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Gasification Can Help Meet the World's Growing Demand for Cleaner Energy and Products

Alison Kerester

Executive Director

Gasification Technologies Council



**The Drivers and
Status of the Texas
Clean Energy Project**

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to Reduce Europe's
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Increased Understanding of Gasification



Liu Baowen
Executive Editor, *Cornerstone*

In 2013, coal accounted for more than 70% of global energy reserves and more than 30% of global primary energy consumption. Thus, for the foreseeable future, coal will remain a principal source of energy. Deploying environmentally-friendly coal utilization technologies is a continuing objective of the coal industry that can offer long-term global benefits.

Gasification technologies can offer a significantly reduced environmental footprint when utilizing coal and other feedstocks. Gasification provides a pathway to create cleaner liquid and gaseous fuels, chemicals, power, and blends of products from indigenous carbonaceous feedstocks, providing an opportunity to address energy security and environmental objectives from around the world. Gasification facilities could also be critical in the struggle to mitigate climate change due to the inherently lower CO₂ capture costs. While China is moving forward with several facilities, one could easily argue that the current level of deployment globally does not fully reflect the potential advantages. It is worth exploring why this may be the case.

Integrated gasification and combined-cycle (IGCC) power plants represent a significant departure from traditional power plants. For instance, IGCCs operate more like chemical production facilities as they often cannot quickly ramp to meet demand fluctuations. Most gasification facilities also come with multibillion dollar price tags; financing can be a challenge, especially because energy markets can fluctuate rapidly. In addition, gasification projects can be water-intensive. Although gasification can offer a decreased environmental footprint, important environmental considerations still exist, such as the generation of wastewater and finding suitable options to utilize or store CO₂. Finally, integration of polygeneration facilities can become so complex that they can become difficult to operate.

Although overcoming such hurdles may have historically slowed the deployment of gasification, the industry is unquestionably gaining momentum today. There are more technologies on the market than ever before and these options are becoming increasingly flexible (in terms of scale, feedstock quality, and products). China's coal-to-chemicals industry is leading the charge and employing technologies that were not available only a few years ago. Although gasification use is spreading, researchers worldwide are still working toward further improvements.

There is still much more room for gasification to grow. Coal-to-gas in Europe could end Russia's stranglehold on some countries' gas supplies. Poorer countries and rural areas could use simplified gasification facilities to provide power or fuels without a high upfront cost while employing local low-rank coals and wastes. Increased integration of some gasification facilities is making projects more competitive. In the U.S., the Texas Clean Energy Project and Kemper County IGCC plant are moving forward to demonstrate a new business model and a new gasification technology, respectively. In India, Prime Minister Modi has even hinted that he'd like the country to ramp up research in the coal-to-liquids arena to reduce oil imports.

This issue of *Cornerstone* is themed on the progress and opportunities in the rapidly expanding field of gasification. On behalf of the editorial team, I hope you enjoy it.

FROM THE EDITOR

- 1** **Increased Understanding of Gasification**
Liu Baowen, *Cornerstone*

VOICES

- 13** **The Drivers and Status of the Texas Clean Energy Project**
Laura Miller, *Summit Power Group, LLC*

ENERGY POLICY

- 19** **Carbon Pollution Standards for New and Existing Power Plants and Their Impact on Carbon Capture and Storage**
Kyle Aarons, *Center for Climate and Energy Solutions*

- 24** **India Re-energized**
A.M. Shah, *Cornerstone*

STRATEGIC ANALYSIS

- 29** **Developing High-Efficiency, Low-Carbon, Clean Coal in China**
Ni Weidou, Song Shizhong, *Tsinghua University*
Wang Minghua, *Shenhua Science and Technology Research Institute Co., Ltd*

- 34** **A Coal-Based Strategy to Reduce Europe's Dependence on Russian Energy Imports**
Roger Bezdek, *Management Information Services, Inc.*

- 40** **The Reliability and Resilience of the U.S. Existing Coal Fleet**
Janet Gellici, *National Coal Council*



4 Cover Story

Gasification Can Help Meet the World's Growing Demand for Cleaner Energy and Products

Alison Kerester

The recent surge in the number of projects, largely driven by coal-to-chemicals in China, marks a renaissance in the field of gasification. In this article the head of the Gasification Technologies Council explains where gasification is growing the fastest and the main drivers for global expansion.





46

TECHNOLOGY FRONTIERS

Improving the Case for Gasification

Harry Morehead, *Siemens Energy, Inc.*

Juergen Battke, *Siemens Fuel Gasification Technology GmbH & Co. KG*

46

The Shell Coal Gasification Process for Reliable Chemicals, Power, and Liquids Production

Rob van den Berg, Zhong-Xin Chen, *Shell (China) Projects & Technology Ltd*

Sze-Hong Chua, *Shell Global Solutions*

50

Distributed Power With Advanced Clean Coal Gasification Technology

Carrie Lalou, *Synthesis Energy Systems*

55

Moving Forward With the Huaneng GreenGen IGCC Demonstration

Xu Shisen, *China Huaneng Clean Energy Research Institute*

61



61

SOCIETY & CULTURE

The Benefits and Challenges Associated With Coal in South Africa

Rob Jeffrey, *Econometrix*

Rosemary Falcon, *University of the Witwatersrand, Johannesburg*

Andrew Kinghorn, *Fossil Fuel Foundation*

66



66

GLOBAL NEWS

Covering global business changes, publications, and meetings

71

LETTERS

74



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Gasification Can Help

By Alison Kerester
Executive Director
Gasification Technologies Council

“Increased flexibility, vastly increased scale, and new applications are driving gasification technologies to gain greater prominence than ever before.”

Energy is fundamental to economic growth. Economies cannot grow and people cannot raise their standard of living without adequate supplies of affordable energy. The global demand for energy is projected to rise by 56% between 2010 and 2040, with the greatest increase in the developing world.¹ This growing energy demand is a direct result of improving individual prosperity, national economies, and infrastructure, and thus living conditions. With this demand in energy also comes a demand for products to support development.

Gasification, which can provide cleaner energy and products, is not new. Its origin dates back to the late 1700s when an early form of gasification was used in the UK to create “town gas” from local coal reserves. More modern gasification technologies began to evolve prior to and during World War II as Germany needed to create its own transportation fuels after being cut off from oil supplies. Later, Sasol in South Africa made the first strides in transitioning toward large-scale production of commercial, economically competitive gasification-derived products and was instrumental in developing the foundations of the modern gasification industry.

Meet the World's Growing Demand for Cleaner Energy and Products

Today's advanced gasification technologies incorporate significant improvements over those early versions; increased flexibility, vastly increased scale, and new applications are driving gasification technologies to gain greater prominence than ever before. The wide deployment of gasification technologies can be largely attributed to socioeconomic, energy security, and environmental issues. In addition, there is more variation in gasification technologies, with some developers focused on reducing costs through integration while others focus on smaller, modular gasifiers. Greater deployment of gasification still faces challenges, but the recent upswing, especially in China, clearly demonstrates the advantages of this technology for utilizing domestic energy sources to produce commercial products.

GASIFICATION BASICS

Gasification is a thermochemical process that converts carbon-based materials—including coal, petroleum coke, refinery residuals, biomass, municipal solid waste, and blends of these feedstocks—into simple molecules, primarily carbon monoxide and hydrogen (i.e., $\text{CO} + \text{H}_2$) called “synthesis gas” or “syngas”. It's quite different from combustion, where large amounts of air are blown in so that the material actually burns, forming carbon dioxide (CO_2). There are several basic gasifier designs and a wide array of operating conditions. The core of the gasification process is the gasifier, a vessel in which the feedstock(s) reacts with air or oxygen at high temperatures. The $\text{CO}:\text{H}_2$ ratio depends, in part, on the hydrogen and carbon content of the feedstock and the type of gasifier. This ratio can be adjusted or “shifted” downstream of the gasifier through the use of catalysts.

A key advantage of gasification systems is that they can be designed to have a reduced environmental footprint compared to combustion technologies. For instance, over 95% of the mercury present in the feedstock can be captured using commercial activated carbon beds. Capturing nearly all the feedstock sulfur is necessary because downstream catalysts are generally intolerant of sulfur. This sulfur can be collected in its elemental form or as sulfuric acid, both of which are saleable products. Slag created from the ash, unreacted carbon, and metals in the feedstock are also captured directly from the gasifier, requiring less equipment than what would be required for post-combustion removal of those same materials in the flue gas of combustion-based systems.

CO_2 emissions can also be captured from the syngas in gasification plants. Greater than 90% of the carbon in the syngas stream can be captured as CO_2 and processed for utilization and/or storage. Some studies have shown that transportation fuels can be produced with near-zero carbon footprints using gasification of coal and biomass with CO_2 capture and storage.²

Gasification typically takes place in an above-ground gasification plant; however, the gasification reaction can also take place below ground in coal seams. With underground coal gasification (UCG), the actual gasification process takes place underground, generally below 1200 feet below the surface in coal seams that are considered not economically mineable. Recent advances in well-drilling technologies are now enabling UCG development of coal seams in the 4000–6000-ft depth range, with increased environmental protection and process efficiency benefits at these depths. The underground setting provides both the feedstock source (the coal) as well as pressure comparable to that of an above-ground gasifier. With most UCG facilities, wells are drilled on two opposite sides of an underground coal seam. One well is used to inject air or oxygen (and sometimes steam) and the other is used to collect the syngas that is produced. The ash and other contaminants are left behind. A pair of wells can last as long as 15 years. Under its New Energy Policies scenario,



Slag captured from the gasification process (photo provided by Westinghouse Plasma Corp., a division of Alter NRG)

the International Energy Agency has estimated that emerging economies will account for over 90% of the projected increase in global energy demand.³ UCG could play a unique role in helping meet this rising energy demand by utilizing deep coal seams that would otherwise be unobtainable economically.

Additional information on the technical fundamentals behind gasification is provided at the end of this article.

TODAY’S GASIFICATION MARKET

Key Benefits

Finding a path to energy security is a chief concern of nearly every sovereign nation. In the past, fast changing markets have rocked economies that were overly dependent on a single fuel source, such as the oil shocks experienced by the U.S. in the 1970s. Today, perhaps the clearest example is the fact that even as European countries pass sanctions against Russia, they are still highly dependent on Russian natural gas. This dependence could be reduced, or even eliminated, through the use of gasification.

Even within borders, diversification of energy sources is crucial. Although the U.S. has access to inexpensive and seemingly abundant natural gas, the extreme cold resulting from the polar vortex in the winter of 2014 saw rapid spikes in natural

gas prices. Around the world, oil and natural gas prices continue to fluctuate dramatically. In addition to avoiding price uncertainty, many nations have a strong strategic desire to use their indigenous energy resources to produce the energy and products needed for economic growth. Gasification facilities can be designed to use the carbon-based feedstock that is most appropriate for a given region.

Environmental concerns are also receiving increased attention globally. For reasons explained previously, gasification can offer environmental benefits in terms of reduction of a wide range of emissions. In addition, CO₂ emissions can be significantly reduced if carbon capture, utilization, and/or storage are employed. Although environmental concerns may not be the principal driver for the deployment of gasification today, the advantages are undeniable. For instance, gasification can be employed to create low-sulfur transportation fuels, thus reducing one of the major contributors to urban air pollution.

Modern gasification technologies are extremely diverse in their feedstocks, operational configuration, and products. Gasification converts virtually any carbon-containing feedstock into syngas, which can be used to produce electricity and/or other valuable products, such as fertilizers, transportation fuels, substitute natural gas, chemicals, and hydrogen (see Figure 1 for examples of products from gasification). Polygeneration facilities can produce multiple products, one of which can be electricity, from the same initial stream of

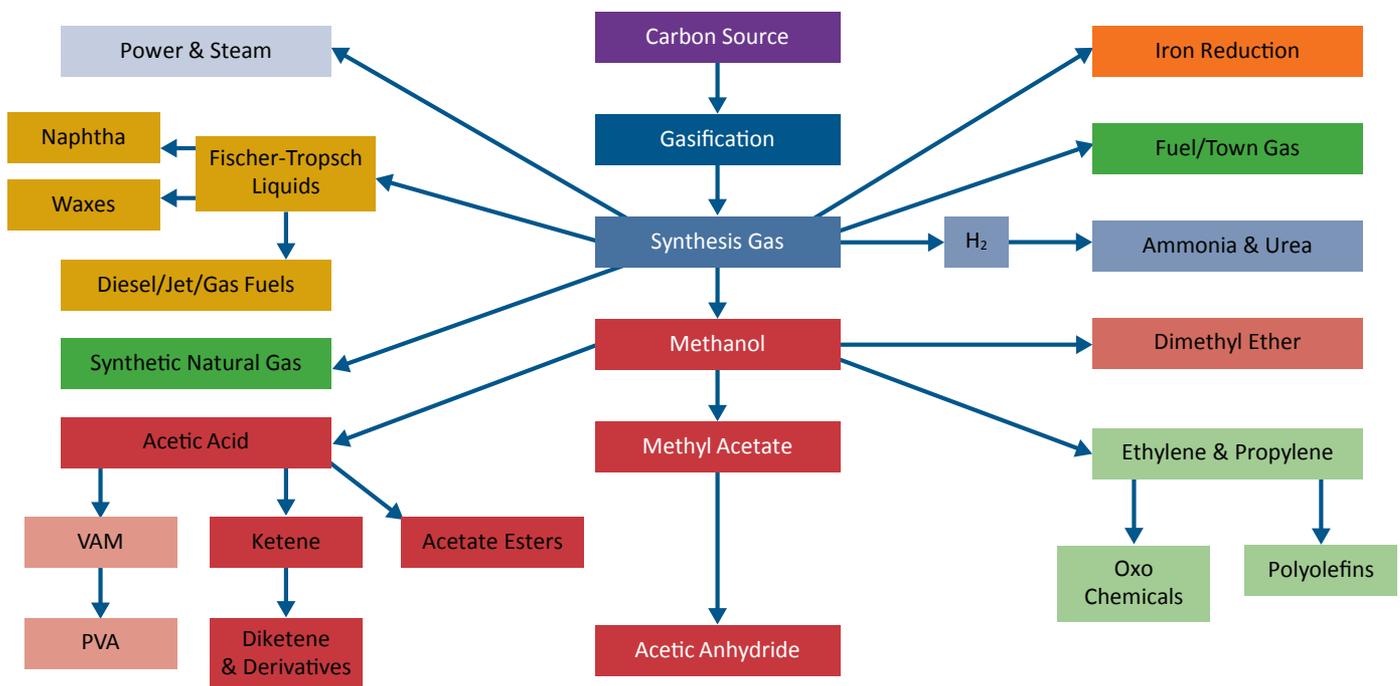


FIGURE 1. Gasification can yield a tremendous variety of products; the examples shown include only the most common (figure courtesy of Eastman Chemical Company).

syngas; the integration of the different components of poly-generation plants can also increase efficiency and provide an overall reduction in the environmental footprint.

Gasification processes can be designed to operate using coal, petroleum, petroleum coke, natural gas, biomass, wastes, and blends of these feedstocks; this diversity is the fundamental reason that gasification can be used to address energy security concerns. Coal is by far the most common source of the carbon feedstock for gasification today—a fact that is likely to remain true into the foreseeable future as countries look for a way to utilize their vast coal reserves. China has clearly seized on this fact and is now leading the way on building new gasification projects.

Market Drivers

Gasification is not a stagnant technology, nor is it a one-size-fits-all technology. Its use is growing globally and the regional growth is far from uniform. Generally, industrial gasification facilities are becoming larger by increasing the number of gasifiers as well as the gasifier size. The economies of scale, and sharing key equipment such as the air separation unit among multiple gasifiers, are bringing down the cost of the final products. However, these large facilities also come with a billion-dollar-plus price tag, so even though the end products may be competitive, in some instances the upfront costs are prohibitive. In such cases there are other options; project developers can turn to smaller, more nimble gasification facilities that are also able to produce power and products. These smaller projects could bring reliable power to a mini-grid. For instance, SES' fluidized bed gasifier can be used to gasify a wide range of feedstocks without changing the gasifier design, making it a contender for distributed power generation.

Today's gasification technologies are able to meet market needs throughout the world. To track projects, the Gasification Technologies Council maintains the Worldwide Gasification Database.⁴ This database is being updated annually, with the next update due in late 2014. The database lists 747 projects, consisting of 1741 gasifiers (excluding spares). Of the 747 facilities, 234 of them, with 618 gasifiers, are active commercially operating projects. As of August 2013, 61 new facilities with 202 gasifiers were under construction with an additional 98 facilities incorporating 550 gasifiers in the planning phase.⁵ The cumulative global gasification capacity projected through 2018 is shown in Figure 2.

Preferred Products

Chemical production is the most common application of gasification worldwide (see Figure 3). Synthetic fuels (both liquid

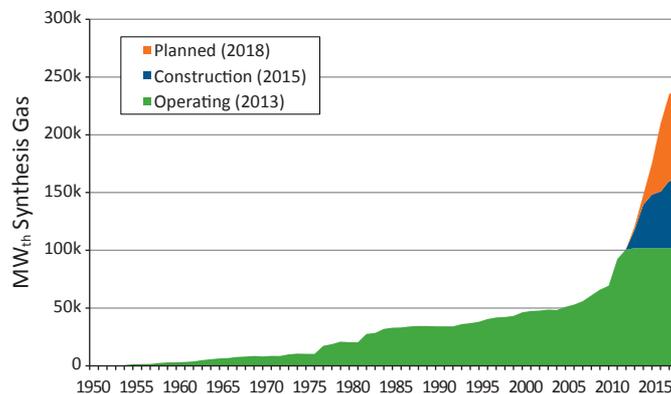


FIGURE 2. Cumulative worldwide gasification capacity and projected growth⁴

and gaseous) are also becoming increasingly important. The second most common application is liquid fuels, although there is also a large amount of planned production of gaseous fuels. About 25% of the world's ammonia and over 30% of the world's methanol is produced through gasification.⁵

In contrast, gasification for power has declined sharply, with many of the planned projects in the U.S. no longer proceeding.⁶ The emergence of abundant and cheap natural gas has been a game changer, making coal gasification less economically competitive in North America. In addition, environmental regulations in the U.S. have resulted in few new coal-based gasification projects being planned. Those projects that are proceeding have been reconfigured to capture CO₂ and/or to produce multiple product streams—generally, power generation and/or urea for fertilizer production, and CO₂ for enhanced oil recovery, such as is the case with the Texas Clean Energy Project. In the U.S. today, a primary interest is in waste gasification, as cities and towns seek to reduce the cost of disposing of municipal solid waste, reduce the environmental impacts of landfilling, and recover the energy contained in the waste. Although North America has generally turned away from new IGCC projects, IGCC projects are moving forward elsewhere; China's 265-MW GreenGen project and the massive (2.6 GW available for export) Saudi Aramco Jazan refinery project are prominent examples.

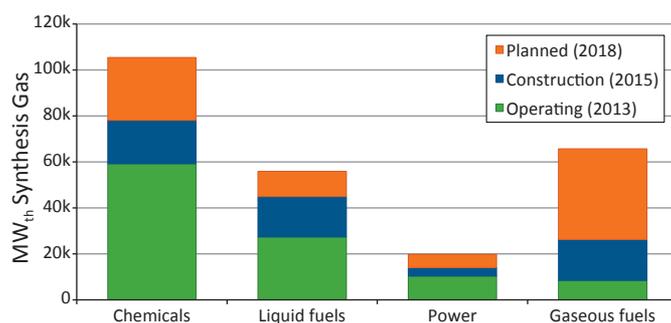


FIGURE 3. Gasification by application⁴

Regional markets dictate which products will be most favorable in specific areas. Figure 4 provides an overview of regional market drivers and the products with the most potential to be economically desirable in the near term. Common traits mostly shared throughout India, China, and most of Southeast Asia are high natural gas prices and vast reserves of low-rank coal, which create a strong market for coal-derived substitute natural gas (SNG) facilities.

Although Figure 4 is based on the common belief that in the EU the potential for the expansion of gasification is limited, it actually could play a major role in reducing the reliance on imported natural gas.

Unquestionably, Asia is experiencing the strongest growth in coal and petroleum coke gasification (see Figure 5), with China leading the way. There are now a number of Chinese gasification technology companies that did not exist a decade ago. The high price of natural gas and LNG, coupled with LNG import restrictions in some countries in Asia (primarily China, India, Mongolia, and South Korea), are prompting those countries to utilize their domestic coal and petroleum coke to produce the chemicals, fertilizers, fuels, and power needed for their economies.

Coal Is the Dominant Feedstock

Coal is the primary feedstock for gasification and will continue to be the dominant feedstock for the foreseeable future (see Figure 6). The current growth of coal as a gasification feedstock is largely a result of new Chinese coal-to-chemicals plants.

Although there are many options for the feedstocks for gasification, coal is far and away the choice most often employed, for several reasons. Of course, energy security plays a role considering that coal is distributed globally. In addition, the price fluctuations in natural gas and LNG are another major concern. Figure 7 shows the price, in US\$/MMBtu, of several fuel sources, including global oil, natural gas at two sites, and fuel oil, coal, and LNG in Asia over the decade from 2003 to 2013.

Fuel price volatility has affected industrial production of chemicals and other products for many decades. In the 1980s, volatile natural gas prices prompted Eastman Chemical Company to switch from natural gas to coal as a feedstock at their Kingsport, Tennessee, chemicals plant. Today, gasification project developers in Asia and elsewhere find themselves facing feedstock choices and fuel pricing options that can dictate project economics. Considering prices in Asia specifically

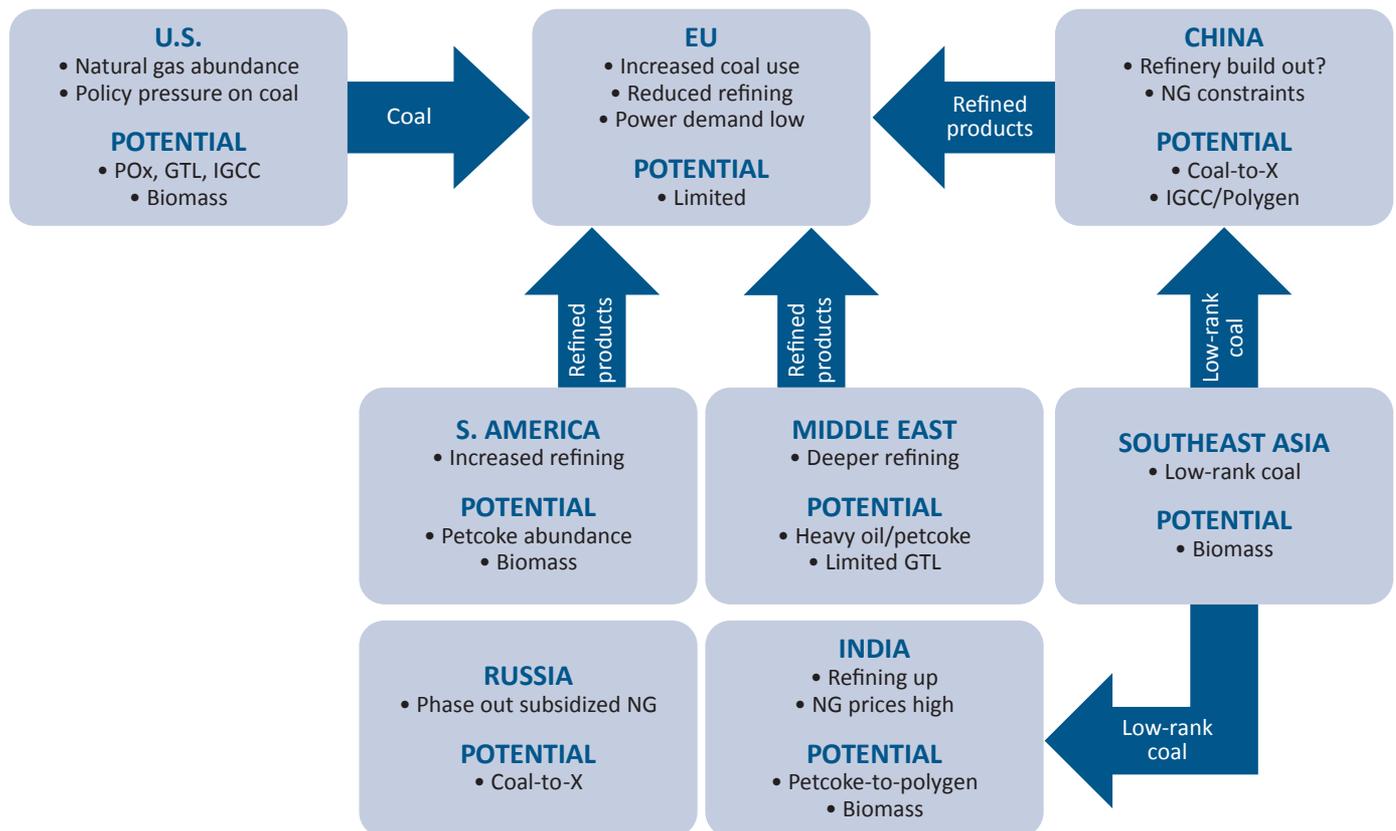


FIGURE 4. Gasification market drivers and products by region (figure courtesy of GE)

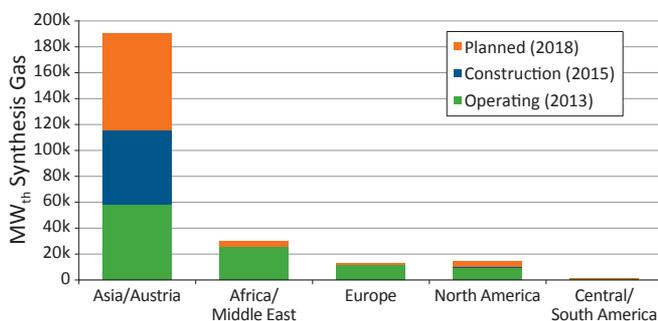


FIGURE 5. Gasification capacity by geographic region⁴

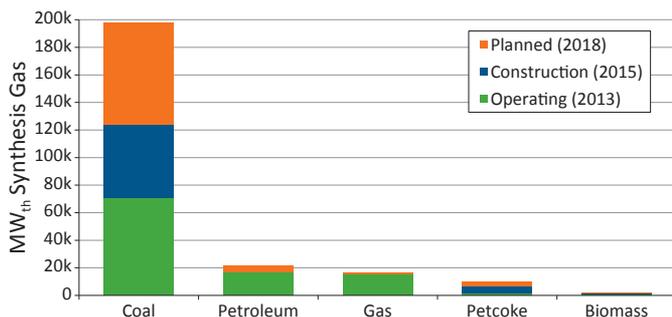


FIGURE 6. Gasification capacity based on primary feedstock⁴

(where most new large-scale gasification is taking place), oil, coal, natural gas, and LNG prices must be compared when considering new projects. In Asia, coal is by far the least expensive option. In addition, the price fluctuations for coal are relatively small compared to those observed in other fuel options.

INCREASINGLY LARGER SCALE PLANTS

With a few exceptions, coal and petroleum coke gasification plants are becoming larger in scale to produce enough product(s) to meet market demand as well as to drive down the product price. Although the sizes of the gasifiers are not increasing substantially, the number of gasifiers per project is increasing. The increasing size of projects is resulting in the scale-up of the supporting equipment, such as the air separation units. Large gasification projects currently under construction or operating include:

- **Reliance Jamnagar Refinery (India):** The world's largest refinery and petrochemical complex will be gasifying petroleum coke and coal for the production of power, hydrogen, SNG, and chemicals. The project will have over 12 gasifiers and is currently under construction. The first gasification train is expected to be completed by mid-2015 and the overall project by early 2016.
- **Saudi Aramco Jazan Refinery (Saudi Arabia):** This will be the world's largest gasification-based IGCC power facility to convert vacuum residues to electricity for use both in the refinery and for export. This project is now selecting vendors and is expected to be completed in 2017.

- **Shell's Pearl Facility (Qatar):** The world's largest natural gas-to-liquids facility using Shell's gasification technology is now operational.
- **Tees Valley (England):** The world's largest advanced plasma gasifiers are being installed in the Tees Valley to gasify municipal solid waste, construction and demolition debris, and coal to produce power for an estimated 100,000 homes. This project is due to start up in 2016.

"Gasification project developers in Asia and elsewhere find themselves facing feedstock choices and fuel pricing options that can dictate project economics."

REMAINING CHALLENGES

Although the momentum behind the application of gasification has increased, a number of challenges remain to increasing deployment. One of the most important is a lack of regulatory certainty in some developing countries. For instance, some gasification projects in India are having trouble gaining a foothold amid concerns about feedstock availability and timely project approvals. Restrictions also are being created by some governments demanding that all technologies be domestically derived, slowing the advancement of deployment in the near term.

The upfront costs associated with large-scale gasification projects remain a hurdle today. Although alternatives to the

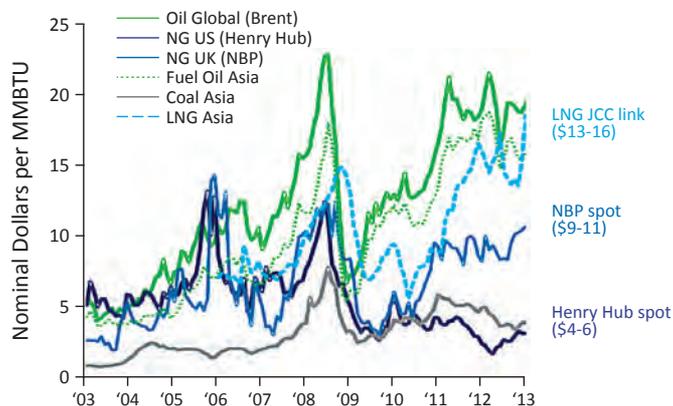


FIGURE 7. Recent prices for gasification fuel options (figure courtesy of GE)

capital-intensive projects exist, they are unlikely to become a suitable replacement for large gasification projects that offer a lower-cost end product and produce the large quantities of products necessary to meet market demand, such as the chemicals and fertilizer sectors. Bringing down capital costs or finding ways to obtain the required investment will remain a challenge.

Although the capital costs for gasification projects receive more attention, the industry is also working to find ways to reduce operating costs, often through efficiency improvements. For instance, the ability to remove contaminants from hot or warm syngas instead of first cooling the gas (for use with today's commercially available processes) has the potential to yield significant energy savings. One promising project is RTI International's warm syngas cleanup project.⁶ Research is also being undertaken on the development of sulfur-tolerant catalysts, which would allow the sulfur in the syngas to be removed at a later stage in the process, which may be more cost effective.

UCG is a promising technology that today remains relatively undeveloped. There are still technical challenges to UCG that must be overcome, but the major hurdles are actually institutional and a lack of public understanding. Successful demonstration projects could deter misconceptions that UCG is unproven and damages the environment. Linc Energy's new UCG project in Poland will help demonstrate the viability of UCG to the world.

A great deal of innovative work is underway on new gasification technologies. In addition to UCG, a number of nontraditional approaches to gasification are emerging. For instance, KBR's new TRIG™ gasification technology, the Free Radical Gasification (FRG™) technology developed by Responsible Energy, and the lower emissions gasification technology developed by ClearStack Power, LLC are all examples of the innovative work currently being conducted that will yield tomorrow's gasification systems.

CONCLUSION

The gasification market has evolved significantly over the last five years. Coal gasification, and particularly coal gasification for power generation, has declined significantly in the U.S., although there is a growing interest in waste-to-energy gasification in North America.

Coal-based gasification (and coal gasification for chemicals)

is dominant in Asia and will likely continue to be so for the foreseeable future. There is a growing market for petcoke gasification in Asia as well, as Asian refineries strive to remain competitive in the Asian market. High natural gas and LNG prices in Asia, the growing demand for energy and products in the developing world, and the need for energy security will all continue to drive the demand for coal and petroleum coke gasification.

“Successful demonstration projects could deter misconceptions that UCG is unproven and damages the environment.”

These new plants are moving the deployment of gasification forward in a way that may not have seemed possible just 10 years ago. The tremendous amount of RD&D occurring globally promises that tomorrow's technologies will be more advanced, less expensive, and more flexible than those in the market today. New experience, technical advancements, and the potential to integrate gasification with CO₂ capture, combined with greater needs for energy security, may mean the coming years will fully unlock the potential for gasification that we've known has existed for decades. 🤖

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GASIFICATION FUNDAMENTALS

Gasification is a thermal process that converts any carbon-based material, including coal, petroleum coke, refinery residuals, biomass, and municipal solid waste, into energy without burning it. The carbon-containing feedstock is reacted with either air or oxygen which breaks down the mixture into simple molecules, primarily carbon monoxide and hydrogen ($\text{CO}+\text{H}_2$), called “synthesis gas” or “syngas”. The undesirable emissions from gasification can be much more easily captured because of the higher pressure and (often) concentration compared to conventional pulverized coal-fired power plants.

