With Proper Spacing and Enough Time, Shale Wells May Produce Much More Gas*

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Abstract

In 1947, the ‘hydrafrac’ process in the No.1 Klepper well in the Hugoton Field, Kansas, combined four cubic meters of naphthenic acid and palm oil with gasoline and sand to stimulate the flow of natural gas from a limestone formation. In 1973, Amoco introduced massive hydraulic fracturing in the Wattenberg gas field of the Denver Basin to recover gas from a low-permeability sandstone. The injection of 50 cubic meters of water and 90 tons of sand proppant succeeded in recovering much greater volumes of gas than had been previously possible. In 1974, Amoco performed the first million-pound frac job, injecting more than 450 tons of proppant into a well in the Wattenberg field. Between 1981 and 1998, a Texas company, Mitchell Energy and Development, experimented with multistage hydrofracturing of horizontal wells in the Barnett gas shale formation. Commercial success came when the company applied slick water, a low viscosity mixture that could be rapidly pumped down a well to deliver a much higher pressure to the rock than before. Today, about half of US natural gas comes from gas shales, with the Marcellus play being the dominant producer and Haynesville a distant second. The oldest play in the US, Barnett, has had up to 18 years of production from hydrofractured horizontal wells that today may show signs of late-time radial flow. Because of public availability of data in the US, one can study gas production well by well for about 70,000 horizontal shale wells. I will present a field data-driven solution for long-term shale gas production from a horizontal, hydrofractured well far from other wells and reservoir boundaries. Our approach is a hybrid between an unstructured big-data approach and physics-based models. We extend a previous two-parameter scaling theory of shale gas production by adding a third parameter that incorporates gas inflow from the external unstimulated reservoir. This allows us to estimate for the first time the effective permeability of the unstimulated shale and the spacing of fractures in the stimulated region. From an analysis of wells in the Barnett Shale, we find that on average, stimulation fractures are spaced every 20 m, and the effective permeability of the unstimulated region is 100 nanodarcy. We estimate that over 30 years on production the Barnett wells will produce on average about 20% more gas because of inflow from the outside of the stimulated volume. There is a clear tradeoff between production rate and ultimate recovery in shale gas development. In particular, our work has strong implications for well spacing in infill drilling programs. A bad early decision on how to develop a lease can affect negatively the long-term production from that lease and ultimate recovery.

References Cited

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With Proper Spacing and Enough Time,

Shale Wells May Produce Much More Gas

Tad W. Patzek, ANPERC/KAUST

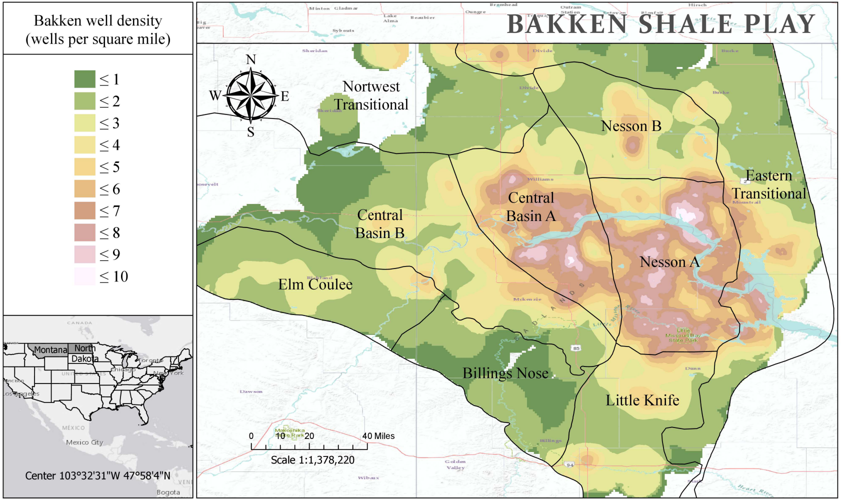
AAPG/EAGE Shale Gas Evolution Symposium, Bahrain, Dec 12, 2018

$116 \times 66 = 7660$ km^2 area in the Bakken core, accessed Feb 2018

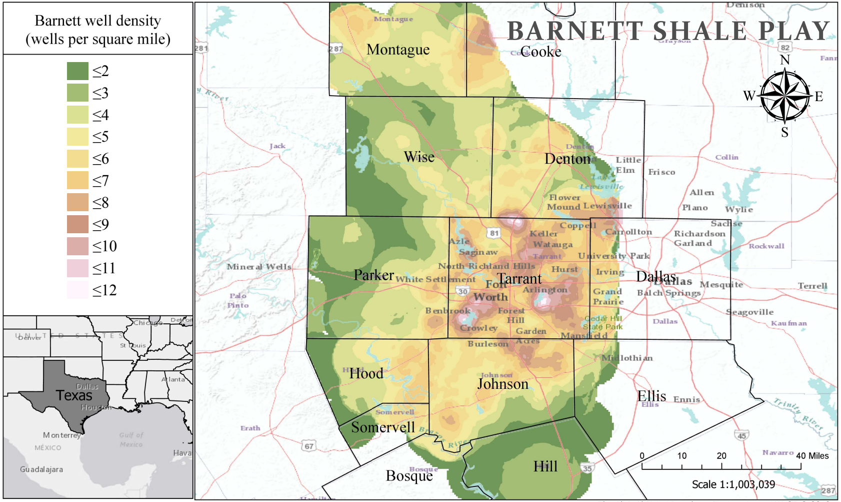
Fifteen wellheads on a tiny piece of the Bakken real estate

Google map of North Dakota, Wardana Saputra, KAUST, Dec. 10, 2018

So how many wells per square mile of a developed shale oil play?

