Fueling Increased Electricity Production in the Emerging Economies of Asia

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Coal's Role in ASEAN Energy
What's Driving India's Coal Demand Growth
Oceanic Storage of CO₂ by Japan and Taiwan
Our mission is to build understanding and gain acceptance for the fundamental role coal plays in powering modern economies. We engage with global thought leaders and policy makers to position coal as a responsible and progressive industry by demonstrating that coal and 21st Century coal technologies are critical to achieving a sustainable and low emission energy future.

Benjamin Sporton
Chief Executive,
World Coal Association
In late 2015 world leaders took a unified step toward addressing climate change with the culmination of the COP21 agreement in Paris. Although implementation will be far from simple, this agreement demonstrates that the world is largely ready to collaborate to meet our common objectives on climate. One of the most challenging aspects of the negotiations leading up to the agreement was how developing countries could participate in the agreement without sacrificing their development goals. Thus, the involvement of developing nations throughout the negotiation process was particularly important.

Asia is home to about 60% of the world’s population and China and India alone make up about half of Asia’s population. While contributing a relatively small fraction of historical emissions, the expanding population and rising living standards throughout the region are poised to increase emissions dramatically.

Few would argue against increasing access to low-emissions, reliable, and affordable energy in developing Asia can improve the quality of life for billions of people. China is leading the way, as the country has achieved full electrification over the last few decades and is now working to grow its fleet of modern, low-emissions coal-fired power plants, in addition to growth in nuclear power, natural gas, and renewables.

Other developing countries in Asia are using coal to fill their increasing energy demand as well. As coal use grows in developing Asia, especially in India and ASEAN, there is an opportunity to apply the best coal technologies—including high-efficiency, low-emissions (HELE) coal-fired power plants. As described in one article in this issue, to avoid “lock-in” of carbon emissions from new power plants, researchers in Japan and Taiwan are advancing research to find safe sub-sea CO₂ storage sites.

HELE coal technologies and carbon capture and storage have the potential to dramatically reduce the footprint of new power plants being built in the developing world. The Paris agreement itself recognizes that technology transfer for a myriad of low-emissions technologies is vital to meeting the goals set by the agreement.

Technology transfer and communication are closely tied and it is my hope that Cornerstone is supporting this process by starting conversations internationally on the research, development, and demonstration of clean coal technologies.

For this reason, I write this letter with a somewhat heavy heart. This is my last issue as Executive Editor of Cornerstone. For the last three years, I’ve been honored to serve in this role and to help tell the story of the technologies and opportunities for coal around the world. Even as I step down to focus more closely on technology development and deployment, I’ll continue to tell the story of coal and plan to do so for the rest of my career.

On behalf of the editorial team, I hope you enjoy this issue of Cornerstone, and thank you for your continued readership and engagement. The challenges facing the energy community can be daunting, but I firmly believe that technologies can and will lead us to success as they have done so readily in the past.
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In the wake of COP21, as the world focuses on climate change mitigation, it can be easy to forget other important energy-sector considerations. For example, the emerging economies in Asia are eager to shake off the currency crisis of 1997 and build a robust and prosperous economic region. However, driving this growth requires more energy. There are many options for energy, and they will all play a role, but coal power is expected to be the principal contributor to increasing electricity production in many countries growing their electricity capacity.

According to the IEA, Asia’s energy demand is expected to grow by 80% between 2013 and 2035, driven by a tripling of the continent’s economy and a 25% rise in population. More investment in generation, transmission, and distribution is required.

“HELE coal technology has generally emerged as the choice for future projects, offering a more resilient and affordable source of electricity to supplement inadequate gas and renewable power.”

By Paul Baruya
Supply, Transport, and Market Analyst,
IEA Clean Coal Centre
in the Emerging Economies of Asia

Aside from the 150 GW of new coal capacity already under construction in India and China, coal-fired capacity in Southeast Asia—in the Association of Southeast Asian Nations (ASEAN)—will double between 2011 and 2020, to 80 GW, and then double again from 2020 to 2035, rising to 160 GW (see Figure 1). Furthermore, Asia is embracing the new paradigm of state-of-the-art high-efficiency, low-emissions (HELE) technologies, capable of burning coal with far less NOx, SOx, particulate matter, mercury, and CO2 emissions.

ESTIMATING POWER COSTS

Poverty is widespread among the non-OECD nations of Asia: 130 million people have no access to electricity in Southeast Asia,1 nor do 240 million in India,2 and although access in China is nearly complete, up to 200 million remain in poverty.3 Increasing capacity while maintaining affordable electricity is critical to individuals as well as to industry.

While renewables, nuclear, and oil are all used for power in the region, new capacity is largely based on renewables, coal, and natural gas. Thus, coal and natural gas are largely in competition for most baseload and load-following power generation throughout emerging Asia.

In 2015, the IEA Clean Coal Centre researched the cost of coal and natural gas power compared in different regions in Asia.4 By estimating the levelized cost of electricity (LCOE) for coal and combined-cycle gas turbines (CCGT), it was possible to determine which fuel is most likely to win the race to provide new capacity in Asian power markets. This article highlights the key findings from that study.

ESTIMATING ACTUAL COSTS

Fuel costs are one of the most important considerations when assessing power station economics. Historically, the price of coal is much lower than gas, even after adjusting for differences in energy content. For example, the average cost of natural gas in China in 2013 ranged between US$500 and US$700 per tonne of oil equivalent (toe), compared to coal, which was just US$160/toe. In ASEAN countries such as Indonesia, Malaysia, and Vietnam, however, domestic pipeline natural gas was less expensive than the average price of coal.

In addition to fuel costs, the LCOE cost per kilowatt hour is also determined by capital costs, which are impacted by the generating output of various plants (see Figure 2 for the average utilization rate of selected plants in China). Baseload plants such as coal, CCGT, nuclear, and geothermal generally recoup their higher capital costs much more quickly because they operate more hours per year.

Large gas-fired CCGT plants are quick to build, taking only two years to construct in Asia, compared to four years for a coal plant. The cost of capital expenditure for CCGT plants is around half that of coal on a per kW capacity basis, while in China and India some coal and gas projects cost almost the same (at about US$500–600/kW).

FIGURE 1. ASEAN electricity generation capacity

CHINA

China is the world’s largest coal market, consuming 3900 Mt in 2014. LCOE analyses suggest that electricity generated via CCGT is twice as expensive as coal in China, almost entirely due to higher fuel costs (see Figure 3). While natural gas prices can vary, and can be as low as US$9/MMBtu for domestic gas, the cost of imported gas in 2013 was 3.5 times more expensive than coal on a per unit of energy basis. The prevailing gas price used was US$9–14/MMBtu, and would need to drop to about US$3/MMBtu to compete with a supercritical coal-fired power plant, and even lower for more advanced coal-based plants. Lower gas prices in the future are possible in China, but such price levels will not provide an economic incentive to develop sustainable and profitable supplies from LNG and unconventional sources such as shale/tight gas.

Despite the favorable economics, coal still faces some challenges in China. Three major zones, including Beijing and Shanghai, have moratoria on coal-fired plants in an effort to improve air quality. In such locations, natural gas plants dominate the power-generating fleet. Yet, China’s emission standards for coal plants are so stringent, a modern coal plant will be cleaner than any built in Europe—so metropolitan air quality would not be substantially affected by coal power, but rather by industrial facilities, municipal and residential boilers, and transportation. Pledges to reduce the role of coal in the power sector will slow growth, but considering the huge existing capacity and plants under construction today, it is unlikely that China’s reliance on coal-fired power will end soon.

INDIA: LEADING NEW GROWTH IN ASIA

India faces severe power shortages on a daily basis due to insufficient coal and gas supplies, made worse by large losses in the grid. Like China, India’s power generation is dominated by coal. By 2035, coal-fired power plant capacity could approach 900 GW if the country can overcome its various
Gas prices in India vary depending on whether the gas is domestic or imported, and whether the supplier is state owned or not. India is the fourth largest importer of LNG, although LNG prices remain high (at least three times higher than that of coal on an energy basis).

India’s coal reserves are sited in the eastern half of the country; in 2013 production reached 600 Mt, while net imports from Australia and elsewhere grew to about 100 Mt/yr.\(^5\) Imported coal is priced at world levels while domestic coal is priced on a cost-plus basis, so prices are allowed to increase modestly with production costs. Coal remains relatively inexpensive (US$72/tonne at 2013 prices), but the coal production industry requires modernization and the rising need for coal washing of India’s low-rank coal will increase the cost in the future. Similarly, gas prices in the past have been low (US$4/MMBtu for domestic gas), but market reforms will lead to rising fuel prices across the board to attract private-sector investment to develop new fields and LNG import terminals with costs closer to US$14/MMBtu.

Unsurprisingly, analysis of LCOE showed that gas-fired power was marginally more expensive than coal in India, although the difference was not as stark as in the estimates for China. However, the lack of availability of natural gas, rather than costs, is probably the chief obstacle to gas power, and for this reason natural gas is unlikely to displace expansion of coal-fired power to any great extent.

“Across the region, HELE coal technology has generally emerged as the choice for future projects, offering a more resilient and affordable source of electricity to supplement inadequate gas and renewable power.”

SOUTHEAST ASIA: LOOKING FOR A NEW MODEL FOR GENERATION

In the past, much of the electricity in Southeast Asia has come from hydropower, natural gas, and oil. To date, the pace of demand growth for power has not matched supply, leading to regular load shedding. Variability and intermittency of renewable sources has led to a greater reliance on natural gas- and oil-fired power in some periods, with the economics of generation being complicated by fuel subsidies that have supported inefficient and higher emissions generation from oil.

Across Southeast Asia, HELE coal technology has generally emerged as the choice for future projects, offering a more resilient and affordable source of electricity to supplement inadequate gas and renewable power. In the background, oil is being actively discouraged in the generating sector where possible, yet remains an essential fuel in remote areas with little or no access to grid electricity.

Looking at past fuel prices in the region, along with project costs and plant performance, the LCOE comparison between natural gas and coal is mixed. The average LCOE in Indonesia,
Malaysia, Vietnam, and Philippines suggests that current low natural gas prices make CCGT more competitive, where gas supplies are affordable and available (see Figure 4 for Indonesia as an example).

In Indonesia, the average LCOE for CCGT is around 7 US₵/kWh, while coal is closer to 8–9 US₵/kWh. In the case of Indonesia, however, the utilization of gas plants seems very low, which could possibly be due to the use of secondary fuels in the plants, meaning that the costs are often more closely based on those of an oil plant.

Evidence suggests that, natural gas-fired power plants have suffered from gas supply shortages, which have resulted in gas plants running at low utilization rates and turning to oil for backup. Indonesia has roughly three trillion cubic meters (tcm) of proven gas reserves and produces 90 bcm per year, but even greater potential lies in coalbed methane, with estimated reserves of 13 tcm, and the smaller resource of 1.3 tcm of shale gas. Without these unconventional resources being realized in Indonesia, it is unlikely conventional gas will serve both exports and future domestic demand from the country. The predicament posed by Indonesia’s gas supply problems is a common theme across the region, and will be faced by almost every major ASEAN economy.

Similar to India and China, the region does not have adequate domestic natural gas and thus is set to increasingly rely on higher cost imported LNG. Average and marginal gas prices must rise to make new gas supply sources economic.

By comparison, Indonesia’s coal reserves are substantial and resources are estimated at 120 Gt, although just 28 Gt are proven and recoverable.

Thus, in Indonesia, coal emerged as the fuel of choice for the government’s two Fast Track Programmes, accounting for 14 GWₑ out of the total 20 GWₑ due for completion by 2014. However, delays in finance and land acquisition are causing the program to lag behind schedule. Geothermal and hydro-power are also important technologies to ensure progress toward a future with lower carbon emissions, but adopting HELE coal power will certainly limit the inevitable growth in CO₂ emissions for the growing number of coal plants in the region. In 2014, the Ministry of Energy Minerals and Resources announced a target to add another 35 GWₑ of new capacity, although the timeframe of this program could also be subject to delay. Nonetheless, by 2024 the state utility PLN expects 60% of the nation’s generation mix to come from coal, while 20% will be from gas and the remainder will be hydroelectric and geothermal renewables.

Most aspirations to build new coal plants throughout the ASEAN region are pegged on the availability of internationally traded coal, and many new power projects across the region are contracted to procure coal from Indonesia.

The story in other ASEAN countries is largely similar to that in Indonesia. While natural gas is cost competitive, resources, infrastructure, and/or production are insufficient to meet future (or even current) needs. In most places, LNG prices are too high to be economically competitive with coal. Thus, with either domestic coal reserves or relatively low-cost coal available for import, these countries are building coal plants to fuel their economies.

Malaysia, for example, has historically relied on natural gas for its power; today, gas accounts for 11 out of 30 GWₑ. Over time, declining gas production caused outages, forcing plant operators to switch to higher cost fuel oil and diesel. Since 2000, a building program for coal stations increased generating capacity by 7 GWₑ, and by 2012 coal accounted for 41% of total generation.

Similarly, to avoid becoming reliant on imported LNG, Vietnam is diversifying its power fleet, building 13 GWₑ of new coal-fired plants, 3 GWₑ of hydro plants, a range of smaller renewable stations, and just one CCGT plant. This new capacity is a large increase on the current generating fleet of 34 GWₑ which is
dominated by hydropower. Coal-fired plants will account for 75% of the total new capacity additions between now and 2020. Most of the new capacity comprises ultra-supercritical HELE coal technology specified for all but the smallest plants, a theme that will increase across the region.

The Philippines’ three natural gas CCGT plants are located in one province, and consume 94% of the country’s gas production. The LCOE of the gas CCGT fleet is slightly higher than that of the subcritical coal fleet, but the costs are broadly similar, generating at around 8 US$/kWh. The country is currently self-sufficient in gas supply, but is expected to import LNG as domestic production has been stagnant. In early 2016, the President announced that more coal plants will be necessary to meet future base load power, especially during dry periods that impact hydropower production.

OTHER REGIONAL CONCERNS AND FINAL THOUGHTS

Natural gas and coal are largely in competition to fulfill new generation capacity in developing Asia. China’s huge fleet of coal-fired power plants is being retrofitted with emissions controls to meet strict emission standards and can be expected make a large contribution to the country’s power sector for decades, with the exception of some key urban areas where natural gas is being promoted by policies. India’s natural gas supply is insufficient to displace coal. The challenges faced by the coal production industry will mean there will be an increasing role for imported coal in the future.

In the past, Southeast Asian countries have been overly dependent on natural gas and renewables and, in some places, oil-based power; however, concerns over the future supply security and the ever growing demand cannot be met without a much more balanced portfolio of fuel types. Thus, coal capacity will be added in Southeast Asia, which is evident in most of the official power development programs in the region. Gas power is far from excluded in the strategies for Asian electricity developments, but rising natural gas prices due to the increase in LNG to supplement a shortage of domestic resources, which greatly impairs the competitiveness of gas.

The shale oil/gas boom in the U.S. has yet to cause a major shift in Asian gas pricing, beyond its impact on the overall price of world oil supplies. LNG exports from the U.S. are limited to a few terminals, and are not sufficient to fill an increase in demand in developing Asia.

It is unclear how Asian coal and gas prices will be affected by developments resulting from COP21. More likely, a recovery in China’s economic growth rates will have more immediate impacts on regional energy prices. In any case, coal-based power will not be abandoned in Asia, especially as the fleet is young and the adoption of HELE technology will ensure it takes a lead in the affordable supply of electricity for many decades.

In essence, looking at LCOE, energy security, and current trends for the power fleet in emerging Asia showed that modern coal power was competitive, even against the high efficiencies offered by CCGT. In some countries gas was, and still is, cheaper; yet paradoxically official strategies suggest coal power as more attractive for future developments, often due to limited natural gas reserves and the expectation that imported LNG will be necessary to fuel new power plants. For the long term, there simply is not enough inexpensive gas in Asia to fuel the rapidly growing demand, and security of supply of future energy sources is taken seriously in Asia. Thus, coal will be the foundation of growth for baseload and load-following power generation in some of the world’s fastest growing markets.