Feedstock

Gasifiers capture the energy value from coal, petroleum coke, refinery wastes, biomass, municipal solid waste, wastewater treatment biosolids, and/or blends of these materials. Examples of potential feedstocks that can be gasified and their phases include

- *Solids*: All types of coal, petcoke, and biomass, such as wood waste, agricultural waste, household waste, and hazardous waste
- *Liquids*: Liquid refinery residuals (including asphalts, bitumen, and oil sands residues) and liquid wastes from chemical plants and refineries
- *Gases*: Natural gas or refinery/chemical off-gas

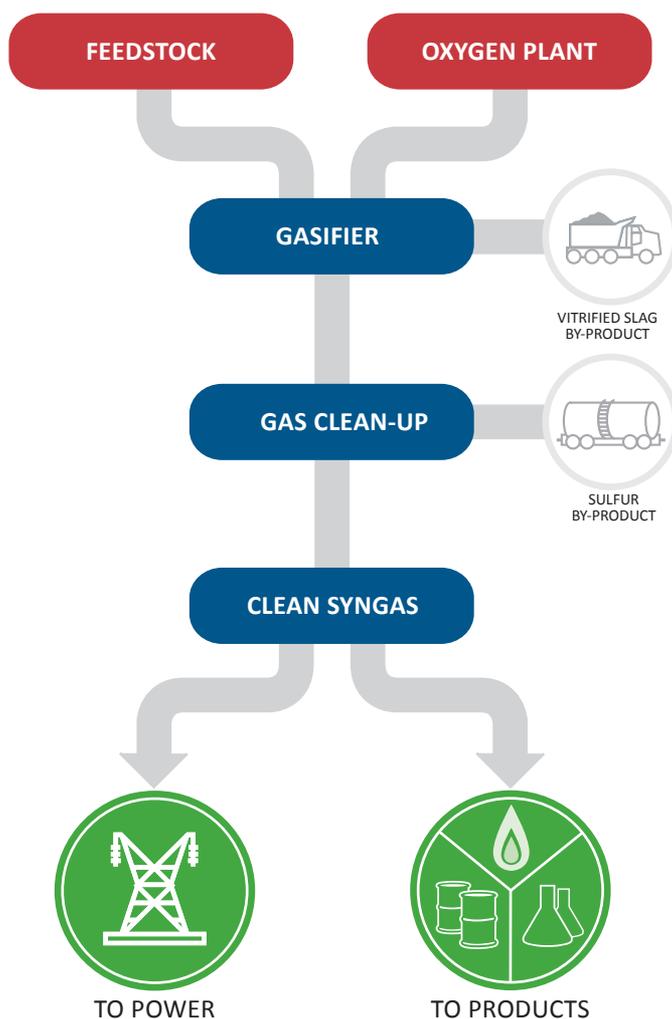
Gasifying Fluid

Gasifiers utilize either oxygen or air during gasification. Most gasifiers that run coal, petroleum coke, or refinery or chemical residuals use almost pure oxygen (95–99% purity). The oxygen is fed into the gasifier simultaneously with the feedstock, ensuring that the chemical reaction is contained in the gasifier vessel. Generally, gasifiers that employ oxygen are not cost effective at the smaller scales that characterize most waste gasification plants.

Gasifier

The core of the gasification process is the gasifier, a vessel where the feedstock(s) reacts with the gasification media at high temperatures. There are several basic gasifier designs, distinguished by the use of wet or dry feed, the use of air or oxygen, the reactor’s flow direction (up-flow, down-flow, or circulating), and the syngas cooling process. There are also gasifiers designed to handle specific types of coal (e.g., high-ash coal) or petcoke.

THE GASIFICATION PROCESS



Prior to gasification, solid feedstock must be ground into small particles, while liquids and gases are fed directly. The amount of air or oxygen that is injected is closely controlled. The temperatures in a gasifier for coal or petcoke typically range from 1400° to 2800°F (760–1538°C). The temperature for municipal solid waste typically ranges from 1100° to 1800°F (593–982°C).

Currently, large-scale gasifiers are capable of processing up to 3000 tons of feedstock per day and converting 70–85% of the carbon in the feedstock to syngas.

Syngas

Although syngas primarily consists of $\text{CO}+\text{H}_2$, depending up on the specific gasification technology, smaller quantities of

methane, carbon dioxide (CO₂), hydrogen sulfide, and water vapor could also be present. The CO:H₂ ratio depends, in part, on the hydrogen and carbon content of the feedstock and the type of gasifier. This ratio can be adjusted or “shifted” downstream of the gasifier through the use of catalysts. Ensuring the optimal ratio is necessary for each potential product. For example, refineries that produce transportation fuels require syngas that contains significantly greater H₂ content. Conversely, a chemicals production plant uses syngas with roughly equal proportions of CO and H₂. This inherent flexibility of the gasification process means that it can produce one or more products from the same process.

Some downstream processes require that the trace impurities be removed from the syngas. Trace minerals, particulates, sulfur, mercury, and unconverted carbon can be removed to very low levels using processes common to the chemical and refining industries.

By-products

Most solid and liquid feed gasifiers produce a glass-like byproduct called *slag*, composed primarily of sand, rock, and minerals contained in the gasifier feedstock. This slag is non-hazardous and can be used in roadbed construction, cement manufacturing, and in roofing materials.

Underground Coal Gasification

With underground coal gasification (UCG), the actual gasification process takes place underground, generally below 1200 feet in depth, although recent advances in well-drilling technologies now make UCG possible at much deeper conditions (i.e., 4000–6000-ft depth range).

The UCG reactions are managed by controlling the rate of oxygen or air that is injected into the coal seam through the injection well. The process is halted by stopping this injection. After the coal is converted to syngas in a particular location, the remaining cavity (which will contain the leftover ash or slag from the coal, as well as other rock material) may be flooded with saline water and the wells are capped. However, there is a growing interest in using these cavities to store CO₂ that could be captured from the above-ground syngas processing or even nearby combustion facilities. Syngas from UCG can also be treated to remove trace contaminants; once CO₂ storage is added, UCG offers another opportunity to achieve

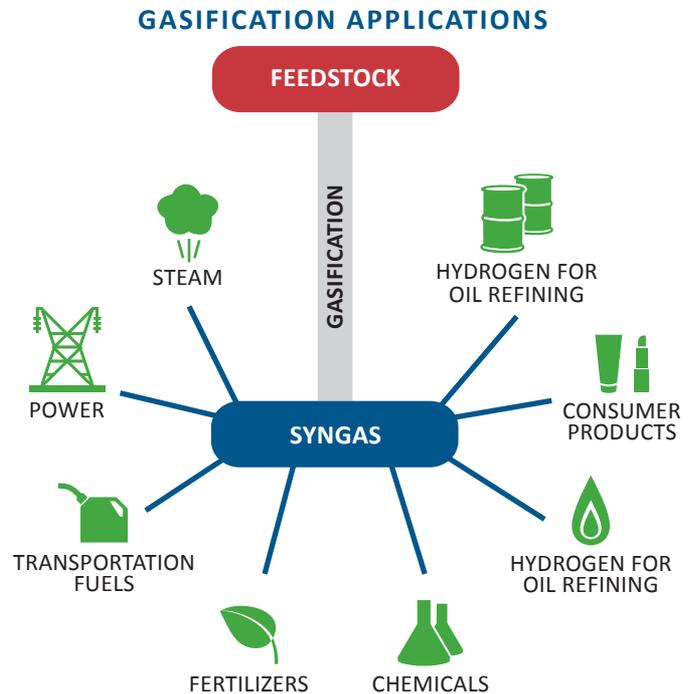
a coal-based, low-carbon source of energy and carbon-based products. Once a particular coal seam is exhausted (after up to 15 years), new wells are drilled to initiate the gasification reaction in a different section of the coal seam.

UCG operates at pressures below that of the natural coal seam pressure, thus ensuring that materials are not pushed out into the surrounding formations. This is in contrast to hydraulic fracturing operations in oil and gas production, where pressures significantly above natural formation pressure are used to force injectants into the formation.

Products

As explained, gasification can be used to yield a number of carbon-containing products, including several simultaneous products at polyproduction facilities.

Gasification is a complex process with decades of development behind it. The future of gasification technologies promise to improve on the work that has already been done.



For more information on gasification, visit the Gasification Technologies Council website: www.gasification.org/

The Drivers and Status of the Texas Clean Energy Project

By **Laura Miller**

Director of Projects, Texas, Summit Power Group, LLC

In a single week this past June, the U.S. Supreme Court voted 7-to-2 to affirm the right of the Environmental Protection Agency (EPA) to regulate carbon dioxide (CO₂) emissions from large industrial sources; four former EPA chiefs, all appointed by Republican presidents, testified before a Senate subcommittee that man's contribution to climate change is a matter of national security; and a coalition of business leaders, including three former U.S. Treasury secretaries, issued a report detailing economic drivers for combating climate change.¹ These are just the latest examples of a growing and increasingly bipartisan consensus in the U.S. that something can and must be done to reduce the amount of manmade greenhouse gas emissions.

THE CARBON CAPTURE CHALLENGE

Despite this growing consensus, making carbon capture, utilization, and storage (CCUS) a standard feature of the U.S. power plant fleet—the largest source of America's greenhouse gases—has proven to be easier said than done. According to a 2012 report by the Congressional Budget Office:

Since 2005, lawmakers have provided the Department of Energy (DOE) with about \$6.9 billion to further develop CCS [carbon capture and storage] technology, demonstrate its commercial feasibility, and reduce the cost of electricity generated by CCS-equipped plants. But unless DOE's funding is substantially increased or other policies are adopted to encourage utilities to invest in CCS, federal support is likely to play only a minor role in the deployment of the technology.²

Although the U.S. DOE announced a new \$8B loan program last December for advanced fossil energy projects that capture or reduce carbon,³ no new grant monies for such projects

“Summit’s quest to build the most ambitious, pre-combustion, carbon-capture power plant in the world serves as an effective case study for a nascent industry...”



The site of the Texas Clean Energy Project (photo courtesy of Jason Lewis, U.S. DOE, National Energy Technology Lab)

are expected to be approved by Congress for the foreseeable future. Likewise, there is currently not an apparent (or at least sufficient) political will to put a price on carbon emissions that would incentivize carbon storage on a major scale.

One potentially cost-neutral approach, which West Virginia's Sen. Jay Rockefeller introduced recently as Senate Bill 2288, was developed by the National Enhanced Oil Recovery Initiative (NEORI)—a coalition of major companies, environmentalists, labor unions, and state officials; Summit Power Group (Summit) was also a participant. NEORI found that an expansion of current federal Section 45Q production tax credits for projects that capture CO₂ for use in enhanced oil recovery (CO₂-EOR) could generate over nine billion barrels of oil over 40 years in the U.S., quadrupling CO₂-EOR production and displacing U.S. oil imports, all while preventing the release of four billion tons of CO₂ to the atmosphere. The group also found that the short-term cost of expanding the 45Q program today would be more than covered by the revenue generated from the increased corporate income taxes and royalties paid on the oil produced from CO₂ injections.⁴

Summit's quest to build the most ambitious, pre-combustion, carbon-capture power plant in the world serves as an effective case study for a nascent industry where the science and the technology are fully proven, but the execution remains challenging for mostly unforeseen reasons: the global economic recession of 2008, a plunge in U.S. natural gas prices, sharply increased oil and gas supplies, and the lack of broad Congressional action to deal with the issue of CO₂.

Summit is a power plant development company, founded 20 years ago by Donald Hodel, former U.S. Secretary of Energy, and Earl Gjelde, former COO of the U.S. Department of Energy. To date, the company has successfully developed over 9000 MW of natural gas, wind, and solar projects, but never any based on coal. In 2006, with national opposition to old-technology coal plants (i.e., subcritical plants not employing the best available technologies and not contemplating any future carbon capture) growing dramatically nationwide, Hodel and Gjelde concluded that for coal to have a future in an increasingly carbon-constrained world, it was time to build a world-class clean, low-carbon, coal-based power project.

Summit's vision became what is today a fully permitted 400-MW coal gasification project with 90% carbon capture near Odessa, Texas, called the Texas Clean Energy Project.

U.S. COAL GASIFICATION IS NOT NEW

The science behind low-carbon emissions, coal-based power was already proven in the U.S. by 2006: Tampa Electric's Polk Power Station in Florida and the Wabash River Coal Gasification

Repowering Project in Indiana were up and running, both built in the mid-1990s with enormous financial support from the U.S. DOE. They demonstrated that electricity from coal gasification could be both efficient and offer significantly lower emissions—essentially vaporizing the coal into a gaseous state that permitted its impurities to be stripped out, rather than burning the coal and trying to capture the pollutants as they were blown through a smokestack.

Industrial-scale carbon capture and utilization was also already commercially proven in the U.S.: In 2000, the Great Plains Synfuels Plant in North Dakota began capturing 50% of the CO₂ off its coal-feedstock synthetic natural gas manufacturing plant and piping it north to Canada for geological storage via CO₂-EOR. The added revenue stream was such a boon to the coal-to-SNG project that its owners repaid the U.S. DOE \$1 billion that it had spent taking over the project in 1986 when natural gas prices plummeted and the original owners bailed on the project.⁵

“Summit's vision became what is today a fully permitted 400-MW coal gasification project with 90% carbon capture near Odessa, Texas, called the Texas Clean Energy Project.”

Hodel and Gjelde saw an opportunity to take these two proven technologies (i.e., coal gasification for electricity and CO₂-EOR) and combine them, for the first time, to build a new generation of coal-based power plants. Despite the fact that burned coal was still powering half of America's homes and businesses in 2006,⁶ the reality was an industry under siege from environmentalists, politicians, and consumers who were tired of the existing, high-emissions, plants and new-construction proposals that were not employing the very latest and best technology. As an example, TXU's Big Brown, a 1150-MW plant in East Texas, had no sulfur-dioxide (SO₂) scrubbers in 2006 and still doesn't today—making it the No. 4 biggest SO₂ producer of 449 coal plants nationwide⁷, with 62,494 tons emitted in 2013. No. 3 is another old TXU plant, Martin Lake, just 100 miles down the road. The EPA began regulating SO₂ emissions in 1971—the same year Big Brown came online.

I was one of those unhappy politicians. As mayor of Dallas in 2006, I was shocked to learn that 18 new, pulverized coal plants were being proposed for our state—11 of them by



After her tenure in public office, Laura Miller has continued to push for the deployment of clean coal technologies globally.

Dallas-based TXU, which already owned three of the state's largest, oldest, and highest-emission coal plants. With help from then-Houston mayor Bill White, we created a coalition of cities, counties, and school districts to fight TXU's plans, which the EPA said did not include using the most technologically advanced pollution control equipment then available. Our widely publicized statewide challenge eventually led to a leveraged buyout of the company and a compromise by the new owners, forged by national environmental groups, to build only three of the 11 plants, including a two-unit, 1600-MW project northwest of Houston called Oak Grove.

During our yearlong battle, I had pressed TXU aggressively to consider doing gasification; when company officials insisted in public debate forums that gasification technology wasn't available on a reliable, commercial scale, I traveled to Florida to tour the Tampa project so I could refute the claim. And when I repeatedly brought up doing carbon capture, TXU said it was happy to consider making the new plants "carbon capture ready"—which sounded promising at the time, but quickly proved to be an often-used excuse for doing nothing. As David Hawkins with the Natural Resources Defense Council once famously put it in a 2007 appearance before the U.S. Senate Committee on Energy and Natural Resources: "It could mean almost anything, including according to some industry

representatives, a plant that simply leaves physical space for an unidentified black box. If that makes a power plant 'capture-ready,' Mr. Chairman, then my driveway is 'Ferrari-ready.'" ⁸

I wasn't against coal. I was against using coal if it wasn't in the cleanest manner possible. When I left public office in 2007, I was asked by several environmental groups if I would go around the country teaching other mayors how to fight dirty coal plants. My response was that it would take forever, only defeat one project at a time, and be an uphill battle in states like Texas (where citizens, not project developers, had the burden in permit hearings to prove that a project wasn't using the best technology available). Why not build the cleanest plant in the world, thus raising the bar forever on the standard for using coal? The Clean Air Task Force promptly introduced me to Summit Power Group.

Summit executive Eric Redman, now our company president and CEO, was passionate about our project for the same reason I was—we want our industry to capture and sequester carbon. Hodel and Gjelde had a somewhat different but related motivation: Both of them wanted to help assure the clean, responsible, publicly accepted future use of America's 300-year supply of coal and other hydrocarbons⁹—one of our country's most stable and plentiful resources—in part so that America can finally fulfill its long-held goal of energy independence and security. These overlapping approaches to the project have resulted in one of TCEP's greatest strengths—solid bipartisan support on the federal, state, and local levels in both Texas and Washington.

While Summit was focused on pre-combustion carbon capture, other forward-looking power companies were determined to capture carbon off existing coal fleets—a far more difficult task. Most commendably, American Electric Power (AEP) had made it a goal as early as 2003 to capture carbon off its existing 1300-MW Mountaineer Power Plant, commissioned in 1980 in West Virginia. With assistance from U.S. DOE, EPRI, and Alstom, AEP proved in a pilot program (which it conceived in 2003 but took until 2009 to achieve) that CO₂ could be captured off an emissions slipstream and stored underground. Despite a \$334M award from DOE to take the pilot program to commercial scale and a 90% capture rate, AEP abandoned the project in 2011 after the U.S. Senate failed to pass a House bill that established a federal cap-and-trade program for carbon emissions, and regulatory authorities in West Virginia were unwilling to pass on Mountaineer's CO₂ capture costs to ratepayers.

"[A]t this time it doesn't make economic sense to continue work on the commercial-scale CCS project beyond the current engineering phase," said Michael G. Morris, AEP chairman and chief executive, in a statement at the time. "It is impossible to gain regulatory approval to recover our share of the costs for

validating and deploying the technology without federal requirements to reduce greenhouse gas emissions already in place.”¹⁰

Although Mountaineer’s demise has been seen as a major setback for post-combustion capture in the U.S., NRG announced in July 2014 that it would start construction on a \$1B tower that would capture 40% of the CO₂ from one of four coal units at its existing, 2475-MW W.A. Parish power plant near Houston. The 1.6 million tons per year of captured CO₂ will be used for CO₂-EOR in a field NRG partly owns 80 miles away. U.S. DOE is contributing \$167M of the cost.

Tenaska was also a major first mover in developing CCUS, proposing two new-build projects: Trailblazer in Texas, a supercritical pulverized coal project with 85 to 90% carbon capture, and Taylorville in Illinois, a gasification project with 65% carbon capture. In 2013, Tenaska abandoned both, citing similar reasons as AEP, plus increasing supplies and lower costs of natural gas and renewable energy.

Today, only one major, new coal-based CCUS power project is under construction in the U.S.: the Kemper County energy facility, a 582-MW IGCC project with 65% carbon capture—a rate that will result in the plant having the same carbon emissions profile as a highly efficient natural gas-fired power plant. Jointly funded by Mississippi Power and Southern Company, with a \$270M award from the U.S. DOE, Kemper has suffered cost overruns and schedule delays, but is set to come online near Meridian, Mississippi, by the end of 2014, which would make it the U.S.’s first successful coal-based CCUS power project and a long-awaited milestone for the industry.

THE TEXAS CLEAN ENERGY PROJECT

The second new-build U.S. carbon capture power project slated for construction is Summit’s Texas Clean Energy Project (TCEP).

Like Kemper, TCEP has also received federal incentives—a \$450M award from Round 3 of U.S. DOE’s Clean Coal Power Initiative (CCPI) program in 2009–2010, and two subsequent federal tax credit awards from the IRS under Section 48A of the Internal Revenue Code. With TCEP’s projected cost at about \$2.5B, the federal assistance covers just part of total construction costs, which will be borne primarily by private investors and bank lenders, but is nevertheless essential to this type of large-scale, first-of-a-kind project (first-of-its-kind because unlike Kemper, TCEP will also produce urea fertilizer, plus capture a much higher percentage of its CO₂). In the case of TCEP, the federal incentives allow it to sell all of its products, including power, at market prices, which is critical in Texas since the electricity market is no longer regulated by the Public Utility Commission and ratepayers are not responsible for cost overruns.

So why—when utilities and other power providers have scrapped their CCUS projects in recent years—is TCEP still moving forward?

One fortuitous factor is TCEP’s design: It is a polygeneration plant—a project that generates multiple products, instead of just electricity—resulting in multiple revenue streams (see Figure 1). About 25% of TCEP’s revenue will be generated by 195 MW of electricity sales; about 55% of revenue will come from the 760,000 tons/year of urea; about 20% of revenue will come from the sales of CO₂ for CO₂-EOR.

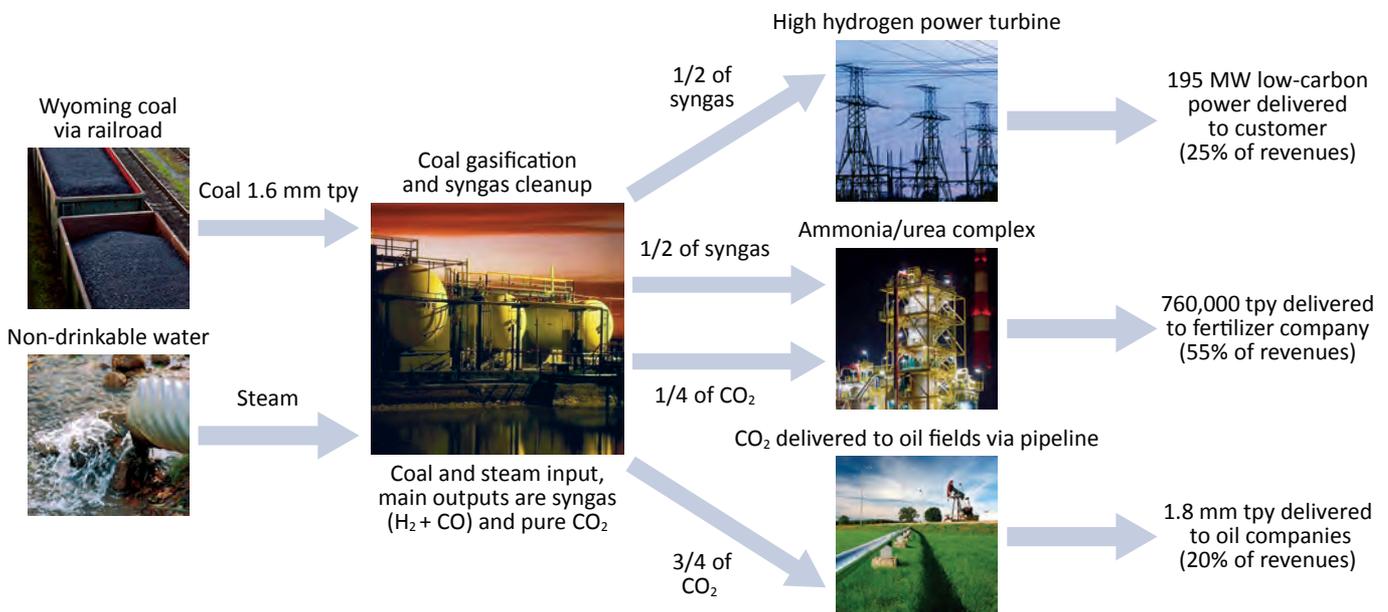


FIGURE 1. Summary flow chart for the Texas Clean Energy Project

Note: Other by-products represent ~3% of total revenue and have been eliminated via rounding; tpy = tons/year

This unusual configuration came about when Summit decided early on to employ Siemens gasification technology to convert Powder River Basin (PRB) coal into clean, high-hydrogen, low-carbon syngas. Because of the gasifier's size, this resulted in more syngas being produced than would be needed to operate the Siemens combustion turbine to produce electricity. After reviewing market forecasts for various products—synthesized gasoline and diesel fuel, ammonia, methanol, synthetic natural gas—urea fertilizer was chosen for its low commodity price risk and ability to displace imports (the U.S. currently imports 70% of its urea). TCEP will sell all of its urea to Minnesota-based CHS, Inc., which sells crop nutrients, both wholesale and retail, to thousands of farmers for millions of acres across North America.

Other TCEP products include sulfuric acid, which will be manufactured onsite from the sulfur captured from the coal, which is also currently done by Tampa Electric's Polk Power Station. TCEP's sulfuric acid will be marketed by Houston-based Shrieve Chemical Company to its mining, manufacturing, and agricultural customers.

Finally, just as Kemper will do, TCEP will take virtually all of its captured CO₂, compress it onsite, and sell it to area oil producers for CO₂-EOR. In TCEP's case, TCEP will transport its 1.8 million standard tons per year of compressed CO₂ for less than one mile to connect with the existing Kinder Morgan system of dedicated CO₂ pipelines, which will deliver it to TCEP customers Whiting Oil and two other Permian Basin producers.

By December 2011, TCEP had achieved virtually all of its project milestones, including: 1) issuance of all required permits, including its Texas air permit and its Record of Decision (ROD) at the end of U.S. DOE's National Environmental Protection Act (NEPA) process; 2) a completed front end engineering and design (FEED) study; 3) signed engineering, procurement, and construction (EPC) contracts and operations and maintenance (O&M) contracts with three EPC contractors; 4) signed off-take agreements for all major commercial products; and 5) commitments of local and state financial incentives for locating the project in West Texas.

In September 2012, the project forged an important alliance with two of the largest companies in China: the Export-Import Bank of China (Chexim), which committed to loan TCEP all of its required debt financing of more than \$1.6 billion, and Sinopec Engineering Group (SEG), a subsidiary of petrochemical giant Sinopec Corporation, which joined the project's EPC team.

In July 2013, with TCEP's project debt and equity funding committed, an update of project costs came in considerably higher than had been anticipated by Summit and its investors, because of a sharp increase in construction costs in West Texas. This in turn was due to an increasingly high demand for skilled labor in

the midst of a statewide oil and gas boom. With no ceiling on labor costs—and big labor contingencies added to the new cost estimates from all three contractors—the project was unable to complete its financing by its goal of December 2013.

Undeterred, and with the support of DOE and state and local officials in West Texas, Summit is now simplifying its EPC structure by bringing in a lead contractor that has successfully built similar plants, China Huanqiu Contracting & Engineering Corporation (HQC), and making improvements to its project design to reduce costs and the amount of needed feedstock (and also residual emissions). In July 2014, Summit and HQC launched a FEED study update that is expected to conclude with new, signed EPC contracts and a financial closing by about 30 April 2015, with groundbreaking shortly thereafter.

“TCEP will take virtually all of its captured CO₂, compress it onsite, and sell it to area oil producers for CO₂-EOR.”

HQC and Summit began the FEED update work during the sixth round of the U.S.-China Strategic and Economic Dialogue in Beijing. In conjunction with that meeting's U.S.-China Climate Change Working Group CCUS initiative, Summit's TCEP was also selected by the U.S. DOE to enter a working partnership arrangement with Huaneng's Clean Energy Research Institute (CERI) and that company's GreenGen project—which is China's cleanest fossil fuel power plant.

“TCEP is a key part of the U.S. CCUS portfolio, and DOE has invested \$450 million into the project,” stated the U.S. DOE's Principal Deputy Assistant Secretary of the Office of Fossil Energy, Christopher Smith, in a 3 July 2014 letter to China's National Energy Administration Deputy Administrator Zhang Yuqing distributed in Beijing that week. “...Under the counter-facting project arrangement, Summit Power and Huaneng will help each other in the planning and operation of TCEP and Phase 2 of GreenGen by sharing non-proprietary information and results from the respective projects. Huaneng will also assist Summit Power in the commissioning of the TCEP plant.”¹¹

LESSONS LEARNED

We do not envision TCEP as a unique demonstration project, but rather the first full-scale commercial gasification plant in a new carbon capture business sector that Summit intends to pursue.

This vision is shared by others in the industry, most especially U.S. DOE—without which none of the CCUS projects currently under construction, or in development, would be alive today. The prize for the entire energy sector is potentially enormous.

Hopefully, the challenges currently being experienced by projects like TCEP and the Kemper County energy facility will be viewed as necessary growing pains in the effort to replace the current low-efficiency, unabated fleet of coal-fired power generation. Through employing improved technologies this fleet could continue to provide reliable electricity while avoiding the release of 1.73 billion tons of CO₂ into the atmosphere as was the case in 2010.¹²

One thing, though, is certain: Unless Congress approves additional financial incentives to build these innovative projects, this will be remembered as a decade that produced only a handful of commercial-scale carbon capture power projects in America—much like the 1990s are remembered for only two coal gasification projects, Tampa and Wabash. Perhaps the Rockefeller/NEORI proposal—which promises double rewards by both capturing CO₂ and using it to bring up oil—can be the winning formula that quickly deploys a new and nimble fleet of game-changing CCUS facilities.

“Hopefully, the challenges currently being experienced by projects like TCEP and the Kemper County energy facility will be viewed as necessary growing pains...”

If the U.S. turns its back on coal entirely, the rest of the world will not. So for coal to remain relevant to a low-carbon U.S. power industry—and for worldwide carbon emissions from coal to be tamed—it is vital that TCEP and other coal-based CCUS projects succeed and stand as beacons, both here and abroad.

As in any industry, it’s simply a matter of getting the first movers up and operating. 🚀

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Carbon Pollution Standards for New and Existing Power Plants and Their Impact on Carbon Capture and Storage

By Kyle Aarons

Senior Fellow, Center for Climate and Energy Solutions (C2ES)

Using its authority under Section 111 of the Clean Air Act, the U.S. Environmental Protection Agency (EPA) is developing a series of rules to reduce carbon dioxide (CO₂) emissions in the power sector. There are separate rules for new plants, existing plants, and modified or reconstructed plants. The proposed new plant rule is relatively straightforward. Essentially, it would require new natural gas plants to be state-of-the-art combined-cycle combustion turbines and new coal plants to use carbon capture and storage (CCS) technology to capture and store roughly 40% of CO₂ emissions.¹

EPA's proposed rule for existing power plants is much more complex. EPA evaluated the capacity of individual states to leverage each of four carbon-cutting "building blocks" in order to propose a 2030 target emission rate for each state to achieve on an electricity system-wide basis.² (In setting these target emission rates, EPA did not factor in the potential of CCS to reduce emissions in existing power plants.) Once these targets are finalized, each state will be able to meet its target however it chooses and will not have to base CO₂ cuts on EPA's building block projections.



EPA Administrator Gina McCarthy signs new emission guidelines during the announcement of a plan to cut CO₂ emissions from power plants by 30% from 2005 levels by 2030, 2 June 2014, at EPA headquarters in Washington, DC.

This article explores the extent to which the proposed new and existing source rules will advance CCS technology. Because both coal-fired and natural gas-fired generation will likely be predominant sources of electricity in the U.S. and most of the world's other major economies for decades to come, it is essential to advance CCS to the point that its use is economical in the context of electricity generation.³

CARBON POLLUTION STANDARD FOR NEW POWER PLANTS

EPA's proposed Carbon Pollution Standard for New Power Plants, released on 20 September 2013, was developed under Section 111(b) of the Clean Air Act.⁴ Section 111(b) calls for a standard that "reflects the degree of emissions limitation achievable through the application of the best system of emissions reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."⁵ The emissions limit must take the form of a standard—in the case of power plants, maximum allowable CO₂ emissions per unit of electricity—and may not prescribe a particular technology.

"Because both coal-fired and natural gas-fired generation will likely be predominant sources of electricity ... it is essential to advance CCS to the point that its use is economical in the context of electricity generation."

Section 111 ostensibly requires EPA to review the technological options available and, if appropriate, establish a new standard every eight years. In practice, standards have typically remained unexamined and unchanged for much longer, often because of resource constraints at EPA.



If the proposed rule is finalized, CCS would be essential to meet the standards for new coal-fired power plants.

The proposed rules would set separate standards for power plants fueled by natural gas and coal. New, large plants (roughly 100 MW or larger) fueled by natural gas could emit no more than 1000 pounds of CO₂ per megawatt-hour of electricity produced (lbs CO₂/MWh), which is achievable with the latest combined-cycle technology. Smaller natural gas plants, which tend to be less efficient and operate less frequently, would have to achieve a less stringent rate of 1100 lbs CO₂/MWh. Coal plants would have two compliance options, either of which would require the use of CCS technology. Under one option, coal plants would have to begin using CCS soon after startup to achieve a 12-month average emission rate of 1100 lbs CO₂/MWh. Alternatively, coal plants could begin using CCS within seven years of startup to achieve a seven-year average emission rate of between 1000 and 1050 lbs CO₂/MWh, with EPA inviting comment as to the final standard within that range. CCS is not yet in use at any commercial-scale power plants, but is being built into coal plants in Kemper County, Mississippi, and Saskatchewan, Canada.⁶ CCS technology is also in place in several industrial facilities, some of which generate as much CO₂ as a commercial-scale power plant.⁷

The proposed rule for new power plants has been subject to considerable criticism. One prominent argument against the proposal is that CCS technology has not been “adequately demonstrated,” as is required by the Clean Air Act.⁸ Since CCS has not yet been deployed on a commercial-scale power plant, proposal critics argue that it is not adequately demonstrated. However, the legal interpretation of “adequately demonstrated” is significantly broader than the lay definition. Courts have found Section 111(b) to be technology-forcing and have previously allowed EPA to set standards based on emissions control technologies not yet in actual routine use.⁹ Since CCS has been demonstrated at a variety of commercial-scale

industrial facilities and at demonstration-scale power plants, EPA’s finding that partial CCS for new coal plants is adequately demonstrated could plausibly withstand legal challenge.

