US shale gas here to stay

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Natural gas produced from unconventional sources such as shale formations has the potential to recast the economics of the power, oil and gas sectors. Its availability is creating opportunities for project financings of everything from midstream assets to new power plants and liquefied natural gas (LNG) export terminals, but environmental concerns and an unclear regulatory outlook could dampen the boom.

There were 60.6 trillion cubic feet of proven shale gas reserves in the US at the end of 2009 according to the US Energy Information Agency (EIA). These reserves are equal to 21% of the total proven natural gas reserves in the country and up from less than 1% of total reserves as recently as 2000. Shale gas fields, commonly referred to as plays, are largely located in the east, south and Rocky Mountain west with concentrations in Arkansas, Louisiana, New York, Oklahoma, Pennsylvania, Texas and West Virginia. Major plays include the Barnett, Fayetteville, Haynesville, Marcellus and Woodford.

Shale gas availability has led to a significant decrease in natural gas prices. Current prices are between $4 and $5 per million British thermal units (BTU) in the US. This is down from a market high of more than $13 per million BTU in 2008. The decrease has made many previously uneconomic activities potentially fairly profitable. The production of shale gas is unlikely to become an opportunity for project finance lenders.

Shale gas players finance exploration and production almost exclusively on balance sheet or through corporate credit facilities. For example, Chesapeake Energys sale of 487,000 net acres of shale gas leasehold in the Fayetteville play to BHP Billiton for $4.75 billion in March was financed entirely on the buyers balance sheet.

Project banks instead have their eyes on midstream infrastructure, such as gathering systems and pipelines, new gas-fired power plants and LNG export terminal projects. Midstream investments will be needed to get gas from well to market, while low gas prices are driving developers preference for combined cycle power plants and the development of at least two LNG export terminals in Louisiana and Texas.

Environmental issues and the potential for new state-level restrictions on production could dampen the future of shale gas. Hydraulic fracturing, or fracking for short, is a method of extracting shale gas that involves pumping millions of gallons of water, sand and often proprietary fracking fluid into a well for days at a time. Wastewater spills and gas leaks from poorly constructed wells have resulted in increasing levels of public and regulatory scrutiny of shale gas production.

Midstream goes mainstream

Shale production will require significant investment in midstream gas infrastructure, particularly in areas without a recent history of hydrocarbons production. Much already exists, for instance, for shale plays in Texas and Louisiana, but significant investments are still needed in regions such as in New York and Pennsylvania. The bulk of this is likely to be financed by natural gas majors and minors but a sizeable, and growing, number of financial sponsors are expected to seek non-recourse financing.

There is a growing niche of private equity firms investing in the gathering systems and pipelines that [shale gas] pro-ducers feed into, says James Guidera, the New York-based managing director and group head of natural resources, infrastructure and power project financing at Credit Agricole. Firms such as Energy Capital Partners and Tenaskas Power Fund, are exploring non-recourse financing for these assets, he says.

El Paso Corporation and Global Infrastructure Partners Ruby natural gas pipeline was one such project. Mandated lead arrangers Credit Agricole, Societe Generale (SG), Banco Santander, BMO, Scotiabank, Royal Bank of Scotland (RBS) and UniCredit put together a $1.51 billion seven-year miniperm to finance the $2.922 billion project. Credit Suisse, Barclays Capital, BayernLB, BBVA, BNP Paribas, DnB NOR, ING, Lloyds, Natixis, Mizuho, RBC and Bank of Tokyo-Mitsubishi UFJ participated in the loan. The 1,086km pipeline runs from the Opal Hub in Wyoming through Utah and Nevada to Pacific Gas & Electrics (PG&E) delivery point near the Oregon-California border. It will initially carry 1.2 billion cubic feet per day (cfpd) of gas from shale plays in Wyoming and Colorado to the California market and can later be expanded to 1.5 billion cfpd.

Some major projects to watch include El Pasos expansion of its Tennessee Gas Pipeline (dubbed TPG 300), Iroquoiss proposed $1.5 billion NYMarc pipeline and Spectra Energys $1.8 billion Texas Eastern Appalachia to Market (TEAM) expansion projects. All three are designed to improve connections between Marcellus shale plays and major markets, especially the New Jersey and New York City area, in the northeast.

Gas aspires again to be the new coal

Shale gas is a game changer for all natural gas users, says one US power plant developer. Low prices, held down by the supply of the unconventional gas, and shale plays proximity to major markets, have driven developers decisions to convert coal-fired to gas-fired plants and invest in new combined-cycle gas capacity.

