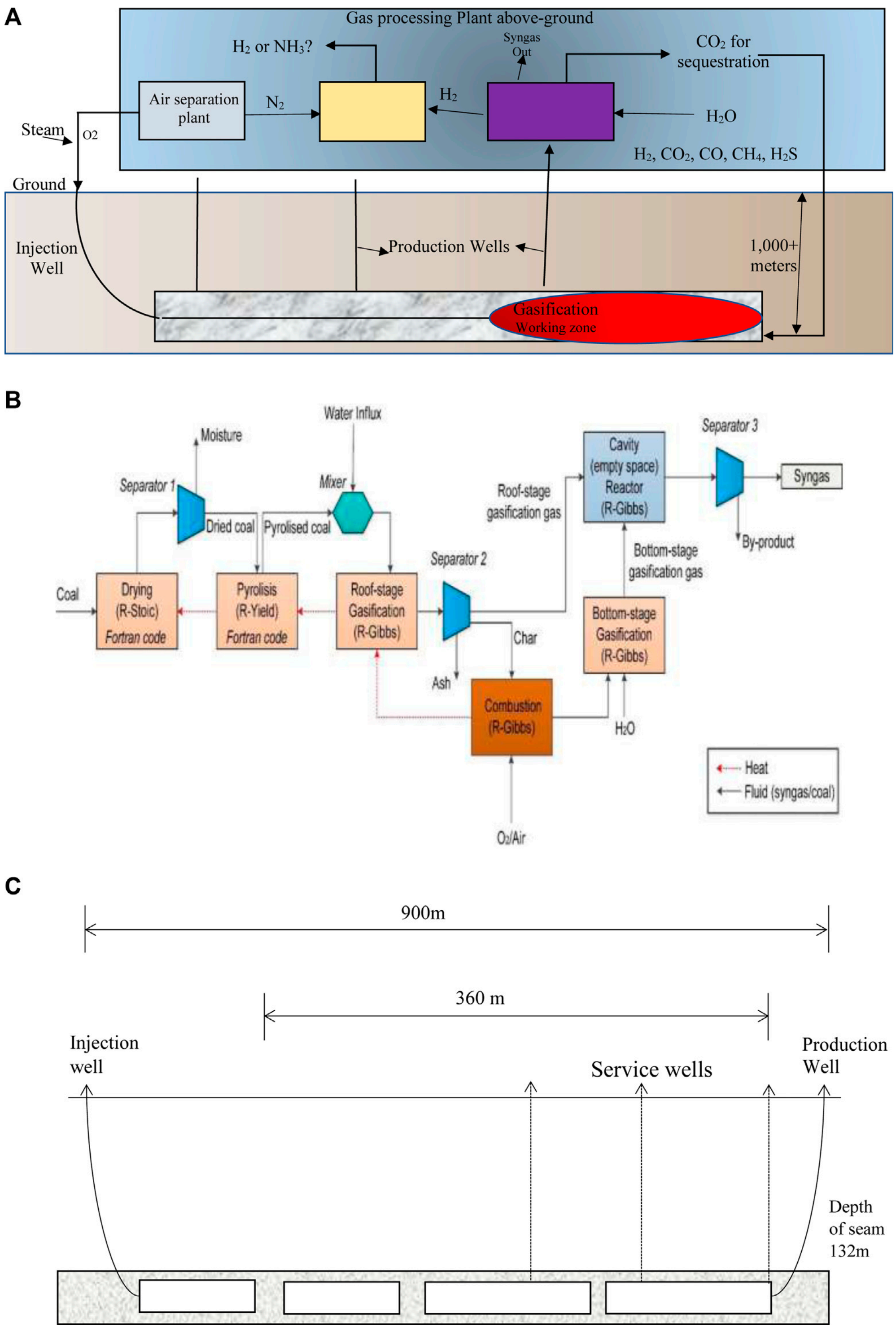

FIGURE 2
(A) Schematic of the CRIP process. **(B)** Chemical process model for simulating CRIP underground layout of (Burton et al., 2006). **(C)** Gasifier layout for linear CRIP configuration.

system control, performance, and syngas quality are adversely affected (Liang et al., 1999). This factor significantly decreases the viability of a simple LVW system. When the coal in the area is exhausted, a new hole will be drilled to replace the new coal, forming new zones. See Figures 3A, B.

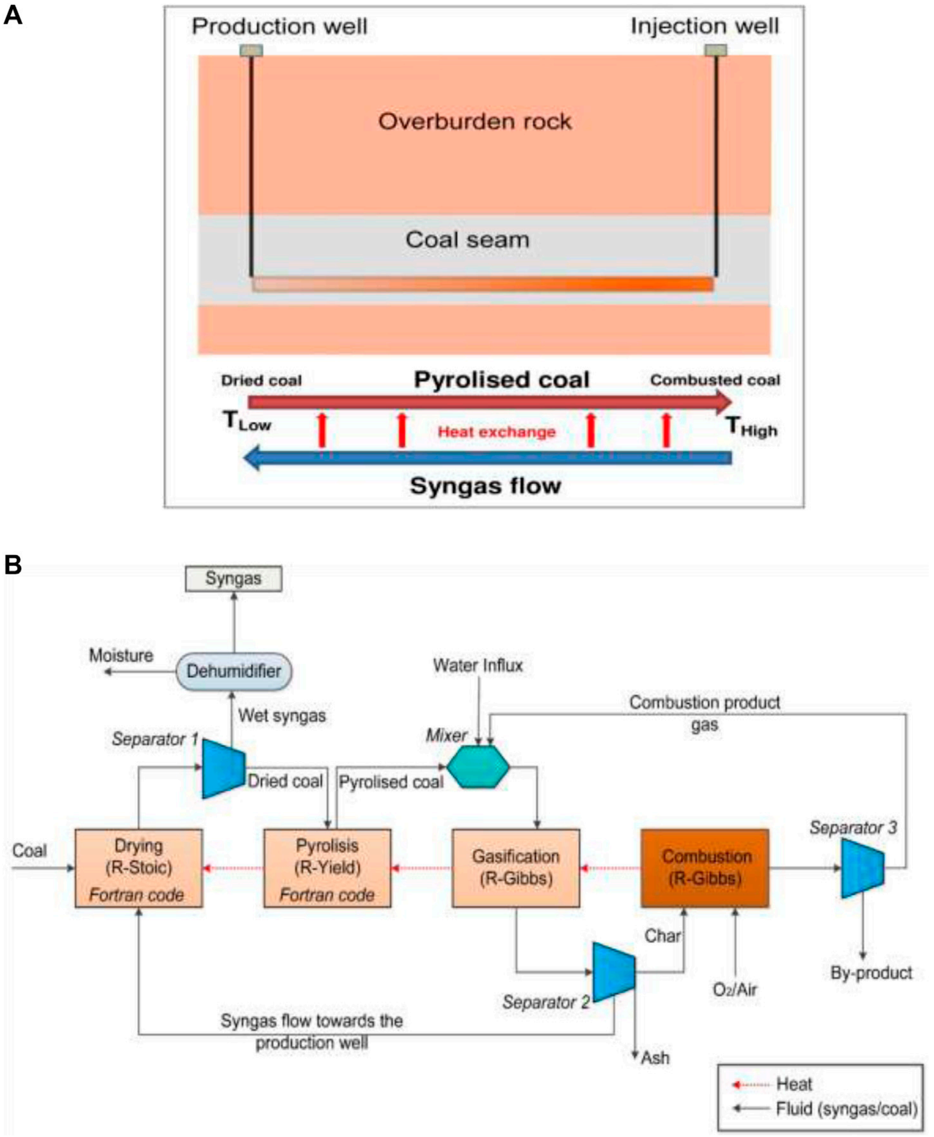

FIGURE 3
(A) Upright cross-section of underground LVW gasifier. **(B)** A chemical process model used to simulate the underground layout of LVW (Liang et al., 1999).

2.2.1 LVW commercialization developments

2.2.1.1 Eskom Majuba, South Africa

The Majuba UCG project has produced syngas and coal since January 2007 and the end of 2010. The project contributed approximately 3 MW of electricity to the total output of 650 MW. Currently, the project is the longest-running UCG test in the Western world. It is planned to expand the facility to an output of 1200 MW, and 30% of the plant's fuel will be provided by syngas (Roddy and Younger, 2010).

LVW configurations have been used at Solid Energy's facility at Huntly, New Zealand, as well as other locations in China and Canada (Laurus Energy). The LVW configuration was also used at Cougar Energy's facility in Kingaroy, Australia (Mostade, 2014). Alternatives of the LVW method are continuously used today, especially at the UCG facility in Angren, Uzbekistan, which has the longest continuous operation in the world (Lavis et al., 2013).

