Floating on air

Gas-to-power (GTP) is ascending rapidly – can it hold on to its gains?asks Gordon Cope.

Gas-to-power (GTP) is in its glory days. Once upon a time (not so very long ago), it maintained a steady 19% of all electricity generation in the US. Subservient to 'King Coal', it was used primarily as a supplier of peak demand when air conditioners were turned on in sweltering summer afternoons. No longer; in the last two years GTP's share of the marketplace has surged, and now claims over 24%. Fitch Ratings, a New York-based research firm, estimates that it could reach 30% by 2020.

GTP owes much of its ascendancy to the growth in shale gas. Oil companies have long been aware that the dense black rock filling many of the basins around North America could contain over 100bn cf/sq mile of gas, but low permeability made it uneconomic to produce using conventional drilling technology. Advances in horizontal drilling and rock fracturing techniques, however, have opened up immense resources. The Texas Barnett shale supplies around 5bn cf/d, or 12% of US daily production. According to the Energy Information Administration (EIA), several other new plays, including the Haynesville shale play in Louisiana and the Utica shale play in New York, could push shale gas production to 16bn cf/d within the coming two decades.

Environmental regulations have also had a profound impact. Although federal carbon legislation has taken a backseat in the election year, a plethora of new rules are emerging from the Environmental Protection Agency (EPA) that favour gas over coal. Stricter emission legislation include the Mercury and Air Toxic Standards (MATS), Cross-State Air Pollution Rule (CSAPR), Clean Water Act provisions limiting once-through cooling, and coal ash disposal regulations.

While many of the regulations have been delayed by court challenges, utilities are taking matters into their own hands. Georgia Power is seeking approval to close two older coal-fired units with a total of 569 MW because of the cost of meeting current and expected environmental regulations. Dominion Virginia Power wants to convert three coal-fired stations to renewable biomass. 'The total coal-fired fleet in the US is around 300 GW, out of a total energy fleet of 1,100 GW,' says Pearce Hammond, Managing Director of E&P Research at Simmons & Company, a Houston-based consultancy. 'About 50–60 GW of the coal-fired plants are reaching retirement age. With environmental regulations getting stricter and gas being so cheap, the utilities are saying "Let's just retire them".'

Nuke takes a hit

Nuclear energy, the third major source of base load electricity generation, is not faring much better than coal. The magnitude 9.0 earthquake that struck north-east Japan in March 2011 and the subsequent devastating tsunami killed at least 25,000 people and damaged much infrastructure, including the Fukushima Daiichi nuclear plant. The plant subsequently experienced several explosions and fires, releasing amounts of radiation comparable to the Chernobyl disaster in 1986.

In addition to public dismay, the nuclear option is also suffering from rising costs. 'Fukushima was bad optics, but nuclear is set to lose ground because the economics are so poor,' says Hammond. Simmons' research shows that the LCOE (levelised cost of electricity – which is calculated by averaging capex and opex over the life of a plant and dividing by the amount of electricity produced) for nuclear is in the 8–9 cents/kWh range, and natural gas is in the 4–4.5 cents/kWh range.

Commodity price, more than anything else, is fueling GTP's rise. In 2011, spot prices on the New York Mercantile Exchange (Nymex) averaged $4.16/1,000 cf. Working gas storage capacity in the US is estimated to be 4,150bn cf. Thanks to overproduction and a mild winter, by early 2012, gas in storage was 3,472bn cf. Prices dropped to under $3/1,000 cf in the US and under C$2/GJ in Alberta.

Not surprisingly, utilities are opting for gas as a base load fuel, especially in high coal-cost regions. 'Most switching has been occurring with Central Appalachia coal, which has a high Btu and low sulphur [content], but they've been mining it for a long time and they're now chasing thinner seams, so it's more expensive,' says Hammond. 'Even Powder River Basin (PRB) coal, which is much cheaper, is taking a hit. PRB is priced at around $12–$14/t at the mine, but it costs around $30/t to ship it by rail, so it's over $40/t at the power plant gate. That cannot compete with natural gas.'

Thanks to existing infrastructure, the switch to gas has been relatively easy. 'There is about 400 GW of nameplate GTP capacity in the US; about half of that is peak load capacity, and half is combined cycle (CC),' notes Hammond. 'A CC plant uses a turbine to generate electricity, but it also uses the hot exhaust gas to heat water to steam to drive a second turbine. The CC is much more efficient; instead of using 12,000 Btu to make 1 kWh, it only takes 7,000 Btu. It's even more efficient than coal.'

That, says Hammond, is where GTP is growing. 'A few years ago, CCs had a utilisation rate of around 35%, and now they are at 50% or more. The existing fleet can run even harder, around 70–80%, so there's still room for growth. And when it comes to building, you can construct a 1,000-MW CC for around $1,000/kWh, or $1bn. A nuclear plant costs up to $7,000/kWh [or $7bn]. It has low fuel costs, but the LCOE just doesn't compare.'

Problems on the horizon

Alas, a combination of legislative and market forces may curtail many of natural gas' advantages. There is, for instance, a growing concern over hydraulic fracturing. During the process, several million litres of water are forced at high pressure down the well and into the shale to create a network of tiny fractures that allow the gas to escape. The water itself is often treated with proprietary chemicals in order to decrease the viscosity (and thus increase penetration) of the water.