Reliably cheap natural gas has become a market reality, even as the allure of other fuels has dimmed. Demand for power in the US is slowly beginning to recover, while at the same time as much as 10GW of coal-fired capacity will begin to be removed from the market on account of new US Environmental Protection Agency (EPA) regulations starting in 2015, according to Morgan Stanley Research. In addition, renewed concerns around nuclear power following the recent incident at the Fukushima Daiichi nuclear power station in Japan has put the brakes on nuclear powers renaissance.

Where demand is and what [coal] plants are retired will determine where and how much new capacity is built but what is will be natural gas-fired, says the developer. Even so, lenders will be cautious about financing such plants on a merchant basis. Much of the most recent gas-fired building boom, early in the last decade, was predicated on plant retirements that never happened

Developers and lenders are discussing financing for at least six different new and expanded gas-fired plants in California, as Project Finance went to press. These include Calpines 619MW Russell City 308MW Los Esteros plants, Competitive Power Ventures (CPV) 850MW Sentinel standby power project, Edison Mission Energys (EME) 500MW Walnut Creek plant, NRG Energys 550MW El Segundo plant and Radback Energys 586MW Oakley project. Project finance bankers expect most, if not all, of these deals to close this year.

The Russell City and Sentinel projects are expected to come to market first. Calpine has joined up with GE Financial Services, which has a 35% equity stake in the project, to build the roughly $600 million Russell City combined-cycle plant, located in Hayward, California. The sponsors are looking to finance construction, which began in December, with bank debt. Calpine intends to invest up to $75 million in equity in the project, which has a 20-year power purchase agreement with Pacific Gas & Electric (PG&E) for its full capacity.

CPV has mandated BTMU, ING, Natixis, RBS and Sumitomo Mitsui Banking Corporation (SMBC) to arrange financing for the Sentinel simple-cycle peaker. Construction costs are roughly $440 million, according to California Energy Commission filings. Southern California Edison will buy the plants full output and make capacity payments to it under a 10-year PPA. Lenders say the plant has very promising fundamentals because of its proximity to new, but intermittently operating, wind and solar facilities that they expect will force the offtaker to rely on back-up power sources, such as the peaker, fairly frequently.

Financing for the other four plants is further away. Calpine plans to contribute up to $30 million in equity to the $300 million Los Esteros project, which involves upgrading an 188MW simple cycle plant to a 308MW combined cycle facility in San Jose. PG&E has a 10-year PPA for the plants full capacity. In March, EME closed a sale-leaseback agreement with AES for two units of its 904MW Huntington Beach plant in order for it to claim emissions offset exemptions that are needed to begin construction of its 500MW Walnut Creek gas-fired peaker in the Los Angeles suburb of Industry. The sponsor has mandated Banco Santander and Union Bank to arrange financing for the more than $600 million plant. Southern California Edison has a 10-year PPA for its full capacity.

NRG plans to invest as much as $243 million in equity in its roughly $600 million El Segundo combined-cycle plant. Located in the city of the same name, it has a 10-year PPA for its full capacity with Southern California Edison. Radback has a purchase and sale agreement with PG&E for its roughly $800 million Oakley combined cycle plant in Contra Costa county. The utility will buy the plant from the developer on or after 1 January 2016.

Thad Hill, chief operating officer of Calpine, predicted significant opportunities for new power plants outside California at an analysts day in March. He said that new capacity would be needed in Texas as early as 2013 and even in the south-east over the medium term. He noted that the latter region, while currently oversupplied, is home to the largest number of coal plants that are slated to be retired and three nuclear projects that might be cancelled.

Industry interest in new gas-fired plants is expected to continue unabated even if natural gas prices rise. Industry participants expect the price of gas to rise to the $5 to $6 per million BTU range during the next few years as supply and demand balance out. Few, if any, expect this to dampen plans for new generating facilities as long as there are similar increases in coal and oil prices. In addition, there is almost universal confidence that natural gas prices will not go through the same level of volatility they experienced during the past decade. One reason for this is the fact that new shale gas wells can be brought into production in as little as 60 days, according to some estimates.

LNG, recast

Shale gas has completely upended the moribund US LNG market. Many import terminals, some built at the height of natural gas prices in 2008, have sat virtually idle during the past few years and present a stark reminder of how quickly markets can shift. Now some owners want to reconfigure these terminals for export.