2.3 The Ergo energy's UCG technology

Ergo Energy's UCG is a proprietary process used by Ergo Exergy and may be based on the former Union of Soviet Socialist Republics (USSR) UCG technology. It relies on using the natural

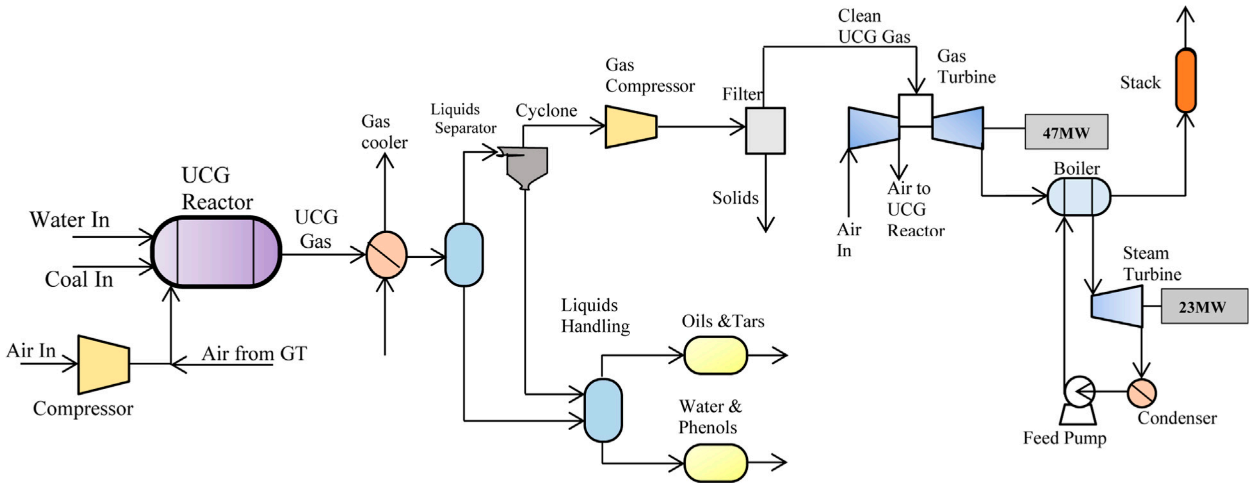

FIGURE 4
Conceptual design of the ergo energy UCG-IGCC plant.

passages at the coal seams and strengthening them as needed to establish a connection between the press-in well and the production well. Ergo Energy's UCG technology is practical and based on the practical experience of operating a commercial UCG factory. The design flexibility and multiple methods and technologies used by Ergo Exergy enable it to be applied to various coal qualities and grades (from lignite to bituminous coal) and geological environments (Burton et al., 2006).

It employs all currently available drilling methods, including precision directional wells and traditional vertical and sloping (tilted) wells. Its arsenal includes different ways to connect wells, different oxidant injections (air, O_2/H_2O.), and different underground vaporizer designs. It can be applied to coal under various geological and hydrogeological conditions. In each geological environment, the specific Ergo Energy's UCG design is tailored to the specific conditions of the coal seam of interest (Power, 2011).

2.3.1 Ergo energy's UCG commercialization developments

The Australian *Chinchilla* project has effectively established Ergo Energy's UCG technology. In this project, a projected 35,000 tons of coal were used to produce 80,000,000 Nm^3 of syngas at 5 MJ/Nm^3. Ergo Energy's UCG technology is also been reviewed for the projected Powder River Basin UCG project and in a cooperative project between Gas Authority India, Ltd. (GAIL) and Ergo Exergy.

The 1997 to 2006 *Chinchilla* I UCG project in Australia (350 km west of Brisbane, Queensland) was the first to establish Ergo Energy's UCG as gas production technology (Maev et al., 2018). Ergo Exergy supplied the technology for the project and designed and operated the plant. In the past 16 years, the technology has been used in four syngas production projects as seen in the 1999 to 2006 *Chinchilla* project (Australia); 2007 to present Eskom (South Africa) project; Kingaroy (Australia), 2010; and the Huntly West (New Zealand), 2012 (Maev et al., 2018). A Conceptual design of Ergo Energy's UCG IGCC plant is shown in Figure 4. Table 3 shows the coalfields where Ergo Energy's UCG is used around the world (Power, 2011).

2.4 Current R&D on UCG monitoring

Early UCG tests applied flow meters, thermocouples, and gas analyzers to monitor temperatures and combustion conditions from the underground (Blinderman and Jones, 2002). These measurements track underground combustion conditions and their corresponding subsidence but are effective for shallow coal seams and lower resolution for deep coal seams. However, in a hot and humid UCG setting, the accuracy of such sensors may be low and may not work properly. In addition Mellors et al. (2016) researched and designed a UCG monitoring system based on a self-organizing network of wireless sensors. However, the system has been tested in the laboratory, and the high temperature and high humidity environmental factors were not considered in the design. Wang et al. (2017) used Siemens S7-300 PLC and Fame View configuration software to develop a real-time monitoring system for UCG. However, the laboratory has tested the system, and the design does not consider the hot and humid environmental factors. Using the Siemens S7-300 PLC and Fame View configuration software, Wang et al. (2017) developed the UCG real-time monitoring system. However, the system is used for teaching experiments, and the design

TABLE 3 Various ergo energy UCG technology projects.

UCG plant	Rank	Thickness, m	Depth, m	Dip, °	LHV, MJ/kg
Lisichansk	Bituminous	0.44–2.0	60–250	38–60	20.1–23.0
Yuzhno-Abinsk	Bituminous	2.2–9.0	130–380	35–58	28.9–30.7
Podmoskovnaya	Lignite	2.5	30–80	<1	11.8
Angren	Lignite	3.0–24.0	110–250	7	15.3
Shatskaya	Lignite	2.6	30–60	<1	11.0
Sinelnikovo	Lignite	3.5–6.0	80	<1	8.0
Chinchilla	Sub-bituminous	10.0	135	<1	21.7
Majuba	Bituminous	3.5–4.5	285	3	20.3
Kingaroy	Sub-bituminous	17.0	200	5	23.5
Huntly West	Bituminous	4.0–22.0	220–540	0–75	24.5
CC Alberta	Sub-bituminous	7.0	150–260	6	20.5–23.0
Alaska SHR	Lignite/sub-bituminous	1.0–12.0	50–650	0–75	11.0–16.5

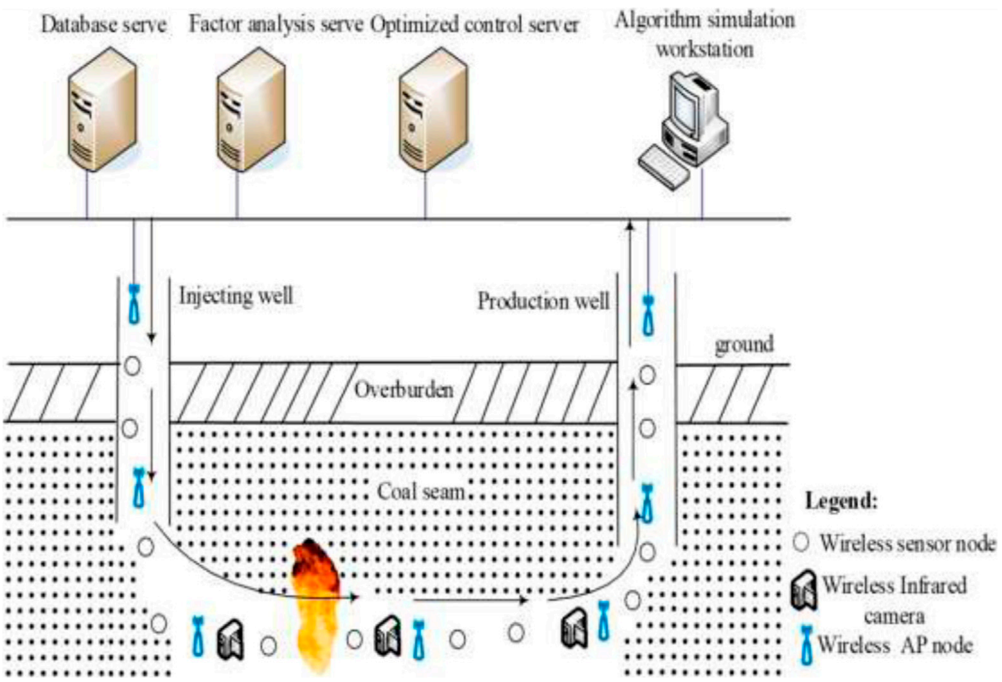

FIGURE 5
UCG monitoring system observation platform (Nurzynska et al., 2014).

does not consider environmental factors such as high temperature and humidity (Guan et al., 2016) built a wireless sensor network and planned a UGS monitoring system to monitor groundwater pollution during gasification. However, its sensor components are inappropriate for the representative UCG high humidity and temperature setting. Barnwal et al. (2017) proposed a new method of producing coal with high moisture and low calorific value to improve the synthesis gas quality of UCG technology. However, these methods are expensive or temporarily not scalable. On the other hand Kostúr et al. (2015) created the UCG visualization information system to visualize the state of the UCG record. Based on this Nurzynska et al. (2014) monitors UCG data using GPR and visualizes them in 3D, see Figure 5. However, standard commercial radar systems are used to check the on-site and off-site coal combustion conditions. The results show that this method monitors and visualizes the coal gasification process under off-site combustion conditions. It is not suitable for other situations; that is, it is impossible to control the combustion state of coal in a real gasification process.