Impact on CCS

Given the cost, power companies currently have little reason to invest in CCS projects. To counter this, CCS in the power sector needs both a regulatory driver and financial support. Requiring CCS for new coal plants would send a clear regulatory signal to power companies, their investors, and utility regulators that power companies will need to invest in CCS technology to utilize the energy value of coal well into the future. Deployment of CCS at coal-fired power plants will lead to reduced technology costs, which should make it more feasible to eventually employ CCS on natural gas plants as well, which will likely be necessary to meet long-term climate goals.

While a CCS requirement is necessary to the deployment of CCS in the power sector (assuming no significant price on carbon in the market), this regulatory driver is not sufficient. Additional financial incentives are also needed. One option is selling captured CO₂ to create an additional revenue stream. The most promising market is enhanced oil recovery, or CO₂-EOR, wherein CO₂ is pumped into declining oil wells to recover additional oil, storing the CO₂ in the well once the process is complete.¹⁰ An idea with some support from coal and oil industry representatives, as well as environmental advocacy groups, is a federal tax credit to cover the difference between the cost of investing in CCS and the sales revenue received for utilizing CO₂ in EOR.¹¹

In addition to revenue from CO₂-EOR, federal support is critical to drive the development and deployment of CCS in the power

sector. Tax credits for CCS developers, grants through the Clean Coal Power Initiative, and loan guarantees for CCS projects all need to continue to be used to advance CCS. A combination of these financial measures, along with CO₂-EOR agreements, have been critical in advancing CCS power projects in development, such as the Kemper plant in Mississippi, the Texas Clean Energy Project, and NRG Energy's Petra Nova project. Less targeted funding could also be helpful. For example, a technology-neutral tax incentive that directs funding to clean energy projects based on environmental performance and stage of technology development, rather than to a specific technology, would benefit CCS deployment. Additionally, CCS projects would benefit financially by being allowed to qualify as master limited partnerships, which would reduce their tax burden.¹² Continued CCS research at the Department of Energy would also help reduce the cost of critical technologies.

CCS projects also need the support of state public service commissions (PSCs), which regulate electric utilities and to date have been reluctant to approve CCS projects because of their cost and the lack of any regulatory requirement. The PSCs of both Virginia and West Virginia, for example, denied American Electric Power's request to have expenses for the installation of pilot-scale CCS equipment at its Mountaineer Plant reimbursed by ratepayers.¹³ The Virginia PSC had previously cited uncertainty regarding federal carbon regulations when denying a rate increase for Mountaineer.¹⁴ Requiring new coal plants to employ CCS technology could give state PSCs the necessary impetus to approve the construction of coal plants with CCS, especially as the first commercial-scale power plants become operational and provide lessons for reducing the cost of CCS. More certainty would likely make PSCs more willing to approve some ratepayer cost recovery for CCS projects, making them a more realistic option for power companies.

Some have argued that the proposed CCS requirement for new coal plants will push the power industry away from new coal plants, thus stifling CCS development.¹⁵ Since the CCS requirement will make new coal plants considerably more expensive, the argument goes, investment will shift away from new plants, which are critical for the demonstration of new CCS technologies. While the CCS requirement will make investment in new coal plants less certain, EPA's new plant rule could, on balance, have a net positive effect on CCS deployment. Without a significant price on carbon or public financial support, there is currently little reason for power companies to invest in CCS deployment. Since CCS has been demonstrated at other types of facilities and pilot-scale power plants, the technology is ready to be deployed at a commercial scale, albeit with a high price tag. Generally, C2ES would prefer a national price on carbon to drive greenhouse gas reductions, which would spur CCS deployment, but this is politically infeasible in the near term. Through the new plant

proposal, EPA is giving power companies a regulatory driver to invest in CCS while giving PSCs justification to allow power companies to recover CCS costs from ratepayers. Additionally, EPA's proposal would not prevent the construction of demonstration-scale coal power plants for the development of new CCS technologies. While we do not agree that a CCS requirement will stifle CCS technology development, we do believe the proposal could be improved through additional flexibility measures, discussed further below.

“While the CCS requirement will make investment in new coal plants less certain, EPA’s new plant rule could, on balance, have a net positive effect on CCS deployment.”

Additional Flexibility Could Help CCS

Establishing a regulatory requirement and providing financial support for CCS would only be part of the solution. Power companies would also need time to bring CCS to the point of being cost-competitive with alternative low- and no-carbon power-generating technologies. Given the importance of this development time, EPA could explore options to allow power companies greater flexibility in installing CCS on new coal plants.³ Although we favor requiring CCS at new coal-fired power plants, we believe a more flexible compliance timeline could hasten the broad deployment of CCS in the power sector. Two possible approaches EPA might take to allow for increased flexibility in the CCS requirement are outlined below. (These options are described for illustrative purposes only.)

One method to enhance flexibility would be to allow power companies to comply with an average emission rate over an extended period of time, similar to the 30-year-average option included in EPA's original proposal for this rule.¹⁶ As an example, EPA could require an average of 40% carbon capture over each coal plant's first 20 years of operation. With this option, a power plant operator would be authorized to construct a new coal power plant, operate it without capture for five years while further developing CCS technology, and operate the plant with 55% capture from then on, such that in the first 20 years it captured an average of about 40% of its CO₂ emissions.^c In addition to allowing time for technology development, this option would give power plant operators a larger revenue stream to invest in CCS construction, including the pipelines and other

infrastructure necessary to deliver captured carbon to CO₂-EOR fields. If a long-term average option provides too little assurance that CO₂ will ultimately be captured and sequestered, EPA could also include an interim deadline by which time some set percentage of emissions must be captured. For example, EPA could require an average of 40% capture for the first 20 years of a plant's operation, with at least 20% capture achieved in the plant's fifth year of existence.

As an alternative to the long-term average option, EPA could require a set percentage of capture by a set date, but allow some time for new plants to operate without CCS. The percentage requirement could be increased from that in the proposed rule to ensure little or no net increase in CO₂ emissions relative to the proposed rule. For example, EPA could require that all coal plants constructed in 2015 or later must achieve at least 50% capture by 2020.

CARBON POLLUTION STANDARD FOR EXISTING POWER PLANTS

On 2 June 2014, EPA released its proposed Carbon Pollution Standards for Existing Power Plants (known as the Clean Power Plan), per its authority under Section 111(d) of the Clean Air Act.² The Clean Power Plan would establish different target emission rates (pounds of CO₂ per megawatt-hour) for each state due to regional variations in generation mix as well as electricity consumption, but overall is projected to achieve a 30% cut from 2005 emissions by 2030.¹⁷

The proposed Clean Power Plan would give each state a unique 2030 target emission rate based on EPA's assessment of its capacity to achieve reductions using the following four "building blocks":

1. Make coal power plants more efficient.
2. Increase use of existing low-emitting natural gas combined-cycle plants with excess capacity.
3. Use more zero- and low-emitting power sources such as renewables and nuclear.
4. Reduce electricity demand by using electricity more efficiently.

Each state could meet its established target however it sees fit. States would be authorized to join multistate programs to reduce emissions collectively, for example, through a regional cap-and-trade program.

Notably, EPA did not factor in the potential of CCS to reduce emissions at existing power plants when setting statewide emissions targets. EPA explored this option, but determined that retrofitting existing plants to include CCS would be considerably more expensive and complicated than including CCS in

the construction of new plants. Therefore, EPA expects every state to be able to achieve its proposed 2030 target emission rate without requiring the installation of CCS at existing power plants. However, the proposed new plant rule would give states the flexibility to count CO₂ reductions from CCS on existing plants if they so choose. This could be done through a direct requirement by a state that certain existing plants must employ CCS, or could be the result of a market-based mechanism such as a carbon price. If the carbon price is high enough, CCS on existing plants may be a cost-effective way of reducing the amount of carbon fees a coal plant operator must pay.

As with the proposed rule for new power plants, EPA's proposal for existing power plants has been met with legal criticism. Several states have joined a coal company to challenge EPA's authority to regulate greenhouse gases from power plants using Section 111(d).¹⁸ Another argument is that EPA must restrict its proposal to measures that can be made at a power plant itself, rather than considering renewable generation and customer-side energy efficiency.¹⁹ As evidenced by several recent rulings, courts are likely to give considerable deference to EPA in its application of broad statutory provisions in specific regulatory contexts.

OUTLOOK AND CONCLUSION

The public comment period for EPA's proposed new plant rule has ended, and the rule is expected to be finalized in the spring or summer of 2015. The 120-day comment period for the proposed existing plant rule will end in mid-October. This rule is expected to be finalized in June 2015, and states will have one to three years to propose plans to EPA as to how they will meet their target emission rates. It will therefore be several years before we can better understand the impact of these rules on CCS development and deployment.

At C2ES we believe that EPA's proposed rules for new and existing power plants should have a positive impact on the development of CCS. The new plant rule will add a critical regulatory driver for CCS, which could lead utility regulators to do more to encourage new CCS projects. Although the existing plant rule does not require CCS, states may choose to require or encourage CCS on existing plants to reduce their system-wide emission rates. Of course, much more support is needed at the federal level to reduce the cost of CCS. This could include a tax credit for the use of captured carbon in CO₂-EOR projects; a qualification for CCS projects as master limited partnerships; a clean energy, technology-neutral tax incentive; direct funding; and continuing research and development at the Department of Energy. Combined with additional financial support, these carbon pollution standards are a positive development to advance critical CCS technology. 



EPA has listed increasing the utilization of existing natural gas combined-cycle plants as one of the options states can use to meet the proposed standards for existing power plants.

NOTES

- A. “The term ‘standard of performance’ means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.” 42 U.S.C. § 7411(a) (2012)
- B. Since a full CO₂-EOR system is dependent on a viable oil well for storage, this opportunity is limited to power plants built close enough to such a well that a pipeline is cost-feasible as part of the overall project. Because of this, CO₂-EOR is not a valid option in all regions of the U.S.
- C. This assumes the plant operates with the same capacity factor throughout. The first 20 years of operation can be summarized as: 0% capture x 5 years + 55% capture x 15 years. Averaging this capture amount over the first 20 years: $55\% \times 15/20 = \sim 40\%$ capture over 20 years.

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India Re-energized

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On 20 June 2014, Narendra Modi, the new Prime Minister (PM) of India, listened to presentations given by two of his ministers, Dharmendra Pradhan (petroleum and gas) and Piyush Goyal (power, coal, and new and renewable energy). They briefed him on energy security scenarios as well as their respective plans for the next five years. Modi is hoping that these two ministers can assist him in ringing in an energy revolution in the country. The overall plan is very simple: The country must be able to exploit most of its domestic coal; this fuel must reach the consumer in the most efficient manner possible; and more oil and gas are to be produced domestically to generate more electricity for Indian homes. While the plan is simple, successful execution will depend on the ability



The BJP party's sweeping victory in India's recent elections gave Prime Minister Modi the largest majority in recent history.

to overcome a myriad of institutional and technical hurdles that have gotten the better of previous national leaders.

During his campaign, Modi sold the dream of having around-the-clock access to electricity for every household in the country. In a nation where one third of the population does not have access to power, 24x7 electricity is a tremendous aspiration. To put it into context, the number of Indians without any access to power is about equal to the entire U.S. population. The rest of the country, on average, faces 8.5 hours of power shedding every day—in some places there is no electricity access for 16 hours each day. This means that such areas have no electricity for 2000 to 3000 hours annually, the equivalent of 83–125 days.¹

“In a nation where one third of the population does not have access to power, 24x7 electricity is a tremendous aspiration.”

Modi seemingly understands that, in a country of 1.25 billion people and multiple stakeholders, providing reliable electricity is not an easy task. In his campaign and in his actions in his previous position he arguably demonstrated the mettle to resolve the entangled challenges India's energy sector faces. Major hurdles include stagnation in clearances for new mines, unclear environmental norms and a general lack of environmental regulations, Coal India's struggle to increase production, relatively low plant capacity factors of key power generation companies, and the troubled finances of many power distribution companies.

Despite the many challenges, India's people have placed their trust in nationalist leader Modi. In an historic verdict, India gave him a full majority—a first in the last 30 years.² His party won 282 seats (not including allies) out of 543. To add to his sweeping victory, in various states Modi's opponents were brought to naught, and several of his party's candidates won by a margin of more than 10%.³

What gave the voters such confidence? Perhaps it was Modi's track record as Chief Minister (CM) of the Indian state of Gujarat, which had double-digit growth even during the global economic slowdown. In addition, Gujarat is also one of only



Infrastructure challenges, such as insufficient rail capacity, present major hurdles for improving India's energy sector.

two states in India with 24-hour electricity access. During Modi's tenure Gujarat started electricity-focused reforms in 2004. In 2005, the state electricity board was unbundled into four separate distribution companies responsible for supplying electricity to different parts of the state. He took a step to segregate the power required in the agriculture sector for irrigation purposes from commercial and residential demand. In 2012-13 the holding company Gujarat Urja Vikas Nigam posted profits of Rs13.81 Crores (roughly US\$2 million)—a notable accomplishment when the national average of losses for power providers is about 27%¹—while the state enjoyed 24x7 access to electricity.⁴ As a PM candidate Modi promised uninterrupted power supply to all Indians; as a major step following up on that promise, on 10 July the national government announced that the Deen Dayal Upadhyay Gram Jyoti Yojna program had commenced; this is the village electrification scheme, named after founder of BJP DD Upadhyaya. For the initial phase Rs.500 Cr (~US\$90 million) has been allocated.⁵

No doubt Modi was able to boast of some major successes as CM, but as PM he faces different challenges. In India, power comes under the “concurrent” list of duties. Modi will not be able to approach energy reforms the same way he did as CM because the central or federal government has a limited role to play. Most of the work will have to be done by the respective states. However, to date the states have not demonstrated that they have adequate organization, commitment, or resources to fix the energy infrastructure challenges in India. For instance, the rail system is insufficient to handle additional coal, environmental regulations are lacking, natural gas production is insufficient, and widespread electricity theft are just a few challenges that have plagued progress efforts to date.

One aspect that may make it possible for the federal government to break through previous bottlenecks is the nature of the sweeping victory that put Modi into power; this momentum makes it likely that Modi's BJP party may win four out of

five upcoming state elections, paving the way for more support at the state level for a transition in the energy sector. Currently Modi's ruling alliance is in power in six Indian states. With 10 or more friendly states, Modi may very well have the influence necessary to jumpstart energy-related changes. It may be the best chance a national-level leader has had to reform India's energy sector, but success is far from guaranteed.

MODI'S ENERGY GAME PLAN

About 60% of India's 249.5-GW installed power capacity is based on coal.⁶ The last 10 years have seen numerous conflicts between the power producers and the major coal producer, Coal India Ltd (CIL). To put it into context, on 18 June, 50% of Indian coal-fired power plants had reached a critical threshold: They had seven or fewer days of coal stockpiles on site—despite the fact that India has ample coal, over 286 billion tonnes of reserves. Per the current Five-Year Plan, ending in fiscal year 2016-17, production of coal is expected to rise to 795 Mt (million tonnes), but demand is expected to be 980 Mt.⁷ These estimates are based on a projected 6–7% growth rate in gross domestic product. To bridge this gap, India imports 12% of its required coal, primarily from Indonesia, Australia, and South Africa. This is in addition to its \$169 billion bill from oil imports.

“With 10 or more friendly states, Modi may very well have the influence necessary to jumpstart changes in the energy sector.”

Modi has a reputation for empowering his team to make decisions and then solidly backing them. One of Modi's first actions as PM was to combine the coal and power ministries and appoint a junior minister over both, Piyush Goyal. Similarly, the petroleum ministry is also headed by a junior minister. This strongly implies that the Prime Minister's Office (PMO) will be directly involved in these ministries. This first step is intended to reduce the amount of bureaucracy that could otherwise spell the failure of potential improvements in the energy sector.

Goyal—a banker turned politician—is devoting his time to fixing the communication gap among these ministries and training the officers to work collaboratively. In addition to other initiatives, Goyal is also trying to house top officers in

a single building to facilitate frequent meetings where they will hopefully identify synergies and reduce delays in decision making. With the single stroke that combined the coal and power ministries, Modi may well have taken the needed action to reduce the hugely problematic delays in energy projects. Now, with more involvement from the PMO, it is hoped that there can be more aligned thinking about how to deal with different fuel options, and thus avoid the problems associated with the slow decisions at the top level of the previous government.

Regarding the logistics supporting the coal industry, the new government is pushing to streamline rail connectivity to mines in remote and difficult-to-access areas; three new railroads could provide access to mines that could yield an estimated 300 million tonnes of coal each year.⁸ The new railway lines include 1) Tori-Shibpur-Hazaribagh (91 km), 2) Jharsuguda-Barpalli-Sardega (52 km), and 3) Bhupdeopur-Raigarh-Mand (180 km). Over the years construction of these lines has been delayed due to challenges related to land acquisition and environment-related clearances. Modi has asked the railway minister, D.V. Sadananda Gowda, to give timelines to his officers and make sure that these timelines are met.

Modi also plans to increase the participation of private players in the mining sector. A bill related to regulation of coal quality is likely to be tabled in the winter session of the Parliament, along with amendments to the Nationalization of Coal Act and Minerals and Mine Development Act. This would pave the way for participation of more private players in mining. There is also some movement around the concept that India must invest in developing the skillsets of mining professionals and also promote underground mining and clean coal technologies to support a more sustainable development of industries that produce and consume coal. The new government has hinted that it wants more R&D in developing coal-to-liquids (CTL), coal bed methane (CBM), and underground coal gasification (UCG). All this would require private and international players to move into the sector.

Given that Modi strongly supports fewer energy imports, without question he will be put an emphasis on the oil and gas sectors. Each year India imports crude oil and petroleum worth US\$169 billion and exports petrol and diesel worth US\$61 billion. Per recent projections, the country's consumption of petroleum products is increasing by roughly 9% annually. The best way to curtail the oil import-export imbalance is to export more, so Modi is planning to increase India's refining capacity by 25 MTPA in the next five years.

Moreover, the new government is looking at alternative sources of crude oil, especially outside the Middle East. With the U.S. importing much less oil from the international market

there is surplus of 350 million barrels of oil daily; India is tapping into these traders. India is particularly keen on looking at opportunities for sourcing oil and gas from North and Latin America, which will continue advancement of diversification. In addition, Modi's team is working to renew India's relationship with Russia with the goal to source more oil and gas—a prospect that may be more appealing to Russia after the recent events in and around Ukraine. Meanwhile, Modi has asked Pradhan to advance India's shale gas exploration to increase domestic production, which may commence by December of this year. The power supply companies ONGC and OIL are already working on this. A decision about a new gas price in the country should be announced sometime after September.

On the solar power front, Modi plans to have two types of new solar farms: 1) large solar farms or “ultra mega” solar power projects, with an installed capacity of more than 1000 MW, which can be connected to the grid and 2) smaller solar “republics”, which may not be connected to the grid but would allow access to electricity for some households that do not currently have such access. As CM, Modi supported innovation in the solar sector and Gujarat is one of the few states that utilizes solar energy to bridge capacity gaps during peak load. In the first budget presentation, Modi's Finance Minister, Arun Jaitely, allocated Rs.500 Crs (US\$90 million) to set up large solar farms in the Indian states of Rajasthan, Gujarat, and Tamil Nadu, as well as the Laddakh region of Jammu and Kashmir.⁹ This money will be routed through the Solar Energy Corporation of India as project capital. For the smaller projects to support solar pumps for irrigation, the government has set aside Rs.400 Crs (US\$75 million).⁹ To support these initiatives, it also reduced the import duty on various types of equipment required for both solar and wind energy.



Large and small solar power installations also have a role in Modi's energy plan.



Narendra Modi shakes hands with Pakistan's Prime Minister Nawaz Sharif on the day he was sworn in as Indian Prime Minister—26 May 2014 (Rex Features via AP Images).

DEALING WITH THE BEHEMOTH

In 2013-14, CIL produced 80% of the coal in India. Although the size of the company is impressive, it has been problem-ridden in recent years. Recently a presidential directive forcing CIL to sign fuel supply agreements was issued.¹⁰ The company refused to accept the decree. The fact that power plants are unable to obtain a reliable supply of fuel and that CIL has repeatedly missed production targets demonstrates the magnitude of the challenges.

What has been recently termed the “most probable” option by various market observers for dealing with the \$41 billion conglomerate would be to break CIL into smaller components through comprehensive restructuring. The end goal of such a move would be to make mining in the country more efficient. Over the years, red tape, strikes, protests against land acquisition, and delays in obtaining environmental approvals have kept coal output far below demand. There are two opposing sides within the Modi regime: Some fully support breaking up CIL, while others strongly oppose the idea. Those that favor a breakup may believe that any reform in the energy sector must begin with Coal India; they argue that it is critical to get state governments involved in energy-sector reforms, specifically the states where CIL operates. Some, however, believe it would be easier to effectively manage coal production on a state-by-state level.

As CM, Modi found value in breaking up the state electricity board, but somewhat surprisingly, now that most of the blueprints of the new government are on the table, the Modi-led national government wants to keep CIL intact. Minister Goyal seems to trust that most of the issues with the company can be fixed. In his view, one argument in favor of keeping Coal India intact is that this improves the stock market valuation of the company; as well, the current structure also helps the “synergy of operations, moving talent and expertise” from state to state as needed.¹¹ However, some have argued that the valuation of the company is based on the monopoly it enjoys, not on its performance. Transitioning CIL into a more successful enterprise will be difficult, to say the least. The company enjoys a near monopoly and has a tremendous amount of political power and has shown a strong will to resist reforms. Modi's leadership is likely to be tested, if not directly challenged, when dealing with CIL.¹²

In addition to finding a functional path forward for CIL, another reform being pushed by the coal minister is to increase the production and quality of coal. From now on there will be a third-party validation of quality. The state-run National Thermal Power Corporation (NTPC), which has the largest portfolio of coal-based power generation has locked horns with CIL on several occasions. The company has been directed to limit e-auctioning of coal to 25 million tonnes this year, down from 57 million tonnes, thus allowing more coal for generation of electricity.¹³

ENERGY NATIONALISM

Narendra Modi minced no words in letting the world know that he wants to reduce India's dependence on imports. India's current trade deficit is roughly US\$88 billion, with the major culprit being energy imports worth US\$185 billion, of which coal imports are a relatively minor US\$15.4 billion. The government is strongly inclined to rationalize the coal imports and increase production domestically. Perhaps as a first indication of the seriousness of such intentions, on 11 July, production began at a 12-million-tonnes-per-year mine. This was the first major mine start-up in India in the last five years, and was fast-tracked after the Modi government took over.¹⁴ This level of production is a drop in the bucket, but was Modi's way of showing his commitment to increasing domestic energy production. Still, the most challenging increases certainly lie ahead. Can Modi's government simultaneously improve the problems of the environmental impact, safety standards, and coal quality assurances that currently characterize coal production in India and increase production?

Rastriya Swayamsewak Sangh (RSS)—a think tank for the ruling BJP party—is also against such a large trade deficit, and believes that increased domestic production of coal will add to employment and would help the indigenous development of the country. In addition, it is likely that the government will ask all new power plants to install equipment (e.g., boilers and turbines) sourced from companies having manufacturing capabilities in India. This will likely benefit the Japanese, European, and U.S. companies having joint ventures in the country.

“India has long eyed the gas flowing through a pipeline from Bangladesh...”

India is also exploring a renewal of its relationship with Pakistan and Bangladesh. Specifically, India plans to sell 1200 MW of power, oil, products from HMEI's Bhathinda Refinery, and LNG through a planned pipeline to Pakistan.¹⁵ India has long eyed the gas flowing through a pipeline from Bangladesh, but to date no progress has been made on gaining access to the gas. Perhaps as a first step to advance many policy items, including energy, Modi invited state heads of all neighboring countries to his swearing-in ceremony, reviving most of these talks.

Expectations are high for Modi, especially within India's energy sector, but we will have to wait for at least a year to analyze which way the “hope” is moving. 🔄

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Developing High-Efficiency, Low-Carbon, Clean Coal in China

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In the last few decades, China has dramatically expanded access to energy and, as a result, has achieved nearly universal electrification. Although this accomplishment is notable, China's energy mix is facing several pressing issues with important domestic and global implications.

China is coal-rich and, for this reason, continues to rely on coal for the majority of its primary energy (over 70%), resulting in cost, reliability, and energy security benefits. However, coal resources are being consumed rapidly. China has built, and is continuing to grow, massive industries that hinge on the availability of coal; therefore, coal conservation through more efficient utilization is in the nation's best interest.

As with any country, energy security is an important issue for China. With few oil reserves, China relies on imports for a



China has achieved near full electrification in recent years, but the country's energy strategy is being revised.

large percentage of its oil, a fact that will be difficult to change as China's oil consumption continues to rise. Approximately 200 million tonnes of oil are produced domestically each year; experts have stated that this amount is a suitable volume for China's oil production and larger volumes could hinder future drilling operations.¹ China's annual oil consumption has reached 450 million tonnes, which means that China must rely on imports for more than half of its oil.

"We believe China's modernized energy development strategies must emphasize the deployment of polygeneration, which could offer energy efficiency, energy security, and environmental benefits."

In addition to national resource conservation and energy security issues, the environmental impact of China's energy production and utilization has become an increasingly pronounced global concern. One of the most problematic issues is the poor air quality in China's urban centers, which can be primarily attributed to two main factors: direct coal combustion without emissions controls and emissions from the combustion of transportation fuels.

The coal-fired power plants being built in China today are larger and more efficient than those of the past. However, many plants still operate at low efficiency and/or have minimal or no emission controls. In addition, direct combustion of coal in industrial applications or for household heating adds to the pollution. These factors contribute to the release of SO₂, NO_x, mercury and other heavy metals, and particulate matter (especially fine particulate matter such as PM_{2.5}).

The burning of transportation fuels is another key contributor to air pollution. The gasoline and diesel produced by China's oil refining industry have always had a relatively high sulfur content, which leads to increased production of particulate matter (including PM_{2.5}).



The Shanghai Waigaoqiao No. 3 power plant is one of the many high-efficiency power plants built in China in recent years.

Another environmental concern is climate change. If the future rise in global temperatures is to be limited to 2°C, some experts have projected that global CO₂ emissions in 2050 would need to be about 50% lower than those in 1990.² China has overtaken the U.S. as the world's largest CO₂ emitter with about seven billion tonnes released each year, which means that China's actions are pivotal to achieving success in mitigating climate change. For this reason, China is under tremendous international pressure to reduce its emissions.

Even with developed countries committed to reducing their emissions by 80%, developing countries would still need to bring down their overall emissions to 36% below 2005 levels. Coal combustion and burning transportation fuels are the main sources of CO₂ emissions in China. Although China has strengthened efforts on energy conservation and the development of nuclear and renewable energy, China's CO₂ emissions are expected to continue increasing; China must also be practical about reducing emissions as it remains a developing country. Therefore, China should be proactive about how best to address emissions reductions with solutions that can be realistically implemented.

While air pollution and climate change are very real concerns, China's energy mix and infrastructure cannot be drastically modified in the short term, so strategies to improve the efficiency of coal utilization and improve transportation fuel quality have become an important topic.

Optimized approaches to coal utilization in a high-efficiency, low-carbon, cleaner manner, including producing cleaner

transportation fuels from coal, could be the solution to the myriad concerns facing China's energy industry. Although there are many approaches to cleaner and more efficient coal utilization, we believe the most valuable option that addresses all the problems explained is gasification of coal to produce chemicals, fuels, power (i.e., polygeneration), and eventually carbon capture, utilization, and storage (CCUS).

APPROACHES TO COAL'S ROLE IN HIGH-EFFICIENCY, LOW-CARBON, CLEAN ENERGY

Several clean and efficient coal conversion methods are currently under development or already available.

Carbon Capture, Utilization, and Storage

Ultimately, the lowest-carbon use of coal is tied to capturing and storing CO₂. China's CCUS strategies should be implemented after considering the impact to China's economy, energy infrastructure, and also the unique opportunities possible to China because it is still growing. We believe China should develop its own technologies and not simply follow the paths chosen by other nations. China's CCUS strategies have potential; the key challenge is how best to coordinate and manage overall efforts.

The costs associated with CCUS are, in part, tied to the cost of the CO₂ capture, which can vary dramatically between different coal utilization options. In terms of power generation, there are two main focus areas for clean coal technology development in China. The first is high-efficiency supercritical and ultra-supercritical coal-fired power plants and the other is gasification [for power production this entails integrated gasification combined cycle (IGCC)].

High-Efficiency Power Plants

China's state-of-the-art high-efficiency power plants are some of the best in the world; these plants produce less CO₂ compared to less efficient subcritical plants and are an important first step in reducing CO₂ emissions.

An example of one such plant is Shanghai Waigaoqiao No. 3 power plant. At 75–81% capacity this plant has an average coal consumption rate of 276 g/kWh (including desulfurization and denitrification—an actual annual efficiency of 44.5%). This compares favorably with China's current average coal consumption for power generation, 330 g/kWh, as well as with the world's most efficient power plant, the 400-MW Nordjylland Power Station No. 3 in Denmark, with double reheat and cold seawater cooling units. At a capacity of 75%, the coal consumption rate at Nordjylland is 288 g/kWh.

China's 600°C ultra-supercritical plants are constructed using expensive imported materials that account for 50% of the cost of a 1000-MW boiler. Increases in temperature and pressure would require even higher-standard materials. Furthermore, in direct coal combustion, collecting CO₂ from the flue gas comes at a relatively high cost; much more research and development is needed to bring down costs.

Therefore, even though the development of high-efficiency coal-fired power plants is vital and will assuredly continue, notable challenges still exist and we believe this should not be the only option pursued by China.

Approaches Made Possible Through Gasification

Compared to high-efficiency coal-fired power plants, IGCC is at an early stage of development and, thus, may offer greater potential for improvements in terms of power generation efficiency. As IGCC also has unique advantages in terms of capturing emissions and can be coupled with polygeneration to reduce construction costs, it is worth further development.

Capture of emissions from a gasification system, including IGCC power plants, differs because it occurs upstream of power generation at a higher concentration and/or pressure. For a conventional power plant, CO₂ capture will reduce the plant's efficiency by about 11%; for an IGCC power plant, the efficiency loss for CO₂ capture is less, about 6–7%. Although the efficiency is high and the capture of emissions is simpler, there is a substantial upfront investment for IGCC, RMB12,000/kWh (US\$1900/kWh).

Thanks to many years of demonstration and commercial use, the reliability of IGCC plants has been gradually increasing. Still, in addition to the costs, another major issue with IGCC plants is that most such plants are not suitable for variable load operation.

For the sole purpose of power generation, gasification is not economically competitive in China and, in our opinion, therefore not currently a suitable solution for widespread deployment. Even so, with the aspiration of bringing down costs, some demonstration and deployment of IGCC is proceeding in China. For instance, the Huaneng Group has built and operated a 265-MW IGCC power plant in Tianjin under the GreenGen project.

Another important clean coal technology that employs gasification is polygeneration, which can be used to combine coal-to-chemicals/fuels and IGCC. In a polygeneration process, coal can be combined with wind, solar, biomass, etc., in a variety of configurations to produce a wide array of products (including chemicals, fuels, electricity, etc.). Of course, one potential product of polygeneration systems could also

be low-sulfur transportation fuels—leading to energy security and environmental benefits. Importantly, polygeneration technology does not require major technical breakthroughs. It is based on existing, proven technologies and thus has much potential to advance the clean and efficient utilization of coal, making it an important direction for development.

Polygeneration allows for plants to be highly integrated and for the overall energy and materials flow to be optimized. With a single-product gasification process, the coal savings for parallel systems at the same facility is minimal. However, integrated serial systems at a polygeneration facility with multiple products can save a significant amount of coal. In fact, the efficiency of an integrated serial system can reach 45.5% without the CO shift. The water consumption per unit power produced for polygeneration systems is also lower than that of conventional power plants.

