Trends in the build-up of US generating capacity

by Ramesh Raman, Paolo Curiel and Juan Marcano, Taylor-DeJongh, Inc.

The adoption by the US Congress in 2005 of the Energy Act has spurred a renewed interest in the US in the future of the power sector. The Energy Information Administration (EIA) forecasts that 347GW of new generation capacity will be needed by 2030 to meet a growing demand. During 2005, electricity generation grew by 1.7%, trailing the US economy real GDP growth for the same period[i]. The nature of these generation capacity additions will differ among regions due to a complex web of factors, including fuel competitiveness, federal and state regulations, tax incentives, emission restrictions, technological change and the structure of the transmission network. On average though, coal seems to be the new fuel of choice for the US power sector.

Building additional capacity

Building additional capacity for future power generation is mandatory. Despite the rapid build-up of capacity in the late 1990s, the market has not seen significant cost-effective capacity additions brought on line since 2002. Capacity additions during and since that period have predominantly been fueled by natural gas, which is uneconomical in this current highly volatile natural gas market. Since no new cost-effective additions have been made over the past few years, current capacity is projected to be insufficient to meet the forecasted increase in demand in the industrial and residential sectors. Adding to the complexity of providing additional baseload generation, environmental regulations are becoming more stringent, which may cause a number of older generating facilities to be retired.

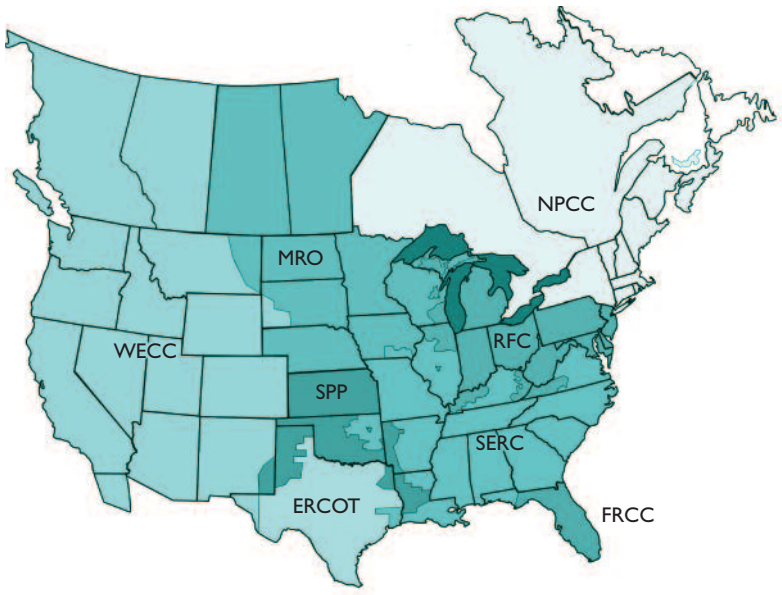
In general, the nature of generating capacity additions, while dependent on nationwide considerations, will also depend on regional considerations.

Structure of the power system

The competitive structure of the US power system, including its system subdivision, is a major factor determining the landscape of new generating capacity in the US.

The deregulation efforts of the federal government during the 1990s have shaped the

Figure 1: NERC regions



Source: NERC

competitive structure of the power system based on the marginal cost pricing of generation. The market is structured into three major control areas or networks. These networks are further divided into eight coordinating and administrative regions. These regions constitute the North American Electric Reliability Council (NERC), and are established to manage reliability and coordination within the network. These NERC regions are designed to allow the transfer of electricity from one part of the network to another. However, transfers can be restricted because of a lack of arrangements or resulting from inadequate transmission capability or instability. Figure 1 shows the distribution of the different NERC regions across the US.