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Recognizing the U.S. Cooperative Difference

By Barbara Walz
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Living in the rural U.S. is different than living in urban areas. Without a doubt, rural life has its advantages: no traffic, close to recreation, knowing your neighbors, etc. But living in rural areas is also challenging: driving for hours to get to the nearest shopping mall or doctor; limited employment options; and, for power providers, consistently delivering affordable and reliable electricity. Rural power providers are specifically challenged by low customer density, the need to install more miles of transmission, and diverse load profiles. These hurdles have largely been overcome by the rural electric cooperatives that supply electricity to rural areas in the U.S., but today the nation’s rural cooperatives are facing a major challenge: how to address new regulations on carbon emissions.

The U.S. rural electric cooperative system was born when President Roosevelt created the Rural Electrification Administration (REA) in 1935 to bring electricity to rural communities. Through REA lending programs, communities were able to join together, create a cooperative, and build the necessary electric transmission and distribution lines and generation resources.

“Despite significant investments in renewable energy and energy efficiency programs, Tri-State remains reliant on fossil fuel-based generation to meet demand, maintain reliability, and control costs to our members.”

The program was, and continues to be, a huge success. Within four years of the end of World War II, the number of rural electric systems in operation doubled, the number of consumers connected to electricity more than tripled, and the miles of energized transmission lines grew more than fivefold. In the

Tri-State relies on coal-fired power plants, such as the Craig Station, to generate its baseload electricity.
1930s, less than 10% of rural residents had electricity. Today, over 99% of those living in the rural U.S. have electric service.

Unlike other power suppliers in the U.S., cooperatives are member-owned and governed, and operate on a not-for-profit basis. The benefit of this model is that cooperatives can provide cost-based electricity, and members have a voice in decisions made by their utility. Because all costs are passed directly through to members, cooperative members address new regulations and requirements differently.

**TRI-STATE G&T: A WESTERN U.S. COOPERATIVE**

Tri-State Generation and Transmission Association, Inc. (Tri-State) is a wholly member-owned generation and transmission (G&T) cooperative serving major parts of Colorado, Nebraska, New Mexico, and Wyoming. The company generates and transmits wholesale electricity to its 44 member-distribution systems (see Figure 1) which, in turn, supply retail electricity in a service area that covers approximately 200,000 square miles with a population of about 1.5 million. The challenges facing Tri-State today largely represent those faced by many rural cooperatives in the larger national network, which collectively provide 13% of power in the U.S.

“Like many other U.S. cooperatives, Tri-State’s current generation mix reflects historical energy policies and member needs.”

Through mergers with other cooperatives, consumer growth, and load growth, Tri-State has evolved over the last 60 years from a cooperative that exclusively manages federal hydropower allocations to a cooperative that meets its members’ needs through a diverse portfolio of G&T resources. The company uses market transactions to optimize its position by routinely purchasing power when the market price is lower than its incremental production cost and routinely selling power to the short-term market when it has excess power available above its commitments to both members and non-members. Tri-State also uses spot market purchases during periods of generation outages at its facilities.

**An Energy Mix Shaped by the Policy of the Past**

Tri-State owns, leases, has undivided percentage interests in, or has long-term contracts with respect to various generating facilities. These generating facilities provide a maximum available power of 2833 MW, including 1866 MW from coal-fired baseload facilities and 967 MW from natural gas-fired facilities. In addition, Tri-State purchases hydroelectric power, under long-term contracts, that provides a maximum available power of 574 MW during the summer and 525 MW during the winter. Tri-State also purchases additional power on a long- and short-term basis, including 172 MW from renewable energy resources such as wind and solar. To deliver this electricity, Tri-State also owns or has interests in approximately 5300 miles of high-voltage transmission lines and 219 substations and switchyards.

Like many other U.S. cooperatives, Tri-State’s current generation mix reflects historical energy policies and member needs. Much of the growth in rural Colorado, New Mexico,
and Wyoming occurred in the early 1980s. As a result, Tri-State and other rural cooperatives added capacity during this time. In 1978, the U.S. Congress passed the Power Plant and Industrial Fuel Use Act (FUA) to address national security concerns caused by the oil crisis and natural gas curtailments of the early 1970s. The FUA restricted construction of power plants using oil or natural gas as a primary fuel and encouraged the use of coal-fired and nuclear power plants. Thus, Tri-State and other rural cooperatives built new baseload generation resources during that period and, therefore, built coal-fired power plants. In 1987, these provisions of the FUA were repealed due to reduced natural gas prices, and, once again, U.S. electricity providers were allowed to use natural gas as a resource for baseload plants. According to the National Rural Electric Cooperative Association (NRECA), in 2012 EIA reported that 37% of the generation capacity serving U.S. cooperatives was coal-based, which produced 70% of the electricity used to serve cooperative members. (See Figures 2 and 3 for information, provided by the U.S. Energy Information Agency, on coal-fired power plant capacity built during the time the FUA was in effect.)

Meeting Member Needs in the Current Energy Policy Environment

Markets, regulation, and innovation all play a role in how electricity is produced, delivered, and consumed. Meeting the historical requirements placed on power producers has led Tri-State to have some of the most progressive distributed generation policies in the U.S. The company continues to generate or purchase power produced from a mix of hydropower, solar, wind, coal, natural gas, and oil resources and is also a leader in renewable energy use. Its baseload power plants are equipped with the latest emissions control technologies. Today, Tri-State is reducing CO₂ emissions by maintaining highly efficient power plants and investing in renewable energy projects. It is projected that 25% of the energy delivered by Tri-State to its members in 2016 will be generated by renewables. Since 2010, the company has added nearly 250 MW of renewable energy and plans to add an additional 281 MW by 2017. This investment was recognized by U.S. Department of Energy (DOE) when it awarded Tri-State the 2014 Wind Cooperative of the Year in the G&T cooperative category. Tri-State also supports (financially and operationally) progressive energy efficiency programs offered by our members and has provided technical assistance and financial incentives to its members to develop their own local renewable and distributed generation projects. At year-end 2014, 16 members were participating in this program and 47 projects had been authorized by the Tri-State board, adding up to a combined 68 MW of generation that is either online or in development.

Despite significant investments in renewable energy and energy efficiency programs, Tri-State remains reliant on fossil fuel-based generation to meet demand, maintain reliability, and control costs to our members. This fact drives our concerns with regulations and legislation that could potentially limit these resources.

Preparation for a Carbon-Constrained World

As part of its ongoing comprehensive carbon emission analysis, in 2009, Tri-State initiated an enterprise-wide effort to assess its ability to manage the risks associated with potential new carbon-focused energy policy. The result of this effort was the Greenhouse Gas Management Roadmap that serves as an internal planning tool. The goals laid out in the Roadmap are wide-ranging, including research into clean coal, carbon capture and storage, renewable technologies, generation and transmission efficiency, demand-side management, and research, development, and demonstration initiatives.
The Roadmap is based on Tri-State’s two-decades-long engagement with the Electric Power Research Institute (EPRI), an organization which brings together scientists and engineers as well as experts from academia and industry to address challenges in the electricity industry. As a full funder in EPRI’s R&D portfolio, Tri-State takes advantage of the synergies between EPRI’s broad array of collaborative RD&D programs and has access to all of EPRI’s research results and products.

In recognition of how the Roadmap reflects successful collaboration with EPRI, Tri-State received an EPRI Technology Transfer Award for its leadership in education and information exchange of technology and research results.

**SUPPORTING TRANSFORMATIONAL TECHNOLOGIES**

Tri-State has long supported research and development in the areas of capturing power plant CO₂ and identifying viable uses for it. Tri-State is looking for technological breakthroughs that would allow power plant operators to convert CO₂ waste into useful fuels, chemicals, and other valuable products. Such CO₂ utilization opportunities have the potential to generate revenue that could help offset the cost of capture and conversion.

In October 2015, Tri-State pledged significant funding for Wyoming’s Integrated Test Center (ITC), which will be hosted at Basin Electric Power Cooperative’s coal-fired Dry Fork Station in Gillette, WY. The ITC will provide a testing facility for researchers working to develop commercially viable uses for CO₂ emissions from coal-fired power plants. The goals and potential benefits of the research to be conducted at the ITC include:

- Developing economically competitive carbon capture and utilization technologies and retrofits for existing and potentially for new coal-fired power plants
- Identifying technologies with the potential to provide less costly solutions to meeting CO₂ regulations (e.g., Clean Power Plan)
- Transforming the perception that carbon is a waste product and liability to an asset and possible revenue stream

The ITC will be completed in time to host the final phase of the Carbon XPRIZE, which is scheduled to begin in late 2017. The XPRIZE Foundation—whose mission is to bring about “radical breakthroughs for the benefit of humanity” through incentivized competition—has agreed to be one of the first tenants in the ITC. This international philanthropic group recently announced a $20-million global competition to encourage development of new uses for CO₂ (see full article on the NRG COSIA XPRIZE in this issue for more details).

**“Tri-State has long supported research and development in the areas of capturing power plant CO₂ and identifying viable uses for it.”**

Tri-State is also reviewing the latest energy storage technologies and, when feasible, testing them throughout its system. Through our membership in EPRI and the National Rural Electric Cooperative Association (NRECA) Cooperative Research Network (CRN) Tri-State is supporting extensive energy storage research, including:

- Developing and field testing of operation safety standards for interconnecting to the system
- Funding a demonstration project with one of its members to learn about “fast real-world” control of electric water heaters in response to the variability of a nearby wind farm
- Working with the developer of a prototype 5-kW zinc-air battery with plans to field test it at a member-system site
- Owning the rights to 40 MW of pumped-storage capacity at the 200-MW U.S. Bureau of Reclamation Mt. Elbert Hydroelectric Power Plant, which is used to meet power demand with increased penetration of intermittent renewable energy in the grid
TRI-STATE’S APPROACH TO THE CLEAN POWER PLAN

Tri-State now faces a potential new challenge: how to meet the U.S. Environmental Protection Agency (EPA) Clean Power Plan (CPP), while continuing to deliver affordable and reliable energy to our member systems. One reason Tri-State opposes the Clean Power Plan is because it does not recognize or even acknowledge the cooperative difference. The EPA ignored that when cooperatives were growing in the 1980s, federal law essentially limited fuel options for new generation to coal. It ignored that cooperatives own a small amount of coal-fired generation compared to our utility brethren, but are relatively much more reliant on, and have more invested in, those units. In addition, the EPA did not take into account that, through the years, cooperatives have invested billions of dollars in increasing the efficiency of those coal-fired units, in addition to investing in renewable energy and energy efficiency programs. The bottom line is that the CPP does not take into account that member-owned cooperatives are regulated differently. The CPP is one-size-fits-all, but does not fit Tri-State or other cooperatives across the nation.

Our response to the CPP has been twofold: (1) Tri-State will work with regulators in the five states in which we operate to develop compliance plans, while (2) challenging the EPA’s legal authority to promulgate the CPP. An initial positive result of the challenges to the CPP came in early February 2016 when the U.S. Supreme Court granted a stay of the controversial rule. This means that the CPP cannot be implemented until the legal challenges have been heard in court. Ultimately, the case being made against the legality of the CPP will likely be heard and decided upon by the Supreme Court—a process that could take more than two years to reach a final outcome.

There has been, and will continue to be, an effort to ensure that the difference between cooperatives and investor-owned utilities is recognized at the state level. This is necessary because the EPA did not modify the CPP based on comments submitted by Tri-State and other cooperatives that explained this important distinction. While we continue to have great concern with the rule, Tri-State is committed to working with officials in the five states in which we operate to minimize the impact on rural consumers and employees at our power plants. As we work with states, Tri-State will be guided by the following principles:

1. Ensure reliable and affordable electricity supply
2. Recognize the remaining useful life of and impacts of stranded costs for each generation facility
3. Maintain a balanced resource plan
4. Consider all compliance options, not just those proposed by the EPA
5. Recognize capacity and infrastructure limitations of renewable and natural gas generation

As Tri-State participates in the process to evaluate how to achieve CPP-related state goals, we will look for options to ensure that our higher efficiency, low-emissions coal-fired plants remain in our electricity generation portfolio.

In addition to working with states to develop plans, Tri-State will continue to work with numerous trade groups to challenge the EPA’s legal authority to propose the CPP. We believe the EPA is attempting to accomplish emission reductions through changes in the way energy is produced, distributed, and used—and not through the application of emissions control technology on affected power plants. Thus, we believe the CPP essentially makes EPA the primary energy regulator in the U.S.—usurping the authority of the state and federal agencies assigned that task and disregarding the scope of its authority under the Clean Air Act (CAA).

The CAA established EPA as the primary regulator of air emissions within the U.S., and EPA has filled that role for more than 40 years, dramatically cutting emissions of pollutants such as sulfur dioxide (SO₂), nitrogen oxides (NOₓ), and particulate matter from power plants. However, no technology currently exists to reduce CO₂ emissions from an existing gas or coal-fired power plant that is adequately demonstrated or commercially available.

In the end, although Tri-State and other cooperatives are different, we do have one thing in common with utilities—a desire to protect the environment while continuing to provide affordable and reliable energy to our members. We simply believe a different approach is needed to mitigate CO₂ emissions.

REFERENCES

4. XPRIZE. (2015). Who we are, www.xprize.org/about/who-we-are
I
ncentive prize competitions are powerful tools for inspir-
ing and showcasing technical breakthroughs, and engaging
a broad community of stakeholders around a common
goal. XPRIZE creates and manages the world’s largest global,
high-profile incentivized prize competitions that stimulate
investment in research and development worth far more than
the prize itself. The organization aims to motivate and inspire
brilliant innovators from all disciplines to leverage their intel-
lectual and financial capital for the benefit of humanity.

XPRIZE conducts competitions in five Prize Groups: Learning,
Exploration, Energy & Environment, Global Development, and
Life Sciences. Active prizes include the IBM AI XPRIZE ($5 mil-
lion), the Shell Ocean Discovery XPRIZE ($7 million), the NRG
COSIA Carbon XPRIZE ($20 million), the Google Lunar XPRIZE
($30 million), the Qualcomm Tricorder XPRIZE ($10 million),
the Global Learning XPRIZE ($15 million), and the Barbara
Bush Foundation Adult Literacy XPRIZE ($7 million).

California-based XPRIZE has been creating and managing
global prize competitions for over 20 years. Most recently,
XPRIZE has brought the prize model to the energy domain
with a global competition for post-combustion conversion
of CO₂ emissions. The NRG COSIA Carbon XPRIZE is a US$20
million global competition to convert CO₂ into valuable prod-
ucts. This competition is the latest and largest push in a CO₂
utilization field that is gaining attention, investment, and
technology acceleration worldwide. The XPRIZE competition
will plug into and support global CO₂ conversion networks
embodied by the EU Horizons 2020 €1.5 million prize, the
Smart CO₂ Transformation (SCOT) network, and other similar
efforts throughout Asia, Africa, and South America focused
on the technology, policy, and finance of low-carbon emission
solutions.

“The NRG COSIA Carbon XPRIZE is
a 4.5-year global competition open
to any team that can demonstrate
the conversion of post-combustion
CO₂ into valuable products.”

ABOUT THE NRG COSIA CARBON XPRIZE

The NRG COSIA Carbon XPRIZE is a 4.5-year global competi-
tion open to any team that can demonstrate the conversion
of post-combustion CO₂ into valuable products. The winning
team will convert the largest quantity of CO₂ into one or more

The NRG COSIA Carbon XPRIZE aims to incentivize innovators across the world to develop breakthrough technologies that convert CO₂ into valuable products.
products with the highest net value. Judges will take into account production costs, energy consumption, market prices of product(s) produced, and market volumes of product(s) produced. Since the competition is intended to encourage sustainable solutions that may ultimately be deployed at scale, there are also limits on freshwater consumption and total land footprint.

The competition itself will proceed along two parallel tracks. In Track A, teams will convert CO₂ in the flue gas from a coal-fired power plant; in Track B, teams will convert CO₂ in the flue gas from a natural-gas-fired power plant. The deadline to register (US$8000) and submit a technology and business plan is 15 July 2016; teams that register before 30 April 2016 will pay a reduced registration fee (US$5000).