As the technology advances, the efficiency of polygeneration technologies can be further enhanced. For example, the efficiency of gasification systems with high-temperature syngas cleanup can be raised to 49.3%. When ionic membrane oxygen separation technology is employed, the system efficiency can be raised to 50.1%. For 1700°C-class gas turbines efficiency can reach 53%. Finally, coal-water slurry preheating technology gasification systems can offer efficiencies of 57.3%. Overall, coal-based polygeneration systems have tremendous potential for using coal cleanly and efficiently, particularly when power and chemicals are both produced.

If China does not expand outside only the traditional technological approaches to coal utilization (i.e., direct combustion), we believe this could lead to a series of problems related to the environment and greenhouse gas emissions. Therefore, from this point forward we believe China's modernized energy development strategies must emphasize the deployment of polygeneration, which could offer energy efficiency, energy security, and environmental benefits.

PRESSING NEEDS UNDER A STRONG POLYGENERATION ENERGY STRATEGY

Under China's current energy constraints and challenges, the synergetic use of coal with other energy sources is needed. We believe this integration is the key to low-carbon development in China and also to utilizing different energy sources in the most appropriate way possible. Polygeneration offers unique opportunities to use coal more efficiently, integrate coal energy systems with alternative energy sources, and dramatically reduce CO₂ emissions (see Figure 1). In order to achieve better synergy, a smart energy network must be established, which will allow the integration of information technology within energy systems to optimize the flow of energy in China.

Polygeneration With Chemical Products

Considering the high costs of IGCC power generation, when taking into account the future requirements for controlling emissions, including SO₂, NO_x, particulate matter, and mercury, as well as CO₂, the best approach today is to reduce costs through chemical product polygeneration.

China has recently built several hundred gigawatts’ worth of pulverized coal supercritical and ultra-supercritical generating units. These high-efficiency plants can be refitted with CO₂ capture in the future. CCUS can also be applied to polygeneration facilities, which offer the lowest-cost option for CO₂ capture and could be used to support demonstrations of CO₂ utilization and storage in the near term. As it takes time for an energy process and systems to develop and mature, if the polygeneration model is not promoted now, the delay could mean paying a higher price in the future.

In terms of energy security, the liquid fuels produced by coal-based polygeneration, particularly methanol and dimethyl ether, are excellent coal-based alternatives for transportation fuels and can help alleviate China’s oil shortage with much-needed low-sulfur fuels. At the same time, methanol can be used to produce polyethylene and polypropylene, an example of using coal-to-chemicals to replace a portion of conventional petrochemicals—again reducing oil imports.

China has already mastered the leading polygeneration technologies including large-scale coal gasification, which has been successfully demonstrated in industrial applications. For example, the Yankuang Group’s IGCC and methanol

polygeneration unit in Shandong is a global first-of-a-kind and has demonstrated long-term, stable operation. This system operates with an efficiency of up to 57.16%, which is 3.14 percentage points higher than has been achieved by independent coal-to-methanol and IGCC systems in China.³ Its power conversion efficiency is as high as 39.5%. As long as the various sectors in China (coal, chemical, and power) are able to break the barriers to cooperation, along with international cooperation, we can tap the potential of polygeneration to improve energy efficiency and reduce emissions.

Synergy With Renewables

China’s wind power capacity ranks first in the world, but about 30% of the wind turbines installed in China are off-grid. Even some of the on-grid wind farms are restricted in their power generation for various reasons, which results in wasted energy.

China now looks to find a way to deploy wind on a larger scale without adversely impacting the overall energy served by other sources. One strategy worth exploring is increased synergy between wind energy and the rapidly developing coal-to-chemicals as well as the proposed polygeneration sector. In China, remote areas are often rich in wind and coal; this remoteness poses challenges related to coal transportation as well as power transmission, but offers opportunities for synergistic energy utilization.

An example of a potential solution to using remote resources, including clean energy, is taking advantage of synergy between wind power and methanol production. The basis of such a concept is to use off-grid wind power to carry out electrolysis of

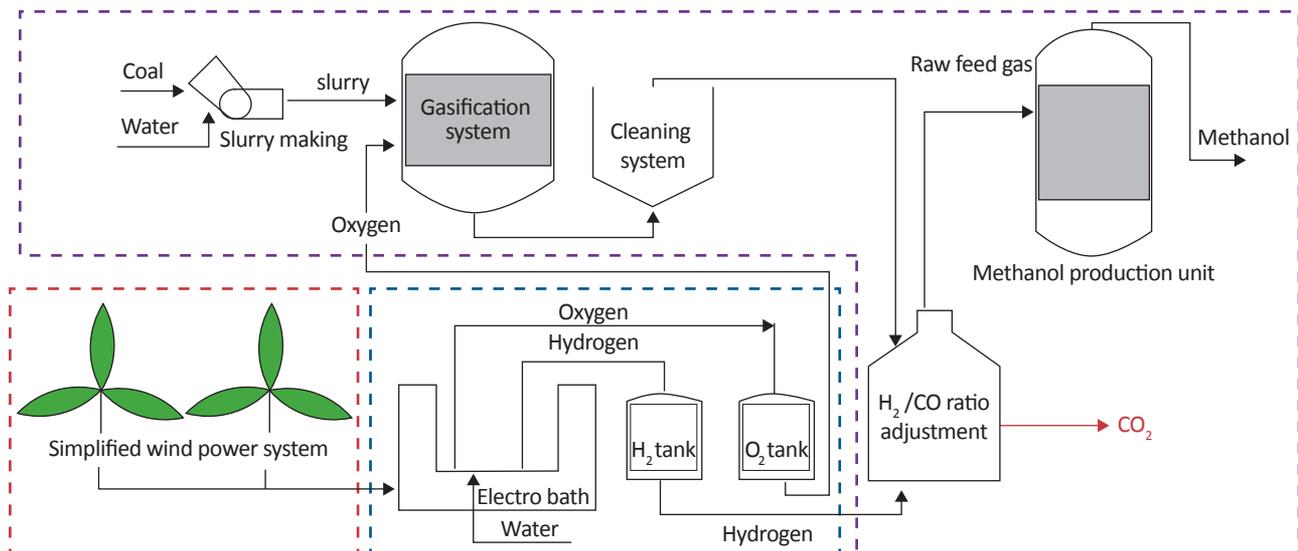


Figure 1. Coal can be integrated with renewable energy sources through gasification; in this example methanol can be produced with a CO₂ stream ready for CCUS.

water (i.e., breaking down water molecules to produce oxygen and hydrogen). The oxygen can be supplied to a gasifier and the hydrogen can be added to carbon-rich syngas produced by a coal gasifier. The ratio of H₂ to CO can thus be adjusted to the appropriate level for methanol production. Compared to conventional coal-based methanol production systems, this integrated system eliminates the need for an expensive and energy-intensive air separation unit, which greatly reduces the amount of gas conversion. With the same amount of coal, the synergetic solution produces twice the amount of methanol. Most of the carbon molecules from the coal are used in the methanol products, thus significantly reducing CO₂ emissions and thereby achieving the best overall results in the use of energy and resources. This is an example of a solution for the problems of wind energy application and that of substantial CO₂ emissions.

Recently, many large cities have been eager to obtain more clean energy, leading many areas that are rich in coal resources (particularly the remote areas of Xinjiang in Western China) and large corporations to turn their attention to a new industrial chain for synthetic natural gas (SNG). Although the energy efficiency of converting coal to SNG is only about 60%, long gas pipelines are more efficient than transporting coal over long distances. In terms of end application, since it is a clean, gaseous fuel, it can be used in a variety of advanced energy systems, technologies, and equipment (such as distributed energy and combined heating, cooling, and power production) for more efficient applications. In this way, the full industry chain may reap the benefits of improved overall energy efficiency and reduced CO₂ emissions. However, the key issue regarding the emission and treatment of CO₂ generated from converting coal to SNG remains. Similar to the example with the methanol plant, if wind can be used to produce the oxygen and hydrogen from the electrolysis of water, the amount of SNG produced per unit coal could be multiplied, thus significantly reducing CO₂ emissions.

Looking at the energy system as a whole, this type of synergy is worth in-depth research to resolve issues surrounding essential technical questions. Testing should take place as soon as possible, and from there, demonstration and deployment should be promoted to minimize the end cost of meeting energy security, energy efficiency, and environmental objectives.

CO₂ Emission Reductions from the Coal-to-Chemicals Industry

China should pave its own way according to the country's actual situation and reconsider how to reduce its CO₂ emissions in phases from this point forward. China is currently

making great efforts to develop the coal-to-chemicals sector (e.g., methanol, dimethyl ether, methanol-to-olefins [MTO], methanol-to-propylene [MTP], direct coal liquefaction, and indirect coal liquefaction). The CO₂ released during these processes is already highly concentrated and pressurized and today most of this capture-ready CO₂ is released directly into the atmosphere. China emits more than 40 million tonnes of CO₂ from methanol production alone. Therefore, reducing CO₂ emissions in China should begin with the coal-to-chemicals sector. We believe China should establish supportive policies such as carbon taxes and subsidies, and gain experience in CO₂ capture from this process (chemical and physical applications, transportation, storage, etc.). The knowledge gained from studying CO₂ emissions reductions in China's coal-to-chemicals sector could be directly applied to polygeneration systems.

CONCLUSIONS

Considering the future of cleaner energy in China, coal-fueled polygeneration as a product should be demonstrated, with gradual advancement toward large-scale development, after which CCUS should be implemented according to CO₂ reduction requirements.

As explained, collecting CO₂ from conventional power plant flue gas requires a tremendous amount of energy resources and investment. We believe China must also conduct research and small-scale demos in this area, but further observation is needed before large-scale commercial implementation.

Coal will remain a driving force in China's future energy mix. It is difficult to find suitable alternatives. Through the gasification of coal (or petroleum coke) and subsequent chemical synthesis, the polygeneration of electricity, liquid fuels, chemicals for products, heating, syngas, etc., can be achieved. In addition, synergetic integration of coal with renewable energy can help to meet overall energy requirements, alleviate liquid fuel shortages, and reduce coal combustion emissions and other energy-related issues simultaneously. From a technical perspective, polygeneration has been demonstrated, including the economic benefits and environmental capabilities, and thus carries great strategic significance for China and the world. 🌍

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A Coal-Based Strategy to Reduce Europe's Dependence on Russian Energy Imports

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"Can Europe stop buying Russian gas? In my opinion it is impossible." – Vladimir Putin¹

Europe is dangerously dependent on Russian natural gas (NG): 13 European nations rely on Russian NG for over 50% of their requirements (see Figure 1). In addition, Europe relies on Russia for about one third of its oil imports.

Europe is acutely aware of this high level of energy dependence, which has been, once again, highlighted by the Ukrainian crisis. The European Council March 2014 Brussels Summit Meeting focused on Europe's energy dependence on Russia, especially for NG.² The Summit recommended that efforts be intensified to reduce Europe's gas energy dependency and that the EU accelerate diversification of its energy supply. However, via a carefully thought out strategy, Europe can significantly reduce its dependence on Russian energy supplies through greater utilization of clean coal.

EUROPE'S NATURAL GAS PROBLEM

The International Energy Agency (IEA) forecasts that Europe's NG production is likely to gradually decline while consumption increases, and the need for imports thus increases over the

next two decades (see Figure 2). Given current trends, the EU will import over 80% of its NG needs by 2030, and the gap between consumption and production will continue to widen.³ Shale gas may be available for incremental production, but no major forecasting agency is projecting significant European shale output for the foreseeable future. High population density, a lack of mineral rights ownership, public opposition, and unique geology are the main impediments.

"Europe can significantly reduce its dependence on Russian energy supplies through greater utilization of clean coal."

Without sufficient production, Europe has historically imported NG, but an increasingly tight global market may make it difficult to reduce reliance on Russian NG. World LNG demand is forecast to grow strongly over the next two decades, especially in Asia—where prices are already the highest. China is in the process of dramatically increasing its LNG import capacity, and some believe that China could become the major driver of demand in the international gas market.⁴

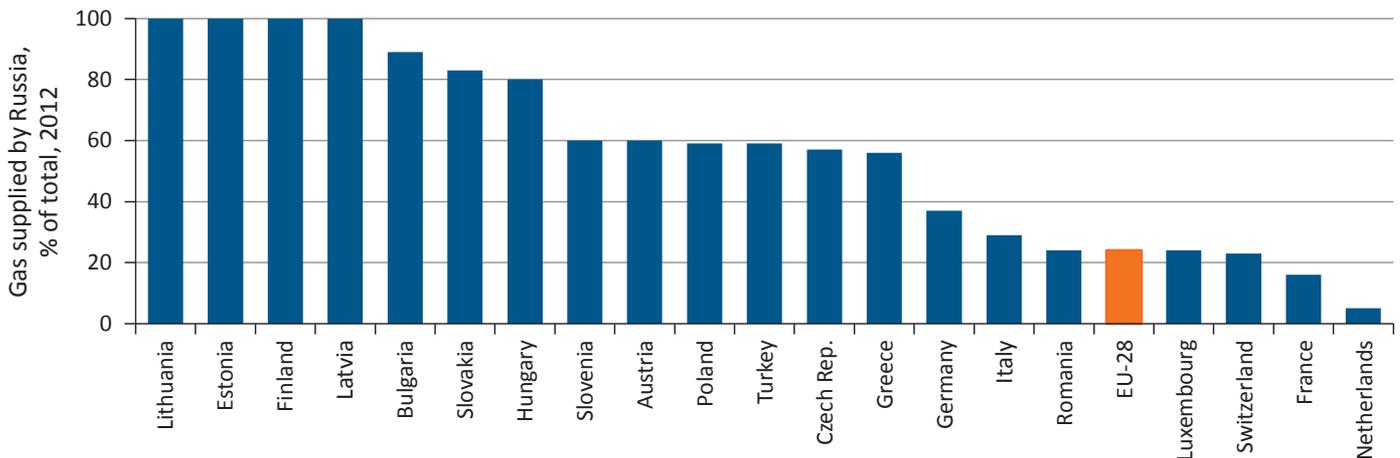


FIGURE 1. European reliance on Russian NG

Source: Eurogas

Note: Belgium, Croatia, Denmark, Ireland, Portugal, Spain, Sweden, and Britain have negligible gas imports from Russia

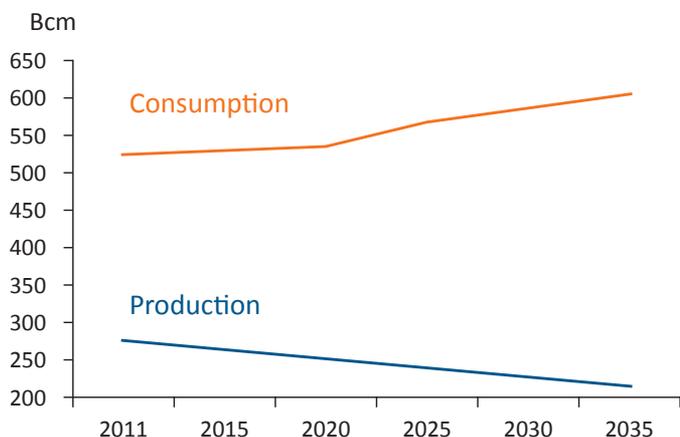


FIGURE 2. Forecast European NG consumption and production
Source: IEA

European LNG prices will continue to increase, and forecasts of U.S. LNG prices in Europe are in the range of \$13–14/MMBtu (2013\$) by 2025.^A NG prices are likely to continue to trend higher than projections because 50% of Europe’s current gas is price indexed to oil.^B LNG at \$11–13/MMBtu for Europe is highly optimistic: Oil-indexed NG prices (2012\$) could exceed \$14/MMBtu within a decade, and this implies that in current (nominal) dollars NG prices could be in the range of \$20–25/MMBtu.

IDENTIFYING OTHER OPTIONS

The EU’s share of global energy resources—about 3%—is relatively small.⁵ Out of the EU’s total resources, supplies of coal and lignite are the largest component, comprising 88% of energy reserves and 95% of resources (see Figure 3). Accordingly, the EU’s endowment of coal is orders of magnitude larger than that of oil and gas combined.⁵ In fact, the EU has a 97-year supply of coal, but just a 12-year supply of oil and gas.⁶ Initiatives that increase the use of coal will thus diversify Europe’s energy sources and enhance its energy security.

Although Europe is still a large coal producer, it supplements its coal production with coal imports.⁷ Russia and Colombia are the two leading sources, with each furnishing about 25% of Europe’s coal imports. The U.S., Australia, Indonesia, and South Africa are also major suppliers.

Through the deployment of two clean coal initiatives the EU can achieve major progress toward its energy security and international treaty objectives: 1) In the near term, bring 21 GW of idled coal-fired electric power capacity back into service and displace significant quantities of imported NG; 2) for the longer term, build gasification-based coal-to-gas (CTG) substitute NG (SNG) plants and use the captured CO₂ for enhanced oil recovery (CO₂-EOR) in the North Sea. If implemented, these

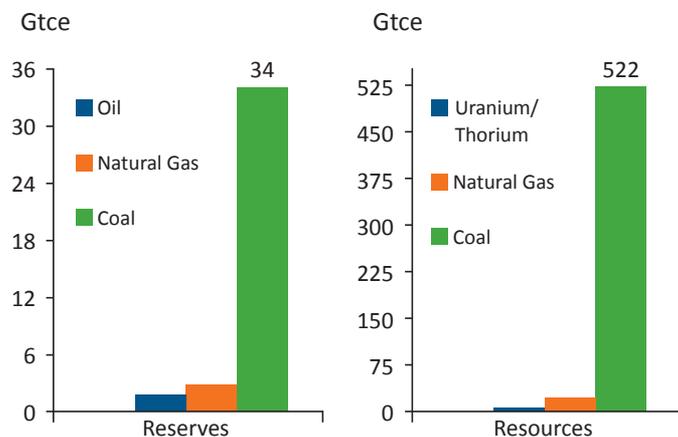


FIGURE 3. Comparative energy supplies in the EU
Source: BGR and DERA Rohstoffinformationen

proposals would provide economic, energy security, and environmental benefits to the EU.

A NEAR-TERM OPPORTUNITY

In Europe, there are currently over 21 GW of recently idled coal power plants that could be brought back online relatively quickly. Nearly half of this idled capacity is in the UK, over one third is in Germany, and 12% is in the Netherlands, with lesser amounts in France, Italy, and Spain (see Table 1).

Increased coal utilization would displace significant NG in the electric power sector and would be an expeditious means of reducing Europe’s current high dependence on Russian NG. This initiative supports the EU’s energy security objectives per the European Commission’s recommendation to begin “increasing EU energy production and diversifying external supplies”.⁸ Thus, restarting recently retired coal plants is an attractive near-term opportunity for reducing the EU’s dependence on Russian gas imports, for the following reasons:

1. If the 21 GW of coal generation was brought back online,

TABLE 1. Retired coal plants

Country	Retired Plants (MW)	Percentage of Total (%)
France	1155	5
Germany	7977	37
Italy	383	2
Netherlands	2658	12
Spain	345	2
UK	8856	41
Total	21,374	100

- EU gas demand would decrease by 2–3 bcf/day.
2. Despite the institutional barriers, this initiative represents the easiest, quickest, and most economical way for the EU to reduce its dependence on Russian gas.
 3. Restarting retired coal plants would require relatively limited capital compared to, for example, building new LNG terminals and infrastructure.
 4. Coal demand would increase by about 40–50 million tonnes annually, but excess coal import capacity already exists in Europe to accommodate this increased demand.

Many of these retired coal plants were initially removed from service because it was deemed that retrofitting them with environmental controls was not cost-effective at the time. Therefore, it may be necessary to add more SO₂ and NO_x controls, and perhaps other environmental upgrades, to the units. These would require about a year to design and 6–10 weeks to install. However, the plants could operate before the upgrades are completed if they use low-sulfur coals. The upgrades would likely cost in the range of €75–400 million per facility. Thus, upgrading all of the units would likely cost in the range of €5–9 billion. Assuming that the plants would go back online over the five-year period 2016–2020, this would involve capital expenditures of about €1–2 billion per year.

“An aggressive CTG initiative will assist Europe in diversifying its energy supply and ensure that Europe’s gas dependency on Russia is eliminated by 2030.”

Bringing the 21 GW of idled coal capacity back online would eventually result in requirements for an additional ~45 million tons (Mt) of coal annually. The ramp-up in demand would occur over the period 2016–2020, and would remain constant after 2020. The increase could be satisfied using Europe’s indigenous coal resources, increased imports, or some combination of the two. This initiative will displace about 5% of Europe’s current NG consumption—nearly 15% of Russian gas imports.

JUMP-START COAL-TO-GAS

Today there is strong momentum to “[e]nsure that efforts to reduce Europe’s high gas energy dependency rates are intensified, and to accelerate further diversification of its energy supply.”⁸ An aggressive CTG initiative will assist Europe in

diversifying its energy supply and ensure that Europe’s gas dependency on Russia is eliminated by 2030. IEA notes that “[c]oal gasification is a versatile conversion technology adding flexibility to energy systems, and there is a huge potential for coal gasification worldwide.”⁹ Specifically, there is much to recommend about CTG:¹⁰ It is a proven process, allows flexibility in feedstocks, allows conversion of carbonaceous feedstocks into high-value products (such as SNG), facilitates CO₂ capture, and decreases energy import dependence.

Basic CTG plant parameters are given in Table 2, which indicates that if feasibility studies begin in January 2015, the first plants would be operational by mid-2023. Thereafter, the plant schedules could be accelerated by mid-decade and then wound down by 2030 (see Figure 4); by 2030 all 45 CTG plants that are needed could be completed.

To fuel all the proposed CTG plants, incremental coal requirements would total 20 Mt annually by 2024, and reach over 150 Mt by 2030. Again, this fuel could be from Europe’s indigenous resources or from sources that are stable and friendly to European interests.

Gasification CTG SNG facilities can come with a high initial price tag, but the economic benefits can also be substantial. CTG SNG is price competitive with LNG and Russian NG; therefore, reducing reliance on Russian NG can also offer the economic benefits associated with less expensive NG. As shown in Figure 5, under a range of assumptions, in 2025 CTG SNG is price competitive with Russian NG, imported LNG, and NG indexed to the price of oil.

TABLE 2. Basic CTG plant parameters

<i>Total CAPEX (2014US\$ million)</i>	
Facilities’ costs	4200
Owners’ costs	550
Financing costs	1084
Escalation	651
Total as-built	6485
<i>Project Schedule</i>	
Feasibility start	Jan 2015
FEED start	Jan 2016
Construction start	Jan 2019
Full operations	Jun 2023

Notes: CAPEX = capital expenses; FEED = front-end engineering design

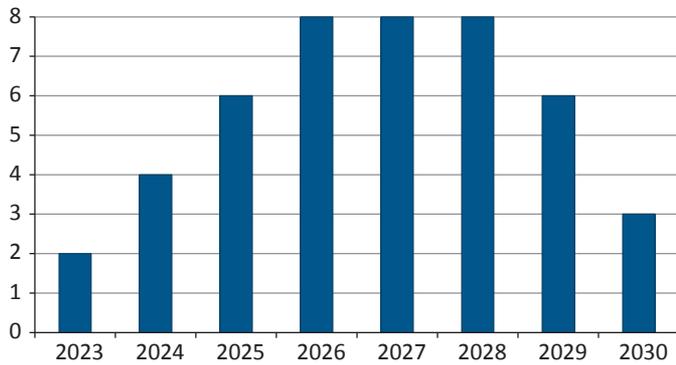


FIGURE 4. Number of CTG SNG plants to be completed annually

CO₂-EOR IN THE NORTH SEA

CO₂-EOR provides the dual benefits of tertiary oil recovery and effective long-term CO₂ storage with nearly 100% of the initially acquired CO₂ for CO₂-EOR operations stored at the end of injection.^{11–13}

The UN, G8, EU, EC, UK, and others have recognized carbon capture and storage (CCS) as a critical source of the CO₂ required for CO₂-EOR. Studies indicate that CCS deployment around the North Sea region could play a significant role in providing low-cost, low-carbon, and secure energy for Europe and have identified the enormous potential of the North Sea for CCUS through CO₂-EOR.^{12,14,15} CCS can be implemented through the CTG plants proposed here (CTG CO₂-EOR).¹⁶

There is, thus, strong rationale for CTG CO₂-EOR in the North Sea:¹⁷

1. It can utilize the vast oil and gas infrastructure already in place.
2. There are decades of experience with the technology.
3. There is less public opposition for CO₂ storage offshore.

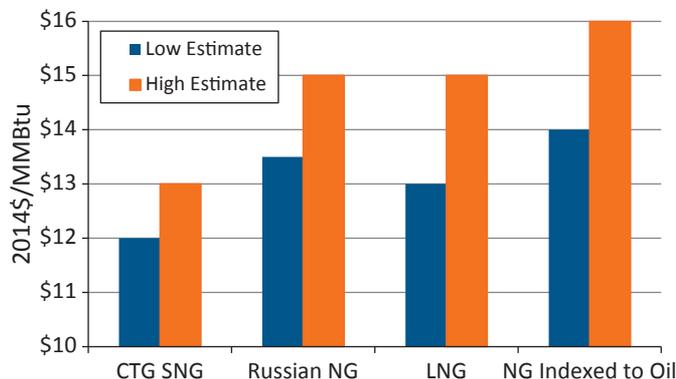


FIGURE 5. Estimated 2025 prices in Europe

Sources: EIA, IEA, EC, SEEC, and MISI

4. The North Sea has the largest carbon storage potential in Europe—enough to store Europe’s CO₂ emissions for many decades.
5. There are more than five billion barrels of oil available for CO₂-EOR.
6. The North Sea requires huge amounts of CO₂ for CO₂-EOR.

By 2030, the CTG SNG plants will produce a cumulative total of about 1.2 billion tons of CO₂ for North Sea EOR (see Figure 6). Assuming that CO₂-EOR revenues are \$10–15/ton CO₂, cumulative CO₂ revenues (2023–2030) total \$12–18 billion (€8.8–13.2 billion).^c By 2030, CO₂ production from the CTG plants would total 293 Mt/yr. Assuming a 2030 CO₂-EOR average price of \$15/ton CO₂, such revenues by 2030 will total about \$4.4 billion annually (€2.9 billion).

Under the CTG SNG CO₂-EOR initiative, 4.7 billion barrels of EOR oil are cumulatively produced from the North Sea through 2030. This represents more than 80% of identified EOR production potential. Assuming oil prices escalate from \$100/bbl to \$150/bbl (2014\$) by 2030, cumulative CO₂-EOR revenues (2023–2030) total about \$600 billion (2014\$), or about €441 billion.

If we assume that the idled coal plants come back online over 2016–2020 and the CTG SNG plants come online 2023–2030 the reduction in dependency on Russian NG can be estimated. If the two proposed coal initiatives were to be fully implemented, Europe’s dependence on Russian gas imports would begin to decline in 2016 as the first idled coal plants come back online; this decline would continue through 2020 as all of the 21 GW of coal capacity is brought back into service. Between 2015 and 2020, Europe’s reliance on Russian NG would decline from about 34% to less than 30%; it would remain at this level until 2023, when it would begin to decline again as the first CTG SNG plants come online. Thereafter, this dependence would decline rapidly as more CTG plants come online every year, and by 2030 it would decrease to a net of zero (see Figure 7).

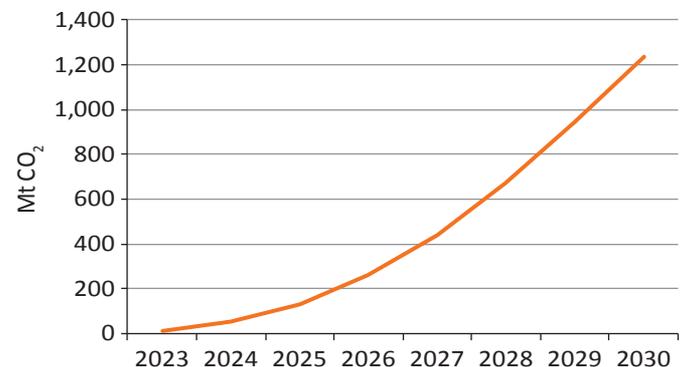


FIGURE 6. Cumulative CTG CO₂ for North Sea CO₂-EOR

Source: MISI

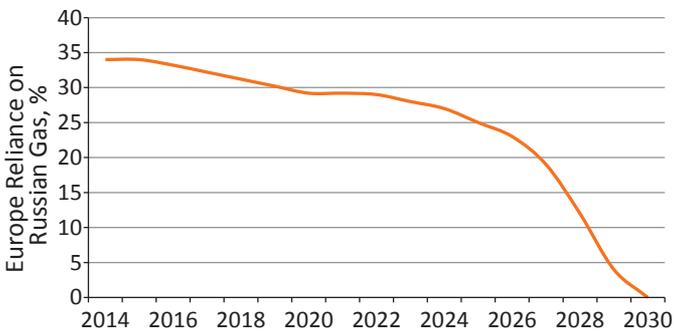


FIGURE 7. Europe’s reliance on Russian NG under both coal initiatives

Sources: Eurogas and MISI

Thus, by 2030 the two coal initiatives can entirely eliminate European dependence on Russian NG. Further, the scheduled certainty of reduced gas dependence resulting from the coal initiatives will immediately increase Europe’s energy security and bargaining power. This is critical and supports the EC’s objectives as stated at the March 2014 Summit and in the May 2014 EC European Energy Security Plan.^{2,8}

REDUCING DEPENDENCE ON RUSSIAN OIL IMPORTS

The EU imports 90% of its crude oil requirements; about one third of the imports are from Russia.⁸ The CTG/SNG/CO₂-EOR initiative proposed here can significantly decrease the EU’s dependence on Russian oil imports. Oil production from CTG North Sea CO₂-EOR grows rapidly starting in 2023, and by 2030 totals over 1.1 billion bbl/yr annually (see Figure 8). Assuming that without the CO₂-EOR initiative Russian oil imports will continue to comprise about one third of the EU’s total allows us to estimate the potential impact of CTG North Sea CO₂-EOR on Europe’s dependence on Russian oil imports.

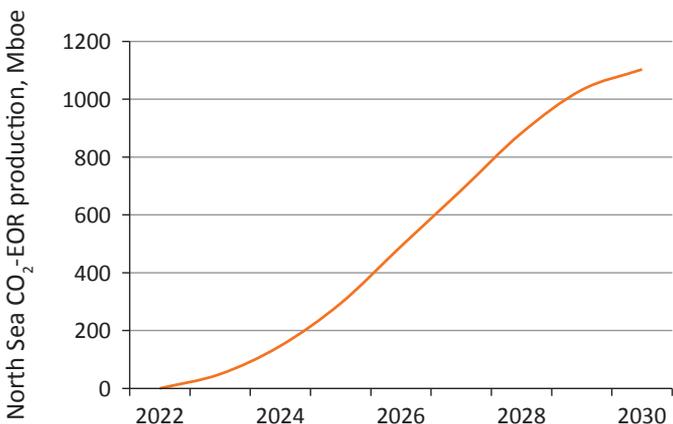


FIGURE 8. Annual CTG North Sea CO₂-EOR production

Sources: IEA and MISI

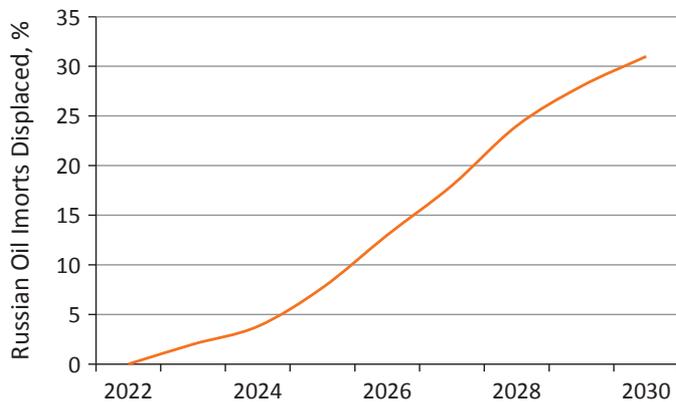


FIGURE 9. CTG North Sea CO₂-EOR displacement of Russian oil imports

Sources: IEA and MISI

As shown in Figure 9, oil production from North Sea CO₂-EOR could begin to reduce Europe’s dependence on Russian oil imports in 2023, after which the displacement of Russian oil imports increases rapidly. By 2030, it displaces nearly one third of Russian oil imports.

ENVIRONMENTAL IMPLICATIONS

In addition to the economic and energy security benefits, the two initiatives are compatible with EU climate goals. These initiatives will not increase GHG emissions from power generation in Europe. Since the CTG SNG CO₂ emissions can be captured at the plant level, CTG SNG life-cycle GHG emissions compare favorably with Europe’s other alternatives: shale gas, imported Russian NG, and imported LNG (see Figure 10).