2.5 Current R&D on UCG control

UCG control is a developing area with few references to theoretical research and laboratory simulations. Kotyrba and Stanczyk. (2017) established and deduced the mathematical expression of gasified coal particles based on the theory of mass conservation, energy conservation, and chemical thermodynamics based on model tests. The calculated value is the same as the model test value. Some scientists have studied the combustion state of the gasifier based on mathematical models (Yang and Liu, 2010). These studies are effective in predicting the state of combustion. However, this is necessary in practice to accurately assess the combustion state in real-time (Khan et al., 2015) provides related properties that affect the combustion state of UCG through laboratory simulation experiments. The team then experimented to determine optimal operating conditions for syngas conversion and studied the effects of numerous operating parameters on changes in the gasified surface (Daggupati et al., 2010). However, a correct mathematical model was not provided to define these processes. Therefore Stanczyk et al. (2012) developed a one-dimensional numerical model to study the influence of operating conditions (for example, temperature, pressure, water flow, gas composition) and coal characteristics (for example, thermomechanical exfoliation characteristics, reactivity, composition) on the growth rate of local cavities and energy efficiency. It has been found that the thermal-mechanical cracking of coal, ash behavior, and the amount of carbon incorporated in the coal mainly affect the combustion rate (Perkins and Sahajwalla, 2006) projected a one-dimensional packed bed model for UCG control, which maintains the expected calorific value of the exhaust gas mixture by controlling the injected gas flow rate. The model can also predict important data parameters such as gas composition and combustion speed. However, in these control models, it is necessary to assume that the total concentration of all gases in the entire active chamber is constant. Uppal afterward improved the design of the simplified UCG model sliding mode control algorithm to ensure the stability of the thermal output value of the entire system (Uppal et al., 2014; Uppal et al., 2018; Saravanan et al., 2018).

3 Power production with UCG

For over 50 years, the Angren power station in Uzbekistan has been utilizing UCG to generate power by co-firing the gas with coal in a boiler (Marques et al., 2018). However, this method is based on old technology and does not realize all the advantages of UCG syngas power generation. Recently, many countries have proposed different UCG power generation projects as the next phase of UCG commercialization using modern technologies such as gas turbines (Linc Energy, 2015). Large-scale commercial UCG power plants are proposed to use combined cycle power plant technology due to their high thermal efficiency, low nitrogen oxide emissions, and low specific capital expenditures, see Table 4. The application of commercial syngas purification technology in the IGCC plant and Linc Energy's *Chinchilla* GTL facility (see Figure 6) is expected to reduce air pollutant emissions from UCG power plants to levels similar to those of IGCC plants. Applying carbon dioxide capture and storage can further reduce carbon dioxide intensity to a level similar to natural gas power generation (Eskom Holdings Ltd, 2008). It is expected that in the next 10–15 years, coal power generation in most developed countries and China will decrease or stabilize, but many developing countries, especially Southern Africa, Southeast Asia, and India, are expected to expand the use of coal due to its low cost and abundant domestic supply is used for power generation (Gregg et al., 1976). However, it is well known that traditional coal-fired power generation has the highest levels of air pollutants and carbon emissions compared with other alternative energy sources such as natural gas or renewable energy. For decades, clean coal technologies such as IGCC have been developing to reduce the environmental impact of coal-fired power generation. IGCC technology has been successfully proven to produce extremely low air pollutant emissions, and the first plant using carbon capture is about to be completed (IEA, 2015). However, mainly due to high capital costs, the level of commercialization of IGCC has been low. There are significant opportunities to develop cost-effective clean coal technologies (such as UCG) as an alternative to traditional coal-fired power generation, especially for developing countries. By avoiding coal mining and surface gasification, UCG power generation has the potential to provide environmental performance similar to IGCC technology at a lower cost.

The UCG process occurs at relatively low temperatures compared to surface gases, and its properties are similar to a

TABLE 4 21st century UCG power projects (Linc Energy, 2015).

Countries	Year of project commencement	Company organization	Objective
China	2011	UCG research centers (Beijing) Seamwell, China energy conservation and environmental protection corporation Zhengzhou coal industry Co., Ltd.	Power generation H_2 for fuel cells
India	2005	Neyvell lignite corporation limited central mine planning and design institute limited central coalfields Ltd., western oalfields Ltd.	Power generation study and evaluate the calorific value of the gas generated
Pakistan	2009	Thar coal and energy board	Power generation
United States	2005	Lawrence livermore national laboratories linc energy, carbon energy and ergo energy	Natural gas liquefaction, developing 3d cavity growth simulators
Australia	2007	Linc energy company	UCG-CCS, UCG-IGCC power generation
Poland	2007	Central mining institute of poland	Environmental and safety issues related to UCG processes

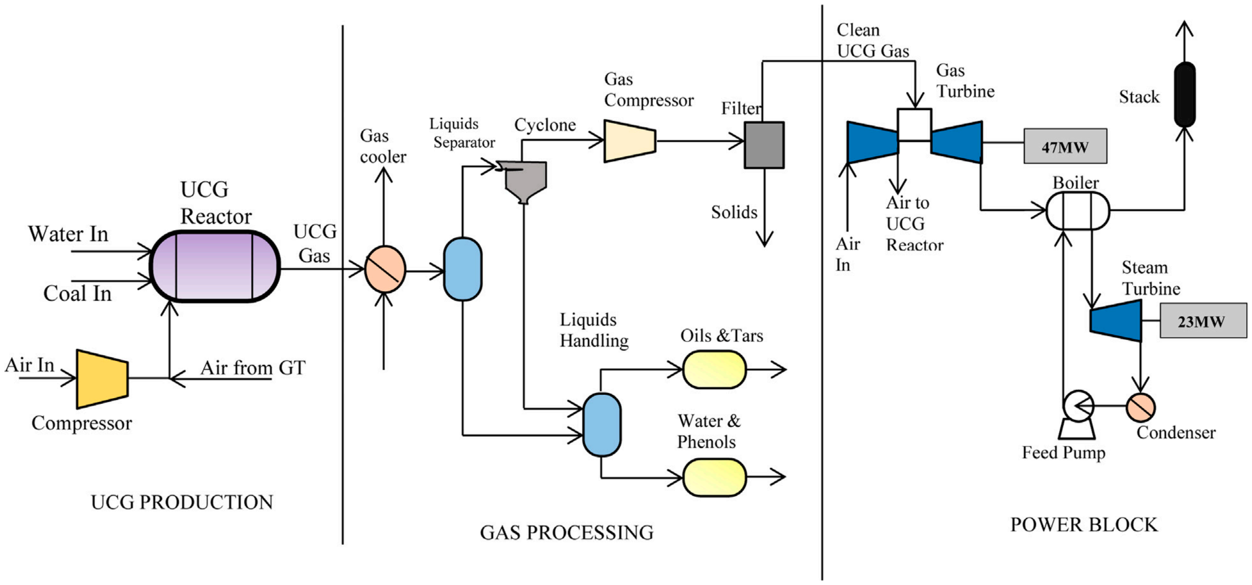

FIGURE 6
Conceptual design of the chinchilla project.

low-temperature fixed bed gas, such as a Lurgi FBDB gasifier (DOE/NETL, 2015a). Compared with high-temperature gasifiers, low-temperature gasifiers generally have higher cooling efficiency, lower oxygen demand, and can produce more hydrocarbon products (Thorsness and Britten, 1989). All modern IGCC plants are based on medium-temperature or high-temperature gasification technology. Compared with UCG-based plants, there are several key differences in gas purification and performance. Typical examples of IGCC plants that have recently adopted medium and high-temperature gasification include Kemper County (TRIG vaporizer), Buggenum (Shell vaporizer), and Edwardsport (GE vaporizer) (DOE/NETL Dennis, 2006). The advantage of medium-high temperature gasification is that synthesis gas composition is simpler, and the content of higher hydrocarbons and tar components is lower. The disadvantage is that high-temperature gasification requires a large amount of oxygen supply, and in order to achieve high thermal efficiency, heat recovery downstream of the gasifier under harsh conditions (DOE/NETL, 2015b). The UCG power generation process is similar to the surface-based IGCC, in which the UCG process replaces the coal mining process, surface gasification islands, and

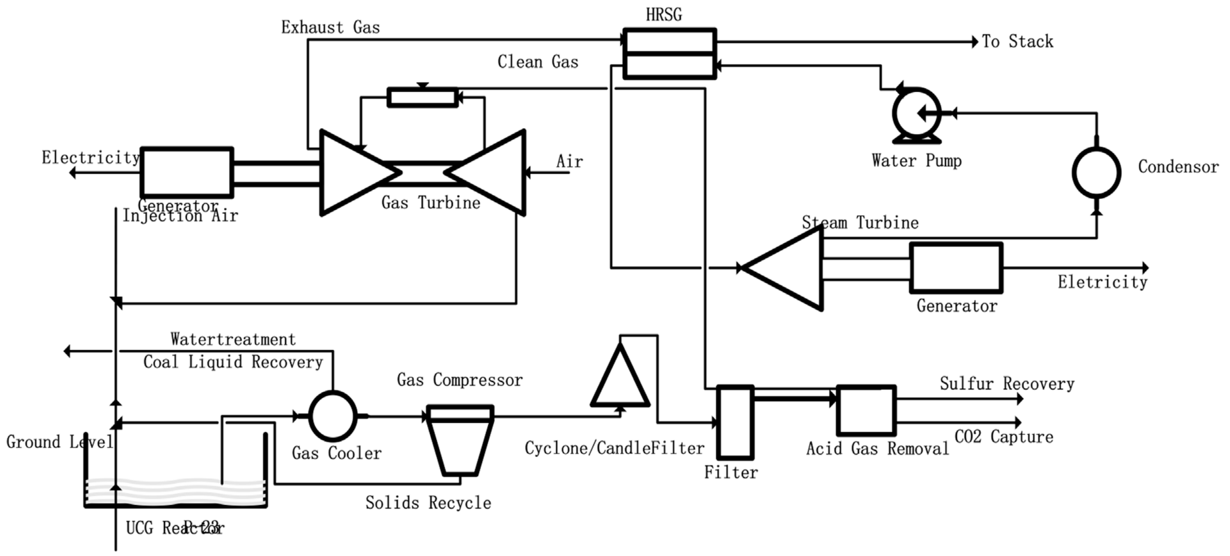

FIGURE 7
Schematic of UCG-IGCC 200 MW power plant (DOE/NETL, 2015b).