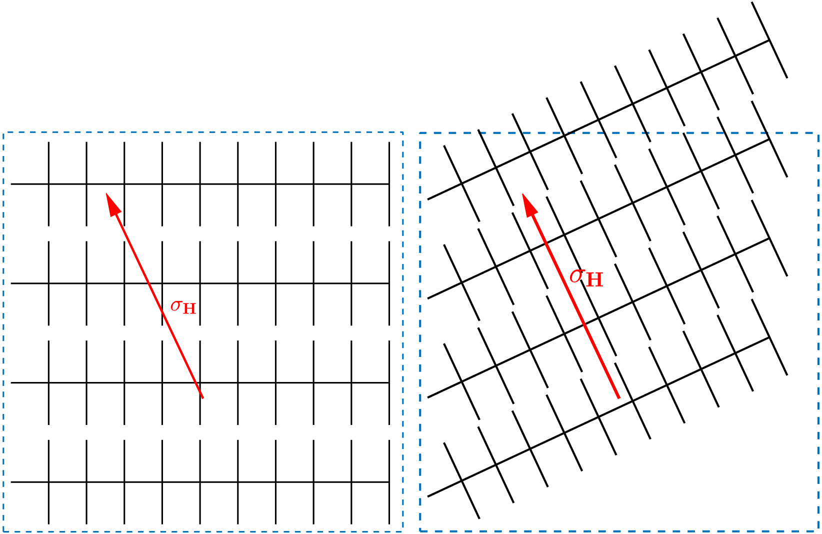


And how many wells per square mile of a developed gas shale play?



The Ali I. Al-Naimi Petroleum Engineering at KAUST © 2018

Filling a 1 square mile section with horizontal wells



5000 ft long wells with 10 frac stages, 1100 ft tip-to-tip hydrofractures

The goal of this presentation

- 18 years have passed since hydrofractured horizontal wells became operational in the Barnett shale
- Many gas production forecasts have been made for the Barnett: How gracefully have these forecasts **aged**?
- Can a combination of extensive data analytics, statistical inferences and physics-based models deliver the **accurate** long-term predictions of the future gas production from shale plays?

Our answer is a resounding YES

Conclusions of my 05/26/11 seminar at UT Austin

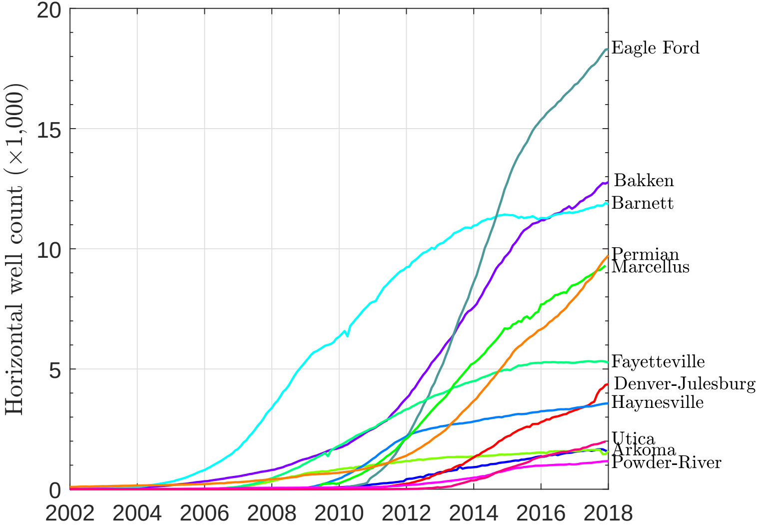
My **early 2011** predictions of ultimate production from the Barnett varied between **16** and **26** Tscf. In late 2018, we predicted that the cohort of existing wells would produce **22** Tscf by 2030

Summary of UT Austin-BEG/Sloan/Shell/Statoil work

1. There were some 30,000 horizontal gas shale wells in the US in 2011
   Question: How to
   - Scale production of all these wells with a first-order accurate physics-based model?
   - What will be their physics-based EURs?
2. In scaling well production, we had to postulate existence of fractures of all origins, spaced every 1-10 meters
3. We then constructed a large-scale rock hydrofracturing model that would explain these fractures