Resource availability and geographic variations

Geography, and thus natural resource availability, have determined the fuel of choice for power generation. Generating facilities in states such as Ohio, West Virginia, Kentucky and Tennessee are the largest users of coal, while in the Pacific Northwest most electricity is generated by hydroelectric plants. Natural gas rich states such as Louisiana, Oklahoma and Texas make use of natural gas for electricity generation. California uses natural gas as well, due to its tight environmental regulations that limit coal-fired generation. The Northeast region depends heavily on petroleum and nuclear power.

Capacity additions will vary across regions. All regions of the US are expected to require capacity additions before 2030, with the largest share going to specific areas of the Southeast, namely Florida and the Carolinas, and the West.

The Southeast market is comprised of different segments. Florida's electric power generation is predominately gas and nuclear, whereas the Carolinas, Georgia, Alabama and Northern Mississippi have predominately coal-fired generating capacity. The Deep South (Louisiana and Southern Mississippi) is expected to remain predominately fueled by natural gas due to accessibility to natural gas from the Gulf of Mexico. Natural gas prices tend to be lower in the South than in the rest of the country due to transportation, making it a more attractive fuel than coal.

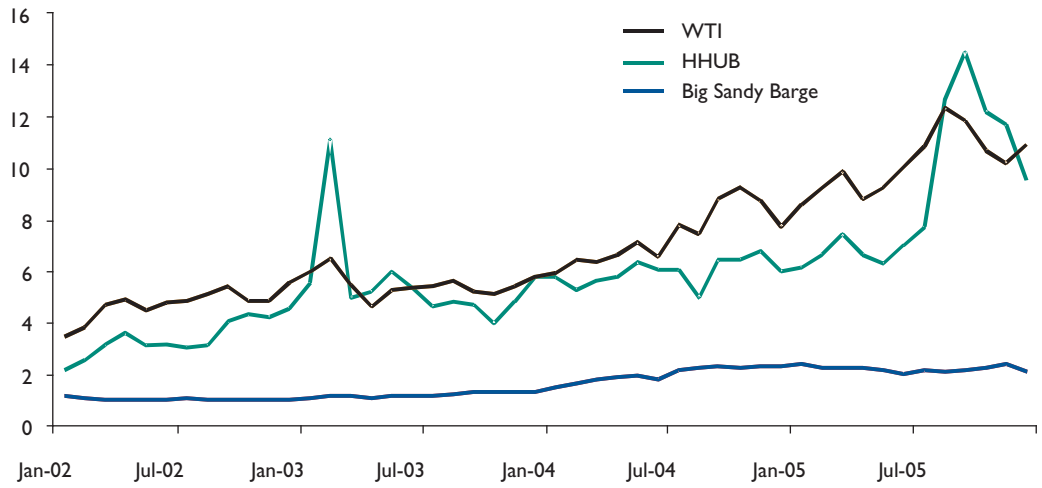
The Midwest, which historically has been coal driven, witnessed the construction of a large number of natural gas-fired combined cycle facilities during the 1990s. During the building boom, the price of natural gas warranted such a shift and produced power at a cost lower than the marginal cost of coal-fired generation as a result of operating efficiencies. However, with the increased cost and volatility of natural gas, and technology advances of coal-fired generation, there has been a resurgence of coal-fired proposals in the Midwest.

Fuel prices

Over the last couple of years, there has been an increase in retail sales prices, mainly due to the increased cost of fuel. The average retail price of electricity rose to record levels, growing 3.2% in 2006[ii], because of the increased price of natural gas, oil and coal delivered to power plants.

The price of the different fossil fuels used for power generation has increased over the last four years. Natural gas and crude prices have steadily risen during that period. Excluding the temporary

Figure 2: Fuel prices



HHUB: Natural gas; WTI: Crude; Big Sandy Barge: Coal.
Source: Bloomberg

effects of hurricanes Katrina and Rita, the price of natural gas has increased from a range between US$2/MMBtu and US$3/MMBtu to approximately US$8/MMBtu. This price increase, and the fact that the majority of recent power plant capacity has been gas-fired, has led to the underutilization of these new plants, and some were even closed. Because of the high current gas prices, such plants are not economically competitive with coal-fired plants. Crude prices increased threefold, going from US$3.48/MMBtu in December 2001 to $10.9/MMBtu in December 2005. The increase in coal prices, while not as drastic as the other two fuels, went from US$1.16/MMBtu to US$2.13/MMBtu during the same period. Figure 2 reflects the price movements associated with various fossil fuels.

