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Unconventional oil and gas: outlook, risks, and potential

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1. UNCONVENTIONAL RESOURCES ARE SIZEABLE AND WIDESPREAD

According to EIA data and SBC analysis, total global unproved technically recoverable unconventional resources amount to around 400 billion barrels of light tight oil (LTO), and 7,200 trillion cubic feet (Tcf) of shale gas. Although the US has pioneered unconventional resource development, that country's unproved resources account for only 17% of LTO and 8% of shale gas resources technically recoverable worldwide. Other countries such as Russia, China and Argentina could play potentially important roles in future production of unconventional hydrocarbon resources.

Shale gas has transformed the natural gas market in North America, but its potential to influence global markets is often called into question. SBC predicts greater international flows of gas over the next decade as a result of surging US supply. Initially, these flows may not affect the existing stratification of international gas markets. Eventually, however, their volumes could be sufficient to influence the world's three-way regional gas-market model that is based on oil-linked Asia; gas-on-gas North America; and a hybrid of both in Europe.

For unconventional oil resources however, their future development will not only depend on supply factors such as the local cost of production and maturity of the oilfield services sector, but also on different growth scenarios for global oil demand.

2. IN THE US, GAS LIFTING COSTS HAS BEEN SYSTEMATICALLY REDUCED EVEN IN MORE MATURE BASINS

Drilling and production efficiency in North America has steadily increased as the industry has developed technology and expertise. As a result, breakeven costs have fallen by more than 40% in several important gas fields, and more plays are becoming economic. In calculating breakeven levels, we have included all development and producing costs, and assumed an internal rate of return of 15% for shale gas projects. US natural gas production has risen accordingly, reaching a record 24 Tcf in 2013, up by more than 20% since 2008. Efficiency improvements have enabled such production levels to be met with only a fraction of the drilling fleet once required.

On the technical side, some subsurface experts have expressed the view that the industry is rapidly exhausting sweet spots and core acreage and is underestimating production decline rates. SBC studies show that improvements in technology and working practices will continue to expand the economically producible resource envelope, identifying new sweet spots across larger swathes of acreage, and blurring the distinction between what is currently classified as core and non-core acreage. In addition, there is now sufficient empirical evidence to rule out a disruptive impact on flow rates and ultimate recovery from production decline rates.

In terms of commodity prices, a prolonged oil price slump would impact associated gas production, but that could quickly be offset by diverting rigs to drill for gas. In this case, drilling rig rates would also likely drop, making more gas economic to develop. Regulations theoretically could halt gas drilling, but individual states regulate much of their oil and gas activity, and the current carbon-sensitive US Administration is supportive of gas production.

Beyond this, the industry continues to have access to land, capital, infrastructure, and service capacity, and remains capable of executing projects efficiently.

As a result, we estimate that at least 1,000 Tcf of US gas and ~500 Tcf of Canadian gas would be technically recoverable at a price of $5/Mcf.

3. US LNG RESOURCES COULD SUPPLY INTERNATIONAL GAS DEMAND AT COMPETITIVE PRICES

Overall, we expect global annual demand for LNG by 2025 to range from 22 to 34 Tcf. In North America, approximately 1,500 Tcf of gas is available at or below a price of $5/Mcf, and 850 Tcf at or below a price of $4/Mcf. Between 2014 and 2025, only approximately 350 Tcf will be required to supply local demand. This means that more than 500 Tcf under $4/Mcf, and around 1,200 Tcf under $5/Mcf are available to supply international demand. This represents from 15 to more than 50 years of supply.

Supply could increase yet further as a result of NGL credits, associated gas, and technology development. Even a small fraction of this volume would be sufficient to flood the LNG market and the supply curve suggests that this kind of volume could be exported without causing a significant increase in local gas prices.

The US, however, is not the only country that could meet this demand. Qatar already meets a quarter of global LNG demand. Australia is building seven new LNG projects and its production capacity will rival Qatar's by the end of the decade. Mozambique is planning to build LNG trains comparable in size to those in Qatar and Australia, and Papua New Guinea will start LNG shipments this year. Other LNG exporters include Indonesia, Malaysia, Algeria, Russia and Yemen. Global LNG capacity could amount to nearly 50 Tcf a year if all proposed projects were to go ahead—well in excess of projected LNG demand by 2025. Although not all LNG proposed projects will proceed as planned, international supply capacity is set to rise considerably and then exceed demand. Does this leave any room for North American shale LNG? The answer is yes, because of the North American gas cost advantage.