Technology developers at various technology readiness levels are invited to participate in the competition.

“XPRIZE challenges scientists, engineers, entrepreneurs, and all creative thinkers to design and deploy real solutions that are truly inspiring.”

The competition will consist of three rounds. Round 1 is a technology and business viability assessment, during which teams submit an electronic document which are evaluated by independent judges on their technology, process, team, and business and operational plan. Judges will select up to 30 teams to advance to Round 2, the semi-finals. During the Round 2 pilot-scale competition, teams will have one year to demonstrate an operating process at a scale on the order of 200 kg of CO₂ per day at a facility of their choosing, using real or simulated flue gas as input. Judges will review team data and performance, and select up to 10 teams to advance to Round 3, the finals. In Round 3, the demonstration-scale competition, finalist teams will demonstrate their technologies at a scale of approximately two to five tons of CO₂ per day at one of two new test facilities built specifically for the competition.

Track A finalists will demonstrate at a test facility adjacent to a coal-fired power station in Wyoming, U.S. Track B finalists will demonstrate at a test facility adjacent to a natural-gas-fired power station in Western Canada (site to be announced).

INSPIRING INNOVATION AND CATALYZING MARKETS

All XPRIZE competitions set audacious, but achievable, targets that aim to drive teams to innovate and demonstrate tangible, transformative solutions. By articulating a clear goal that is beyond anything that has been demonstrated to date, XPRIZE challenges scientists, engineers, entrepreneurs, and all creative thinkers to design and deploy real solutions that are truly inspiring. With CO₂ conversion specifically, the NRG COSIA Carbon XPRIZE aims to support technology game-changers and also to catalyze the markets and investor communities that can advance these ideas by deploying, scaling-up, and
reducing the cost of CO₂ conversion and other CO₂ mitigation technologies. The after-market opportunities are in some sense the true grand prize. Unlike in a traditional “solution search”, teams that compete in the NRG COSIA Carbon XPRIZE stand to benefit from the focused support of investors, media, technology communities, and the public momentum gained during the high-profile, international competition.

INDUSTRY SPONSORS FROM CANADA AND THE U.S.

The NRG COSIA Carbon XPRIZE is a global competition that benefits from unique connections to industry sponsors in Canada and the U.S. The opportunity to develop and test technologies at North American facilities offers competitors the benefit of proximity to North American investors and capital markets. At the same time, the competition offers benefits to groups developing CO₂ technologies for Asian, African, and European markets, since those regions will likely represent the largest market growth and volume in carbon technologies over the medium and long term.

COSIA

In this context, Canada’s Oil Sands Innovation Alliance (COSIA) has partnered with XPRIZE as a co-sponsor of the competition. COSIA is an alliance of international and Canadian oil sands producers focused on accelerating the pace of improvement in environmental performance in Canada’s oil sands through collaborative action and innovation. As a sponsor, they are also overseeing the development of the Track B facilities that will co-host the finals of the XPRIZE. Siting the Track B (natural gas) facilities in Canada will attract innovators to the country for the XPRIZE and beyond, and support ongoing activities in CO₂ conversion, mitigation, and utilization elsewhere in Canada. These include efforts led by the Climate Change and Emissions Management Corporation, an independent body created as a key part of the Canadian province of Alberta’s Climate Change Strategy, and Carbon Management Canada (CMC), a Canadian research network focused on carbon management in the country’s fossil energy sector, and their affiliated research institutes.

NRG

NRG Energy has also partnered with XPRIZE as co-sponsor of this competition. NRG Energy is a U.S.-based company focused on wholesale electricity generation (47,000 MW of total generating capacity, including coal, natural gas, oil, wind, and solar facilities) and retail electricity generation and distribution. Track A finalists will demonstrate their technologies at the under-development Integrated Test Center (ITC, www.wyomingitc.org) near Gillette, Wyoming. The ITC is a public–private partnership that brings together government and industry—including several electric cooperatives—with the shared goal of developing commercially viable uses for CO₂ emissions from power plants. The ITC will be hosted on the site of Dry Fork Station, a 385-MW facility owned by Basin Electric Power Cooperative and the Wyoming Municipal Power Authority. Not only will the ITC serve as a host site for XPRIZE finalists, but also as a center of excellence and innovation in carbon capture, conversion, and utilization, and storage in the coming years.

TEST FACILITIES AS LASTING INNOVATION HUBS

Both test facilities are expected to have a long-term positive impact for the CO₂ conversion community, and for the CO₂ mitigation industry more broadly. Opening during Round 3 of the XPRIZE in 2018, this pair of facilities will be among a very small number of such facilities anywhere in the world that are equipped to test, develop, and refine CO₂ conversion technologies at pilot and demonstration scales. The initial two to five tons CO₂ per day capacity of these facilities places them at the sweet spot for technology commercialization, between grams-per-day early-stage projects and megaton-per-year industry-ready facilities. This testing and evaluation infrastructure could prove to be as valuable and impactful in the long term as the core technology innovation inspired by the XPRIZE competitors.

IMPACT

The NRG COSIA Carbon XPRIZE will accelerate development of breakthrough technologies that turn CO₂ emissions into valuable products, proving to the world that innovation can enable solutions to climate change. Ultimately, we intend that this competition will stimulate new markets for CO₂ mitigation technologies, attract new investment, and inspire other industries, governments, and educational institutions to take concrete positive actions to combat climate change. At the same time, we hope to help shift public attitudes to be more optimistic about the future of energy and how we tackle climate change.

For more information or to register a team in the NRG COSIA Carbon XPRIZE competition, please visit carbon.xprize.org
The Paris Agreement and 21st Century Coal

By Milagros Miranda R.
Policy Director, World Coal Association

When Laurent Fabius, then France’s Foreign Minister, gavelled through the Paris Agreement on the evening of Saturday, 12 December, he signaled the end of four complex years of negotiations on climate change, and also the beginning of many more.

The Conference of the Parties (COP) of the UN Framework Convention on Climate Change (UNFCCC) met for its 21st session in Paris, from 30 November to 13 December. Even during the second week of negotiations, there was not much progress on the main issues at stake, in particular, differentiation between rich and poor countries, the long-term temperature or emissions reduction goals for mitigation purposes, and climate finance. In fact, those issues were possible deal breakers and remained contentious until the end of the negotiations. The trade-offs made on those key issues finally allowed for an outcome more than 24 hours after the conference was due to close.

MAIN ISSUES IN THE AGREEMENT

The Paris Agreement marks the conclusion of the work of the Ad Hoc Working Group on the Durban Platform for Enhanced Action (ADP), which had a mandate “to develop a protocol, another legal instrument or an agreed outcome with legal force under the Convention, applicable to all Parties.” A The Paris Agreement is expected to enter into force in 2020.

The new agreement contains legal obligations for countries, particularly related to the review mechanism for scaling up ambition of the nationally determined contributions (now termed “NDCs” and previously known as Intended Nationally Determined Contributions or “INDCs”). It also encompasses flexibilities for its implementation by developing countries in the application of the principle of common, but differentiated responsibilities and respective capabilities (CBDR-RC).

“The Paris Agreement aims to be a turning point in the world’s response to climate change.”

The main elements in the Paris Agreement are summarized below.

Preamble and “Principle of Common Differentiated Responsibilities and Respective Capabilities”

The preamble of the agreement states that, in pursuit of the objectives of the convention, parties are guided by its principles, including the principle of equity and CBDR-RC, in the light of different national circumstances. This implies that all principles of the UNFCCC apply throughout the Paris Agreement and signifies that a differentiation exists between developing and developed countries. It is also clear that this differentiation should guide the implementation of the agreement, as the principle is explicitly referred to in its purpose section.

It is important to note that the Paris Agreement does not continue the UNFCCC classification of countries. B Rather, it differentiates between developed and developing countries in different sections of the text and includes references to special circumstances of least developed countries and small island developing states, but its commitments apply to all parties. Whether this leaves room to reflect further categorization of countries as per their upcoming levels of development remains to be seen.

Purpose. The Paris Agreement is more ambitious than most observers expected. It aims to keep global warming well
below 2°C pre-industrial levels, while recognizing a new aim, effectively a stretch target of 1.5°C. It also aims to increase countries’ ability to adapt to climate change and foster climate resilience and to make finance flows consistent with the purpose of the agreement. This is particularly important because climate finance for mitigation and adaptation purposes is directly linked with the goal of the agreement.

**Climate Finance.** Until the end of negotiations, finance remained one of the most important challenges of the agreement—and a possible deal breaker. The main question was how to translate differentiation between countries. Developed countries insisted that some advanced developing countries with higher levels of economic growth (sometimes referred to as “emerging economies” or “emerging markets”) must also commit to financial contributions, so as to create a broader base of donors. Developing countries, on the other hand, applying the principle of CBDR-RC, strongly demanded that the Paris Agreement provide guidance for the delivery of new and additional financial resources, a clear roadmap for achieving the Cancun commitment from developed countries to mobilize $100 billion a year by 2020, and a pathway for scaling up mobilization of financial resources beyond the Cancun commitments.

Thus, in the final negotiated agreement, developed country Parties should continue to take the lead and should provide financial resources to assist developing country Parties with respect to both mitigation and adaptation while other Parties are encouraged to provide or continue to provide such support on a voluntary basis. Furthermore, developed countries shall report every two years on their financial contributions.

The Paris Agreement urges developed countries to fulfill their Cancun commitments to jointly provide US$100 billion annually by 2020 and calls on them to increase their financial contribution. Furthermore, the agreement states that countries shall set a new collective quantified goal from a floor of US$100 billion per year, taking into account the needs and priorities of developing countries.

**Mitigation.** This section of the Paris Agreement could also have been a deal breaker, as it contains many important contentious issues. While there were many options for explicit peaking emissions levels, or requiring between 40% and 70% net emissions reductions, the final agreement included neither specific levels of emissions reductions nor a specific time for achieving them, opting simply to call for global peaking of greenhouse gas (GHG) emissions as soon as possible. The agreement recognizes that it will take longer for developing countries to achieve this objective.

**Adaptation.** This section underwent more substantive development than in previous agreements, in particular the Kyoto Protocol, which was primarily focused on mitigation. The adaptation provisions call for enhancing adaptive capacity, strengthening resilience, and reducing vulnerability to climate change, with a view to contributing to sustainable development. It also includes the periodical update of an adaptation communication within the NDC review process.

**Loss and Damage.** The agreement recognizes the importance of averting, minimizing, and addressing loss and damage associated with the adverse effects of climate change. The Paris Agreement sets a voluntary, cooperative framework to address the issue, ruling out—as was so strongly called for by developed countries—any room for compensation or liability provisions.

The Paris Agreement also contains provisions concerning technology transfer, capacity building, transparency framework, and a global stocktake process of the implementation of the agreement, including climate finance contributions and a mechanism to facilitate implementation and to promote compliance with the agreement.

**AN AMBITIOUS AGREEMENT NEEDS AMBITIOUS IMPLEMENTATION**

The basis of the success of the agreement lies within the design of the process leading into the Paris conference. Rather than setting top–down goals, such as were the basis of the Kyoto Protocol, countries were asked to submit their own intended climate contributions (i.e., INDCs) ahead of the meeting, hence forming a bottom-up process. That they could define what they propose to do and how they will do it gave countries confidence in the process.

More than 180 countries, including all the world’s major economies, submitted INDCs. The commitments made and
the means to achieve them are as diverse as the economies of those nations. That means in some cases countries have chosen to focus on forestry, automotive emissions standards, scaling up renewable energy, efficiency in energy consumption, and/or reducing the role of fossil fuels in their electricity mix.

The Paris Agreement aims to be a turning point in the world’s response to climate change. Whether or not this becomes a reality will depend on the early entry into force of this agreement and its implementation by parties. The agreement will enter into force on the 30th day after the date on which at least 55 Parties to the Convention—accounting for at least an estimated 55% of the total global greenhouse gas emissions—have deposited their instruments of ratification, acceptance, approval, or accession.

The landmark agreement opened for signature on the 22 April 2016, in a high-level ceremony at the UN headquarters in New York. 175 countries signed the agreement and 15 of them also deposited their instruments of ratification. Thus, UN Secretary General Ban Ki-moon has called for the prompt entry into force of the agreement.

As the official signature book closes on 21 April 2017, we can anticipate more of those calls and expectations for the Paris Agreement to enter into force.

The agreement calls for a periodic increase in the level of ambition contained in the NDCs, through a five-year review process mechanism. Countries are accountable for this obligation as this is a legally binding element of the agreement.

In fact, the NDC review process may become even more important, as the agreement does not include an enforcement mechanism to hold countries accountable for their NDC. NDCs are therefore expected to be stepping stones for an ambitious implementation of the agreement. Indeed such an implementation relies on the successful execution of the NDC and its increasing ambition over the century through the five-year review cycle.

An initial assessment by the UNFCCC of the 147 INDCs submitted before the COP21 indicated that their aggregate effect will not meet the 2°C scenario. Others have suggested an aggregated effect of those INDCs ranging from 2.7°C to 3.7°C global warming temperatures. At the COP21, 195 countries agreed to the new agreement and 160 NDC representing 188 parties have been filed; nevertheless, those commitments are still insufficient to meet the 2°C scenario.

“The basis of the success of the agreement lies within the design of the process leading into the Paris conference.”

To achieve the 2°C or 1.5°C goal in the second half of this century would require drastic GHG emissions reduction and significant investments concerning infrastructure deployment and low-emissions technologies. However, the responsibility for a successful outcome does not rely on government actions only, but on those of all actors. The new deal marks a global challenge for both public and private sector at the local, national, and international level to work for a low-carbon or zero-carbon future.

The Paris Agreement is expected not only to accelerate the transition toward a low-carbon economy, but also the achievement of the UN 2030 Agenda for Sustainable Development and the Implementation of the Addis Ababa Action Agenda.

A NEW AGENDA FOR 21ST CENTURY COAL

In the implementation of the NDCs, countries will need support to achieve their mitigation objectives while continuing to grow and develop. This is particularly important for developing countries.

We need to remember that 1.1 billion people in the world lack access to modern electricity and double that number lacks access to clean cooking facilities. Many developing countries, particularly in emerging and developing Asia, have identified a role for advanced coal technologies in their NDCs—because, for many countries, affordable and reliable
Advanced coal technologies, and the associated technology transfer, are imperative to the implementation of the Paris Agreement.

electricity is the foundation of their economic development. These economies are industrializing and urbanizing at a rapid rate. Thus, affordable, reliable electricity is essential and, for many, it is coal that will continue to provide that electricity.

It is certain that coal will continue playing a role in the world’s energy mix. IEA’s special report on Southeast Asia highlights that coal is the fuel of choice in the region, due to its relative abundance and affordability. It also indicates that the region’s energy demand is projected to grow by 80% in 2040 and in terms of electricity demand.

Energy generation and consumption efficiency are key components of sustainable development. As countries will continue using affordable and available resources such as coal and other fossil fuels, it is critical to support them in achieving energy access and economic growth with the lowest possible level of GHG emissions. This is doable with the use of 21st century technologies such as high-efficiency, low-emissions (HELE) coal technologies that increase the efficiency of power generation and allow for substantial emissions reductions and CCS that can achieve emissions reductions of more than 90%.

The IEA’s Energy and Climate Change report identified HELE technologies as “essential features of strategies to reconcile future energy use with global aspirations to tackle climate change”.

If the world wants the Paris Agreement to be successful in its implementation, it is imperative to support countries’ efforts to reduce carbon emissions through HELE coal technologies and CCS/CCUS. There is no time to lose.

