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Shale gas production costs: Historical developments and outlook

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A R T I C L E I N F O

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This paper aims at better understanding the potential future of shale gas in the light of the evolution of its wellhead production costs. Based on the most recent literature, we focus on cost data in the US to identify the structure of shale gas costs, their evolution and drivers. In particular, while the role of technology, which has led to a 25%–30% decline of unit capital costs since 2012 is emphasized, the relevance of considering additional risk factors when analyzing future costs is discussed. Further, we investigate future shale production costs on the long term by simulating contrasted supply and demand scenarios (from the authors, as well as replicated IEA scenarios) with consideration of different cost curves adjusted with the latest EIA cost data. Modelling results show costs ranging from \$2.5/MMBtu to \$6.0/MMBtu in 2040, with the conclusion that shale production costs are expected to remain relatively moderate until 2040, whereby the role of technological progress is deemed to be crucial. The paper finally assesses the key determining factors explaining the current gap in shale gas production costs between the US and other world regions.

1. Introduction

Over the last years, unconventional resources have emerged as a resource of substantial importance in North America as they have been progressively gaining shares over conventional gas and oil production. Especially, shale gas shows a large resource potential and its recent exponential development in North America has led to a new configuration of the gas supply scheme at the global level: it currently accounts for about 13% of the natural gas production worldwide, compared to barely 0.5% in 2000 [1,2]. The commercial development of shale gas, which took off in the US around 2005–2007 and since 2008 in Canada, soared with the combined application of horizontal drilling and multi-stage hydraulic fracturing. These technical innovations unlocked the potential for gas production from tighter shale formations. The increase in shale gas production has been accompanied by falling unit production costs, making it possible for shale gas to become rapidly competitive compared to other energy sources.

A key question is therefore to understand how production costs of shale gas plays have evolved over the past years and how these could further develop – both in North America and in potential other producing countries – to help assess the future of shale gas in the global energy system.

2. Evolution of historical US shale gas wellhead production costs in North America

The term "production costs" used in this paper refers to wellhead costs including capital costs (CAPEX) and lease operating expenses (LOE). Land acquisition costs, operating processing and transport costs, taxes and royalties, interest rates are excluded.

Historical data and figures are based on the EIA 2016 Trends in U.S. Oil and Natural Gas Upstream Costs report [3] which analyses five major US shale gas plays: Bakken, Eagle Ford, Marcellus, the Delaware and Midland plays in the Permian basin. Many analyst reports and company statements are publicly available and provide shale gas wellhead costs; however very few offer a consistent analysis for a broad range of plays, including a detailed description of the different cost structure components. In this respect, the analysis focuses on the results obtained from the EIA publication, which is the most comprehensive and exploitable document for this research.

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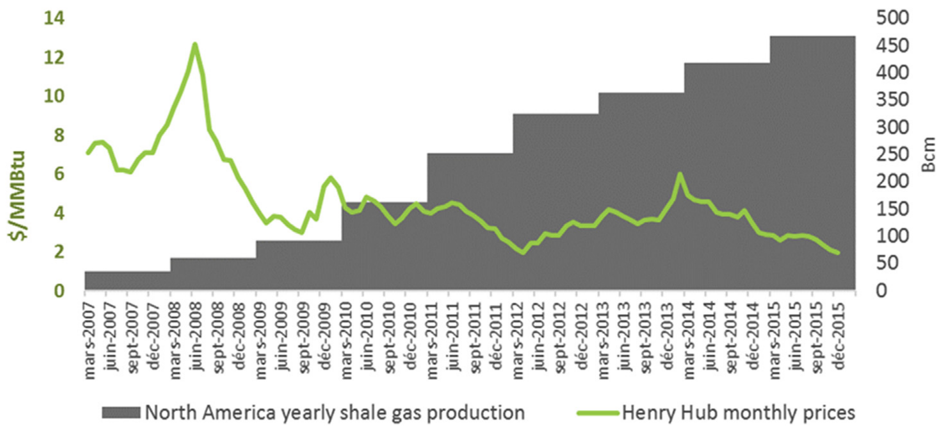

Fig. 1. Evolution of yearly North American shale gas production compared to monthly Henry Hub prices [4,5].