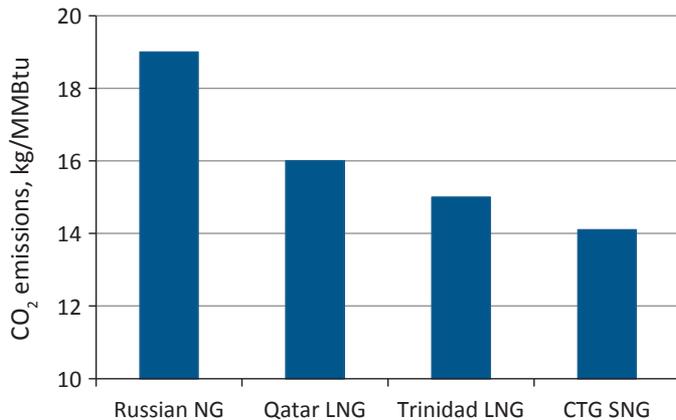


FIGURE 10. Comparative life-cycle GHG emissions

Sources: Carnegie Mellon University, U.S. Department of Energy, National Energy Technology Laboratory, U.S. Environmental Protection Agency, Climate Mitigation Services, Inc., ConocoPhillips, Taglia, Rossi, Altran Italia, and MISI

OVERCOMING THE CHALLENGES

The recent events that have occurred in Eastern Europe have highlighted the need to reduce dependence on Russian imports. The two initiatives proposed in this article could lead to a major advancement in Europe's energy security. Undoubtedly, implementation of these initiatives would meet with opposition as some would protest any increased deployment of coal in Europe. However, I believe that the reduced greenhouse gas footprint of the CTG SNG, the economic revenue generated from production of domestic European oil, and the energy security benefits are too important to be ignored. Whatever institutional challenges exist, they are worth overcoming. 🏠

NOTES

- A. According to Bernstein Research: "We believe that markets are underestimating demand and overstating supply. The LNG market looks tight to us through 2020." Robinson, J. (2014, 3 April). Global LNG market to remain tight through 2020: Bernstein Research. Platts, www.platts.com/latest-news/natural-gas/houston/global-lng-market-to-remain-tight-through-2020-21427366
- B. One problem has been sunk demand, so companies that must buy high-price long-term contracts are feeling pressure and want to change terms. The suppliers, however, want to continue oil indexation because they obtain guaranteed prices and can cover the high cost of infrastructure. It is thus a hybrid pricing system in Europe for NG, but oil indexation is not about to disappear. As Joseph Geagea, President of Chevron, notes: "Crude oil projects dictate the cost of LNG projects. The same drilling rigs, the same engineering contractors and the same labor force as are used in the oil industry are used to build LNG projects." Iwata, M. (2012, 5 December). Chevron: Most LNG prices to remain linked to oil. Wall Street Journal.
- C. The conversion factor used was based on the June 2014 exchange rate of €1 equal to \$1.36.

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The Reliability and Resilience of the U.S. Existing Coal Fleet

By Janet Gellici

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In May 2014, the members of the National Coal Council (NCC) completed a study for the U.S. Secretary of Energy that assessed the value of the nation’s existing coal generation fleet and identified measures to improve its reliability and efficiency while reducing emissions. This fleet of existing power plants underpins economic prosperity in the U.S., providing direct socioeconomic benefits, energy and price stability, environmental progress through continuous technology advancements, and job creation opportunities. Too often the merits of investing in our current assets as well as the opportunities that abound to further enhance the value of those assets are overlooked. In fact, there exists a wide array of options where investment in this fleet is worth considering.

NATIONAL COAL COUNCIL STUDY MISSION

The NCC is a federally chartered advisory group to the U.S. Secretary of Energy, providing advice and recommendations

to the Secretary on general policy matters relating to coal and the coal industry. During its 30-year history, the Council has prepared more than 30 reports for the Secretary on topics ranging from carbon management to coal exports to utility deregulation.

“Only the availability and operation of coal units scheduled for retirement over the next two years enabled the power sector to meet demand during periods of harsh weather events.”

In January 2014, Energy Secretary Ernest Moniz requested that NCC undertake a study detailing what both industry and the U.S. Department of Energy (DOE) could do to facilitate enhancing the capacity, efficiency, and emissions profiles of the existing coal generation fleet in the U.S. through application of new and advanced technology. This article provides

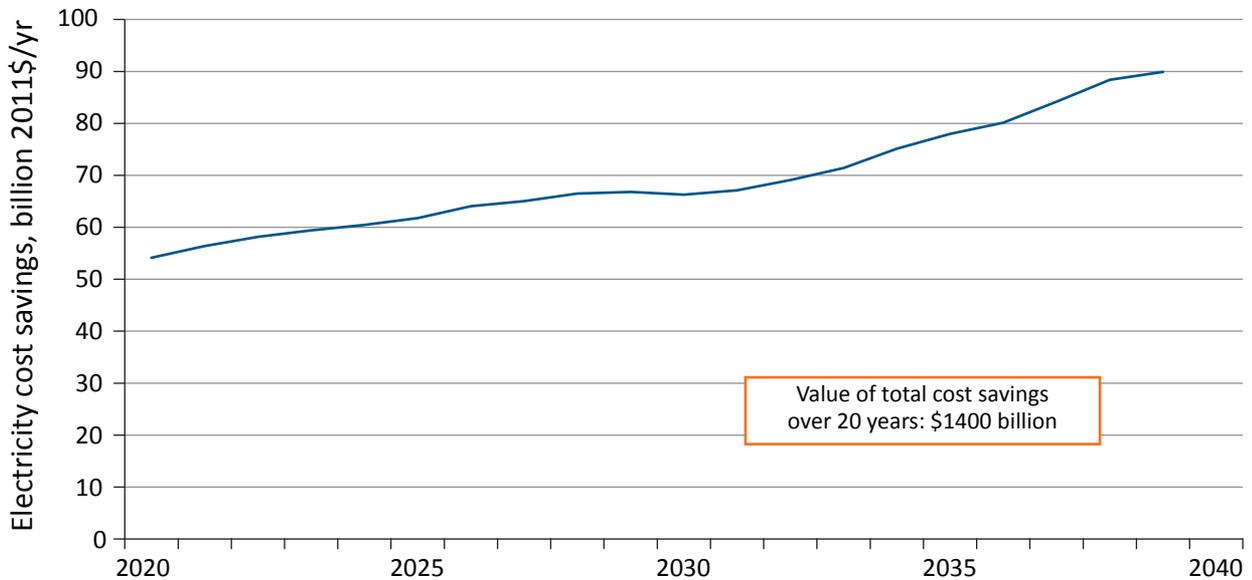


FIGURE 1. Value of existing coal fleet: electricity cost savings

Notes: Annual Value = Average Coal Generation for 2008-12 × (Cost of new NGCC generation/MWh - Cost of existing coal generation/MWh); Total U.S. electricity sales in 2011 = \$371 billion

Source: Technology cost, projected fuel cost, and electricity generation data were taken from DOE/EIA 2013 Annual Energy Outlook⁵

an overview of the key findings and recommendations from the study: “Reliable & Resilient: The Value of Our Existing Coal Fleet”.¹

TODAY’S U.S. COAL FLEET

Since 1950, coal has been the workhorse and leading source of power generation in the U.S., providing upward of 50% of total U.S. generation.² This dominance has resulted from coal’s domestic abundance, accessibility, reliability, and low cost compared with other generation alternatives. In 2013, coal continued to lead U.S. generation, producing 39% of electricity nationwide with approximately 310 GW of generating capacity.

Low-cost coal has helped keep U.S. electricity prices below those of other free market nations. For example, in 2013 the average price of residential and industrial electricity in the U.S. was one half to one third the price of electricity in Germany, Denmark, Italy, Spain, the UK, and France.^{3,4} If the existing coal fleet were replaced with the next cheapest alternative generating source—natural gas combined-cycle power plants—a conservative estimate of the impact on the U.S. economy would be a 1.5% drop in Gross Domestic Product (GDP) and a loss of two million jobs by the year 2040 (see Figure 1).¹

Continuous technology improvements have greatly reduced emissions from the coal fleet and done so during a period in which coal generation has increased substantially. Since 1970, coal-based power generation has increased nearly 150% as key emissions have decreased almost 90%. State-of-the-art technologies have reduced emissions of SO₂ by 88%, NO_x by 82%, and particulates by 96%.⁶

The average U.S. coal-fired power plant has operated for 39 years.⁵ Although the age of a generating unit is not a dispositive criterion in decisions related to its continued operation, age is one of several important considerations influencing decisions regarding capital investments or the prospective of unit retirement to meet future economic and environmental compliance requirements.

THE U.S. ENERGY PRECIPICE

The U.S. benefits from having a diverse portfolio of electricity sources. Despite this, the U.S. Energy Information Administration (EIA) projects very little new coal capacity will be built in the U.S. through 2040.⁷ Therefore, maintaining coal’s role in this diversified portfolio will likely rest on industry’s ability to continue safe and economical operation of the existing fleet, while making the changes necessary to ensure continued environmental compliance.

Reduced demand for electricity provides an additional incentive for continuing to maintain the existing U.S. coal fleet. The nation’s electricity demand grew at 6–11% per year during the 1950s and 1960s, at 2.5% or less since 1995, and was actually negative in 2009, 2011, and 2012. EIA projects that generation will grow less than 1% per year between 2012 and 2040.⁷ This relatively low rate of growth in electric power demand emphasizes the importance of advancing policies and technologies that preserve the existing fleet’s benefits and portfolio value.

“The U.S. benefits from having a diverse portfolio of electricity sources.”

Preservation of the existing coal fleet in the U.S. is being challenged by both marketplace and policy factors. The EIA reports that 10 GW of coal-based capacity was retired in 2012 and projects another 50 GW to retire by 2020, based on a combination of market forces and regulations which have been adopted through 2013.⁸ While these projections take into account the impact of regulations such as the Mercury and Air Toxics Standards (MATS), they do not include the effect of pending water regulations (including Clean Water Act 316(b) and effluent guidelines regulations), solid waste regulations (such as those related to Coal Combustion Residuals), or CO₂ regulations (including recently proposed New Source Performance Standards 111(b) and existing source regulations 111(d)). In fact, the U.S. Environmental Protection Agency (EPA) projects that coal capacity will decrease to 195 GW in 2020 due to 111(d) regulations.⁹

Competitively advantageous natural gas prices have recently caused a decrease in demand for coal-fired generation, although coal’s share of generation recovered somewhat in 2013, primarily in response to increased spot prices for natural gas.¹⁰ EIA’s most recent projections for the price of delivered gas to electric utilities indicate an expected real (constant dollar) increase of 3.1% per year (2012–2040) versus a 1.0% per year increase for coal.¹¹

The risk associated with the projected level of coal plant retirements was made evident during the severe cold weather events of the winter of 2013–2014. During this period, many regions of the U.S. approached a dangerous energy precipice in which both reliability and affordability of supply were impacted. During increased power demand for much of the U.S. in January 2014, for example, alternative fuels were significantly supply constrained. Wind produced only 4.7% of the

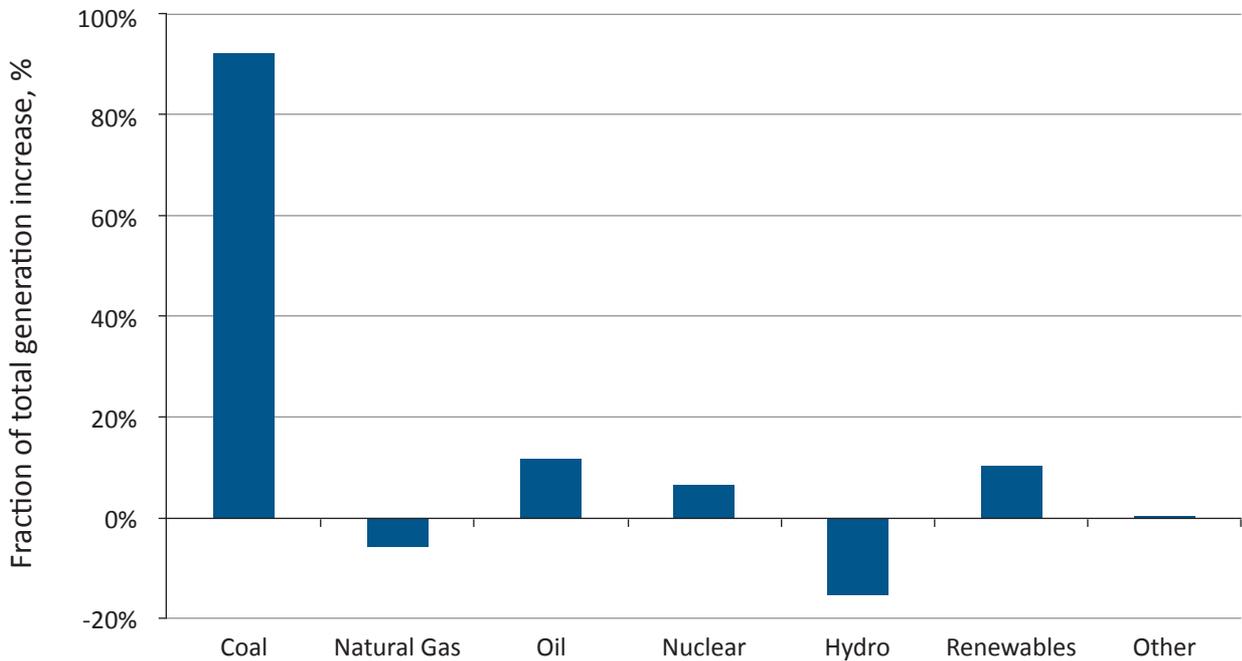


FIGURE 2. Portion of increase in U.S. electricity generation, by fuel Jan-Feb 2014 versus Jan-Feb 2013¹³

nation’s power while solar produced less than 0.2%. Nuclear provided only 5% of incremental year-over-year generation and hydroelectric output declined 13%. Power generation from natural gas decreased when the resource was diverted to fuel residential heating needs and gas prices soared to over three times that of coal (Btu basis).¹²

As shown in Figure 2, coal-fired generation provided 92% of the increase in electric power in the U.S. for the first two months of 2014 compared to the same months in 2013.¹³ The major lesson learned from the polar vortex experiences in January and February 2014 was that the U.S. power grid is less resilient than previously believed. Only the availability and operation of coal units scheduled for retirement over the next two years enabled the power sector to meet demand during periods of harsh weather events.

SHORING UP THE BASE

Ensuring the continued, cost-effective operation of the U.S. existing coal fleet while also assuring compliance with national environmental objectives will require devoting resources to enhance plant efficiency. Decisions to commit resources to energy efficiency measures generally consider a range of factors. These include the positive impacts associated with reducing fuel consumption, lowering operating costs, enhancing operational flexibility, and reducing emissions of conventional pollutants and CO₂, as well as the potentially negative impacts related to New Source Review (NSR; see below).

Thermal efficiency improvements generally require an investment in process equipment and/or in operation and maintenance (O&M). Although the economic incentive to improve efficiency has practical limits, the increasing focus on controlling CO₂ emissions will likely provide a greater impetus to do so. The efficacy and payoff of any given efficiency-improving measure at a power plant is site-specific. The initial design and condition of a plant, age, coal rank, environmental requirements, and maintenance practices determine the payoff that can be derived.

Improving the efficiency of existing power plants is critical to maintaining the value of the current fleet. Existing and emerging technologies offer opportunities to shore up today’s U.S. coal-fired generation base. Their deployment, however, may be hampered by regulatory requirements that impose significant and costly emission reduction requirements that could offset and, in some cases, completely negate efficiency gains by increasing parasitic power demand to operate pollution control equipment.

Regulatory Impediments to Efficiency Improvements

Under EPA’s New Source Review (NSR) program, major new sources and major modifications of existing sources must obtain pre-construction permits that include a requirement to apply state-of-the-art air pollution control technology. Some actions to improve efficiency at an existing power plant could lead to a designation of the change as a “major modification”,

thus subjecting the unit to NSR permitting requirements. These requirements usually entail additional environmental expenditures (that can reduce efficiency), as well as delays associated with processing the permit.

NSR unintentionally limits investments in efficiency. On 12 June 2014, in a presentation at the Coal Utilization Research Council's (CURC) Advanced Coal Technology Showcase in Washington, DC, Senator Heidi Heitkamp (North Dakota) remarked that it would be a "fiduciary transgression" for utilities to consider power plant efficiency improvements without anticipating it would trigger NSR.

EPA itself has confirmed a problem exists with its interpretation of NSR. In 2002, the agency noted: "As applied to existing power plants and refineries, EPA concludes that the NSR program has impeded or resulted in the cancellation of projects which would maintain and improve reliability, efficiency, and safety of existing energy capacity. Such discouragement results in lost capacity, as well as lost opportunities to improve energy efficiency and reduce air pollution."¹⁴

In short, the fundamental barriers to improving power plant efficiency and reliability cited by EPA in 2002 remain in today's NSR rules. The uncertainties created by the NSR rules, their enforcement by EPA, and the substantial, even prohibitive, cost of adhering to NSR create strong disincentives to the widespread deployment of the efficiency measures recommended in the NCC's report. Unfortunately, the NSR shadow has also cast a pall on the research, development, and deployment

(RD&D) that would more than marginally improve the efficiency of the existing coal fleet.

Cleaning House With Technology

The NCC report details numerous measures that could potentially be applied at coal-fired power plants to enhance efficiency.⁸ Steam turbines could be refitted with modern and more efficient multistage rotors. Corrosion and deposition on major heat transfer components (e.g., boiler tubes and condensers) could be reduced, thus improving heat transfer efficiency. Improved sensors and controls could prospectively allow a plant to operate closer to conditions optimal for higher efficiency. It might be possible to use variable speed drives to make motors more efficient, particularly at lower load.

Although many of these technologies already exist and are operating on some units, there is not a one-size-fits-all package of solutions that can be readily applied to or accommodated by the existing coal fleet. In some cases, the opportunity to apply efficiency improvements will be negligible because the unit either is already operating in a highly efficient mode with some or all of the available improvements in place or because the implementation of potential improvements is not cost-effective and/or technically feasible. The degree of efficiency improvement possible at a given unit is highly site-specific and may depend on the design of the unit, current maintenance procedures, whether the unit operates as base load or cycling, the type of coal used by the unit, and the configuration of the unit. Even the location of the unit is relevant to efficiency

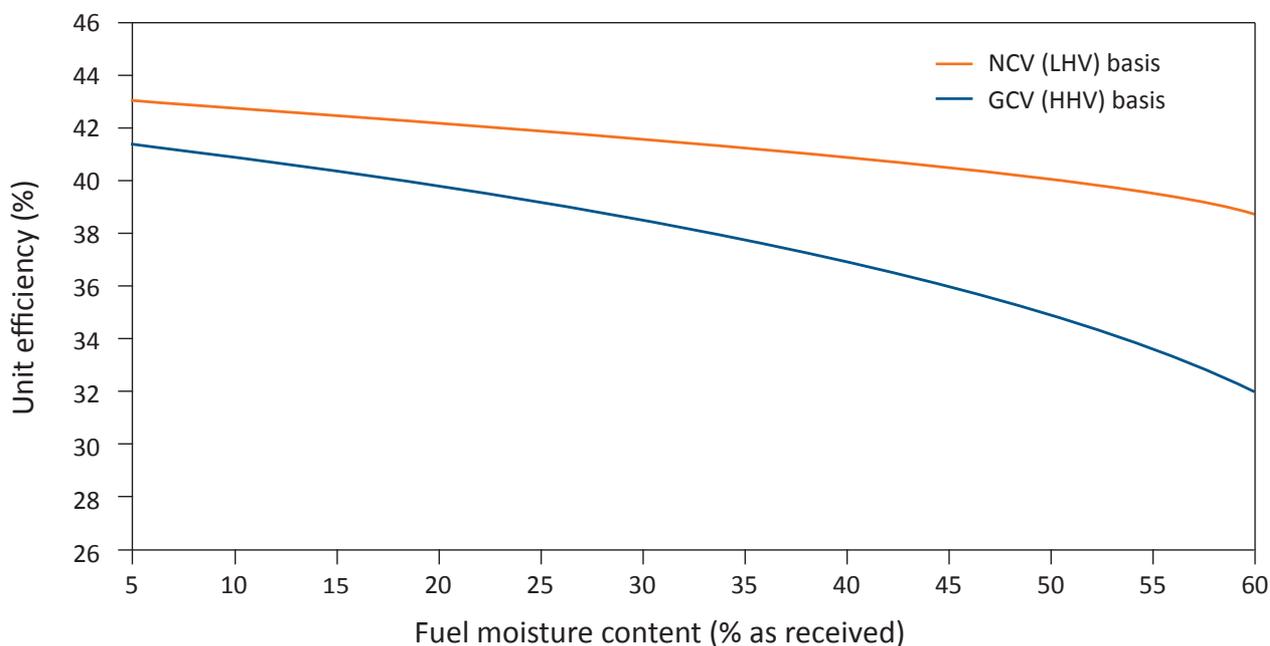


FIGURE 3. Coal moisture impact on efficiency (figure courtesy of E.ON)

because plant efficiency is sensitive to ambient temperature and atmospheric pressure (elevation).

For example, included among the many efficiency-enhancing opportunities addressed in the NCC study is coal drying and beneficiation. Lowering moisture from coal increases boiler efficiency and thus plant-generating thermal efficiency, if the moisture can be reduced using waste heat (see Figure 3). Coal drying with waste heat is a commercially available option, but not one that every plant can effectively deploy. Notably, this technique has been employed by Great River Energy (GRE) in North Dakota using local lignite coals. GRE has reduced the moisture content of lignite from 39% to 29%, increasing plant net-generating thermal efficiency by 4% and lowering heat rate by about 1200 Btu/kWh.¹⁵ Less improvement would be expected for drying higher rank coals (bituminous and sub-bituminous) because they tend to be much lower in moisture content than lignite.

It's also prospectively possible to achieve significant efficiency benefits by altering the composition of coal, beyond removing moisture. Coal beneficiation processes that employ chemical or mechanical treatments to reduce the inorganic content can contribute to controlling regulated hazardous pollutants. Other beneficiation technologies that add compounds to coal during processing hold promise for decreasing moisture and increasing heating value. For instance, PSEG is experimenting with an ammonium hydroxide-based beneficiation process that displaces both water and inorganic material—and has been able, in pilot tests, to decrease coal moisture from about 31% to 7% and increase heating value from 7859 Btu/lb to 11,363 Btu/lb.¹⁶

Coal beneficiation technologies can also reduce boiler slagging and fouling, improve heat transfer in the boiler, and elevate efficiency. Additionally, lower sulfur fuel can reduce the auxiliary power demand for conventional flue gas desulfurization (FGD), increasing net unit power output.

Modest improvements in efficiency are possible at some units with existing technologies to improve heat transfer, reduce heat losses, and make better use of low-quality heat. More significant efficiency gains may be achievable following additional RD&D to advance the commercial viability of emerging technologies, including the enhancement of the conventional Rankine thermodynamic cycle by adding topping or bottoming cycles or by using different working fluids than water.

WHAT TO DO?

In fact, RD&D by industry and government, and through industry–government collaboration, is key to enhancing the

efficiency, flexibility, reliability, and capacity of the existing coal fleet. Past challenges to coal generation, such as the need to reduce emissions of SO₂, NO_x, and mercury, were met through collaborative efforts between the public and private sectors to develop new technologies. The terms “flue gas desulfurization” (FGD), “selective catalytic reduction” (SCR), and “activated carbon injection” (ACI) were not part of the nation’s lexicon in 1970. Today, these systems, developed through such collaboration, are standard equipment on new coal-fired power plants and have been widely deployed on existing units as well.

In fact, for every \$1 of federal funds invested in coal RD&D, \$13 of benefits have accrued to the U.S. Moreover, RD&D in advanced coal technologies can produce products for sale abroad, enhancing U.S. manufacturing, improving the nation’s balance of trade, and enabling more efficient, cleaner operations of coal plants internationally. Continued and accelerated RD&D is vital in the areas of advanced materials, assessment tools, sensors and monitors, cycling impacts and operations, topping and bottoming cycles, and commercial demonstration of carbon capture and storage (CCS).

The existing U.S. coal fleet offers many benefits; benefits that are in jeopardy due to coal plant closures and the nation’s

“For every \$1 of federal funds invested in coal RD&D, \$13 of benefits have accrued to the U.S.”

increasing overreliance on natural gas. The National Coal Council study on the value of the existing coal fleet recommends that DOE lead efforts to maintain coal’s cornerstone role in a diverse generation portfolio and that federal energy policy assessments, such as the ongoing Quadrennial Energy Review (QER), consider the value of that diversity and the impact of coal plant retirements. NCC recommends that DOE lead collaborative efforts with industry to assess the impacts of the 2014 polar vortex experience on price, availability, reliability, and potential consequences of similar future events. The Council encourages DOE to work with EPA to eliminate NSR barriers that disincentivize efficiency improvements to reduce emissions, increase capacity, and enhance plant operations.

In 1882, Thomas Edison’s Pearl Street Station in Manhattan launched a new energy age of coal-generated electric power. The coal-fired power plants in the U.S. have served our nation well ever since. With some additional care and attention,

they'll continue to offer many valuable benefits well into the future. 🙌

NOTES

- A. Capacity-weighted age, as of 2014, excluding retirements in 2013–2014.
- B. The NCC report does not provide a quantitative assessment of the degree to which existing technologies could improve the heat rate (or efficiency) of the existing coal fleet.

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To access the NCC study “Reliable & Resilient: The Value of Our Existing Coal Fleet” visit www.nationalcoalcouncil.org/NEWS/NCCValueExistingCoalFleet.pdf

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Key Findings and Recommendations From the National Coal Council Study

Findings

- The U.S. existing coal fleet continues to play a vital role in meeting our nation’s electric power needs. The extreme cold weather events of the winter of 2013–2014 highlight the need to maintain a diverse portfolio of generation options in order to ensure the availability of affordable, reliable power for residential and industrial uses.
- The historical deployment of advanced coal technologies demonstrates that coal generation can be increased while simultaneously reducing emissions.
- Retrofitting advanced environmental technologies and enhancing efficiency at existing coal plants could result in the creation of 44,000 to 110,000 jobs, depending on the degree of efficiency improvement achieved.

Recommendations

- DOE should lead collaborative efforts with industry to assess the impacts of the 2014 polar vortex experience on power prices, availability, and reliability.
- DOE should ensure that basic federal energy policy assessments, such as the Quadrennial Energy Review and the President’s Advanced Manufacturing Initiatives consider the impact of lower priced electricity facilitated by coal-fired power plants, and include an assessment of the value of diversity of generation sources and how pending coal plant retirements are likely to impact power prices, availability, and reliability.

Download the full study with all key findings and recommendations at www.nationalcoalcouncil.org/NEWS/NCCValueExistingCoalFleet.pdf

Improving the Case for Gasification

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Gasification is a technology with a long and checkered history. It was widely used to produce “town gas” for lighting and cooking in the 1800s before it was replaced by electricity and natural gas. Yet its commercial deployment for industrial applications and power generation has been limited, despite several attempts to kick-start the industry.

Historically, interest in coal gasification has tended to peak when access to other fossil fuels was limited or their prices were high. For example, gasification received a great deal of attention in the 1970s during the oil crisis, and at various periods in recent years as a response to high natural gas prices.

A major factor behind gasification’s stuttering commercialization has been the upfront cost. Coal gasification plants typically require capital investments of hundreds of millions of dollars, and in some cases billions. With the effects of the recent global financial crisis still being felt, bringing down the capital cost is essential if coal gasification is ever to truly take off.

Companies such as Siemens have been able to make progress through technology advances as well as a growing number of

references, which in itself will reduce costs and build confidence in the feasibility of the technology.

The development of the Siemens gasification process—a pulverized fuel, pressurized, entrained-flow gasification technology—was begun in 1975 by Deutsches Brennstoffinstitut Freiberg/Sa. (DBI, German Fuel Research Institute). The main objective was to create a conversion technology that would allow the use of locally abundant lower-rank coals, including lignite, to partially replace the demand for crude oil and natural gas. Many countries are now taking advantage of their local energy resources and converting those resources into low-carbon electricity, chemical feedstocks, and clean transportation fuels. Heading into China’s 13th Five-Year Plan, the China National Coal Association recommends to “shift from viewing coal as a fuel to considering it a raw material to produce a wide array of products. Based on the initial results of coal conversion demonstration projects in China, such as coal-to-liquids, coal-to-olefins, and coal-to gas, China’s coal industry should accelerate the construction of large-scale, clean, and efficient coal-conversion projects, which could effectively replace some oil and gas.”¹

“Companies ... have been making progress through technology advances as well as a growing number of references, which in itself will reduce costs and build confidence...”



Shenhua Ningxia Coal Group’s coal-to-polypropylene project, Ningxia Province, PRC

The government of the former German Democratic Republic intended to build several gasification plants around central Germany to supply major chemical companies through long-distance pipelines with syngas produced from coal. Due to the low rank of this lignite and its high salt content, the gasification process developed had to address special requirements for the feeding system and the gasifier itself. The first test facility, built in 1979 with a thermal capacity of 3 MW, was used to examine the technical concept and to test the targeted saliferous lignite for the construction of a large-scale demonstration facility in 1984 at the Gaskombinat Schwarze Pumpe site.

Between 1994 and 1998 further test facilities were erected at a Siemens site in Freiberg, among them a 5-MW_{th} cooling screen reactor. Up to now these facilities have been used to gasify more than 90 candidate gasification feedstocks—including different ranks of coal, municipal- or industrial-provenance sewage sludge, petroleum coke, waste oils, bio-oils, bio-slurries, and several liquid residues—in order to investigate their gasification behavior and to analyze the quality and characteristics of the gasification products.

Through this systematic research and development, the range of application of the Siemens Fuel Gasification (SFG®) technology was extended from conventional fuels, such as coals and oils, to also include residual and waste materials and biomass. Over the years since its privatization in 1991, the technology has been owned by several companies. Since its purchase by Siemens in 2006, the Siemens gasification group has been organized under Siemens Fuel Gasification Technology (SFGT) GmbH & Co. KG and has extended its footprint to China, South Korea, and the Americas.

TECHNOLOGY

Essentially there are several basic gasifier designs, differentiated by whether they use pure oxygen or air, wet or dry coal feed, the reactor's flow direction, and the syngas cooling process. Oxygen-blown and entrained-flow gasifiers, such as those designed by Siemens (see Figure 1), are likely to be the most popular going forward.

Oxygen-blown gasifiers have the advantage of being a compact, cost-effective design and they produce a very clean syngas that can be directly processed after dust removal. These gasifiers operate under high pressure in the range of

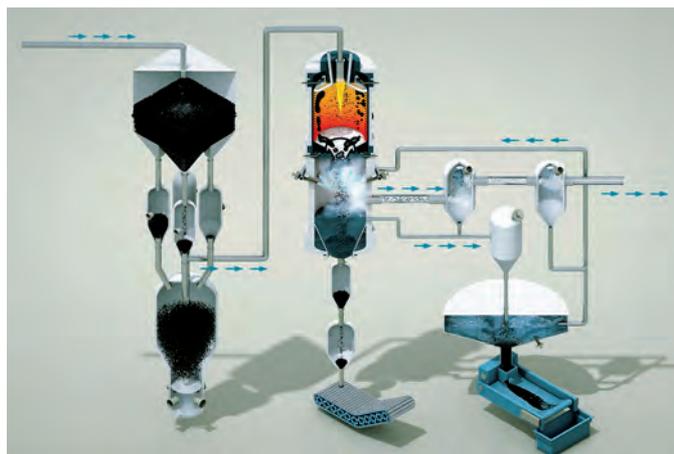


FIGURE 1. Siemens SFG® gasification island with dry feeding system; oxygen-blown, entrained-flow gasifier; full water quench

40–46 bar, which allows a high syngas output per single gasifier, resulting in fewer trains and subsequently lower CAPEX per ton of final product.

Entrained-flow gasifiers operate at temperatures higher than the ash-melting temperature. Typical operation temperatures are in the 1300–1800°C range. At these high temperatures, the gasifier produces only the components hydrogen, carbon monoxide, and carbon dioxide—no hydrocarbons such as phenols or tar, as is the case for fixed-bed gasifiers. The fuel flexibility ranges from biomass, petroleum coke, oils, tar, and liquid chemical residues to all kinds of coals such as lignite, sub-bituminous and bituminous coal, or even anthracite. For most feedstock, the carbon conversion rate is in the range of 96–99.5%.

“Oxygen-blown gasifiers have the advantage of a compact, cost-effective design and they also produce a very clean syngas that can be directly processed after dust removal.”