NOTES
A. Article 2 of COP 17 Decision 1/CP.17: Establishment of an Ad Hoc Working Group on the Durban Platform for Enhanced Action
B. The Kyoto Protocol classified countries into Annex I countries (industrialized countries that were members of the OECD (Organisation for Economic Co-operation and Development) in 1992, plus countries with economies in transition (the EIT Parties), Annex II countries (OECD members of Annex I, but not the EIT Parties) and non-Annex I countries (mostly developing countries). For more information see unfccc.int/parties_and_observers/items/2704.php
C. The UN Sustainable Energy for All webpage indicates 1.3 billion people without access to electricity, but updated information issued by the organization indicates that the number is now 1.1 billion people in energy poverty (See: www.se4all.org/sites/default/files/SE4All-Advisory-Board-Finance-Committee-Report.pdf). Similar information is provided by the World Bank: www.worldbank.org/en/topic/energy/overview

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3. UNFCCC. (2016). INDC portal, unfccc.int/focus/indc_portal/items/8766.php
A Utility Overview of the U.S. EPA Clean Power Plan

By Frank Blake
Staff Engineer, American Electric Power

For more than 100 years, American Electric Power (AEP)—a major investor-owned utility delivering electricity to more than five million customers in 11 states in the U.S.—has provided affordable and reliable electricity that, in large part, has been based on the benefits of central-station fossil fuel generation and a robust transmission and distribution system. Throughout its history and especially over recent decades, AEP has sustained its industry leadership by diversifying its generation portfolio through increased use of natural gas, nuclear, wind, solar, and other generation resources, and by developing more efficient means to deliver power to customers. With one of the nation’s largest fleets of power generation resources, the largest transmission system in the country, and a rich history of technology innovation, AEP is uniquely positioned to offer insight on the capabilities of the existing electric system, as well as on the opportunities and challenges of transforming this infrastructure into the electric system of the future. This transformation of the utility industry will continue, especially in context with the requirements of the Clean Power Plan (CPP) regulation finalized by the U.S. Environmental Protection Agency (EPA or agency) in 2015 which is intended to “[accelerate] the transition to a clean energy future.”¹

“AEP is uniquely positioned to offer insight on the capabilities of the existing electric system...”

As this article was under preparation, the U.S. Supreme Court stayed the CPP, opting to allow legal challenges to be fully vetted before the requirements can be implemented. Regardless

AEP’s 600-MW John W. Turk, Jr. Power Plant in Arkansas, which went into operation in 2012, was the first plant in the U.S. to use ultra-supercritical coal combustion technology. The plant generates electricity more efficiently at higher temperatures, requires less coal, and produces fewer emissions to generate the same amount of power as existing coal units.
of the outcome of those legal challenges, a number of other drivers will continue to transform how electricity is generated, transmitted, and utilized in the U.S.

THE CLEAN POWER PLAN: AN OVERVIEW

On 23 October 2015, the Federal Register published the final version of the EPA Clean Power Plan (i.e., CPP or Final Rule). The Final Rule establishes guidelines to reduce CO\textsubscript{2} emissions from existing fossil fuel-fired steam (i.e., coal, gas, and oil) and natural gas combined-cycle (NGCC) electric generating units under Section 111(d) of the Clean Air Act. EPA estimates that, when fully implemented in 2030, the requirements will reduce CO\textsubscript{2} emissions by approximately 32% compared to 2005 emissions from the sector. The CPP establishes two separate uniform national CO\textsubscript{2} emission performance standards that are applicable to each existing fossil steam and NGCC unit subject to the rule. As an optional alternative, EPA also defined equivalent state-specific emission rate- and mass emission-based goals that individual states may adopt. Overall, the CPP is designed achieve these goals by shifting electric generation from higher emitting fossil fuel-based generating units to lower or zero CO\textsubscript{2}-emitting resources.

The uniform national CO\textsubscript{2} emission performance standards reflect EPA’s determination of the Best System of Emission Reductions (BSER) for reducing emissions from existing fossil fuel-based generating units. For the CPP, EPA determined that the BSER is comprised of three “building blocks” that collectively would result in certain emission reductions.

Building block 1 is based on emission reductions by heat rate (or efficiency) improvements that EPA concluded could be made cost-effectively through various equipment upgrades and the incorporation of best operating practices at existing coal-based generating units. EPA estimated that such measures, on average, could achieve heat rate improvements that ranged from 2.1 to 4.3% based on a plant’s existing operations.

Building block 2 is based on increased utilization of existing NGCC units and shifting generation away from existing....

TABLE 1. Summary of select final 2030 state goals

<table>
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<tr>
<th>State</th>
<th>2012 baseline CO\textsubscript{2} (tons/year)</th>
<th>2030 final CO\textsubscript{2} Goal (tons/year)</th>
<th>2012 baseline CO\textsubscript{2} (lbs/MWh net)</th>
<th>2030 final CO\textsubscript{2} Goal (lbs/MWh net)</th>
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coal-fired units. EPA assumed that all existing NGCC units can operate at a 75% annual capacity factor based on the net summer-rated capacity of these units.

Finally, building block 3 would reduce CO₂ emissions through the deployment of new zero-emission renewable energy resources at their highest historic annual development rates during 2022 through 2030. Block 3 assumes that over 700 million MWh of potential renewable energy resources can be developed through 2030.

To determine the CPP emission reduction requirements, EPA relied upon unit-specific generation and emissions data from 2012 operations as a baseline. First, the agency aggregated the baseline information into three regions that represent the electric interconnection regions in the continental U.S. The building blocks were then applied separately to each region to determine region-specific fossil steam and NGCC emission rates. By selecting the least stringent value among these regional rates, EPA determined uniform national emission performance standards of 1305 lb CO₂/MWh for existing fossil steam units and 771 lb CO₂/MWh for existing NGCC units. EPA also established equivalent state-specific emission rate-based and mass emission-based goals that individual states may choose to adopt as the basis for their state plans. For context, Table 1 contrasts the 2030 final goals set by the CPP to the 2012 baseline for the top 20 emitting states.

IMPLEMENTATION PROCESS AND TIMING

The Clean Power Plan is structured to phase in emission reductions beginning in 2022 with the final requirements becoming effective in 2030. The 2022–2029 interim period is divided into three phases of increased reductions: phase 1 (2022–2024); phase 2 (2025–2027); and phase 3 (2028–2029). States can develop individual or multi-state plans to meet the emission guidelines, and submit those plans for approval by EPA. Final state plans or an initial submittal and request for extension must be submitted to EPA by 5 September 2016. An extension request, if approved, would allow a state two additional years to prepare a final state plan for submittal by 5 September 2018. EPA has one year to approve these state plans. If no state plan is submitted or EPA rejects a state plan, EPA will issue and determine a plan for that state.
Concurrently with the final CPP, EPA proposed “model rules” that states can use in fashioning their plans and that reflect the framework for any federal plan that would be issued by EPA. The model rules use the alternative rate- or mass-based state goals and rely on allowances or emission rate credits that could be exchanged through emission trading programs to facilitate compliance. States have the option to incorporate all or any portion of these model trading rules into their state plans. In addition, EPA has proposed a Clean Energy Incentive Program (CEIP) that would award additional allowances or emission rate credits as an incentive to deploy specific energy efficiency or renewable energy programs in 2020 and 2021, prior to the first compliance period for the CPP in 2022. However, because EPA is seeking comments on many aspects of the proposed federal plan and model trading rules, the options that will ultimately be available under a state plan or federal plan are not yet known.

COMPLIANCE CONSIDERATIONS

The design of the Clean Power Plan is not limited to measures that are achievable solely at individual fossil generating units, but incorporates activities occurring across the electric industry (e.g., actions within and outside the fenceline of affected generating units). Based on the stringency of the state goals and national emission performance standards, the availability of cost-effective emission allowances and emission rate credits through some form of a trading program will be essential for many, if not most, existing generating units to meet the requirements of the program and maintain adequate levels of operation.

However, several sources of uncertainty remain. The first is associated with the design of individual state plans and the content of the final federal plan. Whether states choose mass- or rate-based goals and how individual state plans are designed could limit the ability of sources to engage in trading programs within and across state boundaries. This will be a key factor in determining the feasibility and flexibility of compliance options. Cost-effective compliance options could be greatly enhanced by a process that facilitates exchanges between mass-based plans and emission rate-based plans.

Another consideration is whether the actions included as building blocks can be implemented so that adequate liquidity of allowances or emission rate credits materializes in a timely and cost-effective manner. Comments submitted on the proposed CPP by those that design, operate, and regulate fossil generating units raised significant concerns that EPA had greatly overestimated opportunities for heat rate improvements at coal units, the redispatch for NGCC, and the potential for and rate of new renewable energy development. Other comments expressed concern with the timing of the requirements, especially in context with maintaining grid reliability. EPA, in part, recognized these concerns when it extended the initial compliance period from the proposed 2020 start date to 2022 in the final rule.

LOOKING FORWARD

A number of drivers continue to transform how electricity is generated, transmitted, and utilized in the U.S. These drivers include new environmental regulations, fuel availability and cost, power prices, the need to upgrade or replace existing infrastructure, as well as the development and cost-effectiveness of new technologies. This transformation already has resulted in a significant number of coal generating units being retired, new NGCC and renewable resources being developed, and the expansion of transmission infrastructure. While these trends reflect the concepts embedded within EPA’s building blocks, the degree of transformation to date is far from what will be needed to achieve the requirements of the Clean Power Plan. These trends will continue irrespective of the CPP. However, accelerating this transformation can only be done in a manner that ensures affordable and reliable electricity for the U.S.

REFERENCES

The Importance of System Utilization and Dispatchable Low-Emissions Electricity for Deep Decarbonization

By Jared Moore
President, Meridian Energy Policy

At COP21, all participating countries formally agreed to create self-imposed plans to limit global warming to 1.5°C. Achieving this goal will effectively require complete decarbonization of the electricity sector. The conclusions in this article demonstrate that it is important to recognize this long-term goal—deep decarbonization—when crafting climate policy.

Deep decarbonization necessitates nearly all electricity generation come from low-carbon (i.e., low-emissions) power plants, which tend to have higher capital costs and lower marginal (fuel) costs. The exclusive use of capital-intensive power plants increases the importance of system utilization (i.e., using all the electricity a power plant is capable of producing). To assess how differing electricity mixes affect utilization under deep decarbonization, I created a dispatch model to quantify system-level electricity costs. The analysis was based on different scenarios using unique contributions of wind, solar, and dispatchable low-carbon (DLC) generation. DLC is defined as any low-emissions power plant that is not intermittent and is capable of producing power every hour of the year. This includes nuclear power and natural gas and coal-fired power plants with carbon capture and storage (CCS). Though nuclear and CCS plants have unique costs and load-following capabilities, I assumed they were identical for modeling purposes. Based on data from the U.S. state of Texas, this analysis demonstrates that DLC, solar, and storage are very likely required for cost-effective deep decarbonization because these technologies offer the highest system utilization.

“Policymakers should take a long-term strategy and develop the technologies more likely to offer cost-effective deep decarbonization because of high system utilization.”

The cause of low utilization: early supply and late demand, diurnally and seasonally

The lack of coincidence between the supply of some renewables (wind and solar) and electricity demand underpins the challenge of heavily relying on such power plants under deep decarbonization. Matching supply and demand using wind and solar is challenging because the supply is driven by variable weather cycles. These diurnal (i.e., daily) and seasonal cycles are a result of the earth’s rotation and its tilted axis, respectively. Electricity demand also follows diurnal and seasonal cycles, but peak supply and demand do not match. On a diurnal cycle, solar energy supply peaks during the middle of the day, but power demand tends to peak hours later during the hottest part of the day. On a seasonal cycle, solar energy supply peaks at the summer solstice but the hottest weather of the year (peak air conditioning load) does not occur until months later.

Wind energy supply also has diurnal and seasonal cycles, but the relationships are more complex and unpredictable. Wind is driven by a myriad of local mechanisms, but in many regions, including our study area of Texas, the prevailing factor is the difference in heat (pressure) between the equator and the poles.
As a result, wind’s predominant cyclical characteristic is a seasonal anti-correlation with temperature (demand). This study is limited to Texas, specifically ERCOT (Electric Reliability Council of Texas), which serves the vast majority of the Texan load.

While the supply pattern of wind in Texas is not applicable for every region of the world, we can assume that the overall model results and policy implications are relevant to most regions. Solar patterns are similarly diurnal everywhere, of course, and wind has been observed to be seasonally anti-correlated with load in China, India, and Australia.

The dissimilar supply and demand patterns have profound implications for system utilization under deep decarbonization. For example, the variation in seasonal load in the ERCOT region is affected by 25% solar penetration and then an additional 35% wind penetration (see Figure 1).

Since solar energy is positively correlated with load on a seasonal basis, adding solar reduces the seasonal variation that must be served by non-renewable generators. Adding wind to solar, however, has the opposite effect because wind’s negative seasonal correlation with demand combines with the slightly early seasonal peak of solar generation. Inevitably, given these seasonal relationships, any combination of wind and solar energy dominating the energy mix will result in oversupply in the spring and undersupply in the late summer. This implies that if DLC generators, such as natural gas and coal with CCS, are required to meet late summer load, they will suffer from low utilization in the spring because of the oversupply of renewable energy. While some argue that DLC generation is too expensive under full utilization, its costs will only increase if it is limited to seasonal utilization. So policymakers face a dilemma: if they lean heavily on intermittent renewables to meet modest decarbonization goals, they increase the risk of oversupplying energy diurnally and/or seasonally and vastly increasing the total system-level costs of electricity.

THE ROLE OF BATTERY STORAGE

Demand shifting and energy storage are two frequently mentioned technologies that could help resolve the challenges with intermittent renewables. However, battery storage is technically limited. For example, batteries can transmit only a limited amount of power (MW) and they can only transmit that power for a limited duration—thus limiting the amount of energy (MWh) that can be stored. These constraints are particularly relevant to storing renewable energy since the oversupply episodes can be both acute and chronic.

“Any combination of wind and solar energy dominating the energy mix will result in oversupply in the spring and undersupply in the late summer.”

To demonstrate how power and energy constraints can limit the effectiveness of battery storage, the net load (difference in

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**FIGURE 1. Average monthly net load in Texas (ERCOT) after 25% solar, 35% wind penetration**

![Net load graph showing the difference in load with and without solar and wind energy.](image-url)
hourly supply and demand) of three example days in March, May, and August were modeled (see Figure 2). Negative net load indicates oversupply and positive net load indicates undersupply. Two deep decarbonization scenarios were examined. The “80% Wind Solar” case represents the net load where 80% of annual load is met exclusively with wind and solar energy, and the “80% DLC Solar” case represents a scenario with 60% DLC and 20% solar (i.e., 80% low-emissions energy). In both cases the remainder is met with unabated natural gas plants.

The oversupply and undersupply episodes in Figure 2 are more severe in both magnitude (MW) and duration (MWh) in the “80% Wind Solar” case. The March oversupply episode is persistent and does not allow an energy arbitrage (i.e., storing and selling) opportunity. Utilizing the March supply episode will require storage over long time periods, resulting in infrequent battery utilization. Seasonal storage is very unlikely to be economically competitive given the quantity of batteries required and the limited arbitrage opportunities per year. Diurnal storage (i.e., energy arbitrage on a daily basis) would require less battery capacity and would permit batteries to be used hundreds of times per year.

**STORAGE: VALUABLE FOR DEEP DECARBONIZATION REGARDLESS OF RENEWABLE DEPLOYMENT**

To achieve deep decarbonization, some oversupply is inevitable regardless of the mix of renewables and DLC employed. Therefore, deep decarbonization will likely increase the opportunities for energy arbitrage. Additionally, storage and demand response can offer other services such as capacity, ancillary services, and transmission. It is likely, therefore, that some energy arbitrage potential will be available at little cost. However, while it is likely that more storage will be available in the future, the amount will be limited as the value of storage suffers from diminishing returns. Fundamentally, energy arbitrage opportunities decrease as more storage is added to the system, making storage decreasingly valuable. There are also decreasing returns on the other services offered by storage, too. For example, only a very small amount of storage is required to saturate the ancillary services market. Furthermore, demand response can shift load only for a very limited duration (~8 hours), and this severely limits its ability to rectify persistent oversupply episodes.

There are too many unknowns to determine how much storage is economically justifiable in the long term. As a point of reference, a 2015 study examined various storage technologies and costs under deep decarbonization and found that battery storage capacity of no more than ~25% of the peak demand was economically justified, even if storage costs halved from current rates and the capital costs of DLC generation were $9000/kW. The U.S. Energy Information Administration estimates the capital cost of coal with CCS and nuclear at $4700/kW and $5500/kW, respectively.

