Applied Energy 139 (2015) 398–407

Contents lists available at ScienceDirect

Applied Energy

journal homepage: www.elsevier.com/locate/apenergy

Shale gas technology innovation rate impact on economic Base Case – Scenario model benchmarks

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HIGHLIGHTS

- Cash flow models control which technology is affordable in emerging shale gas plays.
- Impact of technology innovation on IRR can be as important as wellhead price hikes.
- Cash flow models are useful for technology decisions that make shale gas plays economic.
- The economic gap can be closed by appropriate technology innovation.

ARTICLE INFO

Article history:
Received 23 January 2014
Received in revised form 27 August 2014
Accepted 24 October 2014
Available online 26 November 2014

Keywords:
Shale gas
Cash flow
Economic gap
Technology innovation
Technology factor

ABSTRACT

Low gas wellhead prices in North America have put its shale gas industry under high competitive pressure. Rapid technology innovation can help companies to improve the economic performance of shale gas fields. Cash flow models are paramount for setting effective production and technology innovation targets to achieve positive returns on investment in all global shale gas plays. Future cash flow of a well (or cluster of wells) may either improve further or deteriorate, depending on: (1) the regional volatility in gas prices at the wellhead – which must pay for the gas resource extraction, and (2) the cost and effectiveness of the well technology used. Gas price is an externality and cannot be controlled by individual companies, but well technology cost can be reduced while improving production output. We assume two plausible scenarios for well technology innovation and model the return on investment while checking against sensitivity to gas price volatility. It appears well technology innovation – if paced fast enough – can fully redeem the negative impact of gas price decline on shale well profits, and the required rates are quantified in our sensitivity analysis.

1. Introduction

There is a growing interest in the assessment of the world's shale gas resource potential since a groundbreaking global inventory by Rogner [1]. Many regional exploration efforts are underway to establish the presence and volume of prospective natural gas resources [2]. The development of unconventional hydrocarbon fields in shale gas provinces remains economically risky, because the estimated ultimate recovery (*EUR*) often remains poorly constrained – especially during the early stages of the play development [3,4]. Subsurface uncertainties related to geological conditions are particularly high in unconventional gas fields due to the lack of hydrocarbon fluid interconnectivity between adjacent wells. Each well is a new reservoir itself and the intrinsic geological uncertainty causes a large spread in well flow rates, even between adjacent wells. Consequently, *EUR* volumes, indicative for the return on investment, may vary greatly per well within unconventional gas fields [3,4].

In any emerging shale gas play, the volume of oil and gas resources in place (*OGIP*) must first be appraised, which then leads to estimations of technically recoverable resources (*TRR*; Fig. 1a).

Abbreviations: bcf, billion cubic feet; bcm, billion cubic meter; *CAPEX*, capital expenditure; *EG*, economic gap factor; *ERR*, economically recoverable resources; *EUR*, estimated ultimate recovery; GJ, GigaJoule; *IRR*, internal rate of return; Mcf, 1000 cubic feet; Mmbtu, million British thermal units; *NPV*, net present value; *OGIP*, oil and gas in Place; *OPEX*, operating expenditure; *RF*, recovery factor; Tcf, Trillion cubic feet; *TF*, technology factor; *TRR*, technically recoverable resources; US, United States of America; $, US dollar.

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http://dx.doi.org/10.1016/j.apenergy.2014.10.059

The fraction of TRR that remains unrecovered due to unfavourable economics has been coined the economic gap factor, *EG* [5]:

$$EG = TF - RF \tag{1}$$

with technology factor *TF* and recovery factor *RF* defined as follows. The fraction of the estimated initial oil and gas resource in place (*OGIP*) that can be ultimately booked as a proved reserve (the *EUR* volume) is determined by the realized recovery factor, *RF* [6]:

$$RF = EUR/OGIP \tag{2}$$

The volumetric proportion of *OGIP* that can be classified as *TRR* is determined by the technology factor, *TF* [5]:

$$TF = TRR/OGIP \tag{3}$$

TF increases over time as new reliable technology will be made available through research and development (Fig. 1). For example, technology advances like hydraulic fracturing and horizontal drilling have increased the *TF* for shale gas plays. As *TF* increases *TRR* grows, but technology efficiency sets an upper limit for the final recovery factor, *RF*. The fraction of *TRR* remaining undeveloped due to any technology being incapable of extracting more gas (from the established *OGIP*) is given by 1-(*RF*/*TF*). At a certain gas price and extraction cost, only a fraction of the TRR turns out to have a profit potential, which are termed the economic recoverable resources (*ERR*).