Current horizontal well counts in mudrock plays

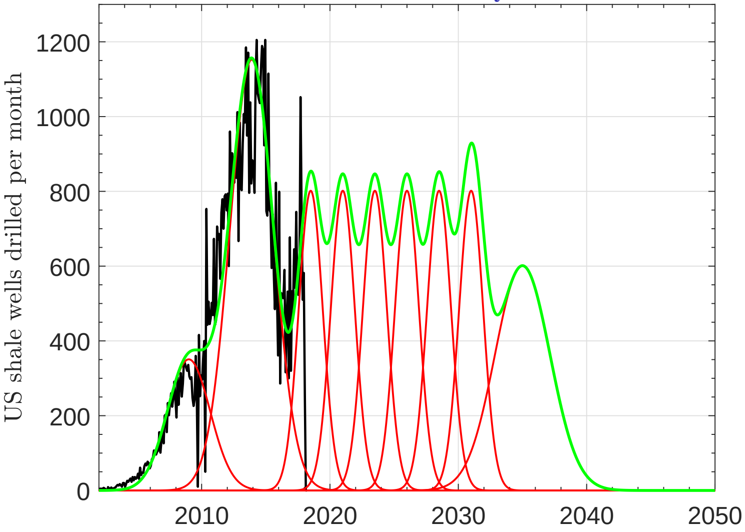
82,000 wells



Patzek, T.W., DrillingInfo, Unpublished, 2018

Future of shales = drilling rate

About 700 horizontal wells will be drilled each month for the next 20 years



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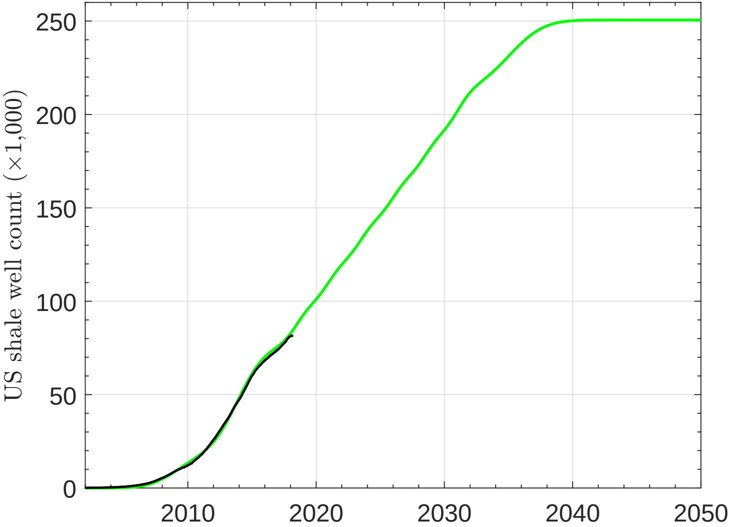
Future drilling cum

Incremental 164,000 horizontal wells in 20 years? That's $1.3 trillion @ $8M per well



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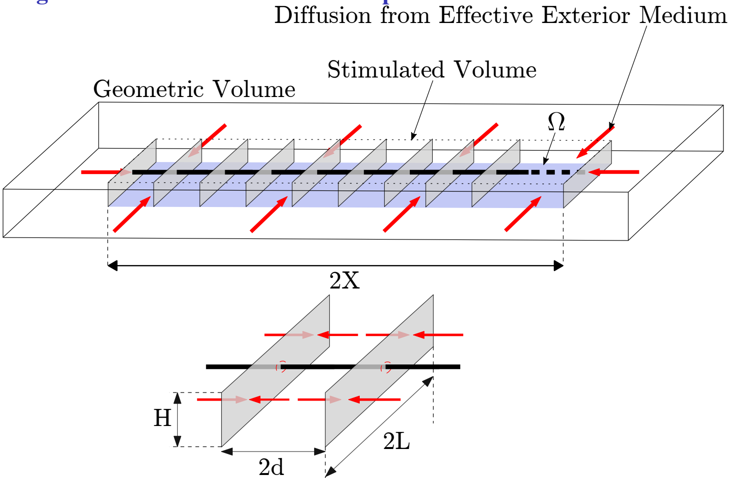
Late-time gas production

Model of late-time gas production

Gas from reservoir regions external to SRV becomes important



Interior problem: SRV = $\Omega \times (2LH)$
Exterior problem: Reservoir volume$\setminus$SRV

Source: B. Eftekhari, M. Marder, T. W. Patzek, JNGSE, May 2018

Solution of the interior gas production problem

The cumulative production of interior gas is scaled with two parameters:

$$\mathbf{m}_{\mathrm{I}}(\tilde{t}) = \mathcal{M} \times \mathrm{RF}_{\mathrm{I}}\left(t/\tau\right), \quad \text{PNAS (2013)} \tag{1}$$

Here the stimulated mass $\mathcal{M} = 4LXH\phi S_g \rho_i$ is contained in the SRV and the characteristic interference time τ is determined by the onset of pressure interference between two hydrofractures $2d$ apart:

$$\tau = \frac{d^2}{\alpha_i}, \tag{2}$$

where α_i is the constant hydraulic diffusivity at initial reservoir pressure and temperature $(p_i,\ T)$:

$$\alpha_i = \left.\frac{k}{\phi \mu_g S_g c_g}\right|_{p_i,\, T}. \tag{3}$$

Source: T. W. Patzek, F,. Male and M. Marder, PNAS, 2013

Solution of the exterior problem of gas production

$$\mathcal{M} = \frac{(2X)^2}{\epsilon} H\phi S_g \rho_i, \quad \epsilon = \frac{2X}{2L} \tag{4}$$

$\mathbf{m}_{\mathrm{E}}$ is the cumulative exterior production, obtained from a solution of the modified IBVP:

$$\mathbf{m}_{\mathrm{E}}(\tilde{t}') = \mathcal{M} \times \mathrm{RF}_{\mathrm{E}}\left(t/\tau'\right), \quad \text{JNGSE (2018)} \tag{5}$$

Here τ' is the characteristic time scale for exterior production, defined as the time it takes low pressure to diffuse from the wellbore over a distance equal to fracture half-length L:

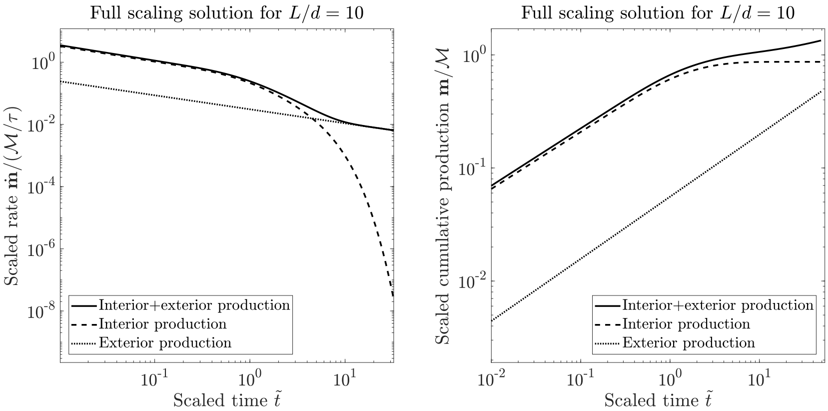
$$\tau' = \frac{L^2}{\alpha_i} = \frac{d^2}{\alpha_i}\left(\frac{L}{d}\right)^2 = \tau\left(\frac{L}{d}\right)^2 \tag{6}$$

For exterior production, τ' defines the new scaled time

$$\tilde{t}' = \frac{t}{\tau'} = \frac{t}{\tau}\left(\frac{d}{L}\right)^2 = \tilde{t}\left(\frac{d}{L}\right)^2 \tag{7}$$

Source: B. Eftekhari, M. Marder, T. W. Patzek, JNGSE, May 2018

Rate of gas production



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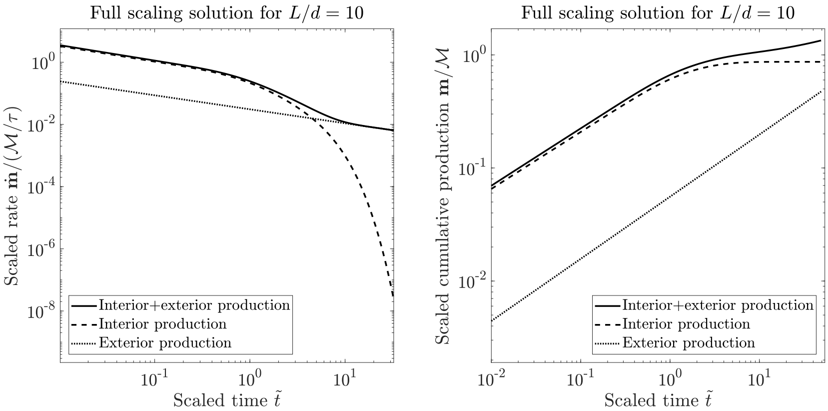
Rate of gas production



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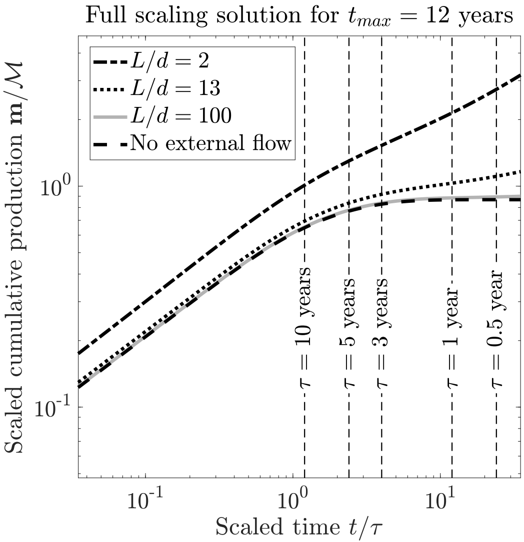
Two $1/\sqrt{(t)}$ decline regimes; the second is radial flow in infinite reservoir

When can one measure late-time production?



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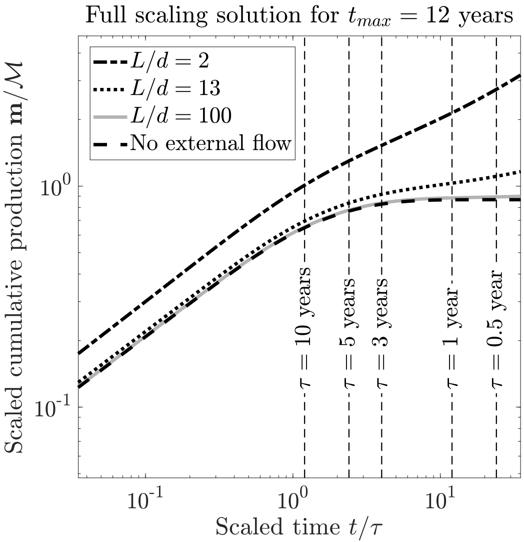