Given the likelihood that a limited but appreciable amount of storage will be available, I assumed that, for all deep decarbonization scenarios, one Tesla Powerwall was installed free of cost in every home in the study area of ERCOT. The purpose of this exercise was to determine whether the addition of storage inspires a fundamental pivot toward different decarbonization strategies. This amount of storage equates to 60 GWh and 17.5 GW of capacity (25% of peak demand). Though this is a significant amount of storage, 60 GWh of storage could only absorb about 8% of the 18 March renewable oversupply episode in Figure 2. Additionally, while the oversupply was as high as 60 GW, the batteries could not absorb anything greater than 17.5 GW.

![FIGURE 2. Net load in ERCOT region under 80% decarbonization scenarios](image-url)
MODELING ANALYSIS: SYSTEM UTILIZATION AND COSTS

To quantify the mix of wind, solar, and DLC generation required for each scenario, I constructed an hourly dispatch model that linearly scales hourly supply data to meet hourly demand for electricity. Transmission and thermal constraints were neglected, as this analysis is intended to isolate system utilization, not grid flexibility.

Eight energy mix scenarios were modeled (see Figure 3). The base case is a reference scenario where it was assumed that all MWh are served by unabated natural gas. Two modest decarbonization scenarios were modeled: an exclusive renewable case (Figure 1) and a DLC-dominated case with DLC and solar generation developed at a 3:1 ratio (60% DLC/S). The 80% and 90% DLC/solar scenarios further develop DLC and solar generation at the same 3:1 ratio to fulfill more aggressive low-carbon energy requirements. Additionally, we show a new scenario, named “90% Diverse”, with the initial buildout of renewables from Figure 1 (25% solar, 35% wind) and then DLC filling the remainder low-emissions energy required.

The results shown in Figure 3 demonstrate that increasingly aggressive decarbonization will result in oversupply. This is especially true in the absence of DLC generation as the total MWh generated are higher in those cases.

To show the value of storage for scenarios in Figure 3, their marginal utilization rates were quantified with storage and without storage (see Figure 4). The dotted lines represent the marginal rate of low-emissions electricity utilization with one Tesla Powerwall (60 GWh of storage for the region) added per home.

All systems suffer from low utilization under deep decarbonization, especially without storage. In addition, the model results demonstrate that storage can be more productive in a system dominated by DLC and a small amount of solar energy (green lines in Figure 4). DLC and solar pair so well with storage because of the diurnal nature of the oversupply episodes: Solar energy tends to oversupply during the day while DLC generation tends to oversupply at night. As their oversupply episodes are less dramatic and occur diurnally and at different times, the battery can perform energy arbitrage more frequently, increasing its value.

Having shown that deep decarbonization can lead to low utilization under certain high-renewable scenarios, it is important to then estimate how the cost of low utilization can affect overall system-level costs and also the marginal cost of carbon mitigation ($/t \ CO_2$). Under full utilization it is assumed that wind, solar, and DLC power plants would have an unsubsidized levelized cost of energy (LCOE) of $80, $90, and $100/MWh, respectively. Theses assumed costs were informed by the estimates from the EIA, but ultimately were picked arbitrarily to demonstrate the importance of system utilization over LCOE.

In addition, the reliability aspect of system-level costs is taken into account by assuming a value of capacity at $330/MW-day. It was assumed that the equivalent load-carrying capability of wind and solar start out at 25% and 50%, respectively, and then fall with increasing penetration.

As shown in Figure 5, under modest decarbonization, high utilization of renewables may be achievable (transmission and thermal constraints neglected). Therefore, given lower costs, renewables alone could be cost effective for modest decarbonization. However, utilization was a dominant factor under deep decarbonization. Consequently, the scenarios where oversupply was limited were more cost effective despite the cost premium assumed for solar and DLC technologies. In other words, even though the assumed cost for wind power was
CLIMATE POLICY IMPLICATIONS

Cost-effective modest decarbonization requires a different strategy than cost-effective deep decarbonization. For satisfying modest decarbonization requirements, wind and solar generation alone may be cost effective. However, at scale, these options can create persistent oversupply episodes that are unlikely to be resolved by battery storage, let alone demand response. For deep decarbonization, electricity systems dominated by DLC and some solar generation achieve higher utilization rates with less storage. Rather than focus on the low-emissions technologies with the lowest LCOE, policymakers should take a long-term strategy and develop the technologies more likely to offer cost-effective deep decarbonization because of high system utilization. That means focusing research, development, demonstration, and deployment of carbon capture and storage in addition to nuclear, solar, and energy storage.

NOTES

A. Hourly ERCOT solar data was procured by modeling NREL’s Solar Advisor Model.\textsuperscript{11} It was assumed that energy was supplied by 10 disperse Texas solar sites with single-axis tracking.

B. Wind supply is scaled based on hourly wind generation and demand in ERCOT in 2012.\textsuperscript{12}

C. The capacity cost of that natural gas is $330/MW-day\textsuperscript{8} and the marginal cost of its generation is $50/MWh.

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Coal’s Role in ASEAN Energy

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The Association of Southeast Asian Nations (ASEAN) is one of the most dynamic and fastest growing regions in the world. Since the declaration of the ASEAN Economic Community (AEC) Blueprint on 20 November 2007—and the formal establishment of the AEC on 31 December 2015—it has contributed significantly to meeting the objectives of reducing the poverty rate, improving the overall well-being of the peoples of ASEAN, narrowing the development gap, strengthening economic development, and expanding both extra- and intra-ASEAN trade and investment.

ASEAN is growing by nearly all metrics. In 2014, the combined gross domestic product (GDP) of the region climbed to US$2.57 trillion, average GDP per capita reached US$4136, and trade reached a record level of US$2.53 trillion. Foreign direct investment (FDI) inflows to the region have also grown steadily over the years to reach US$136.2 billion.1,2

More growth is on the horizon. At the 27th ASEAN Summit on 21 November 2015 in Kuala Lumpur, Malaysia, ASEAN leaders reaffirmed their strong commitment to continue to deepen economic integration over the next 10 years under the ASEAN Economic Community Blueprint 2025.3 With this, the region is projected to grow by at least 4% per year on average over the next five years, but growth could be as high as 6.1%—provided ASEAN moves toward greater integration and that member states continue to implement domestic structural reforms to raise their productivity and competitiveness.4

Increasing energy production and access are key to the realization of the AEC objectives. Although the region’s economy is steadily expanding, its main energy indicators remain substantially under global averages. As of 2013, electricity consumption was 1178 kWh/capita compared to a global average of 2824 kWh/capita, and ultimate primary energy consumption was 0.703 tonnes of oil equivalent (toe)/capita compared to the world average of 1.317 toe/capita. In addition, throughout the ASEAN region about 130 million people still live without electricity access.5

“Over the next decade the projected rapid growth in ASEAN electricity consumption will be largely met by coal-fired power generation.”

A rapid increase in energy requirements is clearly foreseeable in the ASEAN region. This inevitably will create dual challenges of meeting energy demand while also working to rein in greenhouse gas (GHG) emissions and other potential environmental impacts. Thus, the ASEAN community must now determine how to fuel growth in a sustainable way.

RECENT HISTORICAL ASEAN ENERGY TRENDS

The historical development of the ASEAN total primary energy supply (TPES), also called primary energy demand, reflects the trend of steady economic and population growth in the region. Between 1990 and 2013, the ASEAN Centre for Energy recorded that ASEAN TPES grew at an average annual rate of 4.2% to support an average annual economic growth of 5.1% (see Figure 1). Much of this growth in energy supply was filled by coal, oil, and natural gas. In fact, whereas fossil fuels only accounted for 55.4% out of the 238 Mtoe annual TPES in 1990, by 2013 the contribution of fossil fuels had reached 80% of the 619 Mtoe of TPES. While oil contributes the majority, from 37.6% in 1990 to 41.1% in 2013, coal use has grown much faster in the last few decades. From only 13 Mtoe in 1990, or about 5.3% of TPES, coal demand soared to 124 Mtoe in 2013,
or about 20.1%. This equates to an average annual growth rate of 10.4% from 1990 to 2013.

Electricity generation has grown even more rapidly than primary energy. From 1990 to 2013, electricity generation increased by an average of 7.5% per year, from 155.3 TWh in 1990 to 821.1 TWh in 2013. This growth was largely based on fossil fuels, which generated 79.4% of ASEAN electricity in 2013.

Fuel choices have varied over time. There was massive construction of natural gas-fired power plants from 1990–2000 and then growth transitioned as coal-fired power plants were largely built from 2000–2013 by various ASEAN countries. Natural gas and coal constituted 43.8% and 31.5%, respectively, in 2013. Oil-fired power plants lost share in the electricity generation mix, from 42.5% in 1990 to only 4.2% in 2013. During this period of energy growth, ASEAN countries also continued to rely on hydropower, which, together with geothermal and other renewables (e.g., solar PV and wind), contributed 169.3 TWh in 2013, generated from the 45.6 GW of installed renewable energy capacity.

NEAR-TERM PROJECTIONS

ASEAN reliance on fossil fuels is expected to continue in the future (see Figure 1), especially when future growth trends are considered. With the aggregation of national targets for economic growth of 6.1% on average every year and a population expanding at a growth rate of nearly 1%, the ASEAN Centre for Energy’s 4th ASEAN Energy Outlook forecasted that the TPES will grow by an average of 4.7% per year from 2013 to reach 1685 Mtoe in 2035 under a business-as-usual scenario.

While efforts are being made both regionally and nationally to implement stronger policies on various energy efficiency and renewable energy targets, the region is expected to continue to rely on fossil fuels to support projected growth. In fact, over the next decade the projected rapid growth in ASEAN electricity consumption will be largely met by coal-fired power generation. Whereas coal only accounted for 20.1% of the primary energy mix in 2013, coal demand is expected grow faster than any other energy source and make up 33% of the TPES in 2035, equivalent to 556 Mtoe.

Coal is readily available in ASEAN, underpinned by production in Indonesia, one of the world’s major coal producers and exporters. Thus, coal is the natural choice for the region to fulfill the sharp projected increase in its energy needs. In addition, because ASEAN is a net energy exporter as its production of coal and natural gas substantially outstrip the region’s consumption (even considering crude oil imports), increased coal production in ASEAN will continue to serve regional neighbors and beyond.

Coal-based electricity capacity is projected to increase from about 47 GW in 2013 to 152 GW in 2025 and then to 261 GW in 2035, an average growth rate of 8.1%. New and existing coal capacity are expected to generate 867 TWh in 2025 and 1577 TWh in 2035, replacing natural gas as the fuel providing the largest share of ASEAN electricity generation—coal and natural gas will be responsible for 55% and 32% of electricity generation in 2035, respectively. Electricity from renewables is also expected to increase from 2013 with an average growth rate of 4.4%, making up 13% of TPES in 2035.

High coal demand is not a new trend in ASEAN as this region has abundant coal resources. Although the current oil price slump has increased the competitiveness of oil, and in some cases natural gas, compared to coal, there is far more uncertainty in oil and natural gas prices. This fact, combined with the large ASEAN coal reserves (forecasted to be about 12–14 billion metric tons in 2035 at the current production rate), makes coal more attractive than other fuel options. Notably, while ASEAN has historically been a net exporter of natural gas and coal, an internal study from the ASEAN Council on Petroleum on its Trans-Asian Gas Pipeline Masterplan predicted that ASEAN will see a natural gas supply gap starting around 2017. Although there are new prospects in Southeast Asia for natural gas located offshore in deep water or from unconventional production approaches, such natural gas recovery is not currently widely practiced in ASEAN.

Also supporting increased coal-fired power plant deployment is the fact that, throughout the region the infrastructure to generate baseload electricity from coal is already well established, which also contributes to lower prices.

CONSIDERING THE ENVIRONMENTAL FOOTPRINT OF ASEAN ENERGY

Minimizing CO₂ and other emissions from the region will require an increased role for lower-emissions energy. With
limited energy resources and also a need to minimize the environmental footprint of ASEAN energy production and utilization, it is vital to adopt all necessary measures to ensure that coal and other fuels are used with the highest efficiency possible. The current and projected growth in coal utilization gives ASEAN an opportunity to deploy the most efficient coal technologies commercially available, reducing the environmental footprint of coal-based electricity generation.

“ASEAN countries have included HELE coal-based power generation in their Intended Nationally Determined Contributions.”

For improving the efficiency of coal utilization there are several options. For example, supercritical and ultra-supercritical technologies are commercially available, with even higher efficiencies possible when advanced ultra-supercritical becomes available. Power plants using low-grade coals (such as the lignite abundantly available in ASEAN) are candidates for more efficient generation by employing pre-combustion drying. IGCC may also offer higher efficiency and reduced CO₂ emissions if it is more widely deployed in the region. HELE coal-fired power plants are already being built in ASEAN. For example, before 2020, Malaysia is expected to have 1000 MWₑ supercritical and 4080 MWₑ ultra-supercritical capacity; the Philippines 500 MWₑ supercritical; Thailand 600 MWₑ supercritical and 600 MWₑ ultra-supercritical; and Vietnam 19,136 MWₑ supercritical and 1200 MWₑ ultra-supercritical.¹

Such HELE technologies paired with carbon capture and storage (CCS) would be an important low-carbon emissions option for ASEAN countries that are building up coal- and natural gas-fired power plant capacity.

Recognizing that barriers to the deployment of low-carbon emissions technologies in the region exist, through a Joint Ministerial Statement at the 32rd ASEAN Ministers on Energy Meeting in September 2014, the ministers voiced support for the ongoing efforts to develop HELE coal-fired power plants.² They also agreed to generally promote the adoption of clean coal technologies (CCT). Together with the ASEAN+3 Dialogue Partners (China, Japan, and Korea), also meeting in September 2014, ASEAN agreed to step up cooperation on financing and to develop technology cooperation programs; promote policies on CCT, including HELE coal-fired power plants, the upgrading of low-rank coal, CCS, gasification, and liquefaction; and generally develop related industries in the region.³

In the spirit of cooperation that COP21 set into motion, emissions reductions consistent with international climate objectives must be advanced. But for a developing region like ASEAN, environmental protection efforts must be integrated with goals related to energy security, economic development, and poverty alleviation. Thus, ASEAN countries have included HELE coal-based power generation in their Intended Nationally Determined Contributions (INDCs). There is a need for an international mechanism to be established to support both the technical and financial requirements for countries to accelerate the construction of such projects, and to build a pathway for low-emissions coal—and thus a low-emissions energy sector and a better future for ASEAN and the world.⁴

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What’s Driving India’s Coal Demand Growth

By Liam McHugh
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As noted in the International Energy Agency’s (IEA) World Energy Outlook 2015, India is in the early stages of a major transformation. While other BRIC (Brazil, Russia, India, and China) nations face another year of economic uncertainty, the World Bank suggests India’s GDP will grow by 7.9% in 2016, more than twice the global average. Economic growth and modernization will in turn drive energy demand, especially for coal. Moreover, Indian appetite for coal will rise as the government enacts policies to assist those affected by energy poverty. The IEA has estimated that around 240 million people, or 20% of the population, remain without access to electricity. Of equal concern, the agency estimates that 840 million people — more than the populations of the U.S. and the European Union combined — use traditional biomass for cooking. Unsurprisingly, in a speech earlier in 2015, Piyush Goyal, Minister of State for Power, Coal and New and Renewable Energy, stated that “universal and affordable energy access 24/7 ... is the mission of this Government under Prime Minister Modi.”

India is currently the world’s third largest energy consumer; this position will be consolidated over the coming years, driven by economic development, urbanization, improved electricity access, and an expanding manufacturing base. Indeed, the IEA forecasts that India’s energy consumption will be more than OECD Europe combined by 2040, and rapidly approaching that of the U.S.

“Deploying HELE technologies delivers the most cost-effective form of CO₂ abatement when compared to subcritical coal, without sacrificing legitimate economic development and poverty alleviation efforts.”