Today, gasification processes around the world must limit the production of gas, solid, and liquid wastes. Siemens believes the oxygen-blown, entrained-flow gasifiers represent the environmentally best available technology due to a lack of waste production. There are no gaseous emissions. Solids emissions are in the form of vitrified slag, which is inorganic and nonleaching, and can be sold as construction material. Solids entrained in the gas, process fines, are extracted as filter cake. Liquid-phase waste is becoming an increasingly important issue for gasification plants because water consumption must be reduced; almost certainly, zero liquid discharge systems will be a future requirement in many parts of the world. A quench system can be supplied with a variety of process waters, such as gas condensates from the CO shift or condensate from a methanation unit. The combination of an entrained-flow gasifier and a dry-feed system has the lowest freshwater consumption of all available industrial-scale gasification technologies, typically in the range of 0.35–0.45 ton freshwater/ton coal despite having a full water quench, which is usually fed by recirculating the gas condensate. Eventually, water is discharged from the quench system to limit the salt concentration based on the material and fouling constraints. The



FIGURE 2. Siemens Fuel Gasification Test Center, 5-MW_{th} gasifier

typical entrained flow gasifier blow-down rate is lower than other industrial-scope gasification technologies, in the range of 0.1–0.15 ton water/ton coal.

The performance of such entrained-flow gasifiers has already surpassed the older fixed-bed gasifiers, such as those used in the past in South Africa.

SIEMENS DEVELOPMENTS

Prior to 2007-08, the number of Siemens gasification references was very limited and some had been built 30–40 years ago or were no longer in operation. Today, however, there are seven projects operating, in construction or under development with Siemens gasifiers, mostly in China where there are extensive coal reserves. Siemens’ current focus is on “design-to-cost” for the gasification island, taking into account the associated subsystems, in order to simplify the entire process and thus reduce costs.

Generally, larger gasifiers are more efficient and require less pipework and other components. Work has therefore centered on developing a gasifier that offers the optimum size in terms of efficiency and cost.

Much of the SFG development work has been carried out at the Siemens Fuel Gasification Test Center in Freiberg, Germany, which is one of the most comprehensive gasification test facilities in the world (see Figure 2). The centerpiece of the test center is a 5-MW_{th} gasification reactor equipped with Siemens’ innovative cooling screen design. This design allows the reactor to gasify a broad range of coals with ash contents up to 30–35% and high ash-melting temperatures. This reduces start-up and shutdown times at the commercial

scale from two to three days (compared to refractory-lined gasifiers) to approximately two hours. The cooling screen has a lifetime of at least 10 years and eliminates the need for the annual or bi-annual shutdowns customary with refractory-lined reactors, resulting in a significantly higher availability.

This Siemens-owned test center has been instrumental in developing and testing the SFG-200 and later the larger SFG-500 (2000 t/day coal capacity). Six of these units are now successfully operating at plants around the world.

As part of the continuing effort to reduce costs, Siemens has now developed the SFG-850 gasifier, introduced to the market at the end of March 2014 (see Figure 3). The reactor with this system is sized for larger gasification plants producing chemical feedstocks, synthetic natural gas, or clean transportation fuels, as well as IGCC applications using the most advanced gas turbines.

The SFG-850 is designed to enhance the profitability of future gasification plants by reducing specific plant costs, along with the associated production costs of synthesis gas. An SFG-850 gasifier can convert around 3000 t/day of coal into more than

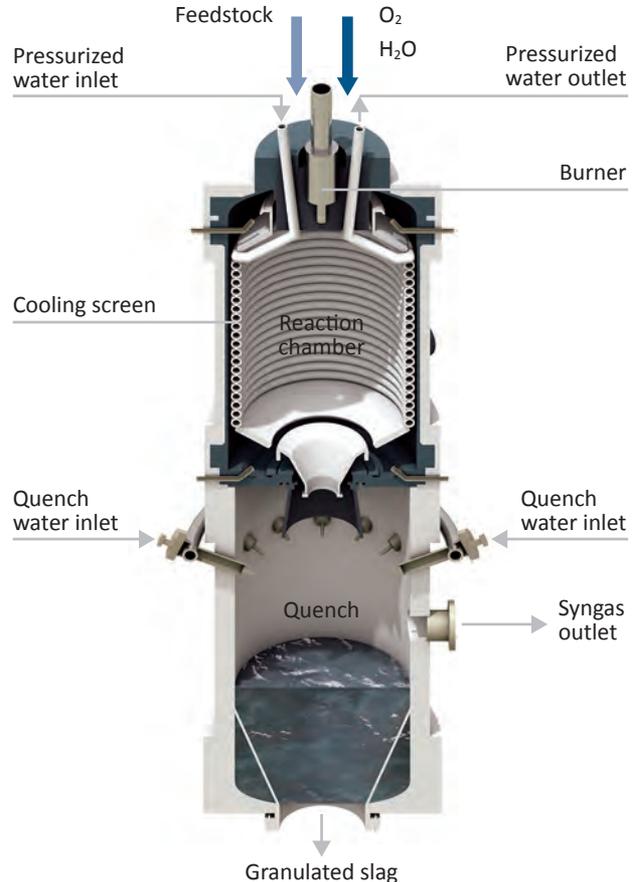


FIGURE 3. Siemens’ new SFG-850 gasifier

five million standard cubic meters (Nm³) of high-quality synthesis gas.

The SFG-850 gasifier is based on the same technical design as the SFG-200 and SFG-500; however, the proven central burner design and dry coal feed system have now been optimized further in the SFG-850. As with its predecessors, the new gasifier has a high degree of fuel flexibility. All of the proven advantages of Siemens gasifier technology, including its short start-up and shutdown times and the tried-and-tested serviceability of its water-cooled design, contribute to its ability to maintain a high level of availability.

The SFG-850, however, is bigger than its predecessor: Its outer diameter is 0.5 m larger than the SFG-500. Although not a huge increase, this offers a 33% increase in coal throughput capacity. With a length of 22 m, an outer diameter of 4.8 m, and weighing 380 tonnes, the SFG-850 gasifier is one of the world's largest. The new model can be completely fabricated and tested at the factory. Despite its size and weight, the unit can be transported to its installation location in one piece, eliminating the time and expense of field fabrication.

GASIFICATION HAS A BRIGHT FUTURE BASED ON TODAY'S HARD WORK

As noted before, the cost of gasification-based plants is the major challenge for the gasification industry. Companies across the industry are working to reduce the cost of gasification and all of the upstream and downstream processes that will allow gasification plants to operate economically. At Siemens, we believe that the introduction of the SFG-850 makes a significant step forward in reducing the cost of the gasification island. In addition to the economy of scale compared to a standard Siemens SFG-500 reference plant in China, Siemens has achieved further reduction in capital investment cost by optimizing the selection of equipment, valves, and instruments—incorporating lessons learned from today's operating plants to select better construction materials and developing a more compact gasification island layout.

Beyond the gasification island, Siemens is partnering with industry leaders in coal milling and drying and CO shift catalysts; improvements in these areas will further increase the

efficiency of tomorrow's gasification plants. For example, Clariant, a world leader in specialty chemicals, and Siemens have introduced a new jointly developed sour gas CO shift technology specifically designed for coal gasification. This advanced "low steam" shift technology with Clariant's ShiftMax® 821 catalyst reduces capital expenditure for the shift unit by up to 20% and optimizes operating costs with up to 30% lower catalyst volume and significantly less steam consumption. This will make gasification plants more economically appealing and, hence, more competitive than what is currently offered.

Ongoing cost reductions will enable greater use of gasification, especially in the industrial sector where countries worldwide are looking to leverage their domestic, low-cost energy resources, such as coal, to produce high-value products including low-carbon power, chemical feedstocks, and clean transportation fuels. The ability to use low-rank coals will make the gasifier particularly attractive to markets such as Indonesia, which currently has no real use for such coal. Gasification would unlock this resource. The same is also true for countries such as Australia, Mongolia, Vietnam, and even Thailand where gasification projects are being considered. There could even be possibilities in the U.S. as natural gas prices rise.

Gasification may also be used as a strategic tool in some countries to reduce dependence on imported fossil fuels. Turkey, which has coal but is heavily dependent on gas imports, is one such country. Ukraine is another prime example; the recent conflict with Russia highlights why gasification might be an attractive option to the purchase of Russian natural gas. As gasification technologies continue to demonstrate better performance, better reliability, and lower costs, more countries will be able to economically justify the use of this innovative clean energy conversion technology to produce the power, chemical feedstocks, and clean transportation fuels they need. 🌱

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The Shell Coal Gasification Process for Reliable Chemicals, Power, and Liquids Production

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EMBRACING CLEAN COAL TECHNOLOGY

Environmentally responsible gasification technologies are helping to unlock the world's coal reserves with increasing efficiency. The synthesis gas (syngas) produced is being used in chemical and integrated gasification combined-cycle (IGCC) plants worldwide. China, in particular, has embraced

coal gasification technology as a way of using its abundant, indigenous coal reserves efficiently and with low environmental impact to manufacture methanol, ammonia, hydrogen, and synthetic liquid hydrocarbons. In other countries syngas, which burns as cleanly as natural gas, is generating power in IGCC plants.

“Environmentally responsible gasification technologies are helping to unlock the world's coal reserves with increasing efficiency.”

The Shell Coal Gasification Process (SCGP), examples of its use, and a description of the continuous improvement culture that is pushing reliability and performance to new levels are the focus of this article.

SHELL COAL GASIFICATION TECHNOLOGIES FOR DIFFERENT NEEDS

With 28 licenses sold worldwide, Shell is one of the main global suppliers of coal gasification technology and is unusual in being both the technology developer and a licensor with hands-on operational experience through an equity investment in a commercial gasification plant. This provides the company valuable operational insights, and a vested interest, in achieving ever-higher operational reliability and performance standards.

Shell began gasification research in the 1950s and built coal gasification demonstration plants in the 1970s and 1980s in the Netherlands, Germany, and the U.S. Two technologies have emerged from this pioneering work: The Shell Gasification Process (SGP) converts refinery residues to syngas and the SCGP uses solid feeds, including petroleum coke (petcoke), anthracite, bituminous coal, lignite (brown coal), and biomass, to produce syngas. There are two SCGP-related lineups for users with different needs.

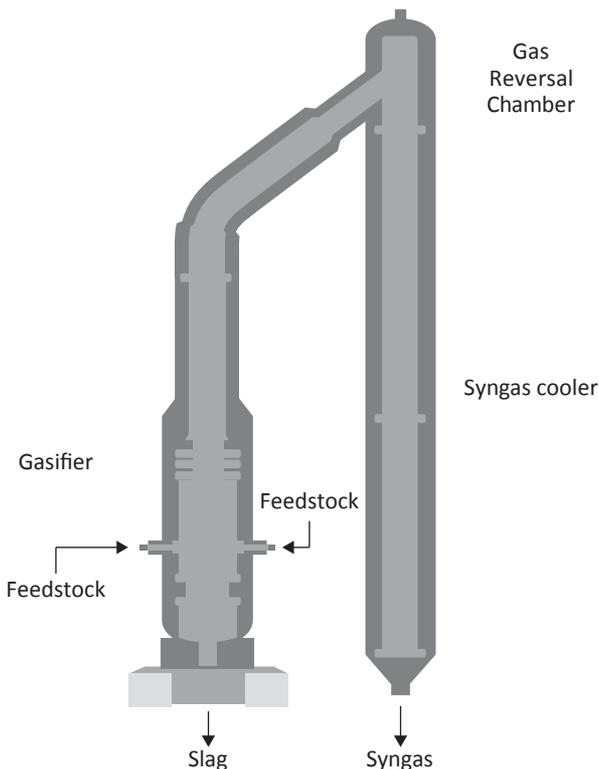


FIGURE 1. SCGP syngas cooler technology

Proven High-Efficiency Technology

SCGP syngas cooler technology (Figure 1) has been used commercially for more than 20 years. It can help achieve carbon conversion rates of over 99% and cold coal gas efficiency (the amount of energy in the coal converted to the energy in the combustible syngas) of 80–83%. A syngas cooler recovers most of the sensible heat in the syngas to produce high- or medium-pressure steam, which can reduce the operating costs within a facility.

An entrained-flow process uses an inert carrier gas to transport dry coal feedstock to the gasifier, where it contacts oxygen and steam. The gasifier has unique features, such as specially designed multiple burners and a membrane wall of high-pressure tubes designed to enable the safe and low-maintenance separation of syngas and slag.

The molten slag flows down into a water bath from where it can be extracted as a solid, thereby reducing wastewater pollution. Dry-filtered and wet-washed syngas quenches the syngas to about 900°C before it leaves the top of the gasifier. The syngas is cooled further in an external cooler to generate high- and medium-pressure steam as valuable by-products. The use of multiple burners provides the potential for easy scaling up and, more importantly, efficient slag removal with only a small amount of a fine fly ash, which is removed downstream to less than 1 ppmv.

In China alone, 23 SCGP gasifiers have come onstream since 2006 and six more are due to start up in the near future. Of these 23 gasifiers, 17 have dry pulverized coal intake capacities of over 2000 t/d. SCGP units are also running or planned in South Korea and Vietnam.

Proven Low-Capital-Costs Technology

For operators that need to lower their capital expenditure and are looking for wider feedstock flexibility while retaining good efficiency levels, Shell has developed a bottom-quench technology (Figure 2). This simplified lineup can reduce capital costs by up to 30% while satisfying the country's basic, and some advanced, efficiency and environmental requirements.

The bottom-quench lineup retains the membrane wall and burner technology of the first lineup but has proven water-quench technology to replace the syngas cooler. This means less steel, less equipment, and a shorter manufacturing time, which substantially reduces capital costs. SCGP bottom-quench technology also helps to eliminate fouling risks to offer wider coal suitability.

In 2013, Shell and Wison Engineering successfully started a 1000-t/d SCGP bottom-quench technology demonstration plant in the Nanjing industrial park, which had 99% carbon conversion. In January 2014, Hulunbeier Jinxin, a subsidiary of the



South Korea is investing in its first IGCC plant, full site as of 31 May 2014 shown above (photo courtesy of Korea Western Power Co. Ltd).

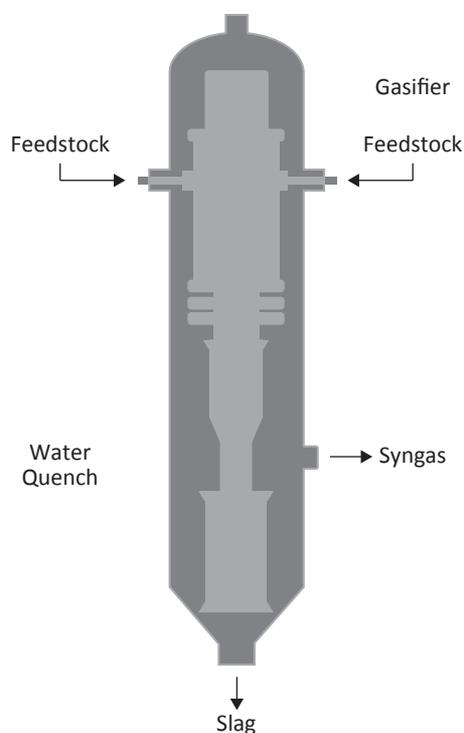


FIGURE 2. Bottom-quench technology

Yuntianhua Group, signed a licensing agreement for a bottom-quench gasifier to process lignite feedstock.

A BROAD RANGE OF APPLICATIONS

Coal-to-Chemicals

In China, SCGP gasifiers are delivering syngas for methanol, ammonia, and hydrogen production. For example, the Yueyang Sinopec and Shell Coal Gasification Co. Ltd. (Dongting) joint venture has been successfully supplying syngas and steam to the associated Baling fertilizer plant since 2006. This has given Shell eight years of first-hand, local operational experience. The facility processes 2000 tonnes of pulverized coal a day and produces syngas for urea/fertilizer and caprolactam (nylon) manufacture.

In 2012, the first of two plants in Vietnam operated by Vietnam National Chemical Group began commercial operations.

Coal for IGCC Power

SCGP licenses for IGCC plants have been sold in Europe and Asia. Importantly for a power plant, the SCGP unit gives operational flexibility with the ability to follow load changes quickly.

In the Netherlands, the 2000 t/d Willem-Alexander (formerly

Nuon) power plant operated from 1993–2013. Commissioned as a demonstration plant, it has proven SCGP technology’s reliability and low maintenance costs, which result from the robustness of the gasifier membrane wall and the long-life burners. The IGCC plant also demonstrated feedstock flexibility by processing more than 20 different coal types and blends, and running successfully with up to 30 wt% biomass.

South Korea is building its first IGCC plant, Taeon IGCC No. 1. Here, Korea Western Power Co. Ltd will be using SCGP and gas-treating technologies for efficient generation of clean power for the country. SCGP technology was chosen for its good economic value, and high reliability and efficiency. Knowledge transfer and training were also key factors in the selection decision.

The 300-MW (net) IGCC plant aims to have a design target of over 42% efficiency (net).

The plant, which will process 2670 t/d bituminous and sub-bituminous coal, is designed to have emissions of less than 30-ppm nitrogen oxides and 15-ppm sulfur oxides. It also opens the possibility of carbon capture and storage for reduced greenhouse gas emissions through a readily available stream of concentrated high-pressure carbon dioxide.



Gasification unit under construction at South Korean IGCC power plant (photo courtesy of Korea Western Power Co. Ltd)

Coal-to-Liquids

In China, Shanxi Lu'an Coal Mine Group is constructing a coal-to-liquids plant with four SCGP gasifiers that will each have a 3200-t/d dry coal intake capacity.

REACHING NEW PERFORMANCE STANDARDS

Since its introduction in the early 1970s, SCGP syngas cooler technology has been continuously improved to enhance performance, extend equipment life, and widen the range of usable feedstocks.

Efficiency and Environment

SCGP syngas cooler technology is efficient and has a low environmental footprint. For example, independent assessments have shown that SCGP gasifiers have the highest exergetic efficiency of all coal gasification technologies.¹ Typical ranges for

oxygen and coal consumption are also low: 310–350 Nm³ oxygen per kNm³ syngas and 510–615 kg standard coal per kNm³ syngas, respectively. Indeed, SCGP gasifiers exceed China's National Development and Reform Commission's (NDRC) basic requirements for energy, coal, and water consumption, and meet many of its advanced requirements (Figure 3). Note that the requirements are for overall projects and therefore a plant's performance depends partly on the downstream process employed.

Feed Flexibility, Selection, and Management

A wide variety of coal has been processed across the world, including feeds with 6–36% ash, up to 35% moisture content, and ash-melting points (fluid temperatures) from 1140°C to well over 1500°C. Low-quality coal types, including lignite, have been successfully gasified in commercial operations. Several SCGP technology users, including four in China, have implemented an effective strategy of blending high-ash coal with petcoke to promote stable gasification operations and high syngas output. These plants have shown the longest continuous runs and greatest uptime of all the SCGP plants. The ability to gasify low-quality coal with petcoke is likely to become increasingly advantageous as more coal-to-chemical facilities come online and coal quality generally deteriorates as high-grade reserves become exhausted.

Gasifying petcoke may be an attractive power-generation option in the Middle East, where petcoke could be a widely available, low-cost feed. Some recycled ash/slag or a locally sourced fresh ash would need to be added, as the SCGP design principle requires sufficient ash in the feed to form a protection layer in the gasifier.

Shell is capturing the extensive and growing knowledge of the behavior of different coal types in the SCGP in a database and has established a basic theory about the effects of coal quality on gasification, which it has verified using the experience database. The result is a powerful and practical modeling tool that is helping users to select and evaluate coal types without conducting expensive trial runs and to make day-to-day production decisions.

Continuous Improvement

Substantial value can be captured early in coal gasification investments through good project definition and smart configuration (developing the best plan). A project's value can be enhanced further by correct project execution and continuous improvement (optimizing the completed facilities).

Shell gives SCGP users intensive operational training and

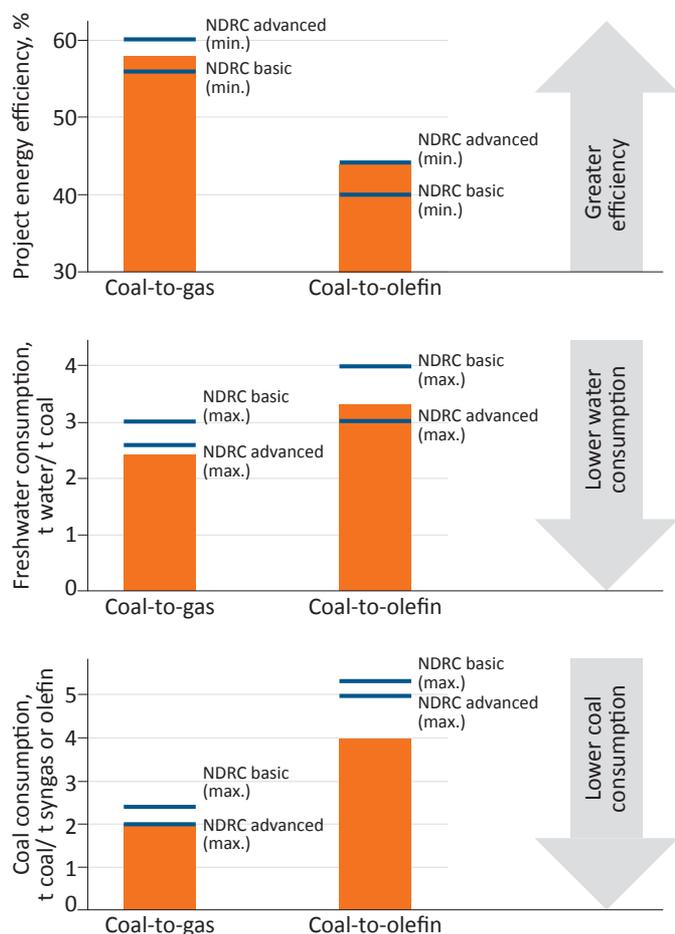


FIGURE 3. SCGP syngas cooler technology performance compared with NDRC requirements (Shell analysis)

dedicated support for start-up and early runs. In addition, they help users to establish a plant management system to improve reliability, manage risk, and plan equipment maintenance. This structured process ensures that users learn about the plant and become familiar with it as quickly as possible, thereby increasing equipment reliability and establishing a solid foundation for high-load operation over extended cycles of use.

Shell also recognizes the importance of creating opportunities to learn from operational experiences in the pursuit of continuous improvement. To this end, all technical information relating to improvements is collected and used to build a database of lessons learned, to the benefit of its licensees. Shell has also facilitated eight global coal gasification technology users' conferences in the past six years. These forums, hosted at different operating sites, provide a platform for licensees to discuss and improve their operations.

In addition, lead users strongly committed to improving the operation and design of this technology are working together on a reliability board to discuss specific experiences and capture the means for achieving good performance. The reliability board meets more frequently than the larger user conference to work on particular issues and implement the lessons learned.

Thus, the experience of solving problems and improving plant performance has become part of the process of continuous improvement. Any issues identified are fed to a team of people at Shell who develop solutions. This team includes process, mechanical, and control engineers. Using their understanding of the technology and their ability to communicate effectively and rapidly with clients, they can help to resolve the issues and, most importantly, feed improvements back to the master design to benefit future customers.

The benefits of this feedback process range from minor improvements and changes in the type of valve used to major developments such as dealing with blockage of the inlet of the syngas cooler or candle filter breakages. Some solutions apply to a range of situations, others just to a single plant. The change process is strictly managed; this combination of actions has resulted in positive feedback from clients.

Effect on Reliability

SCGP users are employing a structured improvement process to achieve high levels of reliability. In China, for example, users typically accumulate more than 300 days per year of normal operation. One chemical plant has achieved over 328 running

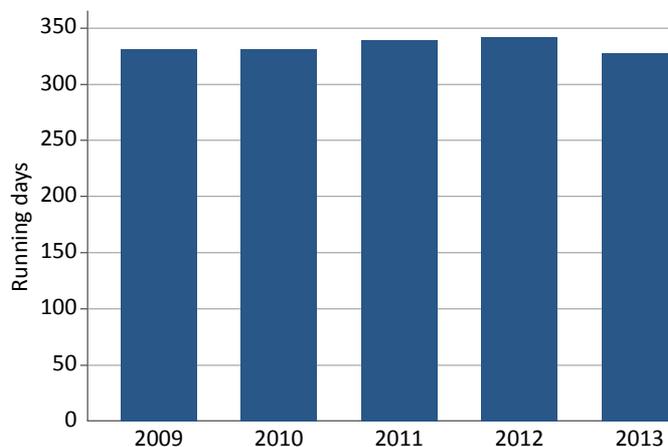


FIGURE 4. Cumulative running days for a Chinese coal-to-chemicals plant employing SCGP technology

days in each of the last five years, with a highest yearly total of 341 days (Figure 4). It is important to note that SCGP lineups do not require spare gasifiers, although multiple units are used for large-capacity projects. Some alternative lineups claim higher reliability levels, but use spare gasifiers, which add significantly to a project's capital costs.

Burner lifetimes typically exceed 8000 hours, and the filter candles typically have lifetimes of two to three years.

To ensure that each SCGP lineup offers improved reliability and performance, Shell captures lessons learned from all the technology users in a database and applies them to improving the master design.

EVER-INCREASING PERFORMANCE

SCGP technology is proven to offer high-efficiency coal gasification, excellent environmental performance, and good feedstock flexibility. It has been applied worldwide to a broad range of successful chemical and IGCC applications, and a coal-to-liquids plant under construction. Due to the structured learning procedure and a culture of continuous improvement culture adopted by users worldwide, SCGP technology operates with ever-increasing levels of reliability and performance. 🔄

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Distributed Power With Advanced Clean Coal Gasification Technology

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One major barrier for clean coal gasification technologies being implemented into conventional energy sectors has been the perception that a large capital investment is required to move away from a natural gas or oil feedstock to a solid feedstock such as coal or biomass, and the conversion thereof. Historically, this has marginally been the case in some places where gasification projects have been implemented to “fuel” chemical, power, fertilizer, and other energy projects. However, projects that can take advantage of the optimal “integration” of gasification and downstream processing technologies and maximize capital effectiveness and efficiency can reap great benefits from gasification technologies. In cases where the lowest cost feedstocks can be used and feedstock flexibility is maximized, again without overspending capital, the projects’ return on investment can be further enhanced.

During the last few decades, many well-established gasification companies have attempted to improve integration with downstream technologies, yielding mixed results. In some instances, the optimized plant configuration resulted in significant cost savings—giving the project a reduced cost of production for its end product. In other instances, the integration was so complex that significant additional capital was required to realize such optimization and the technical

difficulties encountered during startup and operation had a negative impact on the project and its economic performance.

Synthesis Energy Systems (SES) has developed, demonstrated, and deployed its advanced fluidized bed SES Gasification Technology, which is able to cleanly convert low-grade, low-cost coal, coal wastes, and biomass into multiple high-value end products without the same level of capital investment required for most gasification projects. Based on the fuel flexibility and lower upfront costs, SES’ fluidized bed gasification technology has been breaking barriers to enter markets previously not considered feasible for smaller-scale gasification projects. The products at such facilities include direct reduced iron steel, transportation fuels, chemicals, fertilizers, coal-derived synthetic natural gas, and power generation—the one market segment where it has been most difficult for gasification to succeed economically.

“Fluidized bed gasification technology has been breaking barriers to enter markets previously not considered feasible for smaller-scale gasification projects.”

HISTORICAL IGCC IMPLEMENTATION

The first integrated gasification combined-cycle (IGCC) facility using coal as feedstock was constructed in the early 1980s in California using General Electric (formerly Texaco) gasification technology in combination with GE’s heavy-duty gas turbines. It was funded partially by the U.S. Department of Energy as a proof-of-concept. At the time of project initiation, the 1970s oil crisis was in full swing, and there was a mandate from the U.S. government to develop homegrown technologies to replace dependence on imported energy sources, especially oil, in an environmentally friendly manner.

Under the Cool Water Coal Gasification Program, an IGCC plant was constructed in Southern California and operated from 1984 to 1989 on four types of bituminous coals using



SES’ Zao Zhuang New Gas Company Joint Venture Plant that produces methanol from coal—Shandong Province, China (SES ~98% ownership)

high-purity oxygen.¹ The plant released just a fraction of the permitted air-quality-related emissions at the time and achieved about 90% reliability—exceeding the benchmark set by conventional coal power generation technologies. According to the final report issued by the Electric Power Research Institute (EPRI),² a participant in the program, the project accomplished the demonstration of low SO₂, NO_x, and particulate emissions. No solid waste was generated due to sulfur removal, the capital and electricity costs were competitive, and feedstock flexibility was achieved. Actual installed costs for the 93-MW plant were \$315.2MM (\$3387/kW).² EPRI found that the installation cost of a “mature technology” Cool Water plant could be as low as \$1567/kW,² which became the target for future IGCC plants in the U.S. Although the project was deemed to be fuel flexible, the coals gasified at the plant were within 4% of the plant’s designed coal heat content of 11,300 BTU/kWh,² which was actually a very narrow feedstock window.

“In regions where solid feedstocks are available, and gas and oil resources are scarce and expensive, syngas generated from solid fuel gasification can enable the economical production of chemical and energy products...”

During the next two decades, several more commercial-scale IGCC plants were constructed, including³:

- Wabash River Coal Gasification Repower Project (1995), Indiana – CB&I
- Polk Power Station IGCC Plant (1996), Florida – GE
- Willem-Alexander IGCC Plant (1998), Buggenum, Netherlands – Shell
- ELCOGAS IGCC Plant (1998), Puertollano, Spain – Uhde (PRENFLO™)
- Duke Edwardsport IGCC Plant (2013), Indiana – GE

Common to all of the plants listed above, and most of the other commercially operating IGCC plants, is the use of entrained flow gasification technologies, which require the use of expensive, high-quality bituminous and sub-bituminous coals, have a narrow feedstock quality capability, and allow limited

deviation from the intended “design” feedstock. Additionally, all of the subsequent IGCC plants were constructed as one-of-a-kind designs, which does not lead to further cost reductions in implementation from design repeat practices. Lastly, the most recently developed large utility-scale plants (>400 MW_{net}), based on a “bigger is better” mentality, generally require such large capital investments that the multibillion dollar projects have been difficult to develop and finance.

The previously listed large-scale power-producing gasification projects highlight that there is progress being made and sufficient market drivers to advance the deployment of IGCC. However, in some less affluent areas, multi-billion dollar capital investments and reliable access to low-ash coal may not be practical or feasible. Therefore, we believe that smaller, less capital intensive, and more fuel-flexible gasification facilities can serve an important role, often in places where gasification is needed most—developing countries with access to low-rank coal or other solid feedstocks, but limited financial resources.

TRANSFORMATIVE TECHNOLOGY

SES licenses its proprietary fluidized bed gasification technology into markets where high-value products, conventionally produced from natural gas and oil, can be produced from synthesis gas (syngas) via coal, coal wastes, biomass, and other waste materials. In regions where solid feedstocks are available, and gas and oil resources are scarce and expensive, syngas generated from solid fuel gasification can enable the economical production of chemical and energy products such as methanol and its derivatives, fertilizers, electricity, hydrogen for refining, transportation fuels such as gasoline and diesel, substitute natural gas (SNG), reducing gas for metals refining, and fuel gases. SES’ gasification technology, which has over 40 years of development behind it, is well suited for a wide range of carbonaceous feedstocks, including the lowest cost, lowest quality options available. Over the last decade, SES has implemented and enhanced the gasification system design from the original U-GAS® technology, developed by the Gas Technology Institute in Chicago, Illinois.

The SES Gasification Technology includes a dry-feed system with multiple feed ports, using oxygen, enriched air, or air as the oxidant, into a single reactor that operates under a bubbling-bed fluidization regime. A bubbling bed reactor has a forgiving operating envelope; the large volume of feedstock in the gasifier as compared to the feed rate allows the operation of the gasifier to have reduced sensitivity to feedstock fluctuations and other operating parameter changes. The gasifier operates with uniform bulk reactor temperatures, which prevents the formation of tars and oils. The syngas leaves the top of the gasifier through a series of cyclones, which remove the particulate matter and return it to the gasifier for additional

conversion. The ash is removed through the bottom of the gasifier where it is cooled and depressurized for ease of handling. After the first set of cyclones, the hot syngas is used to raise superheated medium-pressure steam, which is then used as a primary fluidizing media in the gasifier along with the oxidant. The syngas is then further scrubbed to remove any remaining particulate matter before it is ready for additional downstream processing into a multitude of potential energy and chemical products (see Figure 1).

Fluidized beds are cost effective to build and operate reliably, which is why the SES Gasification Technology leads to lower capital investment, lower operating costs, and higher plant availability (compared to other commercialized gasification technologies). Fluidized bed gasification systems have simpler equipment designs, reduced oxidant usage, and increased fuel and operational flexibility that include on-stream fuel switching and gasifier turndown capabilities to 30% of the designed syngas production rates. Additionally, the SES Gasification Technology offers minimal wastewater discharge as compared to many other gasification technologies through the use of dry solids handling processes, and no generation of tars and oils from coal gasification, which can be extremely costly to clean from syngas.