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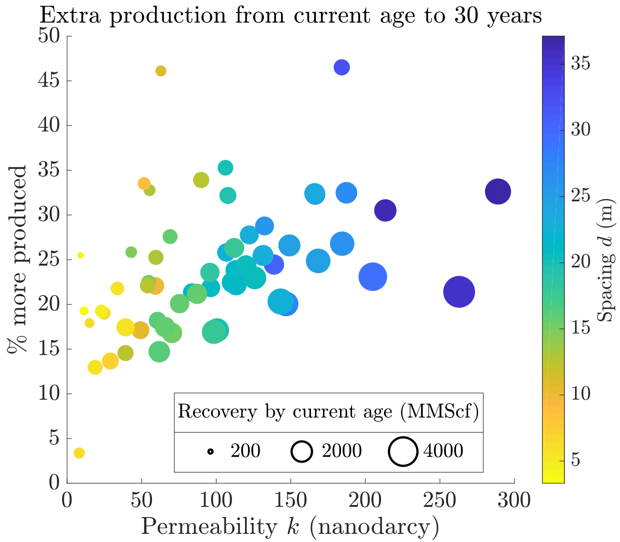
For late-time wells in the Barnett $2 < L/d < 13$

How much more gas will be produced in Barnett?



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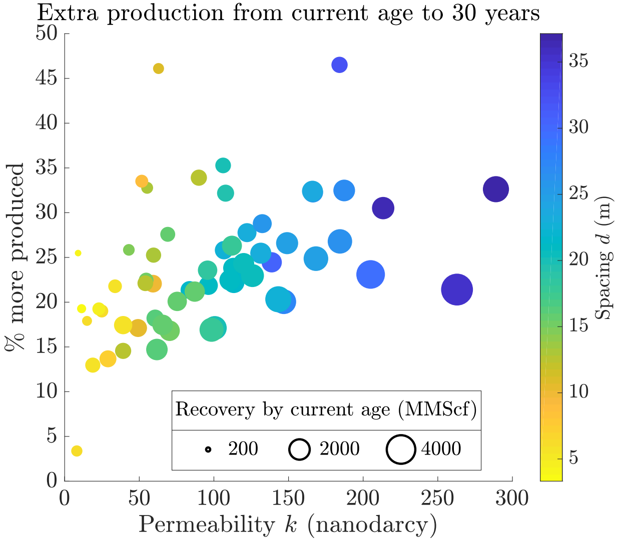
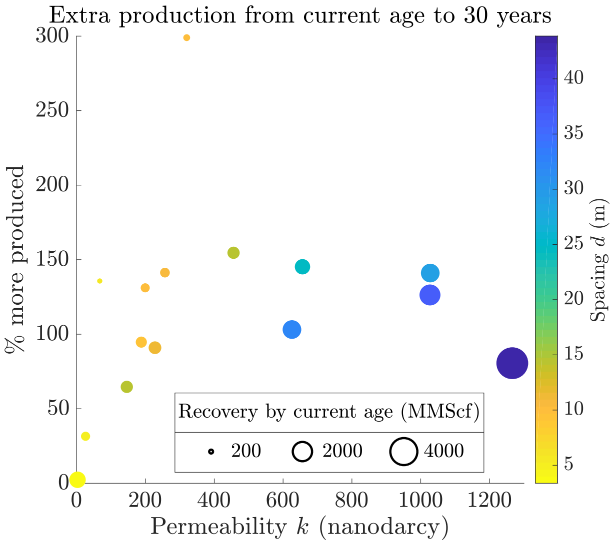


Source: B. Eftekhari, M. Marder, T. W. Patzek, JNGSE, May 2018

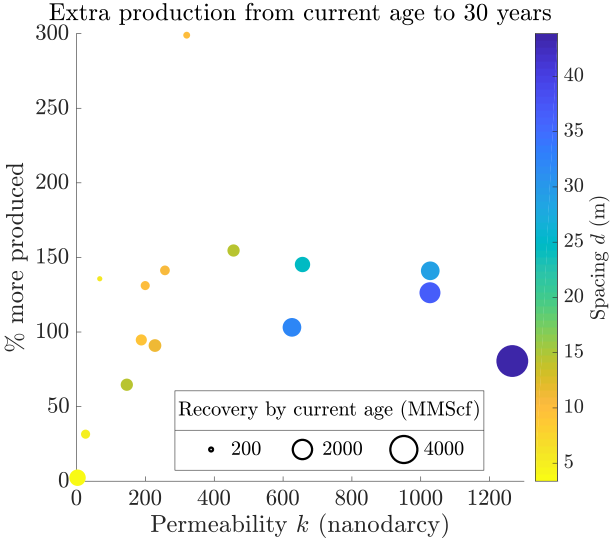
Between 4 and 45% more; 23% on average

Late production responses in the Marcellus



Source: B. Eftekhari, M. Marder, T. W. Patzek, Unpublished, July 2018

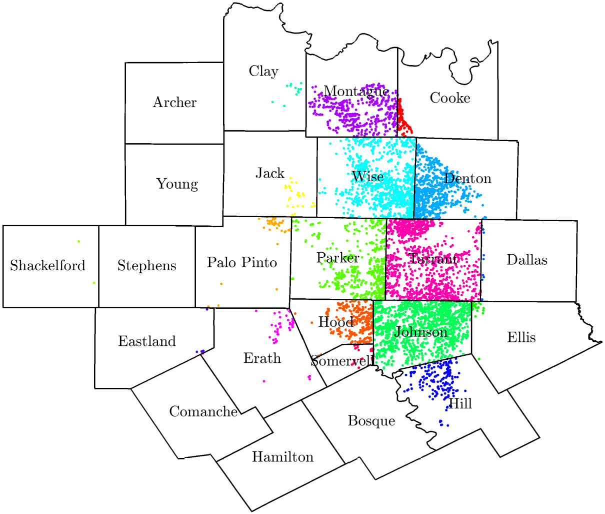
Late production responses in the Marcellus



