COMMENTARY

# Forecasting long-term gas production from shale

**Luis Cueto-Felgueroso[a] and Ruben Juanes[a,b,1]**

[a]*Department of Civil and Environmental Engineering and* [b]*Earth Resources Laboratory, Massachusetts Institute of Technology, Cambridge, MA 02139*

Oil and natural gas from deep shale formations are transforming the United States economy and its energy outlook. Back in 2005, the US Energy Information Administration published projections of United States natural gas supply that stressed the need to develop an import infrastructure (1): by 2025, imports would account for almost one-third of United States consumption. When we compare those forecasts with the current ones to 2040 (Fig. 1) (2), it is inevitable to feel that a disruptive technology has emerged since. Natural gas consumption is expected to increase significantly over the next three decades, with strong demand growth from the electricity generation and industrial sectors. However, the United States will probably become a net exporter of gas before 2020, increasing domestic production by 44% over the projection period.

The trigger for this revolution has been the large-scale deployment of a set of synergetic technologies that allows us to produce oil, and especially natural gas, from mudrock formations that were considered unproductive just a few years ago. Gas shales are tightly packed, fine-grained sedimentary rocks. Hydrocarbons form within these rocks and remain trapped in their pore space because of their ultralow permeability. Unlike conventional oil and gas reservoirs, which are highly concentrated geographically, shale formations are common around the world. The potential abundance of shale gas resources worldwide—and the fact that burning natural gas emits less $CO_2$ and atmospheric pollutants than other fossil fuels—has created the expectation of a golden age of natural gas in the global energy system (3). Estimates of long-term production and technically recoverable resources are, however, highly uncertain (3–5). The fundamental mechanisms controlling shale gas extraction remain poorly understood, and the classic theories and simulation techniques used by the oil and gas industry have proven inadequate for shales (6, 7). In PNAS, Patzek et al. (8) make an important contribution toward reducing uncertainty and unraveling the physical mechanisms behind gas recovery for tight shale formations.

Current shale gas production relies on two quickly evolving technologies: horizontal drilling and hydraulic fracturing. Horizontal drilling enhances the spatial access to the hydrocarbon resource by increasing the length of a single well within the gas-bearing shale. Hydraulic fracturing, or "fracking" (9, 10), provides reservoir stimulation via injection of fluids, granular suspensions (proppant), and chemicals at high pressure, sufficient to fracture the rock and enhance its permeability. Flow through shale poses a distinctive challenge that is not present in classic oil and gas applications: Pore throats in shale have typical widths in the order of a few nanometers, and are rich in organic material (kerogen) with adsorbed gas (11–13). At these scales, the pore size is comparable to the mean free path of the gas molecules, and the Navier–Stokes equations with no-slip boundary condition do not properly represent the flow (11). Much experimental, theoretical, and computational work is still needed to understand the rock-fracturing process and the multiphase flow process that ensues.

Shale gas projects have attracted vigorous opposition, and shale gas is rapidly emerging as a major social dilemma (14). Although the potential economic benefits are already fostering exploration outside the United States, it is unclear that these technologies will be deployed at a large scale worldwide unless uncertainty about the environmental impact of current recovery methods is reduced. There is a need for better understanding of the conditions under which shale operations lead to gas venting (15), to contamination of groundwater by methane or fracking fluids (16, 17), and their potential impact