Federal and state incentives

While coal power plants have higher construction costs, coal tends to be a lower cost fuel source than gas in the long run, particularly in the current context of high oil and gas prices. Federal and state incentives have been enacted into law to encourage the deployment of clean coal technologies, further enhancing the construction of additional coal derived facilities. The tax credits for 'clean coal' under the 2005 Energy Act constitute an additional incentive to build coal-fired power plants. From an energy security perspective, coal represents an abundant resource in the US, whereas most natural gas needs to be imported.

Coal is the main beneficiary of the 2005 Energy Act, which includes a US$1.3bn investment tax credit for the construction or re-powering of coal-fired power plants (US$800m for coal gasification and US$500m for other technologies with low levels of emissions). While in the past, coal suffered from its image as a polluting energy source, new technologies grouped under the generic term 'clean coal' are enabling coal-fired generators to meet new emission standards.

The EIA also forecasts approximately 6GW of the total additional capacity to come from nuclear power plants. Even though nuclear power plants typically have low operating costs and low levels of greenhouse gas emissions, the significant risks associated with development and construction remain. However, tax credits and other tax benefits targeted to foster the development of nuclear energy were enacted as part of the 2005 Energy Act and should lead to a renewed interest in nuclear power plants. As an example of this renewed interest in nuclear power, Southern Company and Duke Power have teamed up to evaluate the potential construction of a new nuclear plant in South Carolina.

Despite the fact that the US did not ratify the Kyoto Protocol, several recent initiatives take aim at reducing the level of greenhouse gas emissions and increasing the share of renewables in power generation. Several states have introduced specific renewables portfolio standards that have fostered an increase in wind capacity. The EIA forecasts that total new renewable capacity will increase 21.9GW between 2006 and 2030, of which 93% will be wind power.

The expiration in 2007 of federal tax credits for hydropower and geothermal plants will have a negative impact on these two energy sources. Renewables remain less competitive as compared to more traditional energy sources. Wind power, with its intermittent nature, tends to make the product less favorable to utilities, as it lacks reliability. Nonetheless, large power developers, such as AES Corp, have recently entered the wind business at full force. The company recently announced plans to triple its investment in wind generation, adding about 2GW to its wind portfolio over the next three years, as part of a planned US$1bn investment in its alternative energy businesses[iii]. Foreign companies are also eyeing the US wind sector. It was recently announced that Spain's Iberdrola plans to enter the US wind market via the acquisition of Pennsylvania-based Community Energy Inc (CEI)[iv].

Emission regulation

Emissions regulations (both at the state and federal level) and tax credits for specific energy sources will have a strong impact on shaping the next generation of power plants in the US.

Emission standards have been tightened by the promulgation by the EPA in March 2005 of the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR). These two rules, which had been proposed by President Bush in 2000 under the Clear Skies Initiative but which had been repeatedly blocked by Congress, regulate the authorized levels of mercury, SO2 and NOx. CAMR adopts the cap and trade approach to reduce mercury emissions, with caps set on a state-by-state basis. The approach is similar to what is being used for carbon credits.

The US currently does not regulate carbon dioxide. Carbon dioxide is not considered a pollutant by the EPA and other federal agencies. However, New York, California and eight other states launched a legal action against the EPA in April 2006 on that very matter. Several proposals for a carbon tax were also made as part of the ongoing debate on global warming. Such a tax would strongly affect coal-fired power plants, which even with recent emissions technologies still emit significant amounts of carbon dioxide.