Source: B. Eftekhari, M. Marder, T. W. Patzek, Unpublished, July 2018

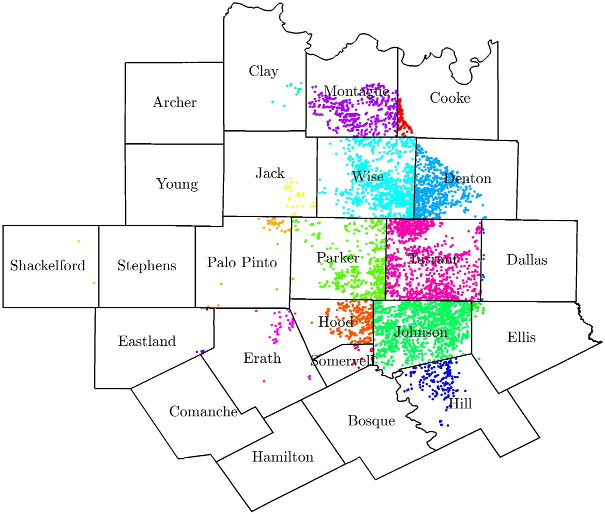
Between 3 and 160% more; 110% on average

Six major gas-producing counties in Barnett



Source: DrillingInfo, August 15, 2018

Six major gas-producing counties in Barnett



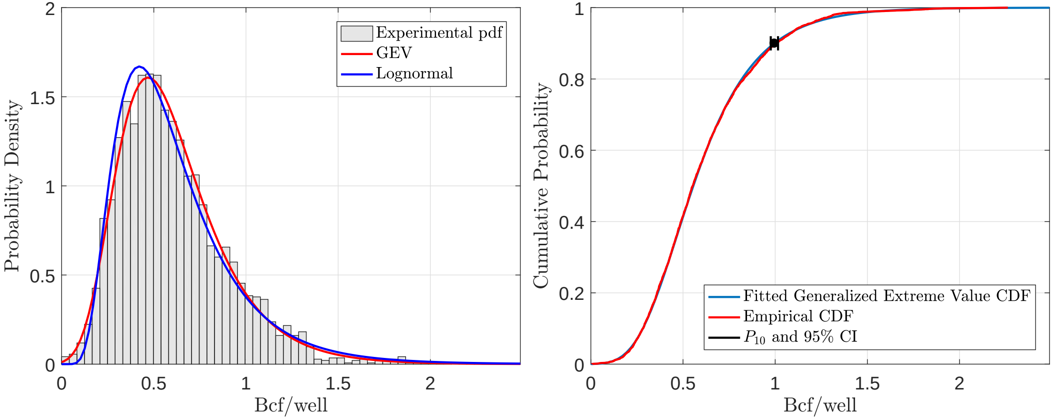
Source: DrillingInfo, August 15, 2018

Tarrant, Johnson, Wise, Parker, Denton and Hood

Work flow

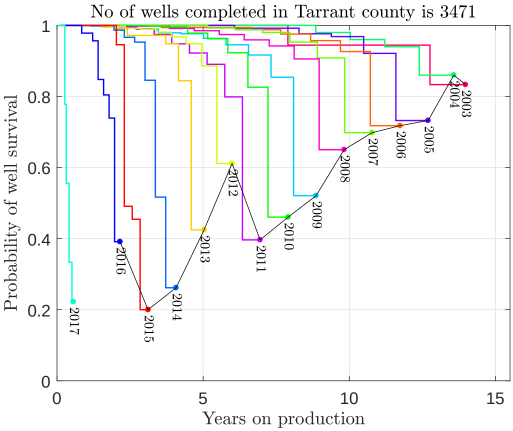
- Sort wells by county and by year of completion
- Calculate the probabilities of survival of wells of a given vintage
- For each county and for $12, 24, 36, \ldots$ months on production fit the distribution of cums with a GEV pdf
- Calculate the expected (P_{50}), high (P_{10}) and low (P_{90})
- Map the dimensionless RF curve from physics-based scaling (PNAS, 2013; JNGSE, 2018) onto each dimensional P_{50} curve, obtaining average well prototype for each county

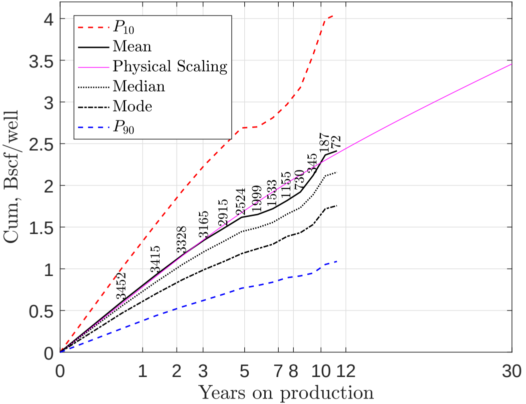
Fit of wells with a set time on production



Cumulative gas production from the Tarrant county wells with **one year** on production. Source: DrillingInfo, 8/15/18