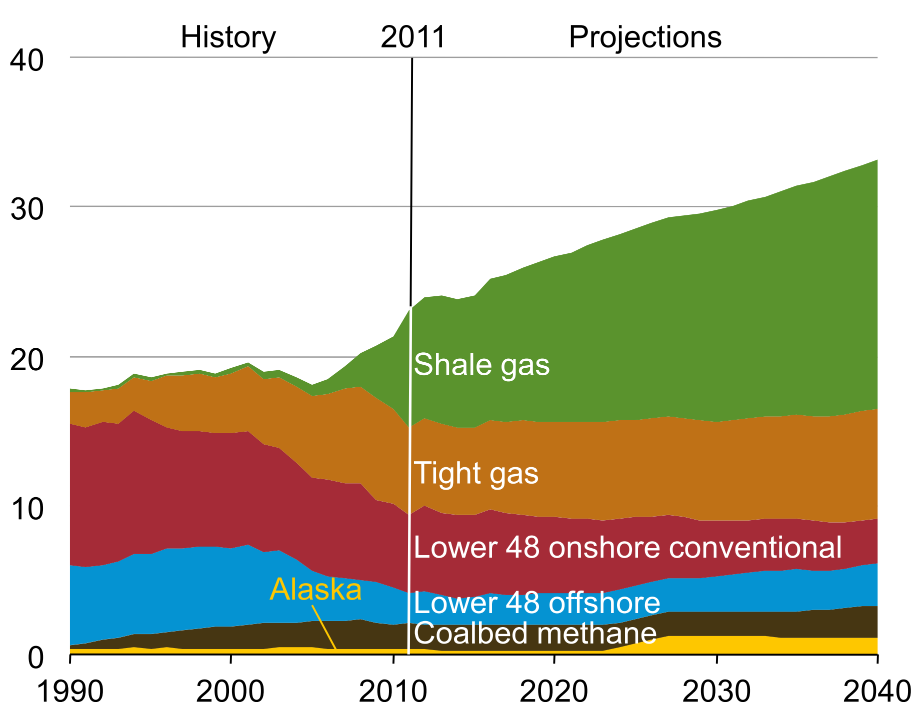


**Fig. 1.** Natural gas production in the United States, by source (in trillion cubic feet per year). Shown are historic data from 1990 to 2011 and projections for 2012 to 2040. Shale gas is expected to provide the largest source of growth in United States natural gas supply. From ref. 2.

Author contributions: L.C.-F. and R.J. wrote the paper.

The authors declare no conflict of interest.

See companion article on page 19731.

[1]To whom correspondence should be addressed. E-mail: juanes@mit.edu.

 www.pnas.org/cgi/doi/10.1073/pnas.1319578110

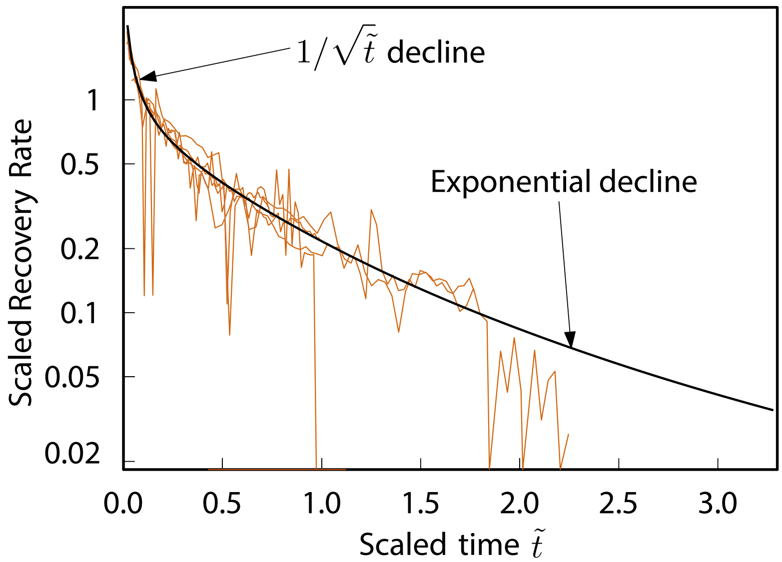


**Fig. 2.** The gas production rate predicted by Patzek et al.'s (8) mathematical model (solid black line) exhibits two distinct regimes: an early-time regime with a $1/\sqrt{\tilde{t}}$ gas rate decline, and a late-time regime with an exponential decline. Also shown is the scaled recovery rate for five wells from the Barnett Shale (orange lines). Adapted from ref. 8.

on regional water quality (18). Recently, methane leakage as a result of improper well construction, and the potential migration of gas, brine, or fracking fluids to shallow aquifers, have been much debated (16, 19, 20). This debate highlights the need for research on fundamental processes, as well as engagement from the industry and regulators.

The work of Patzek et al. (8) is an example of this much-needed research. The authors address the critical issue of long-term gas production from shale-gas plays and use a simple conceptual model: linear flow of gas toward planar hydrofractures, spaced uniformly along the track of a horizontal well. Patzek et al. model gas flow using a Darcy formulation, in which the gas seepage velocity through the rock is proportional to the gas pressure gradient (21). This simple model leads to a "diffusion-type" equation, where the relevant time-scale $\tau$ of the problem is proportional to the square of the half-distance $d$ between hydrofractures: $\tau = d^2/\alpha_i$. The coefficient $\alpha_i$ is the hydraulic diffusivity, which is proportional to the permeability of the rock and inversely proportional to the gas viscosity and compressibility.

This mathematical model can be solved analytically under certain assumptions on the gas-phase behavior; that is, on the relation between gas compressibility and gas pressure (13). The solution exhibits two regimes: (*i*) an early-time regime, corresponding to the period before fracture interference ($\tilde{t} = t/\tau < 1$), for which the recovery rate declines with the square-root of time, $Q \sim 1/\sqrt{\tilde{t}}$ ; and (*ii*) a late-time regime ($\tilde{t} > 1$), for which the fracture interference leads to exponential decay in the gas recovery rate, $Q \sim 1/\exp(\tilde{t})$ (13). Patzek et al. (8) extend the mathematical model to incorporate more realistic phase behavior and find, by solving the model numerically, that the recovery rate still exhibits the same two regimes (Fig. 2).