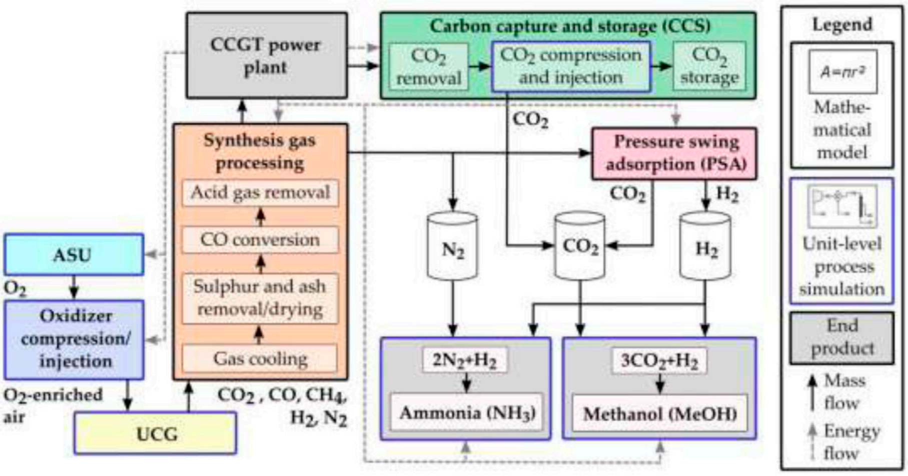

FIGURE 8
Technical and economic model for determining the cost of UCG, CCS and CCU.

ash treatment plants. The air separation unit (ASU) supplies oxygen to the underground gasifier and produces crude syngas. The raw syngas is cooled and purified before being sent to the combined cycle gas turbine. The water separated from the gas is processed and reused, and the liquid hydrocarbon by-product (coal condensate) can be processed for sale or used as supplementary fuel. See Figure 7 for a Schematic of the UCG-IGCC 200 MW power plant.

4 UGC and CCS/CCUS

A robust interaction exists between UCG and the sequestration of carbon. Often, the high temperature and high pressure from the UCG syngas stream can significantly save the cost of carbon recovery and separation. In addition, as stated previously, the cavity formed in the UCG process can be used to store supercritical carbon dioxide. In either case, adjacent rocks may contain depleted oil and gas fields suitable for salinity (non-drinkable aquifers) or carbon dioxide storage (Burton et al., 2006). Figure 8 is a cost-determining practical and financial model for the comprehensive UCG and CCS/CCU scenario with reference from (Higman and van der Burgt, 2008).

CCS technologies can be implemented using various methods: post-combustion (PCC), pre-combustion, and oxyfuel capture (Nakaten et al., 2014). All of these technologies are currently in commercial demonstration, except chemical cycle combustion technologies, which are still in development (Wang et al., 2011).

When considering the potential to capture CO_2 from UCG, it is important to understand the carbon distribution between gas composition and gas species. For deeper coal with greater pressure, it is well known that methane formation will increase (APEC, 2019). The carbon contained in methane can only be captured by reforming the gas, applying oxy-fuel combustion, or using post-combustion capture. Other ongoing developments aim to embrace CO_2 sequestration in the voids from which coal has been extracted (Synfuels, 2012). CO_2 capture occurs at high pressure in front of the combustion plant and is separated and stored using the same drilling and completion techniques as UCG. Even at depths of 1,000 m and above, it operates at the same pressure required for the high-density storage stage of CO_2. The synergistic effect would be even greater if the same process in the gasification well could be modified and reused for storage.

Therefore, if a series of wells are open in the UCG chamber to produce syngas, the CO_2 content is separated and reinjected from the abandoned well into a suitable underground structure for permanent storage. Fuel is efficiently produced for use in a combined cycle or fuel cell gas turbines, resulting in zero emissions for hydrogen and near-zero emissions for hydrogen-methane mixtures (The Trades Union Congress, 2014). Underground storage of CO_2 can meet all minimum standards for leakage prevention. Therefore, it can be proved that the deep well UCG can be reused, regardless of whether it has been modified or not, it can be used for CO_2 injection and permanent storage. Storage targets can also be placed in coal seams, upper layers, or abandoned UCG cavities. Primary estimations specify that at depths above 1,500 m, all CO_2 produced by coal can be recovered (The Trades Union Congress, 2014).

It is necessary to separate and concentrate CO_2 with a purity greater than 95% for injection. Most UCG applications yield a CO_2 by-product stream of this purity level appropriate for GCS. For power generation, the Selexol or Rectisol process can be used to separate CO_2 from the pre-combustion of syngas at a comparatively low cost of about $0.01 kWh. This will enable the carbon footprint of traditional NGCC facilities to generate electricity from UCG syngas (Burton et al., 2006). The syngas flow reaches the surface under severe pressure for deep UCG operations of depths greater than 600 m. For certain marketable applications (such as methanol and DME formulations), pressure can be used to reduce operating costs and energy loss. Equally, some CO_2 capture technologies deliver well at high pressures (such as fluorinated solvents and Nexant's CO_2 hydrate process). These methods can further reduce the cost of capture and isolation. But, not all of these methods have been tested on a bulky profitable scale and need additional analysis before to deployment (Burton et al., 2006).

4.1 Pre-combustion CO_2 capture

Pre-combustion CO_2 capture is largely employed in IGCC and coal gasification-based polygeneration systems. IGCC and CCS/CCUS are currently one of the most promising directions. In the pre-combustion capture process, the fuel is changed into synthesis gas in the reformer or gasifier and then undergoes a shift reaction to yield a mixture of CO_2 and H_2. CO_2 is mainly captured from this gas blend containing H_2 at high pressure of 10–80 bar and moderate CO_2 content of 15%–40%. In addition to CO_2/H_2 separation, the gas supply also contains CO, H_2S, and, other sulfur components. The high pressure of this generated gas stream promotes the removal of CO_2. The main CO_2 removal technology is the absorption process, and the solvent can be a chemical or physical solvent. Removing u sulfur components, such as H2S, is also necessary from the gas stream (European Technology, 2005). See Figure 9.

4.1.1 RD&D proceedings on pre-combustion CO_2 capture

The Project GreenGen, introduced by CHNG, is China's foremost IGCC power plant. GreenGen in Tianjin develops, demonstrates, and promotes power plants with near-zero emissions, improves the efficiency of coal-fired power generation, and emits pollutants (sulfur dioxide, nitrogen oxides, particulate matter) and carbon dioxide. The project is grouped into three phases. The first phase is constructing a 250 MW level IGCC demonstration plant and the Greengen lab with a CO_2 capture capacity of 30,000 tons/year. The second phase is the main IGCC technology and coal chemistry R&D (such as SNG and fuel cell application). The final phase involves the construction of a 400 MW

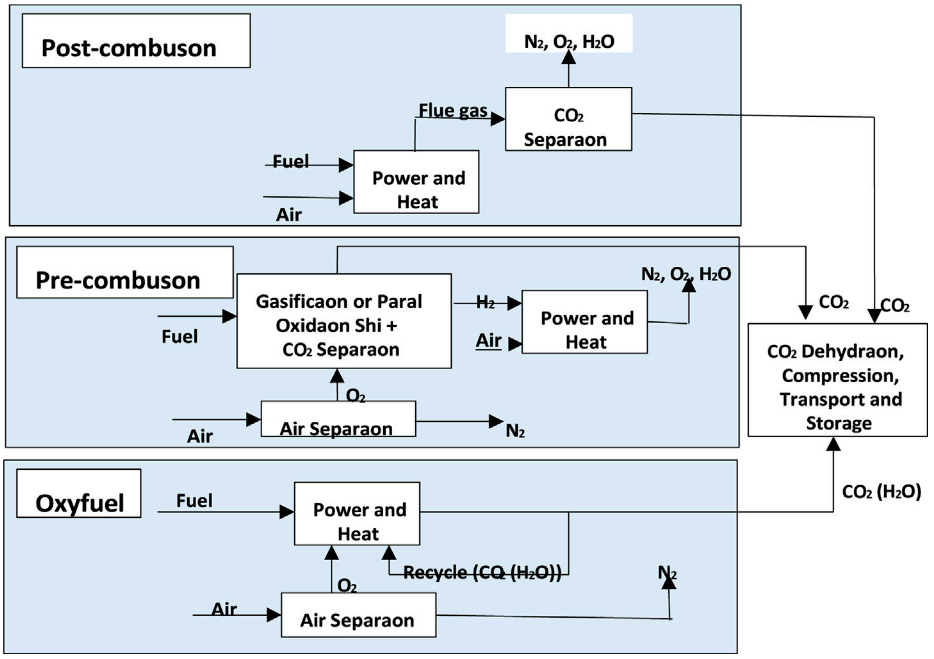

FIGURE 9
Carbon capture approaches and technology options (Tollefson, 2011).