Various jurisdictions are concerned that these chemicals, some of which are known carcinogens, could leak into adjacent groundwater aquifers and contaminate drinking supplies. Pennsylvania and Wyoming have already found suspect chemicals in groundwater, and the EPA has requested service companies to reveal their hydraulic fracturing ingredients. While the American Petroleum Institute (API) and the Canadian Association of Petroleum Producers (CAPP) have announced programmes for the industry to disclose additives, some states have sought moratoriums on shale gas drilling until more is known; should bans spread, they would deal a serious blow to future gas production.

The cheap cost of gas is also attracting new uses. The North American petrochemical industry, long hobbled by high gas feedstock prices is in resurgence, converting natural gas to ethylene. Gas can also be economically converted to liquid fuels; at $2.50/mn Btu, it takes about $16 of natural gas to make one barrel of liquid fuel. Sasol recently announced it will construct the US' first gas-to-liquid (GTL) plant in Louisiana, to take advantage of abundant gas supplies from the Haynesville shale formation.

Plans are also underway to export LNG. Several consortia have advanced projects to liquefy stranded gas in northeast British Columbia and ship it from the deepwater port at Kitimat to Asia. Cheniere Partners, which owns an LNG import terminal in Sabine Pass, Louisiana, has been contracting with various international firms to ship LNG to Europe. BG Group recently announced it will purchase 3.5mn t/y over a 20-year period. Construction of Cheniere's $6.5bn liquefaction train is expected to be finished by 2015, with the initial phase to consist of two trains capable of producing up to 9mn t/y from Louisiana's Haynesville shale gas.

Producers have also taken steps to curtail gas production. In January, Chesapeake Energy announced that it was shutting in 500mn cf/d of US production, and planned to shut in as much as 1bn cf/d. In Canada, Encana slashed output by up to 600mn cf/d from its 2011 production of 3.1bn cf/d. 'It is abundantly clear that a continued reduction of drilling activity will be required to restore market balance,' said Encana Chief Executive Randy Eresman.

In the European Union (EU), GTP accounted for approximately 23% of electricity generated in 2009. Various factors point to increased use in the future, however. In 2011, the Nord Stream pipeline entered final commissioning of its first string. The 1,200-km line, which runs from Russia to Germany beneath the Baltic Sea, will add 27.5bn cm/y of supplies. Construction of the second string will add another 27.5bn cm by 2013.

Explorers are also searching for new shale gas supplies on the continent. The UK Office of Gas and Electricity Markets (Ofgem) estimates European shale gas resources at around 1,250tn cf in place. The UK, France, Sweden and Turkey all have substantial resources; Poland is estimated to have the largest shale gas reserves, with total gas in place ranging up to 350tn cf. Talisman recently cased a well in Poland's eastern Baltic Basin in order to fracc and produce from over 100 metres of oil and gas-bearing shale and limestone formations. IGas Energy reported numerous gas showings in a 1,000-ft section in a well drilled near Liverpool, UK, and independent analysis estimates that there may be as much as 4.6tn cf of gas in place in the Lower Carboniferous shale.

The Fukushima tragedy has also had an impact. According to the World Nuclear Association, the EU has 143 nuclear reactors, about one third of the world total. After the accident, the EU called for 'stress tests' of its members' reactors. Germany closed seven aged plants (out of 17) and has plans for total closure by 2022, leaving a big gap in the base load capacity.

GTP in Europe suffers several potential handicaps, however. Unlike North America, the European continent does not have an integrated natural gas transportation network. Creating a single market would also involve aligning dozens of national and regional regulatory bodies, each with its own priorities and agenda. Public confidence in development of shale gas is ambivalent at best, and downright hostile at worst. France has banned the practice.

Looking ahead

The future for GTP in Europe still remains bright, however. 'In the EU, the focus is on renewables,' says Hammond. 'They have installed a lot of wind and solar, big enough to move the needle. But renewables aren't a base load source, so you need to bring up something else, and that's been natural gas.'

Gas is also expected to maintain its economic advantage in North America. 'The shut-ins that we're seeing will bump the price up in the near term, but it won't have a great impact in the long term,' comments Hammond. 'A few years ago, you needed $7–$8/1,000 cf to drill most gas plays. Now, you can profitably develop a lot of gas for around $5, which is a lot cheaper than coal when you take into account the regulations associated with it.'

LNG is not expected to make a major dent in low prices, either. 'When it comes to exporting gas as LNG, there's going to be a battle royale with the chemical and power generation sectors on one side, and the gas companies on the other,' states Hammond. 'The chemical and utility sectors want lower prices, and the gas producers want to tap into the higher prices that LNG consumers are paying. The advantage that the chemical and power sectors have is that you can create a lot more jobs with cheap gas. US Energy Secretary Chu has come out saying that he supports exports a little bit, so we'll probably see a few liquefaction terminals in Kitimat and the Gulf Coast – but not too many.'

'I think that what has been occurring in the EU is what you will see happening in North America,' concludes Hammond. 'When you look at the capex pie for new utility construction over the next 10 years, I foresee capex going 70% to gas and 30% to renewables. New coal and new nuclear are going to be a tiny sliver of the pie. The future belongs to gas and renewables ●'