The landed cost in Asia of North American LNG will be the Henry Hub spot price plus liquefaction (including conversion margin) and shipping costs. This would amount to roughly $10-$13/Mcf, and would make North America competitive with other suppliers. The actual advantage may be even greater as many recent international LNG projects have incurred substantial capital overruns and delays. There are already 36 proposed export terminals in North America; planned capacity amounts to 12 Tcf in the USA and 8 Tcf in Canada. Federal regulators have already approved 7.5 Tcf of this capacity, although only 1 Tcf has site approval. Nonetheless, the low cost of North American gas production in the field supports a competitive product once chilled and shipped to international markets.

4. REDUCTION OF SUPPLY COSTS IS MAKING LTO MORE COMPETITIVE BUT FUTURE PRODUCTION WILL DEPEND ON DIFFERENT SUPPLY AND DEMAND FACTORS

Currently, LTO production costs range from $50 to $100 per barrel. This makes LTO less competitive than other alternative sources of oil supply, such as EOR, arctic, extra heavy oil and bitumen. Production costs have declined significantly, but fully loaded costs are still in the $80 per barrel range for many basins, and it remains difficult to judge how much the cost per barrel can be reduced.

LTO breakeven will then depend not only on global oil demand, but also on several supply factors such as recovery characteristics, cost of production, and regulatory and fiscal environment—as well as the development of the oilfield services sector. The combination of these different variables makes any projection of future LTO production still highly uncertain.

Since most tight oil plays outside North America have not been tested thoroughly, assessments of global tight oil plays can only be made using North American subsurface analogies. However, actual oil in place and technically recoverable resources could be different from those estimated as peak expected ultimate recoveries vary widely for the North American plays and have been known to be strong function of basin characteristics. In view of that, unconventional field recovery characteristics become an important determining factor for future LTO production capacity.

In terms of cost, horizontal drilling and hydraulic fracturing technologies have made tremendous progress in the last five years, making tight oil commercially feasible. Effective transfer of this technology from North America to the rest of the world will be critical. The relative pace of technology development for the exploration and production of tight oil versus other unconventional energy sources will also determine future volumes of production.

Environmental regulation in each country governing tight oil development is a big uncertainty since much skepticism is attached to the environmental impact of hydraulic fracturing. The regulations governing the use of hydrocarbon fuels could also impact the demand and consequent production of tight oil. On the other hand, government incentives and the opportunity to collaborate with successful operators and oilfield services companies can help in bringing tight oil resources to production. An entrepreneurial environment and financial support for tight oil resource development would determine the speed at which progress is made as well as the cost per well.

Finally, development within the oilfield services sector will be important. Access to skilled and qualified labor, raw materials, and drilling and completions equipment will become crucial.

SBC has estimated several different scenarios for future LTO production. We believe that in 2035, worldwide production could range from as low as 3.9 million bopd with high supply costs and North American production limited to currently producing basins such as the Bakken, Eagle Ford and the Niobrara; to as high as 17.3 million bopd in a high demand scenario and favorable recovery mechanisms that would allow more countries to start contributing to global supply.

In our base case, we estimate global production of around eight million bopd of LTO, with five million bopd coming from North America and three from the rest of the world. In North America, we consider that the Bakken would remain the main contributor. Production in the Niobrara and Eagle Ford increases after 2015, and the Tuscaloosa Marine, Utica and Mississippi Lime plays contribute only after 2015. For the rest of the world we assume that most countries will start drilling after 2020 and that, on average, it will take around 10 years to reduce supply costs to the targeted range of 60% of initial cost. It will also take the same amount of time for the oilfield services sector to reach full capacity.

In conclusion, it is clear that natural gas production from unconventional resources is well advanced with the US being the major player although activity is growing in a number of other countries. For LTO, however, the industry still needs to learn more on how activity will develop as technical innovation increases and technology limits expand before any conclusions can be drawn as to how potential production can impact global oil supply and demand.