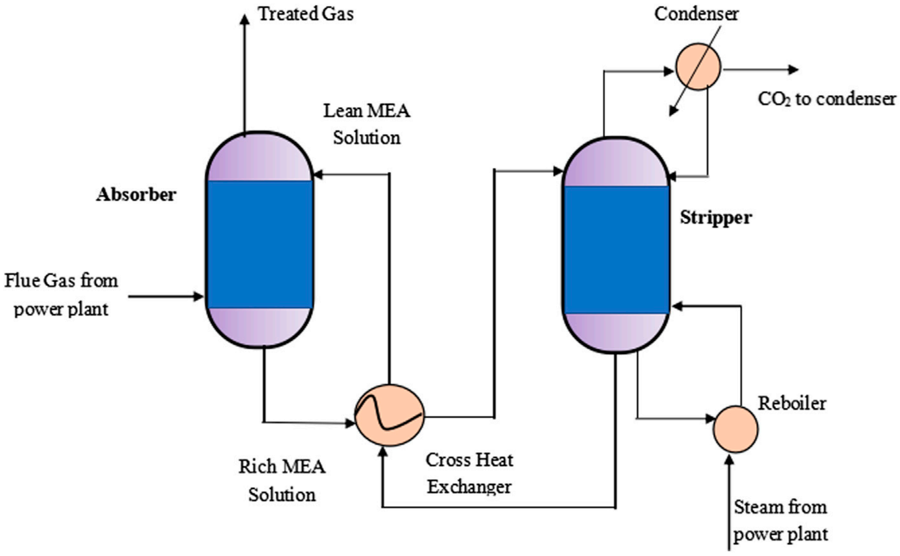

FIGURE 10
PCC based chemical absorption process.

IGCC demonstration power plant to capture and store 60% of carbon dioxide. According to the project's first phase, a 250 MW IGCC power plant was constructed and passed the full trial operation on 6 November 2012 (European Technology, 2005).

4.2 Post-combustion PCC CO_2 capture

PCC CO_2 capture removes CO_2 in flue gas discharged after combustion. Many first-generation CCS projects are expected to be implemented through PCC based on chemical absorption

TABLE 5 Chemical absorption-based PCC processes (Wang et al., 2011).

PCC process	Developer	Solvent	Demonstration	Commercial project
CanSolv	Shell	Amine-based	TCM Norway Aberthaw PCC Wales	Boundary Dam Canada (Operational) bow city Canada (Planning)
Advanced capture process (Nustad)	Aker clean carbon	Amine-based	TCM Norway	Longannet United Kingdom (Cancelled) Porto Tolle Italy (Cancelled)
PostCap™	Siemens	Amino acid salt	TCM norway big bend pcc florida	ROAD Netherlands (Planning) Masdar Abu Dhabi (Planning)
Econamine FG Plus℠	FLOUR	Amine-based	TCM Norway Wilhelmshaven PCC Germany	Trailblazer, Texas (Cancelled)
Advanced amine process	Alstom power/dow chemical	DOW UCARSOL™ FGC 3000	EDF PCC Le Havre, France Charleston PCC, West Virginia	Elektownia Belchatow, Poland (planning) GETICA Romania (on-hold)
CAP	Alstom power	Chilled ammonia	TCM Norway pleasant prairie PCC Milwaukee Karlshamn PCC Sweden Mountaineer CCS phase I, West Virginia	AEP Mountaineer CCS Phase II, West Virginia (Cancelled) Project Pioneer Alberta (Cancelled)
KM-CDR™	MHI/KEPCO	KS-1 (Hindered amine)	plant barry, alabama plant yates, georgia	Petro-Nova CCS, Texas (On-going)
ECO_2™	Powerspan	Amine-based	Burger PCC, Ohio	
HTC	HTC Purenergy/ doosan babcock	Amine-based	international test centre, Canada	Antelope Valley CCS, North Dakota
CO_2 Solution	CO_2 solutions Ltd.	Enzyme-based solvent	Pikes Peak South PCC, Saskatchewan, Canada	
DMX™	IFPEN/PROSERNA	Biphasic solvent	ENEL's Brindisi Pilot PCC, Italy	
RSAT™	Babcock and wilcox	OptiCap		

(Nakaten et al., 2014), as seen in Figure 10. Amine-based post-combustion capture is the most developed of the CO_2 capture options. PCC CO_2 recovery after combustion can remove CO_2 in the flue gas emitted. As shown in Figure 10, numerous first-generation CCS developments are projected to be carried out through PCC connected with chemical absorption (Nakaten et al., 2014). Currently, the utmost advanced CO_2 capture selection is the amine-based PCC.

4.2.1 RD&D proceedings

In July 2008, the China Huaneng Group (CHNG) planned and manufactured the first capture test equipment for PCC CO_2. The PCC system's capture capacity for CO_2 is 3,000 to 5,000 tons per year (Jinyi and Shisen, 2014). A year later, an annual CO_2 capture demonstration device of 120,000 tons was completed in Shanghai and started operation in December 2009 (Tollefson, 2008). The first commercial-scale recovery power plant for PCC in the world is the Canada Boundary Dam Unit 3. It went into operation in 2014 and can recover 1 million tons of CO_2 annually (Wang et al., 2011). Chemical absorption-based PCC developments using traditional amino solvents are currently at different technological levels. See Table 5 for commercial PCC based on the chemical absorption process.

4.3 Oxy-fuel combustion

Combustion enhancement, characterized by oxy-fuel combustion, has been effectively applied in minor pilot projects. For example, the Schwarze Pumpe (30 MW) in Germany, Callide (30 MW) in Australia, and the 35 MW oxy-combustion test unit in Yingcheng, Huazhong University of Science are successful applications (Tollefson, 2011). See Figure 9.

4.4 CO_2 storage and transport

Captured CO_2 is typically pumped into deep saline and undeveloped deep coal or oil and gas-depleted fields (see Figure 11). Recently developed CO_2 utilization technologies include chemical, geological, and bio utilization (Wang et al., 2011). However, traditional storage operations such as in brine formations and oil and gas fields are well known. These technologies are not expected to pose additional risks to the operation of UCG and should be considered the initial project development target. In contrast, storage in non-traditional units (oil shale, basalt) requires more scientific knowledge than is currently available (Burton et al., 2006).

CO_2 transport methods primarily include tankers, vessels, and pipelines, and transporting CO_2 over pipelines is

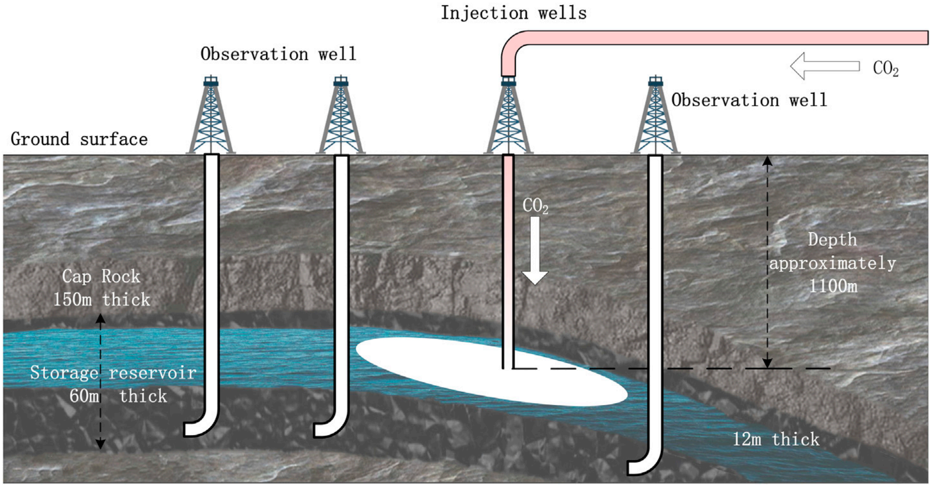

FIGURE 11
Cross-sectional diagram of underground CO_2 storage (Wang et al., 2011).