To put above terms into perspective a brief practical example is merited. The *OGIP* for the US Barnett shale play has been recently estimated at 444 Tcf [7]. As of 2012, already 13 Tcf was recovered [8], which implies a recovery factor *RF* = 2.9%. However, better technology and better well deployment choices (multilateral horizontal wells, precision hydraulic fracturing and finding natural fracture fairways) have lead to cost efficiency, and has brought down shale gas break-even cost. Estimates of the final *EUR* for the Barnett shale when depleted in 2050 range between 26.7 Tcf (Low Case [8]) and 45.1 Tcf (Base Case [8]), which means its *RF* ranges between 6 and 10%. An earlier study of the Barnett estimated *TRR* for the Barnett to amount to 44 Tcf [6], which means *TF* = 10%. Other estimates of *TF* for a range of shale gas plays range between 15% and 40% [9], but these are highly speculative for relatively under-investigated shale plays. If the final *RF* for the Barnett shale play will eventually be managed such that *RF* equals *TF* (i.e., 10%) all of its technically recoverable gas will have been extracted (by 2050 [8]).

One must bear in mind that in addition to technology, economic factors may limit shale gas development. The volume of gas that can be extracted economically gives the so-called economically recoverable resources (*ERR*). The *ERR* may fluctuate with gas prices for any cost of current technology and *ERR* < *TRR* at anyone time (Fig. 1). Gas demand and gas market prices are the most important (but volatile) determinants for which portion of *TRR* will actually be economically recoverable. Prevailing gas prices in the US have been so low in the period 2008–2013, that the economic gap between *TRR* and *ERR* has been growing [10–13]. To reverse the trend and close the gap, finding, development, and completion, costs must come down and gas prices must go up. Over time *TF*/*RF* should ideally converge to 1, otherwise technically recoverable resources remain undeveloped. Other factors influencing *ERR* include proximity to gas transmission and delivery infrastructure, environmental legislation, permitting speed, population density, and degree of public support [14].

There are several ways to increase the output volume and longevity of production from regions with shale *TRR* in place. The principal drivers for reserves growth are (Fig. 2): (a) higher wellhead gas prices due to increased demand (or tight supply), and (b) lower production cost due to technology innovation (and some aid by favorable taxation policies). Both drivers can reduce the economic gap and ideally *RF* and *TF* become equal (Eq. (1)). Technology generally improves over time and efficiency gains reduce cost so that *ERR* grows. The *EUR* cannot exceed *ERR*, because only economic resources may ultimately classify as reserves (Fig. 1b). Fastest growth of *ERR* can be realized when the gas wellhead price, taxation policies and technology innovations all develop favorably. For example, federal or regional government decisions for favorable taxation and royalty policies can help shale gas companies to unlock new reserves from known, technically recoverable resources.

As long as gas prices are uncontrollable and shale gas operators must turn a profit from their assets at prevailing wellhead prices, technology innovation is a key factor which can help to keep operations profitable even when gas prices fall. This study models the effect of well technology innovations which can effectively raise the *EUR* while simultaneously lowering the cost per well. The critical impact of such well technology innovation is a reduction of capital expenditure and a boost of well productivity at the same time. The well technology innovation scenarios considered below are supported by historic well performance improvements reported by SW Energy (an independent US shale gas company), which has halved drill time and doubled the initial well productivity over a five year period (Fig. 3). The doubling of the well productivity can be attributed mostly to the increase in length of the average wellbore, which has more than doubled over the indicated period.

The cash flow models developed below demonstrate what rate of technology innovation is needed to turn out positive earnings when gas prices are weakening. In essence, overall shale gas

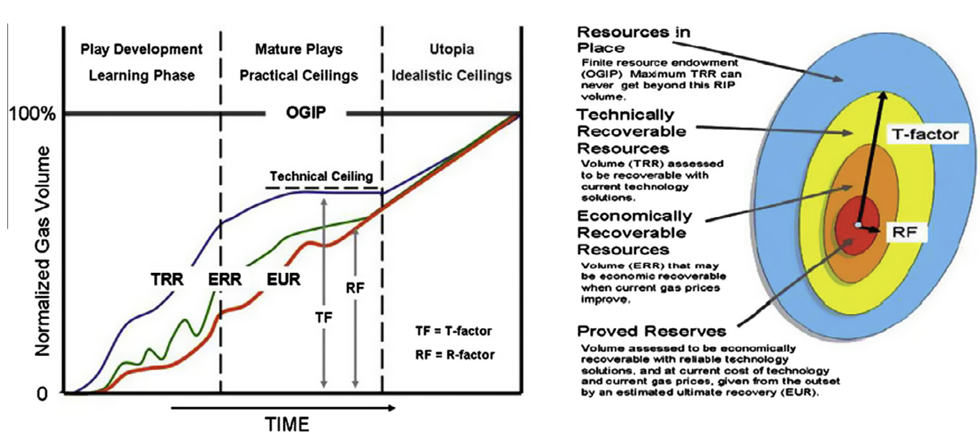

Fig. 1. For any given resource endowment in place (*OGIP*), the *TRR* fraction grows when technology improves; the *ERR* fraction grows when gas prices rise. Negative slopes occur when gas prices slump. The *EUR* is less susceptible to downgrades and tends to grow over time (left graph after Madani and Holditch [6]).