Like China before it, India’s economic growth will be fueled by coal. Thus, in 2012, 45% of total primary energy demand and 72% of generated electricity demand was met by coal. India currently has approximately 205 GW of coal-fired electricity generation capacity, which will soon be augmented by 113 GW of new coal-fired capacity currently under construction.

Recognizing India’s growing role in the international coal market, in late 2015, the World Coal Association (WCA) published “The Case for Coal: India’s Energy Trilemma”. This article provides a synopsis of the report’s major findings.

GOVERNMENT POLICIES TO MEET GROWING ENERGY NEEDS

The Indian government’s policies to meet the growing need for electricity are focused, principally, on developing large-scale coal-fired power plants. Indeed, in March 2015, Arunabha Ghosh, head of the Council on Energy, Environment and Water think tank in New Delhi, told the UK’s Financial Times that “whichever way you cut it, coal is going to be front and centre of India’s future energy mix...”.

Over the next 25 years, electricity demand in India is forecast to grow at over 4% per annum. Under its New Policies...
Scenario, which modeled energy demand and supplies if all new and proposed policies were fully enacted, the IEA estimates that installed coal capacity will reach almost 500 GW by 2040 (more than three times the 2012 installed capacity) (see Figure 1). Although comparatively lower, under the 450 Scenario—in which the concentration of CO$_2$ in the atmosphere would be kept to 450 ppm, the concentration estimated to lead to no more than 2°C warming—increases in coal-fired capacity will still exceed 300 GW by 2040.\textsuperscript{7}

The dominance of coal in India’s energy mix can be attributed to two key factors: affordability and access. Although the competitiveness of renewables and gas-fired technology is likely to improve over time, coal is expected to remain the most affordable option through to 2035, driven by low domestic coal prices and limited gas availability (see Figure 2).

### Table 1: CO$_2$ emissions (tCO$_2$) (over 40 years)

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<td></td>
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<td></td>
<td>SubC</td>
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With such a large expansion program planned for the coming decades, the choice of technology deployed will have...
significant implications for the expenditure required. Looking ahead, the Government appears to be preparing the 13th Five-Year Plan (2017–2022) to call for the development of 100% supercritical coal plants. Cost differences, however, could impact developers’ choices. There is as much as a 40% price difference between the capital costs of an ultra-supercritical and a subcritical coal plant. Analysis show that if all coal plants built from 2020 onward were ultra-supercritical, total capital expenditure would reach $500 billion by 2040, compared to around $387 billion if all coal plants built from 2020 onward were subcritical.

**IMPLICATIONS OF ENERGY TECHNOLOGY CHOICES**

Leaving cost considerations aside, there are clear benefits for deploying supercritical or ultra-supercritical technology. Replacing the subcritical capacity currently in the development pipeline with supercritical or ultra-supercritical capacity would translate into significant reductions in CO$_2$ emissions for India over the life of the power plants (see Figure 3).

Replacing subcritical with supercritical and ultra-supercritical coal technology reduces CO$_2$ emissions at a cost of around $10/tonne in 2035 (see Figure 4). By comparison, abating a tonne of CO$_2$ through the deployment of large-scale solar PV in India can cost up to $40/tonne, even accounting for the cost declines expected through 2035 (~$16/tonne under a low weighted average cost of capital and low capital cost scenario).

**FIGURE 4. Avoided cost of CO$_2$ in India, 2035 (subcritical coal plant used as baseline)**

*No CO$_2$ price assumed

**CO$_2$ ABATEMENT OF ULTRA-SUPERCritical COAL COMPARED TO RENEWABLES**

Building on these abatement findings, WCA’s “Case for Coal” report considers the impact of spending US$1 billion across different generation options in India and Europe. The research takes into account differences in the levelized cost of electricity (LCOE), emission rates across technologies, and the marginal generation technology in each region.

As illustrated in Figure 5, the US$1 billion expenditure can result in more generation (in TWh) and higher CO$_2$ emission reductions when spent in replacing subcritical plants in India compared to replacing combined-cycle gas turbines (CCGT) with renewable technologies in Europe.

**FIGURE 5. CO$_2$ abatement potential of cleaner coal technology in India compared to renewables in Europe**
For comparison, the report also considered deployment of solar PV. Analysis indicates that although renewable technologies in India could result in high emissions abatement, they do not provide the scale of generation growth required to meet electrification targets.

LOW-EMISSIONS COAL TECHNOLOGY FOR COST-EFFECTIVE CO₂ ABATEMENT

The findings of the “Case for Coal” report have important policy implications for governments and should be analyzed carefully when assessing climate change initiatives. The report demonstrates that, on a generation basis, coal has the potential to deliver the most TWh of all technology options (assuming the same expenditure on an LCOE basis, see Table 1). Moreover, deploying HELE technologies delivers the most cost-effective form of CO₂ abatement when compared to subcritical coal, without sacrificing legitimate economic development and poverty alleviation efforts. It is worth noting that this understanding provided the framework for India’s Intended Nationally Determined Contribution (INDC) filed for COP21, which raised the profile for the role of HELE technologies.

Expanding efficient utilization of coal will help address India’s energy trilemma of meeting demand, reducing energy poverty, and actively participating in mitigating global climate change. Importantly, this model of development is not limited to India; it may be applied to a number of emerging economies and forms the foundation of the Platform for Accelerating Coal Efficiency, an initiative that the WCA continues to pursue in 2016.

NOTES

A. For India, the analysis assumes that US$1 billion is spent on replacing subcritical coal-fired power plants (baseline technology) with supercritical and ultra-supercritical technologies, causing a reduction in emissions equivalent to the difference in emission rates between the different coal technologies. For Europe, the analysis assumes that US$1 billion is spent on building renewables, which are assumed to replace gas-fired CCGT plants (baseline technology), causing a reduction in emissions equivalent to the avoided emissions from gas-fired CCGTs.

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### TABLE 1. 2015 technology comparison in India (in $2014)

<table>
<thead>
<tr>
<th>Technology</th>
<th>CAPEX (billion $/GW)</th>
<th>Tariff (US$/MWh)</th>
<th>Load factor (%)</th>
<th>Subcritical coal capacity (%)</th>
<th>Subcritical coal generation (%)</th>
<th>Avoided cost of CO₂ ($/tonne)</th>
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<tr>
<td>Subcritical coal</td>
<td>1.05</td>
<td>48</td>
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<td>PV (large)</td>
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<td>54</td>
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</tr>
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</table>
Pakistan, the world’s sixth most populous country, is a developing nation facing many challenges. Over the last 12 years regional conflicts have taken a considerable toll on Pakistan’s economy and have left the nation with a damaged and vastly neglected infrastructure. The energy sector has been one of the most affected segments and is in desperate need of investment and revitalization. In 2012, the country, with a population of around 178 million, produced only 80 billion kWh of electricity; compare that with the Netherlands, which produced 115 billion kWh of electricity in 2012 for a population of only 16.7 million people.

With the 2013 peaceful democratic transition of government for the first time, Pakistan is finally poised to begin providing more opportunities for its people, including increased public safety, stronger economic performance, better employment opportunities, and greater access to reliable energy. Improving energy production, utilization, and access will be the building block on which other development objectives can be founded.

“\textit{The environment will arguably be helped through development of Pakistan’s coal resources through a diminished reliance on deforestation-causing biomass harvesting and eliminated the emissions from burning that biomass.}”

PAKISTAN’S ENERGY CRISIS AND OPPORTUNITIES

Pakistan has been experiencing an energy crisis for decades and no aspect of the energy sector is untouched by this crisis. The country relies heavily on imports for its energy supplies. In fact, 44% of Pakistan’s energy supply is currently imported—at an annual cost of around US$15 billion.\textsuperscript{2} The utilization rate for the existing electricity sector, which relies on oil, natural gas, and hydro power, was less than 60% in 2012.\textsuperscript{3} This left 56 million people without access to electricity.

Natural gas is an important contributor to Pakistan’s primary energy mix, providing 32% in 2012.\textsuperscript{3} The giant Sui gas field has historically met the majority of the country’s natural gas demand. From the time of its discovery in the early 1950s, production from Sui drove the development of a natural gas distribution system that now extends across the nation. However, as the Sui reservoir depletes at an increasing rate, there are challenges associated with expanding domestic natural gas production.

Although the country produced 1412 billion cubic feet (bcf) of natural gas in 2013, this fell far short of the amount needed. Without reliable natural gas, even households with a connection to the distribution lines were forced to collect biomass to heat their homes and cook. This led to tremendous amounts of in-home pollution and an alarming rate of deforestation.
Thus, Pakistan is now looking to build new pipelines so that it can import natural gas and is also pursuing the construction of liquefied natural gas (LNG) facilities. The country also has 105 trillion cubic feet of shale gas, but economic production is unproven and faces technical and economic challenges. Attempting to increase the role of natural gas in Pakistan’s electricity sector could very well increase the country’s already-high reliance on energy imports.

The once-abundant supply of natural gas spawned the world’s largest natural gas-fueled vehicle count on the roads of Pakistan. Filling stations offering compressed natural gas (CNG) were built throughout the country and CNG car conversion kits were so affordable that low-income taxi drivers converted their vehicles. At least two million vehicles in Pakistan run on natural gas and about 3000 CNG stations are in business today. Although diesel dominates the market for transportation fuel, the transport sector also has strong demand for natural gas, which may be poised to grow further if the country can secure new supplies. Currently, the government is discouraging natural gas for transportation given the country’s shortfalls of the fuel. When the decline in Sui production started accelerating around 2012 mile-long lines at CNG stations appeared. As a result, many drivers have been forced to return to more expensive gasoline or diesel.

The country, like most, is working to phase out oil-fired power plants. Such plants are subject to the extreme volatility in oil prices and also make the country’s electricity sector more heavily reliant on imported oil. Hydro power provides about 30% of the electricity in Pakistan, but is not reliable during summer. The government intends to grow the electric capacity of renewables, such as wind and PV solar, to account for about 15% of its electricity mix, but the intermittency eliminates them as near-term options for baseload power.

Pakistan’s coal reserves are hugely underutilized. The Thar coalfields are estimated to hold about 175 billion tons of low-rank coal that is yet to be mined. Although sufficient infrastructure is not currently in place, the Thar coal resources could probably support 100 GW of electricity production for 200 years. At a time when power shortages in Pakistan are estimated to cost the economy 2–4% of GDP growth and lead to closure of factories and other important employers, harnessing this indigenous fuel is increasingly attractive.

Notably, there are other issues with the electric sector that must be addressed. Transmission and distribution losses are close to 22%. Theft must also be curbed as well as a longstanding circular debt problem plaguing independent power producers. All the issues facing the electric sector result in load shedding of several hours per day, and Pakistanis pay about double for electricity compared to their Indian neighbors. While much work remains, I believe the energy sector reforms being undertaken, such as establishing a special tariff for Thar coal used in electricity production, tackling the circular debt issue by the current government along with streamlining permitting are encouraging and these challenges are finally being addressed with the urgency they warrant.

**BALANCING ENERGY NEEDS WITH ENVIRONMENTAL PROTECTION**

While alleviating energy poverty and providing energy to support economic growth are major goals, energy development
in Pakistan must be carried out in a manner that minimizes the environmental footprint.

Increased domestic natural gas and coal production could support a revitalization of Pakistan’s energy sector. Although energy production is often associated with a detrimental impact to the environment, if Pakistan’s energy resources are developed in a responsible and rational manner, there could be considerable environmental benefits not just for Pakistan, but also help meet global objectives. As indicated earlier, the decline in Sui production, which began to gain momentum around 2012, has led to natural gas shortages and forced a large number of Pakistanis to gather biomass for heating and cooking; the country’s tree cover is now estimated to be 2–5% of what it once was.

This has led to flooding, landslides, and other major environmental disruptions. In addition, when biomass is burned indoors it releases dangerous chemicals. In this way, reliable energy fueled by indigenous resources could immediately benefit Pakistan’s environment.

The first permits for mining the Thar coalfields are moving forward. In addition, developers have opted to build a circulating fluidized bed (CFB) for the first coal-fired power plants using Thar coal. Using CFBs is important because they can successfully utilize low-rank coal like that found in the Thar coalfields. Emissions are also more easily controlled using CFBs, because they produce less NOx due to lower temperature operation, and limestone in the boiler immediately captures most SOx. While this is an important first step, CFBs and other coal-fired power plants are not able to address the need for additional natural gas. In addition, CO2 emissions would need to be mitigated through carbon capture and storage (CCS). However, there is a way that Pakistan can use its large coal resources to meet energy needs beyond electricity generation and largely mitigate criteria emissions as well as CO2.

**COAL-BASED POLYGENERATION AS A SOLUTION FOR PAKISTAN**

Several project developers are looking to produce and utilize the coal resources in the Thar coalfields. One innovative example is TharPak, LLC, a consortium of clean energy companies aiming to deploy a suite of technologies including the use of gasification-based polygeneration to produce synthetic natural gas (SNG) and electricity for Pakistan in an environmentally sustainable manner.

Three specific technologies are envisioned as part of the TharPak project. First, the DryFining™ process, which has been developed and demonstrated by Great River Energy in the U.S., will be applied to dry the low-rank Thar coal prior to gasification. This process utilizes waste heat in a fluidized bed process that removes moisture and some sulfur and mercury from coal. This dried coal is also rendered more stable, can be economically transported over longer distances, and is less prone to spontaneous combustion. The DryFining™ process has been profiled previously in *Cornerstone.7*

Second, KBR’s transport reactor integrated gasifier (TRIG™) will convert the treated low-rank, high-moisture coal into syngas (CO + H2). TRIG has been demonstrated on low-rank coals and is now commercially available. The syngas can be converted into synthetic natural gas (SNG) and/or electricity. The criteria emissions from the process are lower, and the CO2 emissions can also be captured, used, and/or stored to generate low-emissions energy. In the process used to make SNG, the CO2 must be separated, making its capture far more economical than conventional methods.

TharPak aims to use some of the captured CO2 in Algenol’s algae-based process, which can generate liquid fuels as a product at a projected cost of $1.30/gallon.8 The CO2 emissions can also be captured and processed for use in enhanced oil recovery (CO2-EOR) using commercially available processes.

An added benefit of the Algenol process is that it uses saline water and produces two gallons of fresh water for each gallon of fuel produced. There are several large salinated aquifers between the coal seams of the Thar field that are estimated to be the size of giant lakes. The area around is not only arid, the population is among the poorest in Pakistan and an abundant clean water source could help transform the area with agricultural uses year-round. Thus, TharPak’s combination of these proven advanced technologies can help meet demand for electricity and natural gas, while also capturing CO2 emissions. It is also worth mentioning that several heavy oil fields in the vicinity of the Thar coalfields which have been in production since the 1960’s could be recipients of some of TharPak’s CO2 to aid in CO2-EOR.

TharPak plans to use processes that rely on algae to capture some of the CO2 from its polygeneration plant (lab-scale shown here).
Integrated gasification and combined-cycle (IGCC) facilities that produce electricity exclusively have faced economic headwinds abroad. IGCC will be deployed to produce electricity only if it is economically competitive. Low costs for coal production and lower labor rates in Pakistan could enable economic IGCC even as it has been overly expensive elsewhere.

The SNG being produced would need to compete with new sources of natural gas for Pakistan, including expensive LNG. Based on initial estimates, TharPak is confident that, even at the current low prices in the LNG market, the SNG produced by its process will be competitive. Less dependency on imported fuel would add to Pakistan’s energy security and avoid the other environmental risks associated with transporting fuels long distances.

TharPak has been allocated Block IX of the Thar coal resource and is now working to secure the capital needed to advance the project. Although most development banks and other NGOs do not support developing Pakistan's coal resources, there is a strong argument for doing so, especially if environmental concerns are addressed throughout the process.

There is a silver lining in the extensive delay in addressing Pakistan’s energy crisis. Technologies that were not commercially available only a few years ago now exist that can use the low-rank coal in Pakistan to help solve the energy crisis without major environmental disruption. In fact, the environment will arguably be helped through development of Pakistan’s coal resources through a diminished reliance on deforestation-causing biomass harvesting and eliminated the emissions from burning that biomass. The international community only needs to support such energy projects that could dramatically improve the lives of the Pakistani people. I believe that TharPak’s proposed coal-based polygeneration project is one such project.