Toward coal as the fuel of choice?

Today's higher gas prices have resulted in higher electricity prices in many regions, creating a very high value for coal-fired power plants. To date, the US government is tracking the development of about 135 coal plants, comprising 80GW of new capacity.

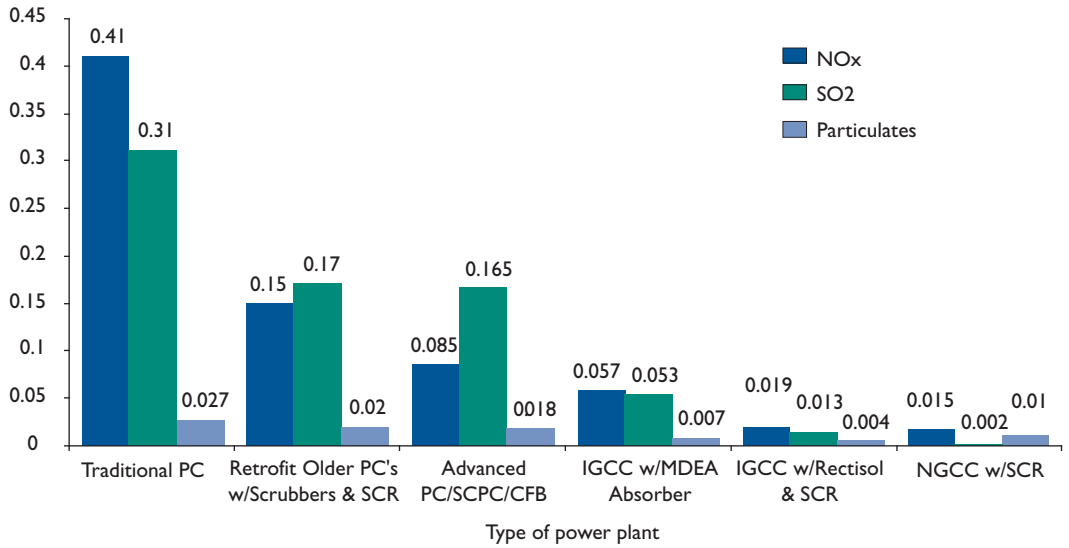
While coal projects seem attractive to developers as long as carbon dioxide emissions are not limited, they could be hit by large additional costs if federal regulations were to change and impose either a carbon tax or more stringent emission constraints. In addition to the uncertainty regarding emission costs, coal projects are notoriously difficult to develop and to permit. Because of these considerations, the development of new coal technologies has attracted a great deal of attention, as they are designed to meet all the current emission requirements for conventional pollutants in a relatively cost-effective manner.

New coal technologies include Super Critical Pulverised Coal (SCPC), Circulating Fluidised Bed (CFB) and Integrated Gasification Combined Cycle Technologies (IGCC). Of all coal technologies, IGCC appears to have garnered the most attention. IGCC has high efficiency, lower emissions profile and is flexible in its ability to manufacture a variety of products. According to an EPA study[v], IGCC thermal performance is considerably better than that of Pulverized Coal (PC) plants (due to the combined cycle electrical generating facility configuration). IGCC also has superior environmental performance as it can significantly reduce sulfur and mercury emissions to levels below those offered by traditional coal technologies. It also offers the added benefit of being capable of capturing and sequestering carbon dioxide at a relatively lower cost and with proven technology.

Emissions comparisons between IGCC and traditional coal technologies are illustrated in Figure 3.