Perhaps one of the most important attributes of the SES Gasification Technology is that it is fuel-flexible—capable of gasifying all ranks of coal, coal wastes, and other solid fuels, thus allowing its end users to secure the lowest cost feedstock for their operations, and further lower the cost of production of the valuable chemical and energy products (see Table 1).

PAIRING SES GASIFICATION TECHNOLOGY WITH GE'S POWER GENERATION TECHNOLOGY

In early 2013, SES and GE's aero-derivative gas turbine group began co-marketing a small- to medium- scale, standardized design, cleaner coal gasification plant for the distributed power market (<300 MW). This plant design is intended to have numerous economic, environmental, and societal advantages.

Chief among the benefits is that the plant enables customers to use the lowest quality, and thereby lowest cost, coals and has the ability to switch coal feedstocks with no plant modifications. It optimizes "reuse" of plant design through use of fuel-flexible gasification technology: The wider the fuel envelope for the gasifiers with little to no impact on the equipment design, the greater the reuse of plant design will be. The plant's modular design standardizes on 90% of the plant, allowing for modifications only in packaged process units (like air separation) or in coal handling units to accommodate different ash content requirements. Staying smaller and standardizing on a nonutility-scale basis widens the market to distributed power

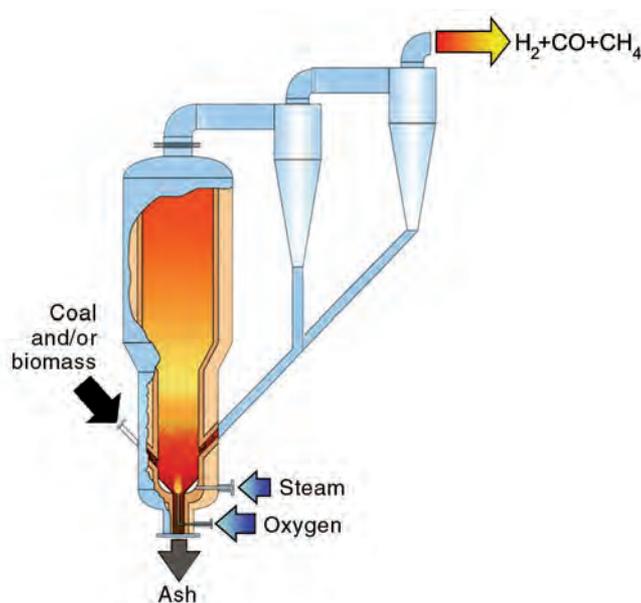


FIGURE 1. SES Gasification Technology based on a fluidized bed gasifier

and captive power users like mining operations and stand-alone chemical or refinery applications. The plant also implements World Bank environmental standards into the base design with allowances for modifications to improve on the environmental performance if local permitting mandates it.

Additionally, the new plant design limits the complexity of integration and avoids the temptation to over-optimize and thus drive up project costs; the simple design also allows for utilization of regional partners. Partnering with local EPC

TABLE 1. Range of fuel characteristics tested with SES Gasification Technology

<i>SES Gasification Technology Fuel Flexibility</i>	<i>Tested Range</i>
Moisture, wt%	1–41
Volatile Matter, wt%	3–69
Fixed Carbon, wt%	6–83
Sulfur, wt%	0.2–4.6
Free Swelling Index	0–8
Ash Content, wt%	<1–55%
Ash Fusion T, °C (initial deformation T1)	1030–1370
Heating Value, kcal/kg	3000–7800

contractors and power project developers also improves the likelihood of project success. Today, SES and GE are marketing to regions where large utility-scale plants are not feasible due to lack of grid infrastructure, natural gas is nonexistent or prohibitively expensive, low-quality local coal is unusable in conventional boilers, and/or power is generated from expensive imported LNG or fuel oil/diesel.

INTEGRATION WITH A LITTLE “I”

Whereas previously designed and constructed IGCC plants placed significant focus on maximizing integration with the intent to maximize plant efficiency, SES and GE have taken a different approach on a small- to medium-scale SES Gasification Technology-based power plant design. By limiting and prioritizing the integration of the gasification and power production technologies, the design lends itself to lower capital costs and simplicity with a greater ease of operation including startup sequencing. The ability for the power plant to maximize the use of prepackaged process units (such as air separation, water treatment, acid gas removal, and sulfur recovery units) and reduce the complexity of startup will allow the plant to benefit from simpler operations and process controls. Although the

installed cost on a per unit of power basis may be higher than conventional coal-based power generation technologies of the same scale, the reduced complexity does not exacerbate this issue, and still allows the cleaner coal plant to surpass CFB boiler and PC boiler technologies in emissions profile and overall plant efficiency. In other words, at this small scale, the reduced integration does not have the negative impact that would be expected when competing against larger, base-load utility coal facilities. Additionally, as gasification plants produce a high-purity CO₂ stream, they are essentially carbon-capture ready.⁴

The integration with a little “i” includes sending syngas to the GE turbines (see Figure 2). Exhaust from the turbines as well as superheated steam is sent to the heat recovery steam generator (HRSG), which is also integrated with a steam turbine.

SES’ DISTRIBUTED POWER PLANT CONCEPT: THE FIRST PASS

In January 2014, the first potential customer for launch of this small- to medium-scale gasification distributed power plant was identified and preliminary engineering efforts were

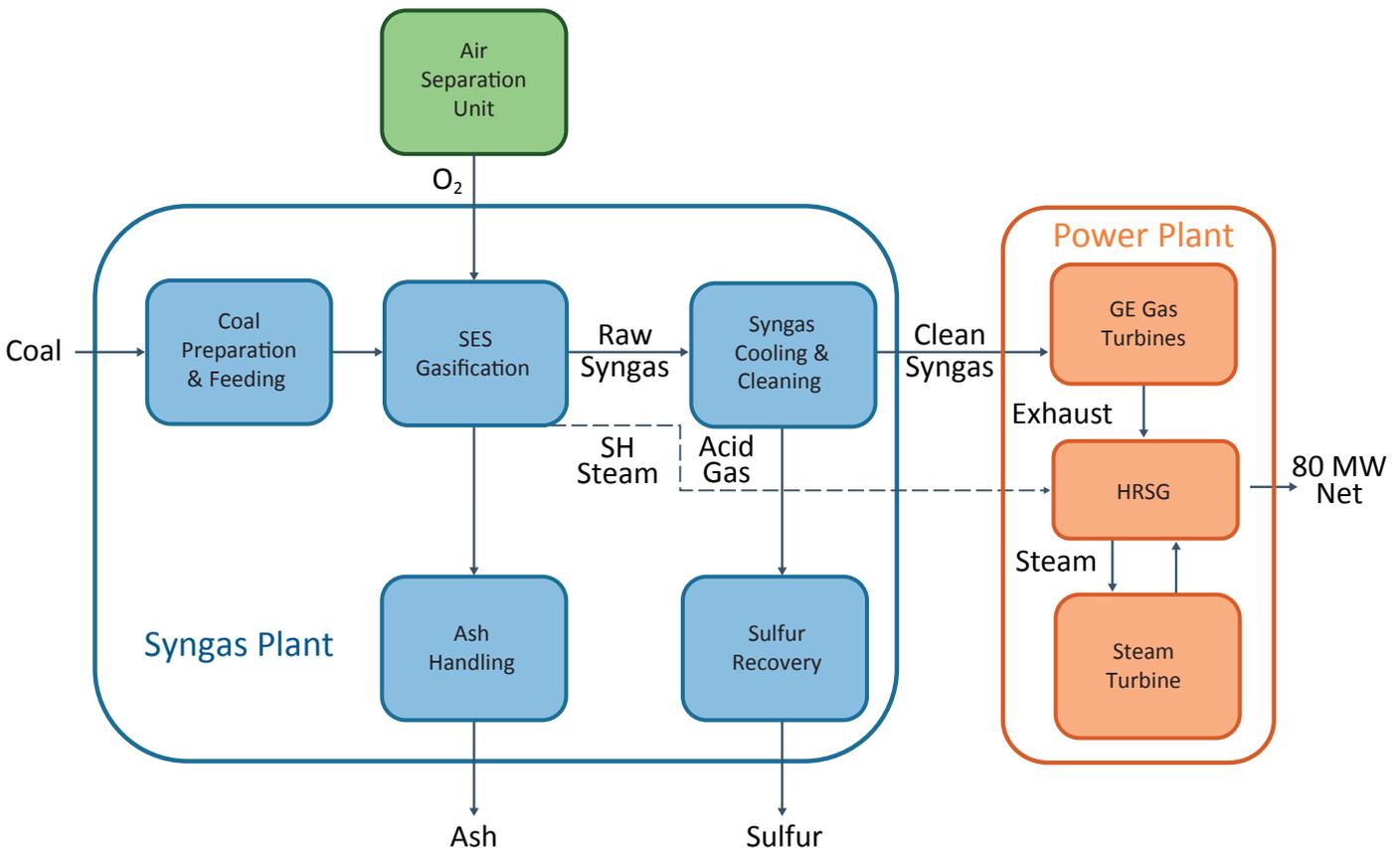


FIGURE 2. Schematic of the proposed integration of SES Gasification Technology with power generation

undertaken. The early work performed by SES, with support from GE and their regional partners Tuten and IstroEnergro Group, yielded the following design components regarding the combined technologies:

1. System Design:
 - a. Single SES gasifier system, operating at nominally 50 bar(g), on high-purity oxygen, and consuming 1100–1700 tonnes/day of coal (depending on coal quality) to produce clean syngas that is suitable for GE’s LM-2500 series aero-derivative gas turbines.
 - b. Two GE LM-2500+G4 gas turbines in combined cycle with a single steam turbine and HRSG.
 - c. SES gasifier system sends excess superheated medium pressure steam to the power plant.
2. Net power output is nominally 80 MW, with projected improvement based on minor modifications to the gas turbine fuel nozzle.
3. Feedstock capability includes lignite, sub-bituminous, and bituminous coals with heat contents as low as 3000 kcal/kg (as received, LHV).
4. Reuse of process units from the SES Gasification Technology system through syngas cooling, fines removal, acid gas removal, sulfur recovery unit, and the gas turbines. The “flex” packaged units would include air separation unit, coal handling and preparation, ash handling,^A and the bottoming cycle in the power plant.
5. Initial budgetary estimates start as low as \$1800/kW installed costs for a China construction basis and are projected to run \$2000–2500/kW for a significant portion of the market; these prices can be achieved through maximizing fabrication of packaged units and major process equipment via qualified and internationally accredited Chinese fabricators.
6. The estimated net LHV plant efficiency is 34–38% depending on coal quality, plant site conditions, and elevation.

7. Operating and maintenance costs, excluding coal costs, are estimated to be 2–3% of the total installed cost basis annually.⁴

A sample of the projected plant economics is provided in Table 2.

DEPLOYING DISTRIBUTED GASIFICATION POWER ONE PLANT AT A TIME

Tackling the major barriers to implementing coal gasification projects is SES’ main focus and the SES Gasification Technology’s capability of converting a wide range of low-cost, low-quality coals is the largest factor in achieving good project economics. In addition, SES has developed equipment manufacturing capabilities in China that help it reduce the capital costs required to build projects.

SES has partnered with Zhangjiagang Chemical Machinery Co., Ltd. (ZCM) for its China and select Asia regional business, forming Jiangsu Tianwo-SES Clean Energy Technologies Ltd. (T-SEC), which is intended to enable global-scale implementation of projects using SES Gasification Technology via the lowest cost supplier of process equipment. This partnership is designed to enable SES to pass on savings to its customers, thereby reducing the overall capital expenditure for historically capital-intensive gasification projects.

SES secured the global exclusive rights to this technology more than a decade ago, and has since constructed five of its low-quality coal gasification systems in two methanol-producing plants in China: the Zao Zhuang New Gas Company Joint Venture Plant (ZZ) in Shandong Province and the Yima Joint Venture Plant (Yima) in Henan Province. Both plants convert low-grade coals and coal wastes, with very high ash content regularly exceeding 40 wt%, into syngas which is then converted into refined methanol. The ZZ plant, constructed in

TABLE 2. Example indicative plant economic factors based on Indonesian lignite

Fuel Input	35 wt% moisture (as received)	3840 kcal/kg LHV
	~1200 tonnes/day	\$30/tonne delivered
Plant Performance	Net Efficiency ~36% LHV	Net Output 80 MW
	Plant Life = 30 years	Availability = 90%
Financing Assumptions	\$240MM Installed Cost	2 yrs construction
	30% Equity/70% Debt (15 yr)	8% Interest Rate
	O&M Costs = 2% Installed Costs (annually)	
Economic Performance	At \$100/MWh (net)	At \$120/MWh (net)
	22% Unlevered ROE	18% Unlevered ROE
	41% Levered ROE	29% Levered ROE



Yima Joint Venture Plant—Henan Province, China (SES 25% ownership)

2007 with commercial operation initiated in 2008, housed the largest U-GAS® based gasifiers ever installed at the time: two SES gasifiers, each with a capacity to produce 14,000 Nm³/hr of syngas.

At the Yima plant, which had its first methanol production in 2012, SES scaled up from the ZZ gasifier capacity and pressure threefold, installing three 1200-tpd SES gasifiers that operate at 10 bar(g), each with the capability to produce 45,000 Nm³/hr of syngas. During the first years of operation at ZZ, SES devised and implemented multiple improvements to the U-GAS® technology, many of which were included in the design of the Yima plant. These improvements increased carbon conversion, overall gasifier efficiency, operability, and heat recovery. These enhancements, along with additional optimizations that are being devised from the larger scale Yima gasifiers, are included in SES' high-pressure gasification system design—optimized for chemicals and energy production where downstream processes benefit or require high-pressure syngas for end-product manufacturing.

CONCLUSION

Gasification is a global solution for the utilization of the world's most abundant natural resource—coal—to produce chemical and energy products cleanly and efficiently. The challenge to do this economically and in markets that are not likely to support a large capital investment has been a historic challenge for gasification, and SES is making headway on knocking down the two major barriers to cost effectiveness: large capital investment and required access to expensive, high-quality coals. Through the implementation of a low-cost source for process

equipment and the ability to use the lowest cost fuels available, SES believes it can enable projects to proceed in even the most challenging market: distributed power generation from coal gasification. SES is excited to move forward with its project partners to implement its clean coal gasification technology into the distributed power market for the production of clean, efficient, and economic electricity production. 🏭

NOTES

- A. Only as a cost savings measure for plants which will have known maximum ash contents for their fuel sources.

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For more information regarding SES and its technology, please visit www.synthesisenergy.com

Moving Forward With the Huaneng GreenGen IGCC Demonstration

By Xu Shisen

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China has abundant coal reserves, but is short on oil and gas resources; therefore, its power generation fleet is expected to rely primarily on coal for the long term. However, coal-fired power generation can result in undesirable emissions such as particulate matter, SO₂, NO_x, Hg, and large quantities of CO₂. As global environmental concerns mount, especially those related to climate change, controlling criteria emissions and greenhouse gas emissions has become increasingly important. How best to realize the goal of clean and efficient utilization of coal for electricity generation is a challenge facing China as well as the broader international energy community.

IGCC CAN BE A SOLUTION

Globally, integrated gasification and combined-cycle (IGCC) power plants are a potential option that would make possible lower-emissions, higher-efficiency coal utilization. However, costs must be decreased and reliability must improve before IGCC is ready for commercial application.

Emergence of IGCC

Research and development on IGCC began in the 1960s. Industry demonstrations started in the 1990s and commercial operation and further developments are now underway globally. IGCC technologies developed in the U.S., Europe, and Japan share the following features:

1. These countries regard IGCC technology development as an important part of their national energy strategies.
2. Core technologies and key equipment are produced in their own countries or regions.
3. Investment in demonstration projects has come from both

“The GreenGen project has already demonstrated that gasification can be an efficient, low-emissions option for coal utilization in China and the world.”



A 250-MW capacity IGCC power station was designed, constructed, and operated under Phase I of the GreenGen Plan.



The full Phase I GreenGen IGCC facility is shown above.

governments and corporations.

4. Through demonstration, project developers are hoping to commercialize their core technologies and become more competitive in the future.

To effectively meet the demands of the future IGCC market, GE (U.S.) and Siemens (Germany) respectively acquired their nationally developed coal gasification technologies. Along with the Mitsubishi Group (Japan), these companies have become global IGCC technology suppliers, offering two IGCC core technologies—coal gasification and syngas turbines.

State of IGCC In China

Currently, Chinese technology providers are able to design and optimize large IGCC power stations and provide gasification, syngas purification, waste heat boilers, steam turbines, air separation, and other systems and equipment for IGCC power stations. This lays a solid technical foundation for large-scale commercial construction and operation of IGCC power stations. In addition, China has recently seen breakthroughs in domestic gasification research and development. The two-stage dry pulverized coal pressurized gasification technology developed by the Huaneng Clean Energy Research Institute is competitive with internationally developed technologies in all key indices. Moreover, the design and manufacture of 1000-t/d and 2000-t/d gasifiers have been completed, which are being used in Inner Mongolia's Shilin coal-to-methanol project and the CHNG GreenGen 250-MW IGCC power plant, respectively. The 1000-t/d and 2000-t/d multinozzle impinging stream coal-water slurry gasifiers developed by Yankuang and East China University of Science and Technology have also been placed into operation. However, gas turbine technology in China still lags behind systems developed internationally. Today the operating conditions for China's systems are not

yet suitable for the commercial application of low-heat-value syngas turbines for IGCC power stations. One ongoing project, however, is focused on the research, development, demonstration, and deployment necessary to advance Chinese IGCC systems.

The GreenGen Plan

In 2004, China Huaneng Group (CHNG) took the lead in putting forward the GreenGen Plan and joined with several power generation and coal-producing enterprises to launch an effort to demonstrate a coal-based power generation system with increased efficiency and near-zero emissions. The purpose of this plan was to research, develop, and demonstrate a new coal-based system that would include hydrogen production from coal gasification, power generation based on combined-cycle hydrogen turbines and fuel cells, and carbon capture, utilization, and storage (CCUS). The plan garnered support from China's National 863 Program in the 11th and 12th Five-Year Plans.

The core technology for GreenGen is power generation based on IGCC—a well-known technology that includes gasification of coal to produce syngas, which is purified before being combusted to drive an electricity-generating gas turbine. The high-temperature exhaust gas from the gas turbine is utilized by a pre-boiler to produce steam, which then drives a steam turbine to produce additional electricity. Compared with supercritical pulverized coal combustion power generation, IGCC can be more efficient, may offer greater potential for improvements, and can be used to realize near-zero emissions, including increased ease of CO₂ capture. Moreover, it can be combined with coal-derived hydrogen and fuel cell power generation technologies to form a more advanced and diversified energy production system. For these reasons,

development of IGCC technologies is an important direction for the future of coal-based clean energy power generation in China.

GreenGen is being carried out in three phases. In Phase I, a 250-MW IGCC power station with proprietary technologies was constructed. In Phase II (currently underway), the key technologies involved in GreenGen will be further researched, developed, and demonstrated. Examples of key technologies include hydrogen production from coal gasification, the separation of H₂ and CO₂ (i.e., pre-combustion CO₂ capture), fuel cell power generation, and CCUS. In Phase III, the plan is to build a 400-MW GreenGen demonstration project that will include full integration of key technologies, realizing high-efficiency coal utilization with near-zero emissions. During all phases the emphasis is on improving the technical reliability and economic feasibility of the GreenGen system in preparation for eventual deployment and widespread commercial use.

PROGRESS TO DATE

From 2004 to 2008, CHNG completed the system design, equipment bidding, and all preliminary work for the 250-MW IGCC demonstration power station, which was sited in Tianjin. In May 2009, the project was approved by the National Development and Reform Commission, which made it clear that the core technologies should be domestically sourced. Construction began in July 2009 and was completed by September 2012. In November 2014 the plant successfully passed the standard test of 72 hours of continuous operation with another 24 hours of operation at full load. The IGCC facility



The Chinese-developed gasifier used in Phase I of GreenGen is shown above.

was formally put into commercial operation in December 2012. Thus, as of late 2012, China joined the ranks of those countries that have mastered IGCC power station design, construction, and operation. This achievement marked a major breakthrough in China's strategic effort to advance its clean coal power generation.

The overall system is based on a 2000-t/d two-stage dry pulverized coal pressurized gasification technology, a proprietary IGCC process design, and a power island with an E-class multi-shaft combined-cycle generating unit. This project realized independent development, design, manufacture, and construction. Many technologies had to be mastered to reach this stage, including the design of a large IGCC power station, gasification, purification, air separation, heat recovery boiler, and steam turbine power generation, all of which are important to further promoting clean coal power generation in China. As the technologies used for GreenGen were domestically sourced, China has also gained an enhanced capacity for independent innovation from project experience. Currently, the GreenGen IGCC demonstration power station has realized steady operation at high capacity (maximum 92% of design) for 29 consecutive days.

Since the successful completion of Phase I of the GreenGen Plan, CHNG has been actively pursuing Phase II: researching and developing the key technologies within GreenGen. Specifically, with the support awarded under the 863 Program, CHNG is developing a pilot-scale system that will draw about 7% of the syngas from the GreenGen IGCC power station, shift CO and H₂O to CO₂ and H₂, and then separate the CO₂ from the H₂ after desulfurization. The CO₂ will be liquefied and used to explore how to enhance oil recovery with the end fate of the CO₂ being geological storage. The separated H₂-rich gas will be sent to the gas turbine for mixed firing after compression.

About 60,000–100,000 tonnes per year of CO₂ will be captured and stored under the Phase II (CCUS) demonstration. Phase II will lay the foundation for subsequent research on CO₂ capture for the entire IGCC power plant.

This demonstration of pre-combustion CCUS will boast the largest capacity and the most comprehensive process evaluation underway in China when it is in operation. Experiments will be undertaken under various loads and other operating conditions, paving the way for the exploration of low-energy consumption, high-recovery CCUS. With the research, development, and design of the demonstration plant for the CO₂ capture technology already complete, the construction under Phase II began in early 2014. Since the sites for the oil displacement wells and CO₂ storage were determined previously, CO₂-EOR and CO₂ storage experiments will be conducted as soon as the CO₂ capture plant is ready.

ANALYSIS OF IGCC’S TECHNICAL FEATURES

Table 1 lists the designed technical indices for the GreenGen IGCC Power Station. The designed power generation output is 265 MW, generating efficiency is 48%, power-supply efficiency is 41%, and coal consumption for power supply is 299 g/kWh.

Table 2 lists the actual technical indices of the GreenGen IGCC Power Station when it began operation. Compared with sub-critical and most supercritical coal-fired units, GreenGen’s designed standard coal consumption of power supply is superior. However, it consumes more coal than a 1000-MW ultra-supercritical coal-fired unit. This can be attributed to the fact that the GreenGen IGCC power plant employs E-class turbines. If F-class, G-class, or even the higher-rated H-class gas turbines are subsequently employed, the efficiency of the GreenGen IGCC power station will increase markedly. In terms of parasitic power, the power consumption from the IGCC power station remains quite high as the air compressor and supercharger units of the power station are currently driven by electricity. If gas-fueled drives are adopted, the station’s power consumption rate is expected to fall from 28% to just 5%, making the plant even more efficient.

Table 3 includes a comparison of the designed indices of three typical advanced coal-fired power stations: the 1000-MW ultra-supercritical power plant of the Phase III Shanghai Waigaoqiao Power Plant, the 1000-MW ultra-supercritical air-cooled Ningxia Lingwu Power Plant, and the GreenGen 250-MW IGCC power plant. Currently, the GreenGen IGCC demonstration power station is competitive with the most advanced ultra-supercritical units in several technical indices. Similar to the standard coal consumption, use of higher-rated turbines would further improve the technical indices of the GreenGen IGCC facility.

TABLE 1. Designed technical indices of the GreenGen IGCC Power Station

<i>Technical Index</i>	<i>Design Value</i>
Generated output, MW	265
Generating efficiency, %	48
Power-supply efficiency, %	41.09
Standard coal consumption for power generation, g/kWh	254
Standard coal consumption of power supply, g/kWh	299
SO ₂ emissions concentration, mg/Nm ³	<1.4
Particulate matter emissions, mg/Nm ³	<1.0
NO _x emissions, mg/Nm ³	<80

TABLE 2. Actual technical indices of the GreenGen IGCC Power Station during initial operation compared with other power plant options

<i>Unit Capacity</i>	<i>Standard Coal Consumption for Power Supply, g/kWh</i>	<i>Station Power Consumption Rate, %</i>
<i>GreenGen IGCC Power Station (265-MW)</i>	299.4	17
<i>300-MW subcritical unit</i>	332.7	5.3
<i>600-MW subcritical unit</i>	324.9	5.2
<i>600-MW supercritical unit</i>	307.5	4.6
<i>1000-MW ultra-supercritical unit</i>	286.1	4.5

Currently, the GreenGen IGCC Power Station emits 0.9, 47.87, and 0.6 mg/Nm³ of SO₂, NO_x, and particulate matter, respectively. The emission rates are far below the emissions of some of the most advanced coal-fired power stations in China and are competitive with advanced gas-fired units. With further possibility to improve on performance as the scale of the technology is increased, the GreenGen project has already demonstrated that gasification can be an efficient, low-emissions option for coal utilization in China and the world.

PLANS FOR FUTURE DEVELOPMENT

Industry-Wide Concepts

Compared with the widely used and fully commercial pulverized coal-fired power plants, IGCC is less developed and in the demonstration stage in China. The high construction and operating costs are among the main obstacles for future development and deployment. It is a top priority to speed up development and demonstration of IGCC technology in China and to promote the technology based on the following:

- Use high-temperature and high-pressure gas turbines to improve IGCC efficiency. If G-class or even H-class gas turbines are used, IGCC power stations could become much more efficient (reaching 58%), making IGCC increasingly competitive.
- Reduce the construction costs for IGCC power stations. Increasing the scale of equipment produced in China, coupled with standardized designs and integration of chemical and power industry standards, will considerably reduce construc-

TABLE 3. Comparison of designed technical indices of typical advanced coal-fired power stations

<i>Technical Index</i>	<i>Phase III Shanghai Waigaoqiao Power Plant</i>	<i>Phase II Ningxia Lingwu Power Plant</i>	<i>GreenGen IGCC Power Plant</i>
<i>Energy conversion efficiency, %</i>	44.5	40.46	41.1
<i>Energy consumption per unit product, g/kWh</i>	276	303.5	299.4
<i>Water consumption per unit product, kg/kWh</i>	1.502	0.782	1.0
<i>CO₂ emission per unit product (in production process), g/kWh</i>	709.54	789.1	778.7
<i>CO₂ emission per unit product (in use), g/kWh</i>	712.2	792.1	781.7

tion costs and thus accelerate the commercialization process.

- Increase the rate of the development of IGCC technology and the building of demonstration projects through support of several large-scale IGCC commercial demonstration power stations. This will advance relevant technologies and the mass production of equipment, so as to bring down specific investments and power generation costs.
- Develop integrated IGCC/polygeneration systems to realize diversified production of chemical products, fuels, and power as end products and thus improve the overall cost-effectiveness of the IGCC system.
- Strengthen research into and demonstration of IGCC-based CCUS technologies to lay a solid foundation to scale up coal-based energy power generation with near-zero emissions and drastic reductions of greenhouse gases in the future.

Future Plans for GreenGen

Based on the success of GreenGen Plan Phase I, CHNG is now executing Phase II with plans to subsequently move forward with Phase III. The steps involved in Phase II and Phase III are detailed below:

Phase II (2013–2017): Carry out trial operations and optimize to improve the existing systems and key equipment and further improve the operating safety, stability, and reliability of the individual units within the overall process. Research and develop IGCC-based CCUS technologies and advance fuel cell and hydrogen-enriched gas combustion technologies. Conduct feasibility studies on large-capacity, high-parameter IGCC and CCUS. Begin preliminary preparations for GreenGen Phase III.

“Efforts will be made to continuously improve the cost-effectiveness and competitiveness of GreenGen-based IGCC units...”

Phase III (2018–2025): The plan is to build a 400–600-MW GreenGen demonstration plant that will include integration of key technologies such as IGCC, CCUS, fuel cell power generation, and combined-cycle power generation based on hydrogen-rich turbines and polygeneration. This demonstration plant will realize efficient coal-fired power generation with near-zero emissions of all major pollutants and CO₂. Meanwhile, efforts will be made to continuously improve the cost-effectiveness and competitiveness of GreenGen-based IGCC units in preparation for widespread commercial deployment.

A COMMON OBJECTIVE

With Phase I complete and Phase II successfully underway, the GreenGen project team is moving forward with the objective that this project can become the benchmark for commercial-scale, cost-effective, near-zero emissions, coal-based power generation. This is a goal that, if realized, would offer much strategic value not only to China, but to the world. 🌍

The Benefits and Challenges Associated With Coal in South Africa

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THE CORNERSTONE OF SOUTH AFRICAN ENERGY

The Electric Sector

Eskom is the state-owned utility charged with providing the country and greater region with power. Thirteen coal-fired power stations are currently in operation, including three that were recommissioned after being mothballed. All but three stations use pulverized fuel technologies.^{4,5}

The important role that coal has played in South Africa’s economic development is often downplayed in today’s world, where fossil fuels are frequently denigrated. Coal supplies over 70% of the country’s energy needs, over 90% of its electricity requirements, and over 95% of its metallurgical carbon (coke) requirements. While these percentages are likely to decline in the long run, they are likely to remain significant over the next 30 years, failing which serious long-term damage to the economy could result.

Coal was South Africa’s primary source of resource revenue for total sales value in 2011, 2012, and 2013 (Figure 1) and the first commodity to generate a total sales value in excess of R100 billion (US\$9.3 billion) in one year.¹⁻³ Such statistics highlight the continuing importance of coal to the South African economy.

“Coal has become to South Africa what oil is to the countries of the Middle East—the basis of its economy...”

Eskom relies on coal-fired power stations to produce approximately 90% of its electricity. These stations operate 24 hours a day to meet demand. Eskom’s Generation Division provides an installed capacity of 37,745 MW from the 13 coal-fired power stations. Their total net output, excluding the power consumed by their auxiliaries and generators currently in reserve storage, is 34,952 MW. Two new coal-fired power stations,

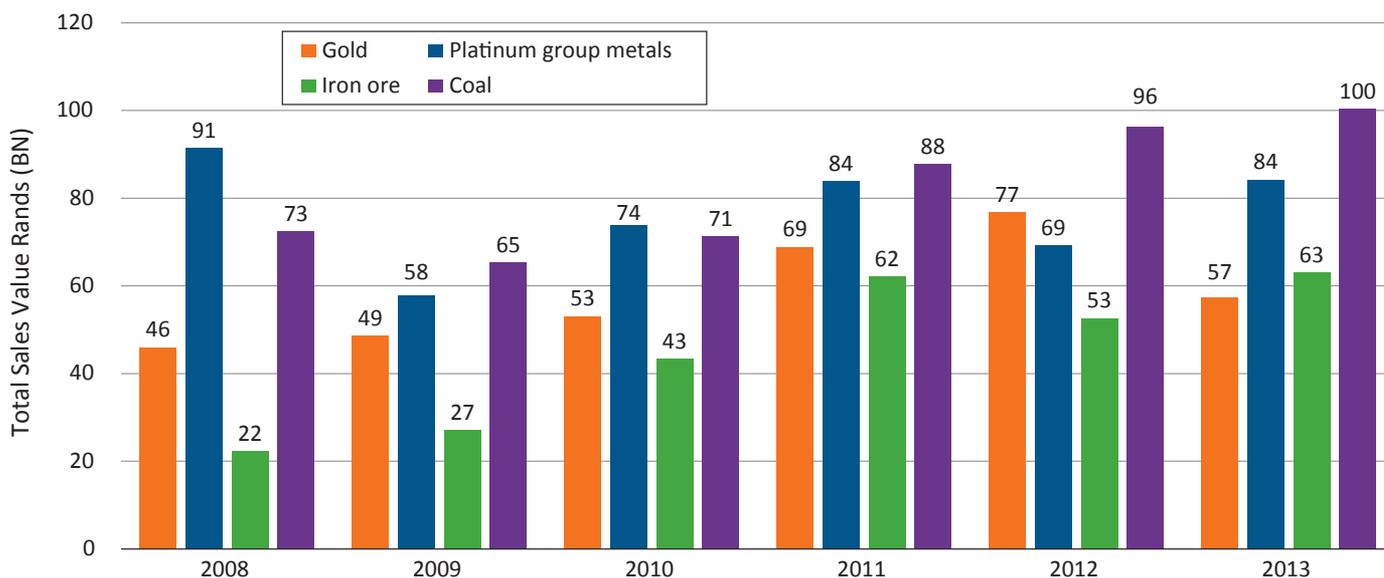


FIGURE 1. South African commodity summary for total sales in Rands (ZAR)

Medupi and Kusile (similar supercritical coal-fired power stations with a planned efficiency of 38% compared to 34% of the subcritical technologies in the older stations), are now under construction and are proceeding in accordance with environmental requirements from funders and legislation.