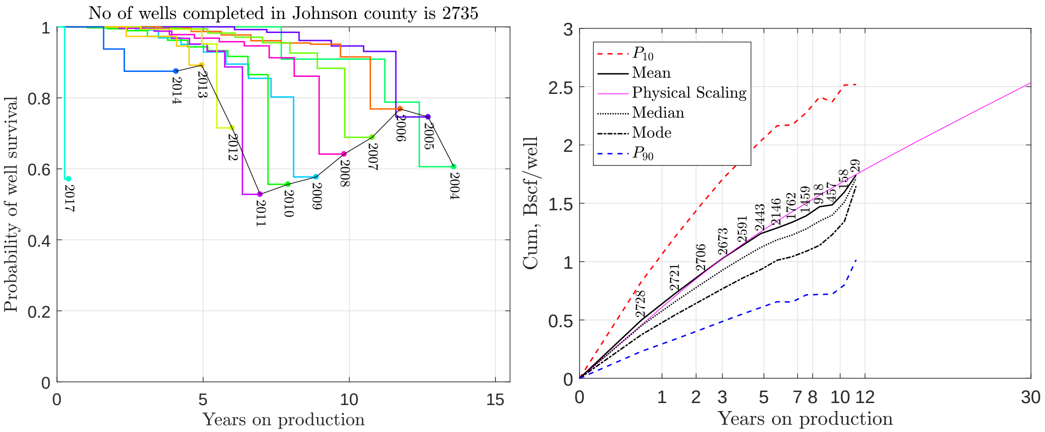
Tarrant county well survival and well prototype





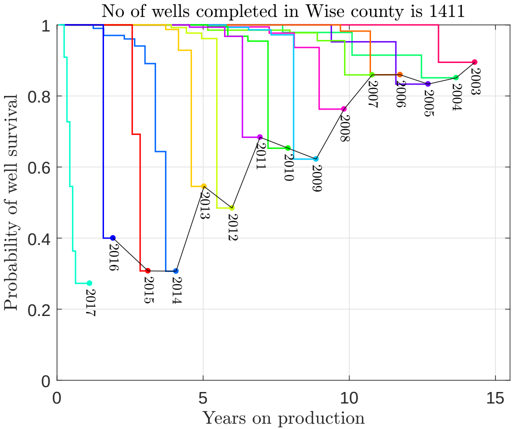
Source: Patzek et al., Submitted, August 15, 2018

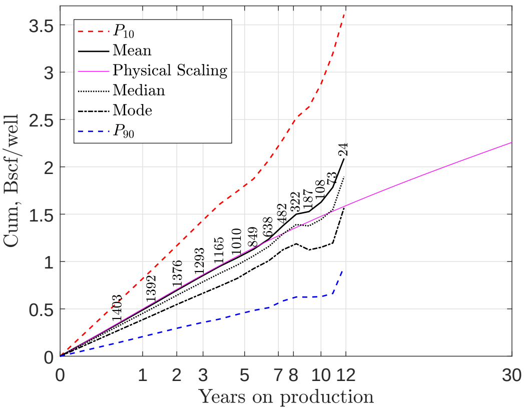
Johnson county well survival and well prototype



Source: Patzek et al., Submitted, August 15, 2018

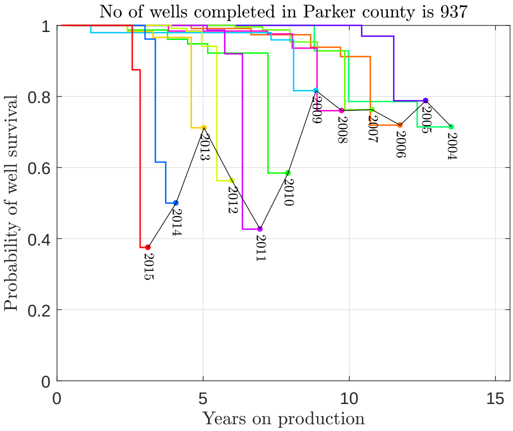
Wise county well survival and well prototype

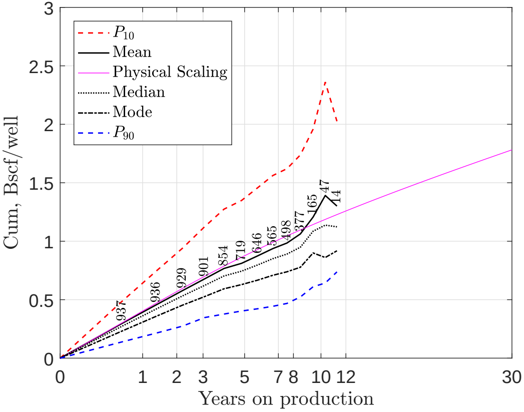




Source: Patzek et al., Submitted, August 15, 2018

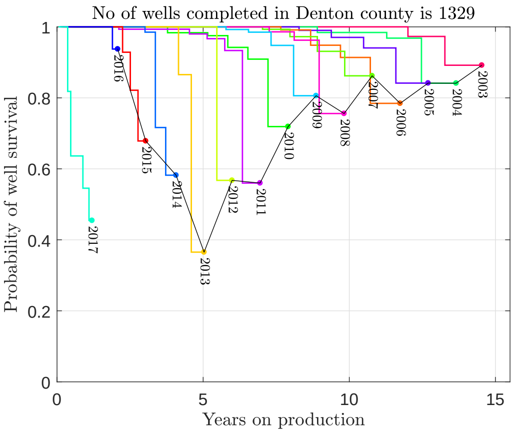
Parker county well survival and well prototype