Current incentives for coal, new developments in technology, abundant availability of coal, and the current higher prices of oil and gas are making coal a very attractive solution for US power generation requirements. These factors have been the drivers behind new initiatives such as FutureGen, a public-private partnership to design, build and operate the first 'zero-emissions' power plant. The plant will

Figure 3: Power plant typical emissions by technology



Basis: Chevron Texaco White Paper (3/03), DOE Report (5/99), and Recent EPA Parmit Data

Source: Eastman Gasification Services Company[vi]

produce electricity and hydrogen from coal, while capturing and storing carbon dioxide. The effort integrates a series of technologies that, if successful, will assure coal as a low-cost, abundant, geographically diverse energy resource for the US power generation needs.[vii]

Despite the high hopes for new 'clean coal' technologies, there are still a series of concerns that need to be addressed before these technologies can be deployed. First, there is the higher capital and operational costs – IGCC technologies are approximately 20% more expensive than regular technologies and have higher operating costs than traditional coal plants. Second, there remain doubts about the viability of these new technology-driven plants without subsidies and changes in regulation. Development costs associated with IGCC tend to be significantly greater than traditional sources of power generation, due in large part to the process engineering and design phase. Finally, there is concern about the cultural resistance to the large chemical component of these plants and the long lead time to plant completion.

Those factors considered, IGCC may represent the first real means for the economy to utilize its abundant resource of coal and a means of capturing pollutants such as sulfur, mercury and carbon dioxide in a more effective manner than offered by competing technologies.

As an example of the big push for IGCC technologies, the Southern Company has recently announced the construction of a 285MW IGCC facility in Central Florida (expected commercial operations date 2010). Of the estimated US$557m total project cost, the US Department of Energy is contributing US$235m.[viii]

Conclusion

Building the required new power generation capacity will be a challenging process. The drive toward competitive energy markets as a general overriding factor, the development and permitting risk of developing projects – with lead times often six to eight years from inception to commercial operation – and the variable regulatory environment require a cautioned approach.

However, new capacity must be added, and the one fact that is inescapable is the need for additional cost efficient generation. Due to a variety of factors examined in this article, including the structure of the transmission network, federal and state incentives, emission regulation, and fuel competitiveness, it is likely that the majority of the new baseload capacity will be generated by coal.

While natural gas was favored in the 1990s, coal is favored for the next decade, due to its abundance in the US. Standard coal-fired plants have been difficult to permit, and the risk of carbon taxes looms large on traditional coal-fired facilities. Because of these considerations, the new technology of coal gasification has attracted the greatest amount of attention due to its environmental attributes and capability of capturing carbon dioxide utilising existing technology.

Coal gasification will increasingly influence the market. Early movers will be established, better price

signals will become available from the technology providers, and added certainty and greater transparency of risk allocation will make these projects cost-effective and competitive with traditional coal technologies.

Notes:

i Data from EIA, Electric Power Monthly, May 2006 Edition and U.S. Department of Commerce.

ii EIA Electric Power Monthly, May 2006 Edition.

iii Project Finance International [May 4, 2006] http://www.pfie.com/story.asp?sectioncode=&storycode=183354

iv Project Finance International [May 4, 2006] http://www.pfie.com/story.asp?sectioncode=&storycode=183585

v Khan, Sikander R. Environmental Footprints of IGCC and PC Plants – An Update, EPA, March 2006 http://www.gasification.org/Docs/Tampa%2006/Khan.pdf.

vi Eastman Gasification Overview, Eastman Gasification Services Online Publications http://www.eastman.com/Services/Gasification/Onlinepub.htm

vii FutureGen website http://www.futuregenalliance.org

viii Project Finance International [March 8, 2006] http://www.pfie.com/story.asp?sectioncode=&storycode=178155

Acknowledgement:

The authors acknowledge the contribution to this article made by Sophie Guiny (Analyst)
Email: sguiny@taylor-dejongh.com

Authors:
Ramesh Raman (Director); Paolo Curiel (Vice President) and Juan Marcano (Analyst)
Taylor-DeJongh, Inc.
1101 17th Street NW, Suite 1220
Washington DC 20036
US
Tel: +1 202 775 0899
Email: rraman@taylor-dejongh.com
pcuriel@taylor-dejongh.com
jmarcano@taylor-dejongh.com
Web site: www.taylor-dejongh.com