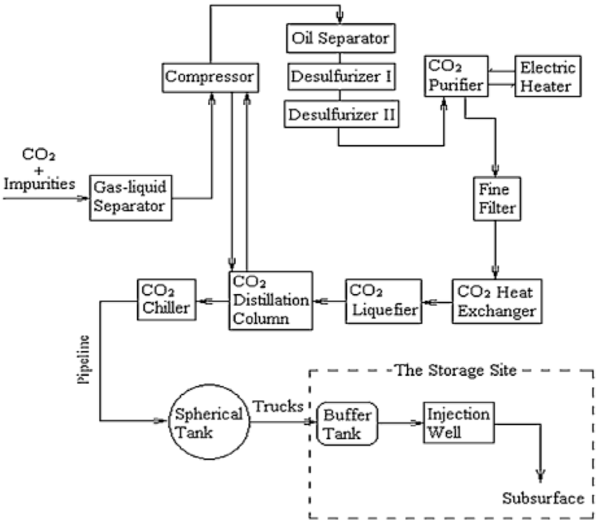

FIGURE 12
Schematic diagram of CO_2 capture, storage and transportation (Tollefson, 2011).

considered the most cost-effective and consistent method for bulk and long-distance transport (Wang et al., 2011). Figure 12 shows a schematic flowchart of CCS and transportation.

4.5 The effect of CO_2 as a gasification medium on UCG

Daggupati et al. (2011) and IEA (2016) carried out research scale UCG tests utilizing superheated steam as a gasifying medium. The advent of steam at a low temperature of 150°C to UCG combustion depth quenches the fire front and leads to unproductive gasification (IEA, 2016). Especially in the light of high ash Indian coals, steam dissemination through an ash deposit within the cavity may decrease the temperature. Furthermore, superheated steam transportation to deep underground cavities (>300 m) is challenging due to heat loss *via* pipelines. The linings of the pipelines result in extensive energy demand in the steam-based UCG process. Thus, according to (Stanczyk et al., 2012), UCG oxygen gasification is deliberate for coals with excessive ash content, and research shows the viability of creating a medium calorific product gas with enhanced CO (~210 kJ/mol) in the absence of steam to the UCG input stream.

In UCG oxygen gasification, the integral moisture reactivity with char enhances the steam gasification reaction at the early stages of combustion; in any case, combustion-generated CO_2 improves the Boudouard equation (Eq. 1) by reacting it with the adjoining char sites at the moisture depleted conditions of the coal seam.

Boudouard equation:

$$C + CO2 \rightarrow 2CO\, \Delta H = +168.9\, \mathrm{Kj/mol} \tag{1}$$

Therefore, research results from (Stanczyk et al., 2012) show high UCG practicability to be carried out in a CO_2 mode, which is a promptly accessible enhancer for gasification. In addition Prabu and Jayanti (2012), examined Indian coal inherent gasification kinetic parameters in the temperature range of 800–1,050°C given CO_2 based UCG with a thermogravimetric analyzer (Mandapati et al., 2012) experimented on O_2/CO_2 UCG gasification with different

TABLE 6 A. Industrial CCS large-scale projects (>0.4 Mt/yr) (Wang et al., 2011).

Facility name	Facility status	Country	Operation date	Facility industry	Capture capacity (Mtpa)	Summary
Steel Industry						
Abu Dhabi CCS (Phase 1 being Emirates steel industries)	Operating	UAE	2016	Iron and Steel	0.80–0.80	EOR application
chemicals and petrochemicals						
Illinois industrial carbon capture and Storage	Operating	United States	2017	Ethanol production	1.00–1.00	Geological Storage
Lake charles methanol	In development	United States	2022 (estimated)	Chemical production	4.20–4.20	EOR application
Sinopec Qilu petrochemical CCS	In construction	China	2019	Chemical production	0.40–0.40	EOR application
Yanchang integrated carbon capture and storage demonstration	In construction	China	2020–2021	Chemical production	0.41–0.41	EOR application
Shenhua Ningxia CTL	In development	China	2020 (estimated)	Coal-to-liquids (CTL)	2.00–2.00	
Refining Industry						
Acorn scalable CCS development	In development	United Kingdom	2020 (estimated)	Oil refining	3.00–4.00	Geological storage
Alberta carbon trunk line (ACTL) with North West redwater partnership's sturgeon refinery CO_2 stream	In construction	Canada	2019	Oil refining	1.20–1.40	EOR application
Hydrogen Production						
Air products steam methane reformer	Operating	United States	2013	Hydrogen production	1.00–1.00	EOR application
HyNet North West	In development	United Kingdom	2020 (estimated)	Hydrogen production	1.50–1.50	Geological storage
Northern Gas Network H21 North of England	In development	United Kingdom	2026	Hydrogen production	1.50–1.50	
Quest	Operating	Canada	2015	Hydrogen production	1.00–1.00	Geological storage
Natural Gas Production						
Century plant	Operating	United States	2010	Natural Gas processing	8.40–8.40	EOR application
CNPC Jilin Oil Field CO_2 EOR	Operating	China	2018	Natural Gas processing	0.60–0.60	EOR application
Gorgon carbon dioxide injection	In Construction	Australia	2019	Natural gas processing	3.40–4.00	Geological Storage
Great plains synfuels plant and weyburn-midale	Operating	Canada	2000	Synthetic natural gas	3.00–3.00	EOR application
In Salah CO_2 storage	Completed	Algeria	2004	Natural gas processing	0.00–0.00	Storage in depleted gas reservoir
Lost cabin gas plant	Operating	United States	2013	Natural gas Processing	0.90–0.90	EOR application
Petrobras santos basin pre-salt oil field ccs	Operating	Brazil	2013	Natural gas processing	1.00–2.50	EOR application
Shute creek gas processing plant	Operating	United States	1986	Natural gas processing	7.00–7.00	EOR application
Sleipner CO_2 storage	Operating	Norway	1996	Natural gas processing	1.00–1.00	Geological storage
Snøhvit CO_2 storage	Operating	Norway	2008	Natural gas processing	0.70–0.70	Geological storage
Terrell natural gas processing plant (formerly val verde natural gas plants)	Operating	United States	1972	Natural gas processing	0.40–0.50	EOR application
Uthmaniyah CO_2-EOR demonstration	Operating	Saudi Arabia	2015	Natural gas processing	0.80–0.80	EOR application
Fertilizer Production						
Alberta carbon trunk line (actl) with agrium CO_2 stream	In construction	Canada	2019	Fertilizer production	0.30–0.60	EOR application
Coffeyville gasification plant	Operating	United States	2013	Fertilizer production	1.00–1.00	EOR application

(Continued on following page)

TABLE 6 (*Continued*) A. Industrial CCS large-scale projects (>0.4 Mt/yr) (Wang et al., 2011).

Facility name	Facility status	Country	Operation date	Facility industry	Capture capacity (Mtpa)	Summary
Enid fertilizer	Operating	United States	1982	Fertilizer production	0.70–0.70	EOR application
Sinopec eastern China CCS	In development	China	2020–2021	Fertilizer production	0.50–0.50	EOR application

B Key CCUS pilot projects in China (Global CCS Institute, 2017)

	Project name	Capacity (ton/year)	CCS source	Technology for final storage	Construction/Operation status
1	CHNG Shanghai Shidongkou CCS project	120,000	Shanghai Shidongkou No. 2 power plant, phase ii project, USC unit	Industrial utilization and food	Commissioning in 2009, intermittent operation
2	CHNG Tianjin green coal power project	100,000	Tianjin, Binhai New District, 400 MW IGCC unit	Mostly for abandoned land oil and gas reservoirs	Capture facility completed; storage facility delayed
3	Sinopec Shengli Oilfield CO_2 CCS and flooding demonstration	Phase I: 40,000 Phase II: 1 million	Shengli Power Plant Unit No. 5	EOR	Phase 1: operation in 2010
4	Sinopec Qilu petrochemical CCS project	Phase I: 350,000 Phase II: 500,000	Sinopec Qilu Petrochemical Co., Ltd. Coal Gasification Plant	EOR	Phase 1: CCS unit completed in 2017
5	Sinopec ZPEB CO_2-EOR Project	100,000	Zhongyuan Refinery Flue Gas	EOR	CCS facility completed in 2015
6	Yanchang petroleum yulin chemical CCS	50,000	Shaanxi Yanchang Petroleum Yulin Coal Chemical Co., Ltd. gasification plant	EOR	Completed in 2012 in operation
7	Shenhua Erdos full process demonstration	100,000	Shenhua Coal-to-Liquid Chemical Co., Ltd.	CO_2 storage in saline aquifers	Commissioning in 2011, intermittent operation
8	PetroChina Jilin Oilfield EOR demonstration	Phase I: 150,000	New Natural Gas Plant in Songyuan City, Jilin Province	EOR	Phase I: commissioning in 2007
		Phase II 500,000			Phase II: commissioning in 2017, with size reduced
9	CPI Chongqing Shuangyu Power Plant CCS demonstration project	10,000	Chongqing Hechuan Shuangyu Power Plant Phase I 1# 300 MW unit boiler	Welding protection, hydrogen cooling replacement for generatoretc.	Commissioning in 2010, in operation
10	HUST 35 MW oxyfuel combustion project	100,000	Hubei Jiuda (Yingcheng) Co., Ltd. Thermal Power Plant II	industrial application	Completed in 2014, operation suspended
11	Lianyungang clean coal energy power system research facilities	30,000	Lianyungang 400 MW IGCC	CO_2 storage in saline aquifers	Commissioning in 2011, in operation
12	Xinjiang Dunhua Oil Co., Ltd. Project	60,000	Xinjiang Dunhua Oil, Refinery Exhaust	EOR	Commissioning in 2015, in operation
13	China energy Guohua Jinjie power plant CCS full process demonstration project	150,000	Coal-fired power plant flue gas	Storage/EOR	To be completed in 2019
14	CR Haifeng project	20,000	Guangdong coal-fired power plant flue gas	CO_2 food grade/industrial grade	Commissioning in 2019

CO_2 concentrations in a virtual coal seam. It was observed that CO_2 UCG gasification increases the CO/H_2 product gas ratio and improves gas calorific content. For proficient gasification, preheating the CO_2 as a gasifying medium to high temperatures is cost-effective relative to the generation of superheated steam in a UCG steam-based operation. Furthermore, CO_2 gas can be delivered at room temperature to the profound underground cavities for *in-situ* gasification.