REFERENCES


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The Future of Gasification

By DeLome Fair
President and Chief Executive Officer,
Synthesis Energy Systems, Inc.

Gasification technology has experienced periods of both high and low growth, driven by energy and chemical markets and geopolitical forces, since introduced into commercial-scale operation several decades ago. The first large-scale commercial application of coal gasification was in South Africa in 1955 for the production of coal-to-liquids. During the 1970s development of coal gasification was propelled in the U.S. by the energy crisis, which created a political climate for the country to be less reliant on foreign oil by converting domestic coal into alternative energy options. Further growth of commercial-scale coal gasification began in the early 1980s in the U.S., Europe, Japan, and China in the coal-to-chemicals market. The technology quickly transitioned into an alternative cleaner energy platform with the first coal-to-natural-gas project completed in the U.S. in South Dakota and the first integrated gasification combined-cycle (IGCC) project demonstration at Cool Water, California. In the 1990s the completion of the Polk and Wabash cleaner coal commercial IGCC power projects further advanced the technology. As energy prices continued to trend ever higher, the development of cleaner energy projects using coal gasification accelerated rapidly in the early 2000s.

In the U.S., this dynamic quickly changed with the ensuing drop in natural gas prices associated with the emergence of hydraulic fracking of shale for natural gas extraction. Development of coal gasification projects in the U.S. then slowed significantly, with the exception of a few that were far enough along in development to avoid being cancelled. However, during this time period and on into the early 2010s, China continued to build a large number of coal-to-chemicals projects, beginning first with ammonia, and then moving on to methanol, olefins, and a variety of other products. China’s use of coal gasification technology today is by far the largest of any country. China rapidly grew its use of coal gasification technology to feed its industrialization-driven demand for chemicals. However, as China’s GDP growth has slowed, the world’s largest and most consistent market for coal gasification technology has begun to slow new builds.

“Market forces in high-growth regions are more aligned than ever with the capabilities of gasification technology.”

Recently, growth in the coal gasification industry in general has slowed as the global energy price landscape has shifted significantly. If the gasification industry continues to think about coal gasification as it has been historically defined (i.e., large projects focused on conversion of high-quality coal into mainly chemicals), I believe the future will continue to look challenging. But, if historical conventional thinking about the

Successful gasification projects demonstrate that viable markets exist.
role of coal gasification is left behind, and market trends are carefully evaluated, I believe market and geopolitical forces are aligning to allow for a new wave of significant growth in coal gasification.

**NATURAL GAS PRICES**

The main competitors to coal gasification are oil- and natural gas-based energy and products and natural gas prices are the single most important indicator for the viability of coal gasification projects. When natural gas is inexpensive and plentiful, coal gasification projects are unlikely to be built. Figure 1 shows projections for liquefied natural gas (LNG) prices in Japan, natural gas prices in Europe, and natural gas prices in the U.S. Figure 2 shows the landed LNG prices around the world in early 2016.

Looking at the information provided in these two charts, several key conclusions can be drawn:

- With the exception of the U.S., natural gas prices around the world are expected to remain elevated well into the future.
- While projected to be stable, natural gas is still subject to high volatility.
• Although landed LNG prices shown are under $6/MMBtu, LNG regasification and pipeline transportation add additional cost before the fuel becomes available to the end user. For example, over the past year, I have seen natural gas prices in China ranging from 2.5 to 3.5 RMB/Nm$^3$ ($10–15/MMBtu).

The bottom line is that natural gas prices in the areas of the world anticipated to have the highest growth (China, India, Indonesia, Brazil, Africa) are expected to remain high for the extended future. This sets the stage for an emerging large opportunity for lower cost alternatives to expensive natural gas and LNG, such as clean syngas from coal gasification, to enter the markets.

**ENERGY DEMAND**

Canada and the U.S. are by far the highest users of energy on a per capita basis, although these numbers have decreased recently (see Figure 3). The European countries shown in Figure 3, while highly developed, have a lower energy utilization per capita. It is reasonable to assume that as developing countries continue to grow, they could eventually approach the energy utilization per capita of the EU.

China, for example, has already seen major increases in its per capita energy consumption over the last few decades, and additional growth is likely. With China’s population of about 1.35 billion people, increasing the energy per capita from the 2012 level to 5000 kWh (slightly lower than all the EU countries in 2012) would require about 250 GW of additional power generation capacity. For India, with a population of about 1.25 billion people, more than 600 GW of additional capacity would be required to achieve this level. These numbers do not take into consideration the additional power capacity required, due to further increases in population which are likely to occur in these countries. Additional electricity and fuel capacity will be necessary to meet the energy demand of these growing populations (see Figures 4 and 5).

Figure 4 shows both a historical perspective and a future projection. Notably, the rate of growth in energy consumption for non-OECD countries mirrors the shape of the coal consumption curve shown in Figure 5. In fact, most of the growth in electricity capacity will be in the non-OECD countries, and these countries will use coal. Gasification can play a big role in this growth by providing low-cost, low-emissions clean energy from locally sourced coal with superior carbon capture retrofit capabilities, compared to traditional coal-based technologies.

**POTENTIAL FOR COAL GASIFICATION FOR NEW POWER ADDITIONS**

As power providers and governments make decisions about new power generation options, several key factors must be considered. First, a decision needs to be made regarding the fuel that will be consumed. Often, the most important selection factor is the cost of the fuel. In addition, considerations will be made regarding the long-term availability of the fuel, and the domestic energy security impacts of imported fuel versus domestic fuel. Finally, the emissions will increasingly be scrutinized as evidenced by the Paris Agreement resulting from COP21.

![Figure 3. Energy use per capita in select countries](image)

![Figure 4. Global energy consumption predictions](image)

![Figure 5. World energy consumption by fuel](image)
In parts of the world with a large discrepancy in the cost between natural gas and coal, it is highly likely that coal will still be selected, as it is economical and locally available. While developed markets will likely attempt to offset the carbon emissions from coal plants by building more expensive renewable technologies, such as wind and solar, the large emerging markets need economical and reliable new power capacity at large scale immediately. This dynamic has driven, and will likely continue to drive, large increases in the demand for coal-based power projects. Coal gasification can play a significant role because of its ability to generate economic, reliable power with very low levels of criteria emissions.

In the case of coal-fueled projects, a choice must be made between traditional pulverized coal-fired boilers and coal gasification-derived power. Key considerations will be the time required to build the plant, the capital cost of the plant, and the availability of low-cost financing. Another important decision will be the capacity of the plant. Traditional large-scale coal power generation plants capable of generating 600 MW and larger may not always be desirable, due to lack of centralized load demand and adequate long-range transmission capability. In these cases, smaller-scale power generation in the 50–300 MW range will be more desirable, due to the more distributed nature of load demands.

Criteria and greenhouse gas emissions are also important considerations. Coal gasification-derived power is capable of producing power with far lower criteria pollutant emissions, such as SO\textsubscript{x}, NO\textsubscript{y}, and particulate matter, compared to traditional pulverized coal. In addition, as CO\textsubscript{2} utilization technologies are developed and demonstrated, existing coal gasification facilities will offer significantly less expensive and commercially demonstrated methods to retrofit for the capture of carbon.

Coal gasification-derived power cannot only compete in the electricity market, but can quickly grow into a leader for coal-based power in these markets. However, there are a couple of key requirements. First, the gasification technology must be able to economically gasify low-cost, low-rank coal (such as lignite, brown coal, or high-ash coal), and coal wastes. The power plants must generate electricity with criteria pollutants much lower than historical coal power production. And finally, coal gasification providers need to continue to educate and drive the message regarding the superior retrofit capability of carbon capture of gasification. While the coal gasification power plants being built in the near term may not include capture, the ability to retrofit operating plants to drastically reduce CO\textsubscript{2} emissions at a low cost has significant value and hedges the investment risk in a carbon-constrained world.

Coal gasification technologies exist that can fill the needs of the power market. For example, Synthesis Energy Systems (SES) has developed a small-scale, coal-fed power generation product. This new product, iGAS, combines the superior low-rank coal capability of SES Gasification Technology (SGT) with small-scale gas turbines for the production of low-cost, low-emissions power on a distributed power platform.

OTHER ENERGY DEMANDS

In addition to the production of electricity, coal gasification can be used to generate other forms of energy. Two emerging markets are the production of substitute natural gas (SNG) and the production of syngas to replace natural gas or other fuels in industrial applications. Gasification for the production of SNG can be profitable, if the price of the coal is low and the price of alternative natural gas is high. However, this will still likely be more of a niche opportunity, with plants built at the coal source with access to existing natural gas pipeline infrastructure.
A new and emerging market for gasification is the use of low-priced coal to generate clean syngas that can be used directly as a fuel in an industrial setting, such as in the production of ceramics, glass, or aluminum. SES’s initial three such projects—licensed by its China Joint Venture, Tianwo-SES Clean Energy Technologies Company—were announced in December of 2014. The first of these projects started up in July 2015, and is estimated to save the Aluminum Corporation of China (the facility owner) more than $50,000/day in fuel costs for its aluminum products. Syngas can also be used to replace natural gas in the production of direct reduced iron in the steel industry.

THE CHANGING FACE OF GASIFICATION

What does the coal gasification industry need to do to capture a share of this large potential energy market? First, it needs to change focus from producing chemicals to producing clean energy. Chemical production projects will still be built, but I believe the real growth opportunity is in clean energy. Second, the industry needs to readjust its geographic focus. Historically, the location for coal gasification projects has been centered in eastern China and the U.S. China will still dominate as a major market for coal gasification, but next-generation markets will expand to include all of Asia, including countries such as India, Indonesia, Mongolia, Pakistan, and Vietnam. In the longer term, there will also be demand for this technology in other developing markets such as Brazil and Africa.

Finally, it is likely that many of the next-generation gasification projects will not be built by large-scale companies and government-owned entities with ready access to capital and financing. Coal gasification technology providers will need to expand beyond the traditional role of supplying license and equipment, to being able to provide turn-key gasification islands and become more involved in assisting the project developers in securing equity and financing to help these projects get started. With the favorable economics of these clean energy projects, equity investment by the technology providers themselves can also be a very lucrative opportunity.

KEY CONCLUSIONS

In summary, several key conclusions can be taken away from this analysis:

• Market forces in high-growth regions are more aligned than ever with the capabilities of gasification technology.

• Coal gasification technology providers have a great opportunity in large, high-growth mega-markets of energy.

• Gasification is a clean energy technology.

• Coal will be utilized heavily to fuel much of the global growth.

• Gasification is the best option for coal in a CO₂-constrained world.

• Project decisions will be driven by (1) speed, (2) low CAPEX, (3) economics, and (4) environmental performance related to criteria emissions, capability for CO₂ capture retrofit, and water consumption.

Coal gasification technology providers that have aligned their focus to take advantage of this unique combination of market dynamics and changing customer requirements will be successful. At SES, we believe our technology has the ability to meet the energy needs of the future and continue to utilize coal, the world’s largest energy resource, to provide clean energy to those who need it most.

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Application of Circulating Fluidized Bed Combustion With Low-Rank Asian Coals

By Ian Barnes
Consultant, Hatterall Associates

Low-rank coals (i.e., lignite and brown coals) have been estimated to account for approximately 50% of global coal reserves, with as much as half of those reserves considered to be economically recoverable. While the principal deposits are concentrated in the U.S. and the Russian Federation, significant reserves also exist across Asia. Over 50 billion tonnes of proven recoverable low-rank coal resources have been identified in China alone and significant reserves of lignite exist in India, Pakistan, and Thailand. These low-rank coals are considered to be low grade because of their high moisture content and low heating value. Such coals also may have higher sulfur content, requiring the application of additional technologies for its capture and removal.

In common with other relatively low-value fuels, no free-market mechanism exists for low-rank coals used in power generation because their low energy content usually makes transport over longer distances uneconomic. For this reason, lignite-fired power plants are commonly built adjacent to lignite mines. A power plant and surface mine then form a single economic entity in which lignite is transported by dedicated infrastructure, typically a conveyor belt, and delivered directly to the nearby power plant.

“CFBC … is thought likely to feature strongly in Asia’s future fossil fuel power generation fleet.”

The role of some coal-fired power plants has changed significantly in recent years as co-combustion of biomass and waste become more commonplace. The utilization of low-rank coals and other fuels in an efficient and environmentally benign way poses many technical challenges. Circulating fluidized bed combustion (CFBC) is particularly well suited to utilize low-rank coals and other challenging fuels, which is why there are about 130 such plants in operation in Asia and more under construction.

BENEFITS OF CFBC

CFBC was first demonstrated in the late 1970s, but it was not used for power generation until 1985 (see Figure 1 for a generic CFBC process). The basic concepts behind CFBC rely on...
gas velocities high enough so that particles are entrained and carried out of the boiler. Flue gas passes through solid separators (typically cyclones) that return ash and other solids to the lowest part of the combustor and thus prevent unburnt fuel from leaving the furnace. This creates a recycle loop through which fuel particles can pass 10 to 50 times until complete combustion is achieved. The prolonged combustion time results in much lower temperatures (800–900°C) than those found in pulverized coal combustion (1400–1600°C), which has traditionally led to lower operating efficiencies in CFBC.

Although CFBC has been used for decades, higher-efficiency plants are now successfully operating on increasingly large scales. A 460-MW supercritical CFBC unit at the Lagisza power plant in Poland has been operating since 2009 and a 600-MW supercritical unit recently began operation at Baima in China, while the four 550-MW supercritical units of the Samcheok power plant in South Korea, scheduled to begin operation soon, constitute the world’s single largest CFBC power plant. Unit sizes have been steadily increasing, with 600- to 800-MW supercritical CFBC systems now commercially available and larger units under development.

CFBC power plants are particularly well suited to burn low-grade fuels and mixtures of such fuels. A large amount of inert bed material makes it possible to have considerable variation in fuel properties, or to change fuels during operation without significant disruption to the combustion process. Circulating solids also improves heat transfer and makes it possible to burn high energy content fuels while maintaining the combustion temperature in the region of 850–900°C. This relatively low combustion temperature minimizes fouling and slagging of heat surfaces since ash melting and softening points are generally much higher than CFBC temperatures. The low temperatures also make emissions control more straightforward as the amount of NOx created is relatively lower and solids circulation provides a long residence time for fuel and limestone particles, resulting in high SO2 capture efficiency and lower limestone consumption. In fact, the supercritical unit at Lagisza has demonstrated up to 95% SO2 removal with a calcium to sulfur ratio of two or 99.8% removal at a calcium to sulfur ratio of three. Additionally, CFBC plants have exceptional flexibility and can operate effectively while running at as little as 30% of full load.

Increasingly liberalized and volatile fuel markets, coal sources of highly fluctuating quality, and the trend toward biomass and/or waste co-firing in some regions are all factors that can make CFBC a more attractive technology for power generation. For example, if the price of higher quality imported coal becomes too great, a switch to lower grade, locally sourced coal can be made without significantly altering the performance of a CFB boiler. In this way, the flexibility of CFBC can act as a contingency against variation in fuel supply.

**CASE STUDY: THE SURAT HIGH-SULFUR INDIAN LIGNITE CFBC PLANTS**

India’s demand for coal-based electricity is forecasted to increase dramatically over the next few decades, and utilization of relatively low-quality coals, including high-sulfur lignite, will be necessary to meet this demand. Thus, much like the rest of developing Asia, there is a strong potential for increased deployment of CFBC power plants in India.

The combustion of such coal can pose significant challenges, which were overcome by Bharat Heavy Electricals Limited (BHEL), an Indian state-owned power plant manufacturer, as they operated two 125-MW CFBC units at Surat that were modified specifically to burn high-sulfur lignite (see Table 1 for the units’ design parameters).