Shale gas could turn US natural gas into a viable export, says Charles Zabriskie, a Houston-based partner at the oil & gas advisory firm Acquest Advisors. He stresses that production of the unconventional gas is primarily responsible for todays low natural gas prices in the US but that it is another thing to be confident that the country will have a sufficiently steady surplus of the fuel for the 20 or so years to be a competitive LNG exporter. Today, natural gas is selling for between £6 ($9.90) and £7 per million BTU in the UK, which is seen as a benchmark for global prices, compared to under $5 in the US.

Expensive gas in the US compared to abroad and a prevailing opinion that domestic gas production was on the decline spurred the development of a number of import terminal projects during the past decade. Cheniere Energy financed and built the roughly $2 billion Sabine Pass LNG import terminal in 2005 (and refinanced it twice in 2006) and ConocoPhillips, Michael Smith and Cheniere the roughly $1.1 billion Freeport LNG receiving terminal in 2008. Their current owners want to convert them into bi-directional facilities but whether they can pull it off remains to be seen.

Cheniere is unlikely because of the complexity of their financial situation, says a source who works on LNG projects in the US. HSBC and SG were bookrunners on the original $822 million loan for the Sabine Pass terminal in Cameron Parish, Louisiana, that closed in 2005. Total was contracted to take 1 billion cfpd of capacity. Later the same year, Credit Suisse provided a $600 million subordinated B loan and the sponsor signed a separate contract with Chevron for another 1 billion cfpd of capacity.

In 2006, the developer received approval to expand the facility to 4 billion cfpd from 2.6 billion cfpd and closed a $1.5 billion debt facility, also arranged by HSBC and SG, to refinance the phase one senior debt and pay for the expansion. Finally, Credit Suisse was appointed to refinance all of the debt with two high-yield bond issues for a total of $2.03 billion late that year. Now, in order to proceed with its $1.6 billion Sabine Pass Liquefaction Project, the sponsor must renegotiate all of these financial obligations and its capacity contracts. Gaining the necessary consents to reconfigure the plant would be much easier with a group of bank lenders than the bondholders that replaced them.

Freeports bi-directional terminal is more likely, because it has more financial flexibility and it is not as highly leveraged as Sabine Pass. It should, therefore, be able to renegotiate its existing contracts so that it can raise the necessary non-recourse financing, as long as market conditions hold. The $780 million import project was financed with a $383 million private placement, placed by RBS, and a $460 million loan from ConocoPhillips in 2005. Conoco, Dow Chemical and Mitsubishi have contracts for the majority of the facilitys 1.5 billion cfpd capacity. The $2 billion bi-directional project involves building four liquefaction trains with a total capacity of 1.4 billion cfpd. In November 2010, Macquarie Capital agreed to share development costs for the liquefaction project, market 50% of the proposed terminals capacity and be responsible for upstream and downstream development with the developer.

Natural gas export restrictions are one potential dampener. Regardless of the availability of shale gas, current US Department of Energy guidelines restrict exports to countries that have free trade agreements with the US. This makes exports to Japan, South Korea and China three of the largest markets for LNG in the world impossible.

(Un)stable outlook

Shale gas is not without its downsides. Environmental concerns about fracking continue to dominate headlines, with at least one state coming out flatly against the extraction process. But considering the sheer size of proven reserves and the US drive to become less dependent on energy imports, few think any of the proposed restrictions will do much to limit the production of shale gas.

Methane leaks and illegal dumping of untreated wastewater have prompted the concerns about extraction. The 2010 documentary GasLand featured a number of cases where people living near wells in Colorado and Pennsylvania could set their tap water on fire, thanks to methane leaks from nearby wells. In addition, millions of gallons of potentially harmful wastewater have gone unaccounted for in Pennsylvania, say critics.

Restrictions are state-by-state. New York State currently has a ban on high-volume fracking, pending further environmental studies, and Pennsylvanias Department of Environmental Protection has called on shale gas producers to stop bringing wastewater to water treatment facilities. In both cases, officials cited the threat of toxic chemicals contaminating drinking water when making their decisions. Other states with significant shale gas production are not expected to implement such restrictive regulations. Federal restrictions are unlikely, after fracking was exempted from various national environmental laws under the Energy Policy Act of 2005.

The issues around wastewater are serious but ultimately solvable problems, says Credit Agricoles Guidera. Shale gas is here to stay, it just may not happen everywhere. His opinion is echoed by others who are working in industries that benefit from production of the unconventional gas. So while some regulation will undoubtedly come into force, shale gas and its associated infrastructure opportunities are here to stay.