2.1. Trend over the last decade

The cost breakdown of shale gas is different from conventional gas, as production moved from vertical wells to horizontal or multidirectional shale wells. Thus, CAPEX and drilling costs of shale gas wells are significantly higher than for conventional gas wells: two thirds of the observed production costs[1] are CAPEX, which themselves mostly include drilling and completion (D&C) costs (nearly 95% of CAPEX). All analyst reports or dedicated publications picture fast falling production costs for existing US shale gas plays over the last years and underline the crucial role of technology improvements. The EIA report provides a more detailed and nuanced analysis of this evolution over the last ten years [3]. Interestingly, the US shale gas production boom was accompanied by a disruptive trend in D&C costs over the past: these rose by 40–50% between 2006 and 2012, before dropping at an average yearly rate of 10–15% to reach around $6 million per well on average in 2015.

The main reason for the past D&C cost increase was the growing design and technical complexity of the wells built. Over 2006–2012, the average vertical and lateral length of North American wells rose by 50% to about 15,000 feet. With the multiplication of fracking stages, the total amount of proppants and other completion fluids used rose more than tenfold over the period, hence increasing the associated completion costs. However, major gains in wells productivity and efficiency, combined with new extraction technologies, have enabled a massive increase in wells performance over the last years, leading to the decline of unit capital costs observed since 2012. To a lower extent, further factors have contributed to cost reductions: as an example, the recent lower activity in the shale gas industry puts pressure on services rates (e.g. maintenance, artificial lift equipment) and led to OPEX reduction (estimated 5% decrease of LOE in 2015); energy savings have allowed for additional cost reductions as well. Driven by decreases in both CAPEX and OPEX, unit production costs reached $3.2–3.6/MMBtu on average in 2014 (range with low and high OPEX[2]) and $2.8–3.6/MMBtu in 2015 [3].

The relationships between shale gas production costs, production levels and gas market prices are complex, and any cost assessment should therefore include a thorough consideration of both supply and demand market mechanisms. When examining this through the lens of history, several distinct periods and effects are observed. In 2007–2008, at a time of important gas demand levels, shale gas production in the US was driven by high gas prices on the market (Fig. 1). In 2008–2009, the economic crisis drove gas demand down and, combined with a quickly increasing shale gas development, led to a collapse of the US gas prices; these prices were strongly disconnected from other major international gas prices as the US could not export its tremendous oversupply. In return, the lower prices put pressure on US shale producers to keep a positive price/cost ratio. In order to maintain their profit, they turned to tight oil by applying the shale extraction techniques to tight oil plays, which was made possible due to the relatively high oil prices at that time. Substantial volumes of shale gas associated to tight oil exploration hence contributed to the continuous increase of shale gas production, at a minimal production cost (as shale gas was produced as a "by-product" of tight oil). Meanwhile, technological improvement and efficiency have enabled to keep shale production costs decreasing from 2012. With the oil price collapse since mid-2014, producers have made considerable efforts to run more efficient operations and drive unit production cost down; despite the fall of drilling activities over the last few years, the higher wells efficiency and performance have enabled to push shale gas production up and to face with the decrease of gas prices so as to meet the growing gas demand.

2.2. Main cost reduction drivers

As mentioned above, technical improvements have been a key enabler for US shale gas cost reductions over the last years. Technological parameters play a significant role by either enabling to directly decrease costs (e.g. pad drilling allows to drill multiple wells without moving the rig) or by contributing to improve the performance and production of the well (e.g. through the use of longer laterals). Multi-pad drilling represented 5% of the total number of wells drilled in 2006 among the nine biggest US shale plays but accounted for about 60% of the wells drilled in 2013. It allows for considerable economies of scale as several wells share the same facilities and cost can be spread across the wells: some operators using multi-pad drilling cut their costs up to 20% in 2015. Although total proppants costs per well have increased, new proppant mixes (e.g. using water with gel) ensure better performances and make efficiency increase quicker than costs, leading to lower unit costs per well.

Besides these technical improvements, various factors can affect the economics of unconventional gas or oil plays. On the one hand,

[1] This cost structure estimate reflects the weight of the different cost components as of 2014, based on the average of the above-mentioned plays weighted by the Expected Ultimate Recovery (EUR) estimated by the EIA.

[2] Due to the high variability of OPEX among the different plays, the EIA delivers analysis based on low and high OPEX figures.