Several works of literature have outlined ongoing research that uses CO_2 gas as a key coal gasifying agent (Chen et al., 2013) carried out two-stage underground coal gasification using CO_2 air as the gasifying medium. It was observed that with a rise in the CO_2/oxidant molar ratio, the calorific content of the syngas reduced progressively. At 0.5 M proportion of CO_2/oxidant, a syngas with a least standard calorific value of 65 kJ/mol is delivered. Figure 12 shows the calorific value of the product gas for the experiment in (Chen et al., 2013). Thus, it was established that the ideal stream rate of CO_2 is 0.2 LPM for the O_2/air molar proportion of 0.11 for coals with low ash. However, relative to high ash coals, the rise in the CO_2 stream rate to 0.3 LPM led to quenching within the borehole combustion front. In this way, 0.2 is the ideal molar ratio of CO_2/oxidant for high ash coals at the O_2/air molar ratio of 1.

5 CCS demonstration projects in major economies

At present, economies such as the United States, Norway, Australia, France, and China have all carried out CCS demonstration projects, some of which have reached the commercial scale. By October 2017, there were 37 large CCS/CCUS integration projects (Daggupati et al., 2011) (each with a capture capacity of over 400,000 tons/year). Among them, 17 large-scale projects are in operation with a total CO_2 capture capacity of 30 million tons/year: 10 EOR projects in North America, two saline formation storage projects in Norway, 1 EOR project in Brazil, 2 EOR projects in the Middle East and two saline formation storage projects in North America. CCS/CCUS is also developing rapidly in China, with several commercial demonstration projects successfully carried out (Wang et al., 2011). See Table 6.

Major economies have implemented CCS demonstration projects and gained commercial scale. These are evidenced in Australia, the US France, Norway, and China. There were 37 large-scale CCS/CCUS integrated projects, each having a recycling capacity of more than 400,000 tons/year as of October 2017 (Geeta and Prabu, 2017). Seventeen of them operate with an overall CO_2 capture capacity of 30 million tons/year. In North America, there are 10 EOR projects and 2 salt storage projects. In South America, particularly Brazil, there is 1 EOR project, Norway has 2 salt storage developments, and the Middle East has 2 salt storage projects. CCS/CCUS technology is emerging quickly in China, and numerous marketable demonstration projects are being effectively implemented (Wang et al., 2011). See Table 7.

5.1 Industrial demonstration and application of CCS/CCUS in China

Under the guidance of national policy and with the support of government departments at all levels, China has built more than a dozen CCS demonstration facilities with a CO_2 capture capacity of over ten thousand tons in coal-fired power plants and coal chemical plants. The largest CO_2 capture capacity in these facilities is over 10 million tons per year. In addition, CO_2 injection demonstrations have been conducted in the enhanced oil recovery and carbon storage industry, with the largest reserves exceeding 15 million tons per year. Completed demonstration projects include 10 million tons per year for brackish terrestrial CO_2 storage projects, microalgae carbon capture projects (Global CCS Institute, 2017). See Table 6 for an overview of major CCUS pilot demonstration projects in China. Table 8 shows key project events and the budget for the Shenhua CCS project.

5.2 Comparison of UCG generation costs with NGCC, IGCC, UCGCC and PC methods

5.2.1 UGC base case cost evaluation without CCS

When UCG is fused with a CCS system, there is a reduction in the cost associated with CO_2 capture and compression. Therefore, one of the policies for sustaining worldwide energy demand is the effective application of UCG technology. Research by Ni and Jiang (2016) Shows the base case cost evaluation and relates the power generation cost of theoretical plants of NGCC, IGCC, UCGCC and PC lacking the installation of CCS systems. It was established that IGCC generated the maximum cost with a range from \$104–117/MWh. When the coal price dropped to \$10/ton, the generation costs of PC and UCGCC were similar, at about \$45/MWh.

Conversely, PC showed further coal price sensitivity and its price was more than the UCGCC when the coal price was higher than \$10/ton. NGCC would show massive competitiveness with a price lower than UCGCC if the natural gas price was less than \$4.50/GJ, or \$4.85/kscf. Overall, the UCGCC generation cost was low (\$45–50/MWh) and showed less sensitivity towards the fuel price. The reason is that UCG joins both coal mining and

TABLE 7 CO_2 Utilization Projects and Key UCG projects and developments in 2017.

A CO_2 utilization projects						
Facility name	Facility status	Country	Operation date	Facility industry	Capture capacity (Mtpa)	Summary (CO_2 utilization)
Steel Industry						
Arcelor mittal steelanol	In construction	Belgium	mid-2020s	Iron and steel	0.15–0.15	Bioethanol
Cement Industry						
Skyonic carbon capture and mineralisation project	Operational	United States		Cement production		Sodium bicarbonate production
Chemicals and petrochemicals						
SABIC carbon capture and Utilisation Project	Operational	Saudi Arabia		Chemical production	0.40–0.50	Methanol, chemical and Urea production
The valorisation carbone Québec (VCQ) Projec	In construction	Canada	2019	Chemical production	0.00–0.00	
CO_2 Utilisation plants using the KM CDR process®	Operational	Multiple		Industrial applications		Industrial/methanol production
Hydrogen Production						
Port Jérôme CO_2 capture plant	Operational	France	2015	Hydrogen production	0.10–0.10	
Fertilizer Production						
Alcoa kwinana carbonation plant	Operational	Australia		Fertilizer production		Carbonation
Waste to energy (wte) industry						
Saga city waste incineration plant	Operational	Japan	2016	Waste Incineration	0.00–0.00	Crop cultivation and algae culture
Twence Waste-to-energy CO_2 capture and utilisation	Operational	Netherlands	2014	Waste Incineration	0.00–0.00	Sodium bicarbonate production
Other Industries						
CO_2 Utilisation Plants—Europe	Operational	Multiple		Industrial applications		
CO_2 Recovery Plants in China	Operational	China		Industrial applications		Food and beverage
CO_2 Utilisation plants—North America	Operational	Multiple		Industrial applications		
CO_2 Utilisation plants—Oceania Region	Operating	Multiple		Various		Food and beverage and industrial application
CO_2 Utilisation plants using the Fluor Econamine FG process	Operational	Multiple		Various		
Saint-Felicien pulp mill and greenhouse carbon capture project	Operational	Canada	2018	Pulp and paper production	0.01–0.01	Vegetable greenhouse

B Key UCG projects and developments in 2017			
Company organisation	Countries	End product	Scale
UCG Research Centres +, Sino-coking, ENN Xinao, Seamwell, Honghi	China	Power generation, and chemicals, H2 for fuel cells	25PJ/y, (792 MWt)
EU—E4.1M Tops	UK, Pl, NL, SA, CH, AU, US	Coupled UCG_CCS Site Characterisation and risk	Feasibility modelling, environment
Coal of India, CMPDIL	India	Issuing Coal Blocks for UCG New Pilot study announced Mar17	166MT and 178 Mt +5MWe pilot
Mining/power companies	Mongolia/Kazakhstan/ Indonesia	Power production	not specified

(Continued on following page)

TABLE 7 (*Continued*) CO_2 Utilization Projects and Key UCG projects and developments in 2017.

B Key UCG projects and developments in 2017			
Company organisation	Countries	End product	Scale
Polish national project	Poland	Awaiting new commercial partner	1400 h Pilot Scale
Linc energy/carbon energy (in administration)	Australia China	Power, SNG and CTL applications (technology available)	400 MW–750 MW
Leigh Creek Ltd., South Australia	Australia	Site characterisation complete. approval of pilot underway	Power, SNG and fertilizers
Yerostigas, Angren	Uzbekistan	Commercial steam for power plant continuous operation since 1960s	100 MW–1200 MW
Eskom (also, Africa)	S Africa	Power generation, co firing and CCGT, further pilot work	400 MW

utilization processes and evaluates only the royalties and severance fees. Thus, this saves substantial prices in obtaining coal, its storage, and handling.

5.2.2 Cost evaluation—with CO_2 capture system (CCS)

Ni and Jiang (2016) further conducted an experiment to relate the generation cost ($/MWh) and the cost of captured CO_2 by installing a Selexol pre-combustion capture system on IGCC and UCGCC plants. In addition, an amine post-combustion capture system was installed on the NGCC and PC plants. It was observed that IGCC-CCS had the peak cost. The cost gap between the IGCC and UCGCC was more significant in the CCS case than in the base case. This means there is a significant impact on the PC relative to the UCGCC when setting up the CCS system. Low fuel prices were recorded for the NGCC-CCS (below $4.50/GJ). Conversely, the UCGCC-CCS recorded decreased generation cost than the NGCC-CCS at increased fuel prices (above $4.50/GJ). It is evidenced that the highest CO_2 capture cost was recorded for the NGCC-CCS, followed by the IGCC-CCS and PC-CCS. UCGCC-CCS recorded the least cost for CO_2 capture. Decreased CO_2 capture cost obtained by the UCGCC process makes it a massive benefit in the CO_2 consumption market.