**Plant Design**

In BHEL’s CFBC units, the pre-crushed lignite is extracted from the storage bunkers by two variable-speed extraction drag-link chain conveyors and fed through rotary valves and slide gates, which can isolate the fuel feed system from the combustor in case of an emergency. The system has two parallel coal feed lines, both of which need to be operated for optimal fuel combustion. Inert material such as bed ash or sized sand, required for initial start-up, is fed to the combustor directly through a rotary valve. Pre-sized limestone stored in silos is gravity fed through variable-speed rotary valves at a rate based on the SO2 content in the flue gas.

Ash handling is hugely important during CFBC operation. At the BHEL CFBC units, ash is removed from four different locations
in the system: Coarse bed ash exits toward the bottom of the combustor, bed ash from the furnace is removed at bottom heat exchanger, fly ash is removed from the collection hoppers below the convective pass and air heater sections, and fly ash is also captured and removed via the electrostatic precipitator. In order to maintain an appropriate solids inventory in the combustor, bed ash is extracted continuously from the lower combustor and furnace bottom heat exchanger through a cooled ash discharge.

Operating Experience and Lessons Learned

While BHEL’s CFBC units have generally performed well, there have been some challenges around solids handing and deposition in the system. For example, three outages occurred due to ash hold-up in the cyclone at low loads of about 20 MW and another outage was caused by a suspected blockage of the cyclone standpipe when the plant was operating at about 70 MW. An investigation into the incidents concluded that the most probable cause was the recarbonation of calcined limestone that had not reacted with SO₂.

The limestone also was found to be much finer than recommended. This resulted in high throughput during low loads because, due to an equipment malfunction, the SO₂ measurement was not available to control the volumetric feeder of the limestone. In addition, the timing of pulsing air has been subsequently reduced, as it was found that the gas temperature is a key parameter in avoiding the formation of sticky deposits.

The following remedial steps were taken to prevent further outages attributable to cyclone standpipe blockage:

- The limestone feed size was checked continuously with additional sampling.
- The limestone feeder hopper size was reduced.
- The operating procedure was revised to maintain higher combustor temperatures before commencing limestone addition.
- Automatic air pulsing was incorporated at the junction of the cyclone and standpipe to disturb particles and avoid agglomeration.

After incorporation of these changes, the challenges around limestone injection were resolved.

Another operational challenge related to heavy and rapid deposit build-up on the flue gas side of the boiler heat transfer tubes. The deposit build-up was most severe at the low-temperature superheater tube bank. There were also ash deposits in the final-stage reheater tube bank during the initial period of operation. These deposits increased the gas-side pressure drop and in turn forced the operation of the induced draft fans at high loads, causing boiler trips.

The deposits occurred as the boiler was brought online after resolving the cyclone blockage problem when the limestone feed rate was increased to meet SO₂ emissions limits. It was suspected that the formation of sticky deposits, as previously observed in the cyclone, initiated the formation of the larger deposits on the tubes. To assess the cause, samples were taken and confirmed that the primary mechanism of fouling was the recarbonation of free lime followed (i.e., CaO to CaCO₃) by slow sulfation of the deposit. Improvements in the soot-blowing mechanism along with an increase in its frequency have helped overcome the fouling issue.

After the implementation of high-pressure soot blowers along with a fluidization arrangement for smooth evacuation of the ash falling onto the hoppers, full load operation with limestone addition to ensure sulfur capture of more than 98% (versus 97% design) was achieved.

Although the supercritical CFBC power plant operated by BHEL experienced some challenges, after detailed technical

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Units</th>
<th>Design Value</th>
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<tr>
<td><strong>Main Steam</strong></td>
<td></td>
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<td>Flow</td>
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<td><strong>Reheat Steam</strong></td>
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<tr>
<td>Flow</td>
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<td>Outlet pressure</td>
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<tr>
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<td>Feedwater temperature</td>
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<td>Moisture</td>
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<tr>
<td>Ash</td>
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<tr>
<td>Higher heating value</td>
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<tr>
<td><strong>Ultimate analysis (dry ash free)</strong></td>
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<tr>
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<td>Oxygen</td>
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assessments and some operational modifications, both units were able to operate reliably and with low emissions. As an increasing number of CFBC power plants are deployed in India and throughout the rest of Asia, there will be lessons to be learned around optimal operation and additional R&D needed to further increase the efficiency.

CONCLUSIONS

Low-grade coals are a significant energy resource in Asia, but require technological solutions that can cope with the demanding requirements of these fuels. CFBC has demonstrated its effectiveness in handling a wide range of coal types and combinations of coal and other fuels and is thought likely to feature strongly in Asia’s future fossil fuel power generation fleet. Although some operational challenges may be encountered, experience to date has demonstrated that such challenges can largely be overcome and are minimal compared with the advantages offered by the increased deployment of CFBC.

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This article is based on work undertaken by the author for the IEA CCC in “Operating Experience of Low Grade Fuels in Circulating Fluidised Bed Combustion (CFBC) Boilers,” (CCC/253, ISBN 978-92-9029-574-4, 68 pp, June 2015). The author can be reached at ianbarnes@hatterrall.com
Oceanic Storage of CO₂ by Japan and Taiwan

By Chen-Tung Arthur Chen
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As energy capacity increases in developing Asia and elsewhere, associated emissions of CO₂ and other greenhouse gases could increase unless low-emissions technologies are employed. Carbon capture and storage has emerged as a potential low-emissions technology, but suitable and safe storage sites must be identified. As capacity to produce electricity grows, there is ongoing research in Japan and Taiwan to identify promising CO₂ storage sites that could benefit not only the region, but also the world.

A variety of schemes have been proposed to store CO₂. Deep oceanic disposal (i.e., storage) of CO₂ is one such scheme. Two approaches have been pursued: direct injection of a concentrated stream of CO₂ and biological sequestration via ocean fertilization.

FEASIBILITY OF OCEANIC STORAGE

The oceans are the world’s largest CO₂ sink. The 39,000 Gt that are stored in the oceans is almost 50 times the amount that is in the atmosphere. Accordingly, putting all atmospheric CO₂ into the oceans would only increase the oceanic concentration of CO₂ by 2%. Additionally, the oceans turn over every 1000 years, so any CO₂ pumped into the deep oceans would stay there for roughly 1000 years before returning to the oceans’ surface to be exchanged with the atmosphere. In this way oceanic storage can buy time.

In 1977, the concept of pumping liquefied CO₂ into the oceans at a sufficient depth that it would not form bubbles and rise back to the surface of the ocean was proposed. In fact, at a sufficiently low temperature and a sufficiently high pressure, which prevail at a depth of around 2600 m in deep oceans, liquefied CO₂ transforms into hydrates (see Figure 1). These CO₂ hydrates are denser than seawater and thus sink to the bottom of the ocean and dissolve slowly. Subsequent researchers found that once the CO₂ touches the calcium carbonate in the bottom sediment, it is neutralized.

The ocean fertilization concept is based on the fact that vast regions of the oceans contain large amounts of nutrients, but have low biological productivity because iron is lacking. As a result, “fertilizing” these areas with iron could promote the growth of phytoplankton, which would absorb CO₂.

FIGURE 1. Natural CO₂ hydrates on the seafloor (courtesy K. Shitashima)
To test the iron fertilization hypothesis a novel experiment—termed IRONEX—was conducted in October 1993.\(^8\) After releasing 800 L of iron sulfate (at a concentration of 0.5 mol/L) over an area of 1.5 km\(^2\) close to the Galapagos Islands, the amount of chlorophyll, primary productivity, and biomass all increased, confirming the iron fertilization hypothesis was correct. Many iron fertilization experiments have followed. Perhaps the most dramatic support was observed in the aftermath of the eruption of Mt. Pinatubo in the Philippines in 1991. This single event reportedly\(^10\) added approximately 40,000 tons of iron dust to the oceans, and resulted in an easily observed decline in the global atmospheric CO\(_2\) concentration.

Japan

Japan ranks fifth in the world in CO\(_2\) emissions,\(^11\) and is thus researching many solutions, including a long history of researching oceanic hydrothermal systems. Scientists have utilized the deep submersibles (see Figure 2) Shinkai 2000 and Shinkai 6500 to investigate deep hydrothermal vents, and have observed the formation of CO\(_2\) hydrates and liquid CO\(_2\) at great depths. These observations have formed the basis of research into direct CO\(_2\) disposal in the oceans. This research in Japan is multifaceted, addressing CO\(_2\) capture, transportation, disposal, and environmental impact.\(^12\)–\(^24\)

\[\text{"About 100,000 tonnes CO}_2\text{/year or more is to be stored in two separate saline aquifers at approximate depths of 1100 m and 2400 m under the seabed off the Tomakomai Port."} \]

The Abiko Research Laboratory of the Central Research Institute of Electric Power Industry held the first International Workshop on the Interaction Between CO\(_2\) and Ocean in December 1991. Discussion of the direct oceanic disposal of CO\(_2\) was the main theme. The formation of CO\(_2\) hydrate and the inversion of density between liquid CO\(_2\) and water in the deep sea were discussed and findings from observations made using the Shinkai 6500 submersible were presented.\(^13\)

The second international workshop was held at the Tsukuba Center for Institutes in June 1993. Technical perspectives on the transportation of CO\(_2\) to the deep ocean floor and dispersion at intermediate depths, including using pipes from an injection vessel, pipes from a semi-submersible platform, floating pipes, and pipes from a tension leg platform were introduced.\(^14\) Beyond technical details, the framework of an international agreement on deep-sea biological studies in relation to the disposal of CO\(_2\) was discussed.

Under the sponsorship of the Ministry of the Economy, Trade and Industry (METI), the Japan Agency for Marine-Earth Science and Technology, and the Ministry of Education, Culture, Sports, Science and Technology, much work has been done on oceanic disposal of CO\(_2\):\(^16\)–\(^21\),\(^23\),\(^24\),\(^26\) Yet, owing to international regulations (discussed later), recent research efforts have been concentrated on sub-seabed geological storage. For example, the International Institute for Carbon-Neutral Energy Research, Kyushu University, previously had a division that examined the oceanic disposal of CO\(_2\), but it now concentrates on geological storage while maintaining research on sub-seafloor geological storage.\(^20\)–\(^24\)

Further, METI has started a large-scale CCS demonstration project in the Tomakomai Area on the island of Hokkaido for the period 2012–2020 to demonstrate and verify the total CCS system, ranging from to CO\(_2\) capture, to compression, to sub-seafloor storage.\(^24\) About 100,000 tonnes CO\(_2\)/year or more is to be stored in two separate saline aquifers at approximate depths of 1100 m and 2400 m under the seabed off the Tomakomai Port. In 2014 drilling and retrofitting of three observation wells were completed. The main construction of the capture and injection facility and the drilling of CO\(_2\) injection wells are underway and expected to start operations later this year.\(^26\)

Japan carried out its first in situ iron fertilization experiment in the summer of 2001 in the subarctic Pacific Ocean.
Approximately 350 kg of iron, in the form of acidic iron sulfate, was released. Chlorophyll a, primary production rates, biomass, and efficiency of photosynthetic conversion of energy increased relative to waters outside the iron-enriched patch. However, no evidence of increased export flux of carbon to depth—which is needed for long-term carbon storage—was observed.17

**Taiwan**

Taiwan, ranking 25th in the world in CO₂ emissions, is also researching options for oceanic, including sub-seabed, storage.11 A small group of researchers began working on OTEC (ocean thermal energy conversion) and artificial upwelling in the late 1970s. A small industry related to the use of deep ocean water to produce mineral water now exists. One of the concerns associated with extracting deep seawater is that it is rich in CO₂, which is released to the atmosphere when the deep water reaches the surface and the pressure falls. The depth of a deep seawater intake pipe, however, can be adjusted to ensure that the upwelled seawater is rich in nutrients relative to CO₂. Consequently, the enhanced phytoplankton growth induced by these nutrients results in the absorption of more CO₂ than is released by the deep water in the surface layer, contributing to net CO₂ storage.28 The depth of the discharge can also be adjusted to ensure that the nutrient-rich effluent plume remains in the euphotic zone to allow time for the growth of phytoplankton.17,28

“Currently sub-seafloor CO₂ storage seems to be the most promising for the region.”

On a larger scale, the Green Energy and Environment Research Laboratories, Industrial Technology Research Institute, has a 1.9-MWth pilot plant for capturing CO₂ using calcium looping technology.29,30 The raw material, CaCO₃, is obtained from a limestone mined in northeast Taiwan, adjacent to the deep West Philippine Sea. The captured CO₂ can be used to grow phytoplankton or liquefied for potential oceanic storage. Taiwan’s Environmental Protection Administration also has an eye on this limestone mine, and has plans to experiment with causing CO₂ in seawater to combine with water and the CO₃ in CaCO₃ to form HCO₃ and Ca ions, which are both abundant and harmless in the oceans. This process, however, is likely to be relatively expensive.31,32

**FURTHER CONSIDERATIONS**

The oceanic disposal/sequestration of CO₂ must comply with international conventions, such as the Oslo Convention (Convention for the Prevention of Marine Pollution by Dumping From Ships and Aircraft) and the London Convention (Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter). The results of iron fertilization experiments have tended to show rapid increases in biological productivity, but whether the generated organic carbon is indeed transferred into the deep oceans for storage or whether it simply decomposes close to the surface of the ocean, releasing CO₂ back to the atmosphere, is uncertain. Questions remain regarding the long-term impact on the ecosystem.1,15,21,33 As a result, in May 2008, the United Nations imposed a moratorium on ocean iron fertilization. Currently sub-seafloor CO₂ storage seems to be the most promising for the region.31,32

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REFERENCES


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International Outlook

**Australia**

The Indian mining company Adani has made new progress toward its US$21.7-billion Australian coal mine by concluding the final landholder compensation agreement.

**China**

China’s National Bureau of Statistics reported that the China’s Gross Domestic Product (GDP) reached 67.67 trillion yuan (US$10.29 trillion), up 6.9%, while coal production was 3750 million tonnes, 3.3% less than in 2014.

Electricity production reached 5810 TWh, increasing by 0.3%. Of this, thermal power dropped to 4242 TWh, a decrease of 2.7%; hydro power reached 1126.4 TWh, a 5% increase; and nuclear power reached 170.7 TWh, a 28.9% increase. Total power generation installed capacity reached 1508.28 GW in 2015.

China’s General Administration of Customs released data on imported coal in 2015. Total coal imports (including lignite) reached 204.06 million tonnes, a reduction of 87.14 million tonnes (29.9% less than 2014). Coal was mainly imported from Indonesia, Australia, North Korea, Russia, and Mongolia.

**India**

India has decided to temporarily delay opening commercial coal mining to private companies, which could make it difficult for the country to achieve its ambitious production targets. The world’s third-largest coal importer, India aims for private companies to contribute about one third of the annual production target of 1.5 billion tonnes by 2020.

**U.S.**

The U.S. Supreme Court granted a stay of the Clean Power Plan (CPP). Thus, the rule intended to reduce CO₂ emissions from the existing power fleet will likely be heard by the court before states can be made to comply. While some U.S. states are moving forward with preparations to meet the CPP emission limits, others have halted work.

**Vietnam**

According to the Mineral’s Council of Australia, Vietnam’s demand for Australian coal increased by nearly 540% from February 2015 to February 2016.

**Movers & Shakers**

The Gasification Technologies Council announced an expansion to become the Gasification and Syngas Technologies Council (GSTC), which will now encompass the syngas production, processing, and conversion industries as well. For more information, visit www.gasification-syngas.org/

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

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<th>Conference Name</th>
<th>Dates (2016)</th>
<th>Location</th>
<th>Website</th>
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<td>IEA Clean Coal Centre High Efficiency, Low Emissions Coal-fired Plant Workshop (HELE 2016)</td>
<td>23–25 May</td>
<td>Tokyo, Japan</td>
<td>hele.coalconferences.org/ibis/HELE/home</td>
</tr>
<tr>
<td>International Pittsburgh Coal Conference</td>
<td>8–12 Aug</td>
<td>Cape Town, South Africa</td>
<td><a href="http://www.engineering.pitt.edu/pcc/">www.engineering.pitt.edu/pcc/</a></td>
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Across Asia, HELE coal technology has generally emerged as the choice for future projects, offering a more resilient and affordable source of electricity...