In a nutshell, Patzek et al. (8) propose a minimal-ingredients model of gas production from shale in the form of a universal scaling function and two adjustable parameters (per well): the interference time between hydrofractures, $\tau$, and the mass of gas in place that can ultimately be recovered, $\mathcal{M}$. The authors test their model against a comprehensive record of gas production from one of the oldest shale-gas plays in the United States: the Barnett Shale in Texas. Despite the many simplifying modeling assumptions, Patzek et al. find that the production data from thousands of wells agrees well with their scaling theory. This study is remarkable in two ways. First, it is an excellent example of parsimonious modeling: the development of a minimal-ingredients model that is able to explain observations. Second, their theory can be used to estimate, with limited data, lower and upper bounds of cumulative production.

The work of Patzek et al. (8) is a timely and welcome contribution to PNAS, as it brings much-needed clarity to a crucial aspect of the shale gas revolution: forecasting long-term production. The parsimonious nature of the proposed model raises several important challenges, too. It is conceivable that the conceptual model of linear, single-phase flow of gas into parallel, equidistant fractures may not be universally applicable. The complexity of hydrofracture geometries, the stimulation of networks of preexisting (natural) fractures, adsorption and desorption processes, and non-Darcy multiphase flow through the chemically heterogeneous shale, are all phenomena that could potentially result in a departure from the scaling behavior proposed by Patzek et al. This complexity points to exciting avenues of research, to exploit mechanisms that overcome an exponential decline of gas production from shale and, more generally, to provide improved scientific understanding that should guide the decisions on shale gas deployment worldwide.

**1** US Energy Information Administration (2005) *Annual Energy Outlook 2005 with Projections to 2025*, Technical Report DOE/EIA-0383(2005). Available at www.eia.gov/oiaf/archive/aeo05/. Accessed November 1, 2013.
**2** US Energy Information Administration (2013) *Annual Energy Outlook 2013 with Projections to 2040*, Technical Report DOE/EIA-0383(2013). Available at www.eia.gov/forecasts/aeo/. Accessed November 1, 2013.
**3** International Energy Agency (2011) *World Energy Outlook 2011. Are we Entering a Golden Age of Gas?* Available at www.worldenergyoutlook.org/goldenageofgas/. Accessed November 1, 2013.
**4** Kerr RA (2010) Energy. Natural gas from shale bursts onto the scene. *Science* 328(5986):1624–1626.
**5** European Commission Joint Research Center (2012) *Unconventional Gas: Potential Energy Market Impacts in the European Union*. Available at http://ec.europa.eu/dgs/jrc/downloads/jrc_report_2012_09_unconventional_gas.pdf. Accessed November 1, 2013.
**6** Monteiro PJM, Rycroft CH, Barenblatt GI (2012) A mathematical model of fluid and gas flow in nanoporous media. *Proc Natl Acad Sci USA* 109(50):20309–20313.
**7** Cipolla CL, Lolon EP, Erdle JC, Rubin B (2010) Reservoir modeling in shale-gas reservoirs. *SPE Reservoir Eval Eng* 13:638–653.
**8** Patzek TW, Male F, Marder M (2013) Gas production in the Barnett Shale obeys a simple scaling theory. *Proc Natl Acad Sci USA* 110:19731–19736.
**9** Hubbert MK, Willis DG (1957) Mechanics of hydraulic fracturing. *Petrol Trans AIME* 210:153–163.
**10** Economides MJ, Nolte KG (2000) *Reservoir Stimulation* (John Wiley and Sons, Chichester, England).
**11** Javadpour F (2009) Nanopores and apparent permeability of gas flow in mudrocks (shales and siltstone). *J Can Pet Technol* 48:16–21.
**12** Sakhaee-Pour A, Bryant SL (2012) Gas permeability of shale. *SPE Reservoir Eval Eng* 15:401–409.
**13** Silin D, Kneafsey T (2012) Shale gas: Nanometer-scale observations and well modelling. *J Can Pet Technol* 51:464–475.
**14** Howarth RW, Ingraffea A, Engelder T (2011) Natural gas: Should fracking stop? *Nature* 477(7364):271–275.
**15** Howarth RW, Santoro R, Ingraffea A (2011) Methane and the greenhouse-gas footprint of natural gas from shale formations. *Clim Change* 106(4):679–690.
**16** Osborn SG, Vengosh A, Warner NR, Jackson RB (2011) Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing. *Proc Natl Acad Sci USA* 108(20):8172–8176.
**17** US Environmental Protection Agency. (2012) *Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources*, Technical Report EPA 601/R-12/011. Available at www2.epa.gov/hfstudy. Accessed November 1, 2013.
**18** Vidic RD, Brantley SL, Vandenbossche JM, Yoxtheimer D, Abad JD (2013) Impact of shale gas development on regional water quality. *Science* 340(6134):1235009.
**19** Engelder T (2012) Capillary tension and imbibition sequester frack fluid in Marcellus gas shale. *Proc Natl Acad Sci USA* 109(52):E3625, author reply E3626.
**20** Fisher K, Warpinski NR (2012) Hydraulic-fracture-height growth: Real data. *SPE Prod Oper* 27:8–19.
**21** Muskat M (1949) *Physical Principles of Oil Production* (McGraw-Hill, New York).