5.3 UCG cost comparison with electricity and IGCC

UCG-based power plants are similar to IGCC power plants, except for surface gasifiers (Burton et al., 2006). A simplified comparison of the capital costs of UCG power plants and IGCC can be made by comparing the required process units and capacity. The published cost estimate of the IGCC process unit is based on the analysis of a GE airflow gasifier with a carbon capture function (Burton et al., 2006). According to the design configuration and simulation results, the main differences between UCG and IGCC ground equipment. By eliminating the surface gasification device and reducing the size of the ASU, the overall capital cost of the UCG power plant is expected to be saved by 33%.

Several studies have been published on the economics of IGCC power plants and pulverized coal power plants, the current standard. According to the information developed by Burton et al. (2006), the cost of a supercritical pulverized coal (SCPC) power plant ranges from $1200 to $1460/kW. The same study estimates that the next-generation of IGCC power plants will be about 10% more expensive than the SCPC plants (vs. the current 20–25% premium). These places the cost of IGCC plants at $1440 to $1750/kW current technology, and $1320 to $1600/kW (advanced technology). Peng et al. (2016) has estimated the cost of an IGCC plant at $1,350/kW, which is in the same range as that estimated by Burton et al. (2006) for the advanced technology IGCC plants.

Much research has been published on the economics of IGCC power plants and the current standard pulverized coal power plants (Burton et al., 2006) states that the charge range of supercritical pulverized coal (SCPC) power plants are between $1200 to $1460/kW. Furthermore, future IGCC power plants will be approximately 10% cost higher than the SCPC power plants. These bring the cost of the IGCC plant to current technology from $1440 to $1750/kW and $1320 to $1600/kW (advanced technology). Peng et al. (2016) and (Burton et al., 2006) estimates a similar cost range of the IGCC plant or the advanced technology IGCC plant to be $1350/kW.

Another indicator of cost competitiveness is electricity prices (COE). Estimates by Peng et al. (2016) place COE for IGCC plants and SCPC at $46.6/MWh and $49.9/MWh. An advanced competitive

TABLE 8 Important procedures and cost of the Shenhua CCS project.

A important procedures of the shenhua CCS project	
Time of event [dd/mm/yyyy]	Project key events
2007	Approval of the pre-feasibility study proposal by US-DOE
10/2008	Initiation of the feasibility study
08/06/2009	Foundation of the project group
25/12/2009	Approval of the feasibility study report
07/04/2010	Completion of 3D seismic data field acquisition
01/08/2010	Completion of engineering design
10/10/2010	Cementing of the injection well
18/11/2010	Formation test in the injection well
26/11/2010	Completion of well test in the Majiagou formation
02/12/2010	Completion of acid fracturing and fluid drainage for the Majiagou formation
06/12/2010	Completion of well test in the Shanxi formation
13/12/2010	Completion of hydraulic fracturing and fluid drainage for the Shanxi formation
22/12/2010	Completion of well test in the Shihezi formation
27/12/2010	Completion of the monitoring well 1 (MW1)
01–06/01/2011	Trial injection into the Shanxi and Shihezi formation
09–23/05/2011	The 1st testing injection
30/05/2011	Start of the 1st formal injection
16/09/2011	Start of the 2nd formal injection
23/06/2012–03/07/2012	The 2nd testing injection
09/2013	The 3rd testing injection
09/2014	The 4th testing injection
04/2015	End of injection and close of the injection well

B Cost of the Shenhua CCS project (Global CCS Institute, 2017)		
Budget terms	Cost [USD]	Percent [%]
Construction	5,620,796	18.32
Materials	4,635,547	15.11
Installation	919,237	3.00
Capture and transportation	766,762	2.50
Surface storage equipment	448,859	1.46
Subsurface equipment	12,703,810	41.40
Supporting system	259,241	0.84
Miscellaneous	5,329,545	17.37
Total	30,683,797	100.00

economic study (Nakaten et al., 2014) indicates that for UCG power generation, the Levelized COE is estimated at €49/MWh without CCS and €72/MWh with CCS. Regarding figures released by Ergo Exergy (Maev et al., 2018), UCG-IGCC plants significantly have lower COE and construction costs. The cost of capital for a 177 MW plant presented by Maev et al. (2018) is approximately $600/KW and $450/KW for a 280 MW plant. The COE is projected to be around $12/MWh. According to Green (2018), CO_2 emissions from UCG power generation using combined cycle gas turbine (CCGT) range from 570 to 785 kg CO_2/MWh without resources to CCS, compared to 400 kg CO_2/MWh natural gas. CCS can decrease UCG emissions to less than 100 kg CO_2/MWh. These remarkable figures make UCG comparable to renewable energy and achieve the highest fossil fuel emissions in CCS.

5.4 Recent and key UCG developments worldwide

Recently, UCG projects are common in China, South Africa, and Australia. These projects have chemical plants or operating power plants powered by UCG syngas. However, in Canada and the US, these projects are still in their development stages (Clean Air Task Force Report, 2009). Studies by Burton et al. (2006) state that the recent promising blend of technological features offers a commercially viable opportunity for the UCG process by enhancing the UCG technical variables and lowering the extreme effect on the environment. The same studies indicate that the first nation to introduce a general program for UCG R&D was USSR. By 1928, different national research projects had been organized, and in 1933 underground experiments began in Kurtova, Tula, Shati, Rennis-Kuznets, Korevka, and Lysychansk. While carrying out the experimental plan, theoretical plan and laboratory research were also carried out.

Currently, in the US, there are no UCG facilities in operation, and no major company is working on UCG research, but many other research projects are underway. In other regions, UCG projects have set off a new upsurge (Dalton, 2004) demonstrates the primary UCG projects overseas in the 20th century (from 1934 to 1997). Primary UCG projects from 2007 to 2011. In 2017, Geeta and Prabu (2017) pointed out that UCG activities were intense in many countries, which signifies a reduction in global UCG development 3 years ago. Table 7 shows the major UCG schemes and progresses in 2017.

The Chinese government has decided to develop the UCG project to reduce the pollution of coal-fired power plants, Private companies, like Seamwell Int. Hongli Clean Energy and others continue to maintain an interest in UCG feasibility and semi-commercial studies, mainly in Inner Mongolia, for the production of chemicals and power from UCG syngas (Khadse et al., 2007). According to Daggupati et al. (2010), this places UCG test centers in China to approximately 15 (Blinderman, 2005).

6 Concluding remarks and future works

This paper has provided an overview of UCG coupled with the CCS/CCUS technology process. These technologies emerge as excellent green technology which will keep global warming in check along with securing energy demands. From the above study, the following conclusions can be drawn;

- Although the knowledge of UCG is not current and can be traced back about 100 years ago, most global coal-producing regions have recently renewed interest in UCG technology. UCG is an integrative process because it involves different engineering phases (chemical, drilling, geotechnical) and connected disciplines (hydrogeology, hydrology).
- The processes by which UCG promotes carbon capture are identical to surface-based IGCC. However, UCG has no ash treatment plants, coal mining, or surface gasification. Therefore, under equal settings, the general thermal efficiency of the UCG power plant is higher than the equivalent surface IGCC, and the CO_2 intensity is lower, especially considering the general CO_2 emissions, including CO_2 emissions from coal mining.
- Countries most interested and active in R&D UCG projects are the US, China, South Africa, United Kingdom, India, Poland, Canada, Australia, and Hungary.
- The Countries closest to UCG commercialization are China, South Africa, and North America. Presently, South Africa is ahead of the commercialization of UCG, investing more than $100 million in three major electricity projects.
- Many developments in the aforesaid countries rely on CRIP UCG technology developed in the United States in 1975 by the Lawrence Livermore National Laboratory. However, most UCG projects, both in operation and presently under expansion over the last 20 years, use UCG technology from Canadas Ergo Exergy Technologies. In addition, several Ergo Energy's UCG projects are under consideration in Canada, India, Turkey, *Argentina*, and Pakistan.
- High UCG practicability to be carried out in a CO_2 mode is a promptly accessible enhancer for gasification. For proficient gasification, preheating the CO_2 as a gasifying medium to high temperatures is cost-effective relative to the generation of superheated steam in a UCG steam-based operation.
- Chemical absorption-based PCC technology is a short-term practical option for deploying marketable CCS. This technology has been widely validated through pilot plant testing, and various aspects of the technology have been

investigated through modeling and simulation. Marketable products for modeling and simulating such developments are now available along with the technology and can be store-bought from various vendors such as Alstom, Shell, and Siemens.

Author contributions

ST: data curation and writing—original draft preparation. YZ: supervision. MS: conceptualization, methodology, software, and investigation. FZ: formal analysis and revision. YL: english language modification. PT: writing—reviewing and editing.

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Conflict of interest

Publisher's note

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