The Integrated Resources Plan for Electricity (IRP) envisages a further 6250 MW of new coal being required before 2030.⁶ We believe this will be totally inadequate if South Africa is to achieve higher rates of economic and industrial growth. The IRP envisages 9600 MW of new nuclear power. We are concerned that there will be fairly substantial delays in bringing nuclear power on line by 2023, given that the normally accepted lead time for nuclear power is 14 years. This could mean the new nuclear power may not come online until 2029 at the earliest.

Coal would be a more reliable and lower-cost baseload option for the time frames under consideration. The capital cost for coal-fired power stations, in particular, is substantially less than for nuclear power stations. We believe that the higher capital costs may well have compromised South Africa's sovereign ratings and, therefore, its ability to fund other essential infrastructure and social development programs. Although nuclear power should not be excluded, a smaller nuclear allocation would be a more prudent solution. Thus, we recommend that at least 8 GW of new coal capacity is required if South Africa is to achieve the higher levels of economic growth required by the National Development Plan. The fact is that energy, electricity, and employment growth are the keys to South Africa's future economic, social, and political prosperity, sustainability, and stability. Ensuring the security of supply of energy sources for electricity at competitive prices is a prerequisite for this to occur. Fossil fuels—in the form of gas and coal in South Africa's case—are the only sources of local energy that can provide sufficient security of baseload electricity supply for this to be a realistic, achievable goal.¹

The Cost and Coal Cliffs

A key national decision after the Second World War was that South Africa's industrial development should be based on inexpensive energy to promote growth. Given the resources available, coal-based energy became the central driving force behind the modern economic state of South Africa.

However, today's energy prices are skyrocketing. Eskom's tariff has more than tripled from R20 c/kWh in 2003 to >R70 c/kWh in 2014⁸ [compared with an average price of R212 c/kWh for Independent Power Producers (IPP) in 2013]. This is a result of the influence of the ruling party during the late 1990s when Eskom's proposal to build further coal-fired power stations due to diminishing spare capacity was rejected in favor of

IPPs which ultimately did not materialize, the current indecision regarding the way forward, and the World Bank's lending terms. The estimated cost of power from both Medupi and Kusile is expected to be about R1.00/kWh. In addition, the price is expected to double in the next five years. Known as the *cost cliff*, this is further exacerbated by the fact that most municipalities charge a 100% markup. This is caused by a multitude of factors, ranging from increases in the cost for coal and new-build power plants to policy measures, and means that homes and offices now pay ~R140 c/kWh, for example, in Gauteng.

Looking to the future, South Africa is facing a dramatic power crisis largely caused by the lack of sufficient coal for power generation over the next five years. Known as the looming *coal cliff*, the size of the coal shortfall ranges from 60 to 120 Mt and is expected to impact the country between 2014 and 2019. South Africa's biggest near-term energy challenge, therefore, is to supply Eskom over the next five years. Of the four billion tons of coal that Eskom will need over the next 40 years, two billion tons will need to come from new sources.

Sasol and CTL

In South Africa, Sasol has been producing fuels and chemicals using Fischer–Tropsch technology since 1955 and has evolved into one of the country's largest corporate contributors to economic development. Sasol contributes about R40 billion, or 4%, to South Africa's national annual gross domestic product (GDP). Sasol supplies about 25% of the country's liquid fuel needs through synfuels derived from coal and natural gas at Secunda, and an additional 12% from conventional fuels derived from crude-oil refining via their Natref oil refinery at Sasolburg. This saves the country more than R30 billion a year in foreign exchange as a result of not having to import finished



Sasol plays an important role in reducing reliance on imported oil by producing synthetic transportation fuels.

liquid petroleum product, chemical feedstock, intermediates, and final products.

SOUTH AFRICA'S ENERGY RESERVES

South Africa possesses an abundant supply of most key economically important minerals, with the key exception of crude oil. Natural gas on the Cape South and West coasts and the potential of the Karoo shale gas deposits could well resolve South Africa's energy problems for the next two or three generations. The largest energy resource is coal; the country is endowed with estimated coal reserves sufficient to cater for both domestic and export demand for 200 years with a sizeable reserve beginning to be exploited in the Waterberg in Limpopo Province and in the neighboring countries of Botswana, Zimbabwe, and Mozambique.

CHALLENGES

Coal has become to South Africa what oil is to the countries of the Middle East—the basis of its economy as the primary source of foreign exchange, energy, and its manufacturing industry. However, the future of coal in South Africa also faces many challenges, not the least of which is a lack of a clear strategy for the future.⁷ As the National Planning Commission (NPC) noted:⁷

While most of South Africa's energy comes from coal, it is striking that government has no integrated coal policy. South Africa ranks fifth internationally as a coal producer and exporter, yet government has no clear export strategy. There is also no integrated development of mining, rail and port infrastructure to facilitate either exports or anticipated increases in local production and consumption, within acceptable environmental constraints. The private shareholders of the Richards Bay Coal Terminal have expanded export capacity to 91 million tons per year. However, Transnet has barely been able to transport 60 million tons per year from the central coal fields to the coast. Government urgently needs to bring together all relevant players (mining companies, Transnet, Richards Bay Coal Terminal, relevant government departments, banks and others) to forge an agreed investment strategy and plan to accelerate coal exports, which could have beneficial balance of payment and current account impacts. An expanded export drive would need to be framed within a national policy on the optimal use of depleting coal reserves, including secure supplies for legacy power stations, and the opening of the Waterberg with the required rail links. The private sector has initiated work on a Coal Road Map. Government needs to be an active partner.

Although the current contribution of the coal value chain to the South African economy—in terms of employment, income, energy supply, and contribution to GDP, coupled with South Africa's significant coal resources—demonstrates a strong potential for continued economic benefit and energy security, there are a number of challenges to the value chain that will shape its future. Not the least of these is efforts to mitigate climate change, which is increasingly shaping international energy debates.

Therefore, serious consideration must be given to the risks and weaknesses that are starting to threaten this mineral commodity, as well as to the potential strengths and opportunities that could arise from a new approach in the future.

“The future of coal in South Africa also faces many challenges, not the least of which is a lack of a clear strategy for the future.”

Several major concerns confront coal in South Africa. For instance, *the run-of-mine coal qualities are now generally higher in ash content and therefore lower in grade* as much of the better quality coals have already been selectively extracted. Coals on the thermal (steam) market in South Africa are sold on grade (i.e., calorific content). From the late 1970s well into the 1990s, South Africa mined out and sold very clean low-ash coals (known as Special Grade) to Asia as blend coking coals (7% ash) and moderately clean (10–14% ash) coal to Europe (high-grade steam coals or Grade A).

The top grades (Grades A to B) with ash contents of 15% or less (note that little such coal remains) are now either exported or sold at a premium domestically/export parity. Such coal products are few and far between today and often not economically profitable to produce from the high-ash materials now being mined. This means that over 80% of local coals sold to the inland market (including Eskom and Sasol) are now classified as Grades C and D, with average ash contents of 20–30%. India is also a purchaser of some of these grades for their Indian power stations (generally ash contents of 20–25%), leaving local users with even lower grades for home use. Eskom now burns coal averaging 35–45% ash contents in some of its more recently built power stations.

Beneficiation of the coals currently being mined is therefore mandatory in order to provide products suitable for local and

export market purposes; this is with the exception of Eskom because they have designed their power stations according to the available coal.

The shortage of water for beneficiation processes is also becoming a serious concern, especially in remote coalfields such as those north of the main Karoo Basin. This is a limiting factor in the chain of production. Dry coal beneficiation processes are now under serious investigation. Eskom aims to reduce fresh-water usage and eliminate liquid effluent discharge through effective water management processes, water conservation and water-demand practices, as well as the treatment and potential use of mine water. The future key performance indicator targets progressively reduce to 1.20 L/kWh by 2017.

The production of ever-increasing tonnages of discard stockpiles arising from beneficiation is an ongoing point of concern for land owners and environmentalists. Currently over two billion tons are stored in stockpiles in various coal mining districts, with a further 60 million tons accumulating each year. Technological processes are being investigated to make use of this potentially useful carbon resource.

The coalfields of the future lying farther afield will require considerable infrastructure and development before such resources can be fully utilized. In turn, this is likely to incur increased costs not only for establishing new mines and supporting urban, retail, and industrialized areas, but also for transporting coal to the traditional areas of industrialization (Gauteng).

Logistics for the transport of coal to and from remote coalfields and from current coalfields to the Richards Bay Coal Terminal for export is constrained by railage limitations at present, thereby impeding the export capacity of South African coal to markets abroad. Road transport is currently damaging the surfaces of the roads in the northeastern sector of the country, a fact which is currently receiving considerable attention.

The threat of acid mine drainage from defunct mines remains an ever-present concern. Government is seeking solutions to these problems arising from the past and is imposing stringent regulations in the form of environmental impact assessments and mine closure insurances on currently operating mines.

The storage of CO₂, the most abundant greenhouse gas produced predominantly from the power stations boilers and petrochemical gasifiers in this country, may be limited by a lack of underground storage capacity in South Africa. Currently identified sites are relatively far removed from point sources.

Environmental pressures are increasing and, notwithstanding the future potential benefits of carbon credits, carbon taxes are already making their first appearance. International trade

partners appear to be considering the banning of exports from countries whose exporting manufacturers have unacceptably high carbon footprints. In a country such as South Africa, where power generation and petrochemical production give rise to high carbon emissions with little chance of commercially feasible CO₂, such threats are of serious concern.

Notwithstanding the issues outlined above, the South African coal industry is buoyant and currently addressing the many issues that face the industry. Several of these issues can be addressed through the development and deployment of domestically derived clean-coal technologies that are being designed to specifically suit the needs in South Africa, including high-ash coal, low water availability, and socioeconomic requirements.

CLEAN COAL TECHNOLOGIES

Given the undeniable need to use coal as the baseload source of energy in South Africa, the country has been undertaking research in a number of clean coal technology areas, and in some fields South Africa can now be considered a global leader.

For instance, acid mine drainage research has shown that such water can be used for agriculture, with fly ash from power stations used as a filter in the upgrading/treatment process.

Beneficiation has been developed to an advanced, world-class degree, which provides cleaner coal that can improve plant efficiencies and reduce CO₂ emissions. A number of new dry coal beneficiating technologies are now undergoing pilot-scale testing in an attempt to reduce the requirement for water in such processes. The results to date have proved highly successful, with considerable beneficial impacts in user processes; for example, the upgrade (i.e., deshaling or the removal of contaminating rock) from the coals being sold to the Eskom power stations.

The upgrading and use of coal washery discard materials is undergoing further review as a source of energy in fluidized bed combustion and gasification processes. The ash from such processes is being developed for use in cement manufacture, and in building and road materials.

Furthermore, cleaner and more environmentally friendly processes, including underground coal gasification (UCG), are now being developed, with Eskom's UCG pilot-scale initiative being considered a world-class feat. The process has been in use at the Majuba Colliery in KwaZulu-Natal for about three years and gas with calorific values averaging 4 MJ/L has been fed into the Majuba power station on a pilot-scale basis. Should this process continue to prove successful in larger-scale operation, this technique could make possible considerably cleaner in-seam utilization of the many deeper and poorer-grade coal seams in South and southern Africa.



Eskom is working to increase the efficiency of its coal fleet. The under-construction Kusile power plant is shown above.

© Rute Martins of Leoa's Photography

The logistics of transport are under discussion in terms of privatizing railroad links and increasing rolling stock (i.e., rail wagons and locomotives). In addition, smaller mines are collaborating to share stockpiling and sidings in an attempt to rationalize road transport.

To increase efficiencies of coal utilization (i.e., using less coal for more power, thereby reducing greenhouse emissions), Eskom has set and achieved high targets in terms of increased combustion efficiencies in some of the world's largest coal-fired power stations, some of which are using coals with ash contents well in excess of 45%—a feat not yet achieved anywhere else.

Increased boiler efficiencies in all other industrial coal-using plants to ensure considerably lower emissions of CO₂ are ongoing and the subject of current training and consultations.

In terms of criteria emissions, flue gas desulfurization (FGD) systems are being installed in some power plants, while smaller capture-ready units are readily available for others. However, given the low sulfur, mercury, arsenic, and chlorine contents of South African coals, control over these toxic emissions may not need to be as stringent as is the case in the coals of the Northern Hemisphere. Research conducted in South Africa on coals in the Highveld Coalfield has shown that sulfur reduction through beneficiation prior to use could be more cost-effective and efficient than through the installation of post-use FGD processes.

With regard to CO₂ emissions, research is currently being targeted at CO₂ utilization rather than storage. Long term, relatively advanced research is currently underway in South Africa to utilize CO₂ by developing algal and/or bamboo farms for CO₂ adsorption and biomass co-firing adjacent to power stations, coal-to-liquids plants, and agricultural land.

CONCLUSIONS

The future sustainability of energy in South Africa—whether based upon coal, nuclear, or renewables—will depend on the ability to fund it by the government of the day. The consumer, who ultimately foots the bill, will be the key factor in determining how the energy mix functions.

While many legislative, technical, and economic steps remain to be taken, and minds must be turned to achieving the goals of an environmentally “clean” South Africa, much has already been initiated. The future will depend on the vision of *those yet to come, for the road is long and the plans of action are more than one generation in duration*. One thing is certain, however: The value of coal as an energy source and a highly prized carbon-based chemical source can never be underestimated. Coal is undeniably the source of the most valuable commodity in the South African economy as it provides low-cost energy and is the source of some of the most valuable chemicals known to man. 🧪

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International Outlook

Australia



Australia's Senate has voted to repeal the country's carbon tax. Prime Minister Tony Abbott has said that he will seek to replace the carbon tax with an AUS\$2.55-billion taxpayer-funded plan that will pay industries to reduce emissions and employ clean energy.

Bangladesh

Bangladesh's government has approved the country's first coal-fired power plant, which will be a 1200-MW ultra-supercritical station that will receive support from the Japan International Cooperation Agency.

China

Wu Xinxiong, president of the China National Energy Administration, provided insight into the planning of the 13th Five-Year Plan as it relates to coal use in China. The percentage of coal used for power generation will be increased, while coal consumption intensity and emissions will be reduced. For instance, efficiency improvements will be required so that coal consumption for a new power station and any existing plant larger than 600 MW must be less than 300 gsce/kWh within five years.

Japan

Japan's Ministry of Economy, Trade, and Industry has cut tariffs for solar power by one fifth in the two years since an ambitious plan began to ramp up solar production. Lower-than-projected solar installations—only 13% of approved projects have been installed and are operating—may pave the way for restarting more nuclear stations.

Japan recently announced that it will be increasing financial support to coal-fired power plants being built in other countries. The increased funding is aimed at ensuring that newly built plants will be able to operate with higher efficiencies and have the latest clean coal technologies applied than what might be possible without support.

United Kingdom

The European Commission recently confirmed that funding for the €300-million White Rose CCS project in Yorkshire will be provided through the NER300 program.

United States



The Kemper IGCC facility under construction (2013, Sept.)

The combined-cycle unit at Mississippi Power's Kemper IGCC plant was successfully placed into commercial operation in August. The next milestone will be the heat up of the lignite-fueled gasifier; commercial operation using the gasifier is scheduled to begin in the second quarter of 2015.

The U.S. EPA has approved permits for the FutureGen clean coal project to store CO₂ underground, representing an important milestone for the project.

The U.S. Department of Energy announced that construction has begun on the commercial-scale Petra Nova CCUS project, sited in Texas. Once operational, the 240-MW project will capture 90% of the CO₂ from an existing coal-fired power plant and use the CO₂ for enhanced oil recovery.

International

The U.S. Department of Energy, Office of Fossil Energy has requested support from China's National Energy Administration to increase collaboration on the Texas Clean Energy Project (TCEP). The Export-Import Bank of China has already agreed to provide some financing for the project while the Huanqiu Contracting and Engineering Corporation, a subsidiary of the China National Petroleum Corporation, will provide engineering services. In addition, it has been proposed that the TCEP be a counter-facing project for the Huaneng GreenGen Phase 2 Project. Under the proposal the two projects would share non-proprietary information for the benefit of both projects. In addition, under the proposed collaboration Huaneng will provide assistance to TCEP during commissioning.

Movers & Shakers



Graham Kerr
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BHP Billiton announced that Graham Kerr, currently Chief Financial Officer, has been appointed Chief Executive Officer designate of the new company that BHP Billiton plans to form in a demerger. Kerr will retire from the Group Management Committee on 1 October 2014 and will be replaced as CFO by Peter Beaven, currently President, Copper. Brendan Harris, currently Head of Group Investor Relations, has been appointed CFO designate of the new company.

Rio Tinto chairman Jan du Plessis will join the board of SABMiller plc as an independent non-executive director effective 1 September 2014. SABMiller also announced that its board intends to appoint Mr. du Plessis as chairman in July 2015.

Recent Select Publications

Energy Technology Perspectives 2014—Harnessing Electricity’s Potential — International Energy Agency — In a special section focused on India, the IEA explores how India can utilize all of its energy resources to provide energy access to all its citizens. Full report available at www.iea.org/w/bookshop/add.aspx?id=472

Prospects for Coal and Clean Coal Technologies in Turkey — International Energy Agency Clean Coal Centre — Turkey’s fast-growing economy will require access to increasing amounts of energy, but the country is facing issues related to energy supply. Indigenous energy resources consist of lignite and some hard coal, with nearly all oil and gas being imported. Therefore, Turkey’s government is supporting research, development, and demonstration of clean coal technologies. This report examines technologies and their potential. Full report available at bookshop.iea-coal.org.uk/report/80561//83384/Prospects-for-coal-and-clean-coal-technologies-in-Turkey,-CCC-239

Key Meetings & Conferences

Globally there are numerous conferences and meetings geared toward the coal and energy industries. The table below highlights a few such events. If you would like your event listed in *Cornerstone*, please contact the Executive Editor at cornerstone@wiley.com

Conference Name	Dates	Location	Website
International Pittsburgh Coal Conference	Oct. 6–9	Pittsburgh, PA, U.S.	www.engineering.pitt.edu/pcc
International Conference on Greenhouse Gas Technologies	Oct. 6–9	Austin, TX, U.S.	www.ghgt.info/index.php/Content-GHGT12/ghgt-12-overview.html
China International Coal Industry Expo	Oct. 16–18	Taiyuan, China	www.cicne.com.cn/zhanhui/zhanhui_xxx.asp?ZhanHuiID=22
Gasification Technologies	Oct. 26–29	Washington, DC, U.S.	www.gasification.org
World Clean Coal Conference, China	Oct. 29–30	Beijing, China	www.worldcleancoal.org/
IHS Asia Pacific Coal Outlook Conference	Nov. 4–6	Bali, Indonesia	www.ihs.com/products/coal/events.aspx
U.S. Coal Mine Methane Conference	Nov. 18–20	Pittsburgh, PA, U.S.	www.cmm2014usconference.com

The UCG Association will also host a one-day workshop on underground coal gasification in conjunction with the International Pittsburgh Coal Conference. The workshop will be held on 6 October. For more information visit www.ucgassociation.org

There are several Coaltrans conferences globally each year. To learn more, visit www.coaltrans.com/calendar.aspx

From the WCA

World Coal Association's Sustainability and Safety Policy Statements

The World Coal Association (WCA) has published two new policy statements highlighting the importance of sustainability and safety to the global coal industry.

These policy statements represent a commitment by WCA members to be leaders in the global coal industry and set a high bar for performance on sustainability and safety issues.

The sustainable mining practice policy statement underlines the significance of responsible mining to ensure a sustainable future for coal. The new policy encourages companies in the coal industry to work together to share their knowledge and experience in sustainable mining practice.

The safety policy statement demonstrates the critical importance the coal industry places on safety in its operations. Nothing is more important to WCA's member companies than ensuring people return home safely at the end of the working day. The goal is the elimination of fatalities, injuries, and workplace illnesses. The policy statements are available through these links:

Sustainable Mining Policy: [www.worldcoal.org/bin/pdf/original_pdf_file/wca_sustainable_mining_policy_statement2014\(29_07_2014\).pdf](http://www.worldcoal.org/bin/pdf/original_pdf_file/wca_sustainable_mining_policy_statement2014(29_07_2014).pdf)

Safety Mining Policy: [www.worldcoal.org/bin/pdf/original_pdf_file/wca_safety_policy_statement_2014\(29_07_2014\).pdf](http://www.worldcoal.org/bin/pdf/original_pdf_file/wca_safety_policy_statement_2014(29_07_2014).pdf)

WCA Case Study: Alpha Natural Resources — Running Right

Safety is the top priority for mining companies. The industry understands there's no good reason not to put safety first.

Alpha Natural Resources, a member of the World Coal Association, is safety conscious, even by the WCA's high standards. Since its introduction in 2004, the company's operating philosophy—"Running Right"—has informed everything from its safety values to more tangible elements like its management structure, embodied in the position of Vice President of Safety and Running Right. But the most tangible expression of that philosophy is the Running Right Leadership Academy, a 136,000-square-foot safety training facility opened in West Virginia, U.S., in June 2013.

The design of the facility and its curriculum are founded on consultations with miners. Alpha also conducted site reviews and gathered knowledge from existing training centers to ensure the Academy would be the best possible. It needed to fulfil Alpha employees' current and anticipated future needs, bolster basic job functions, and evolve to address new regulations and technology as well as remove obstacles to learning.

To find out more about the Alpha Natural Resources' Running Right initiative, download the full case study via the World Coal Association website: www.worldcoal.org/resources/case-studies/alpha-natural-resources-running-right-leadership-academy/

case study

USA
Alpha Natural Resources

With its state-of-the-art Running Right Leadership Academy, Alpha Natural Resources has helped raise the bar for safety training in the coal mining industry.

Safety is the top priority for mining companies – nothing is more important to the coal industry than ensuring people return home safely at the end of the working day. The industry understands there's no good reason not to put safety first.

Alpha Natural Resources – a member of the World Coal Association – is safety-conscious, even by these high standards. Since its introduction in 2004, the company's operating philosophy – "Running Right" – has informed everything from its safety values to more tangible elements like its management structure, embodied in the position of Vice President of Safety and Running Right.

But the most tangible expression of that philosophy is the Running Right Leadership Academy, a 136,000 square foot safety training facility opened in West Virginia, USA in June 2013.

Alpha and the companies it has acquired recognized the need for such a facility. Two external factors spurred the decision to provide it:

1. The US National Mining Association (NMA) launched the CORESafety initiative, which challenges members to achieve

zero fatalities and a 50 percent reduction in the injury rate over five years (2012-2016), the 0.50S Goal.

2. Alpha acquired Massey Energy, subsequently reaching an agreement with the US Government to create a safety training facility as a positive outcome following Massey's Upper Big Branch mine accident in 2010.

Alpha seized the opportunity to realize its vision of an exceptional facility, actively contribute to the 0.50S Goal and fulfil its public duty.

The design of the facility and its curriculum are founded on consultations with miners. Alpha also conducted site reviews and gathered knowledge from existing training centres to ensure the Academy would be the best it could be. It needed to fulfil Alpha employees' current and anticipated future needs, bolster basic job functions, and evolve to address new regulations and technology as well as remove obstacles to learning.

In practice, this means creating the most realistic possible learning environments – without any real-life risk. The Academy's virtual simulator studio lets trainees experience working or operating heavy machinery such as continuous mining machines, roof bolters, shuttle cars and surface haul trucks while providing real-time feedback. Students practise tasks during which most injuries and fatalities occur, so that and never isn't an option if you're learning them on the job – but at the Academy it's the norm.

Instructors are in control of every aspect of the virtual scenarios. Most are Alpha staff with decades of first-hand experience of mining environments and hazards – though external specialists are also brought in to teach specific classes such as physiology.

While simulators are ideal for familiarising trainees with particularly high-risk activities, the Academy aims to provide hands-on experience of real equipment whenever it's safe and practical.

"I believe that we'll have safer, more compliant and productive operators with this training"

Running Right Leadership Academy trainee

www.worldcoal.org

World Coal Association | August 2014

Corrigendum: Volume 2, Issue 2, page 39, Figure 1: Bulgaria was listed twice in Figure 1. The second column associated with Bulgaria actually represented the data for Denmark.

VOLUME 2, ISSUE 2

ENERGY POVERTY IN INDIA AND WHAT'S NEEDED TO ADDRESS IT

I found this article to be very interesting. The data in the article seems to be the most recent available and, to my knowledge, has not yet been presented in other publications. This actual data about the energy situation in India can lead us to think about the development of India in a different way, especially considering the role and challenges for the new Prime Minister, Narendra Modi.

During his time as Chief Minister of the state of Gujarat, Modi led a state with strong economic growth even during the global financial crisis and slowdown. Based on this and the newly planned construction of power-sector infrastructure, we are hopeful that there could be a new round of robust economic growth in India that will contribute to the greater global economy in the near future.

The data provided in this article is valuable for the purpose of research—as we look at India today, we see some significant similarities with China of years past. Generally, perhaps one can reach the conclusion that India's energy sector will follow the same model as China—primarily that economic growth will be fueled by coal. This gives the world a chance to search for opportunities in India, not only in the realms of energy exports and infrastructure construction, but also within the field of technology transfer.

We could see that data in recent IEA reports and also reports by others are not the same as what was provided in the recent *Cornerstone* article. This perhaps indicates how fast changes can happen in India.

We recommend that the editors invite more articles about the energy situation in India. We are keen to learn more about the fascinating growth occurring in that nation.

Lei Qiang
Manager

Shenhua Science and Technology
Research Institute Co., Ltd

SHENHUA GROUP'S PREEMPTIVE RISK CONTROL SYSTEM: AN EFFECTIVE APPROACH FOR COAL MINE SAFETY MANAGEMENT

Safety must be the perpetual theme of coal industry. As the basic energy source that has fueled China's economic development, coal will continue to supply the majority of primary energy for the long-term future. Without safe coal production, there is no transformation and upgrading of the

coal industry and even perhaps a lack of social stability and economic growth. Coal mining is characterized by inherent hazards, which requires coal companies to carry out safety precautions at all organizational levels. It is imperative to regularly examine key criteria for disaster management including coal mine hazards associated with water and methane and dust releases. To address these concerns there must be continuous progress on technologies and equipment, improvements in quality standard systems and evaluations, and proper safety incentive mechanisms.

The modernization of coal mines and the standardization of quality control in coal mining constitute the foundation of safe coal production and improve the scientific and technical standing of the coal industry. In order to further improve coal mining safety, China's government has issued numerous laws and regulations and also conducts random safety inspections. As the largest coal-producing enterprise in China, Shenhua Group has set the benchmark for safe coal mining in China and has thus played an important role in leading safe coal production for the country. This article describes the coal mining risk pre-control management system created by Shenhua Group through year after year of practice, continuous improvement, evaluating theory, and systematic verification. It is of high significance for increasing safety in China's coal mines. This system not only incorporates laws and regulations, but also can readily be understood and used by coal miners. As a person working within the coal mining industry, I am very appreciative that this system has been carried out and promoted in many Chinese enterprises and also hope that even more coal enterprises will communicate on their safety experiences and lessons learned to improve national coal mining safety.

Gao Yujie
Journalist

China National Coal Association

SUSTAINABLE CHARCOAL: A KEY COMPONENT OF TOTAL ENERGY ACCESS?

I write in response to Aaron Leopold's worthy, interesting, but entirely misleading article, "Sustainable Charcoal: A Key Component of Total Energy Access?"

He is absolutely right to point out that most people in the densely populated tropical countries of the developing world, especially those in Africa and the Indian subcontinent, lack access to affordable, clean fuel for cooking and, for that matter, electricity and transport.

However, their lack of cheap energy is the principal cause of their poverty. Anybody traveling to and working in these countries is aware of the widespread destruction of their

woodlands because so much of these have already been chopped down for the manufacture of charcoal.

To become “sustainable” for charcoal production in such places, “sustainable biomass” (trees) would need to be grown in police-state conditions, surrounded by razor wire and protected by shoot-to-kill police— because the land it would have to be grown on is already so heavily over-populated and tree growth, however desirable, must compete with living space (houses, schools, roads, etc.), and crop and livestock cultivation.

Trees take a generation to grow but are turned into charcoal in hours. Charcoal from “sustainable” biomass is therefore an oxymoron in most of Africa and the Indian subcontinent. Anyone who doubts the truth of my observation should take a real-life look at Haiti or almost anywhere in Africa, India, and Bangladesh.

For the foreseeable future, given the society that exists, however imperfect, if the poor are to become any less desperately poor, they will need access to affordable energy that is appropriate to the times in which we live and the global economy we have all created. This energy must include electricity, as well as transport and cooking fuels, as Mr. Leopold and I would no doubt agree. Where and how these are sourced will vary according to the location and local resources.

Electricity from sunshine and wind is getting cheaper all the time; electricity storage, while still too unreliable and expensive for widespread deployment in most developing countries, will soon be available to allow poor people liberation from dependence on expensive, albeit reliable, kerosene and diesel fuel.

If deforestation for cooking charcoal is to be halted, low-cost “smokeless coal”, such as was widely manufactured and used in Europe following clean air legislation in the 1950s, along with more efficient and purpose-designed cooking stoves, would seem to me a much more practical and environmentally friendly way forward, to replace the destruction caused by the charcoal industry.

Hugh Sharman
Owner and Director
Incoteco (Denmark) ApS

Response: Charcoal from “sustainable” charcoal is not an oxymoron, it is a work in progress. As the global population has exploded over the past two generations, cooking traditions, still the central ritual of daily life for much of humanity, have remained just that, traditional. The example of looking at Haiti is a good one: Search for satellite images of the Haitian–Dominican border and you will find what was formerly lush forest on both sides now nearly completely devoid of life on the Haitian side but lush and healthy on the Dominican side. Whether these forests were decimated to make your kitchen table or to cook rice, this clearly illustrates that the sustainability of any natural resource is about its proper management, and not about either its absolute availability or of the availability of a technical fix. What is needed in the case of the billions of people still using dirty, dangerous, and unsustainable cooking, with wood or poor-quality charcoal, is education that there are easy, affordable options for them that offer better solutions and do not force them to significantly alter their culturally important, generations-old cooking traditions. These include the clean cookstoves and improved methods of producing charcoal noted in the article and further elaborated in the Practical Action-authored publication “Sustainable Feedstock Management for Charcoal Production.”

Aaron Leopold
Global Energy Advocate
Practical Action

I found Aaron Leopold’s recent article, “Sustainable Charcoal: A Key Component of Total Energy Access?”, to be insightful and compelling. The time is right to convert sustainable-growth wood and wood waste to charcoal as a transitional step toward even cleaner energy sources. It’s amazing how many people in the world need such an energy source for heat and cooking in order to survive. Because of charcoal’s light weight, compactness, and cleaner burning characteristics compared to wood, it makes a lot of sense. This approach will give us time to bring newer and cleaner technologies to bear on the situation without jeopardizing the livelihood of so many people in the world. The world needs a diversified portfolio of energy sources to meet our current and future needs.

Jim Corlett
Chief Executive Officer
Corlett & Associates

Coal Classification Industry Approach to Hazard Classification under the Revised MARPOL Convention and the IMSBC Code

The International Maritime Organization (IMO) has introduced new environmental and health classification criteria for internationally shipped solid bulk cargoes under the International Convention for the Prevention of Pollution from Ships (MARPOL) and the International Maritime Solid Bulk Cargoes (IMSBC) Code.

The World Coal Association (WCA), together with ARCHE - a specialist environmental toxicology consultancy - has prepared a package of reports to assist coal companies with complying with the new environmental and health classification requirements. The package consists of three reports and a summary document:

Report 1: New Compliance Requirements of the MARPOL Convention and the IMSBC Code

Report 2: Analysis of Coal Composition, Ecotoxicity and Human Health Hazards

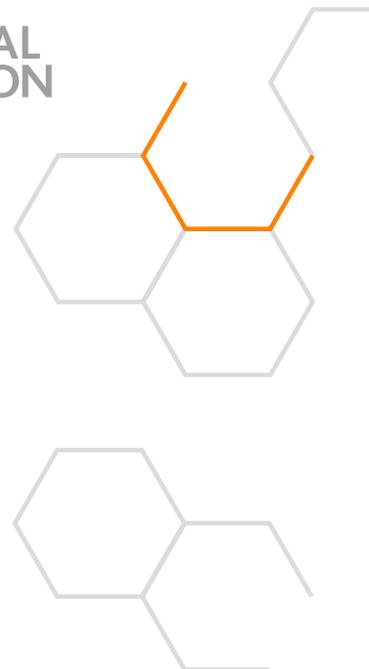
Report 3: Coal Classification Guidance



The reports are available free of charge to WCA Members.

The reports are also available to non-WCA Members to purchase. If you would like information on purchasing this package of reports, please email the WCA Team at: classification@worldcoal.org

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