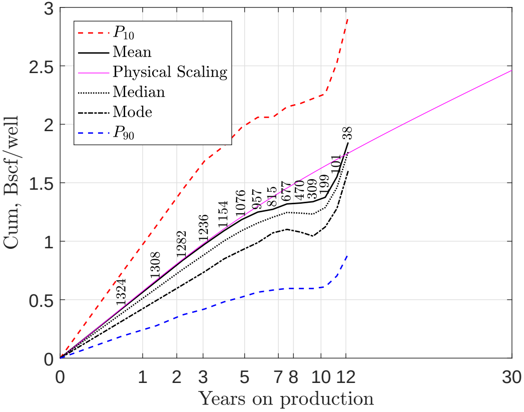




Source: Patzek et al., Submitted, August 15, 2018

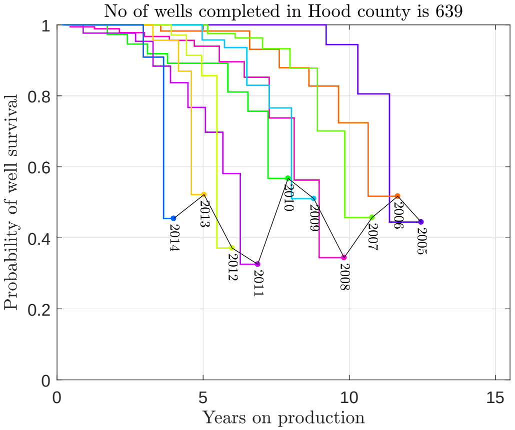
Denton county well survival and well prototype

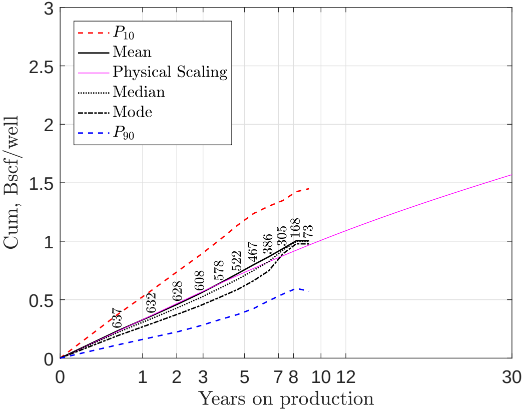




Source: Patzek et al., Submitted, August 15, 2018

Hood county well survival and well prototype





Source: Patzek et al., Submitted, August 15, 2018

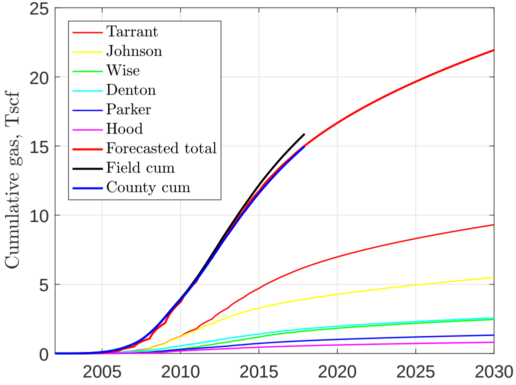
Let's harvest the fruits of a massive data analysis

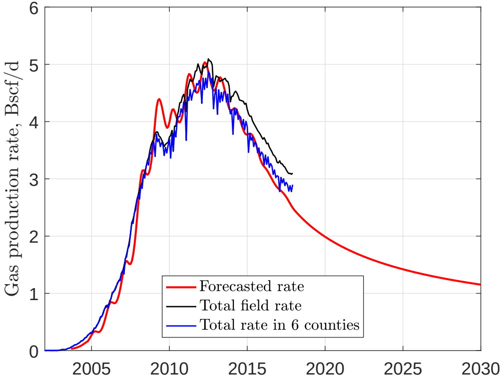
- Now we have 6 prototypes of average wells for each of the major gas-producing counties in the Barnett
- These prototypes are based on the GEV statistics of cumulative production from each of 10,814 wells well in the counties
- By adjusting the physics-scaled solution valid for early and late times on production, we now have 6 well prototypes with 30 years on production
- Well attrition, new technology, gas prices, and worsening well locations are all captured by the prototypes

Let's harvest the fruits of a massive data analysis

- Since we know how many wells were completed in each county every year, we can add the prototypes and time-shift them
- As a result, we should match the cumulative gas production from the six counties with no adjustable parameters
- The field production rate is obtained from differencing cumulative production and some smoothing

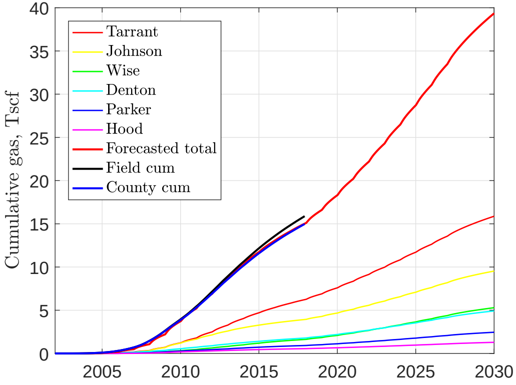
Match of production from the Barnett

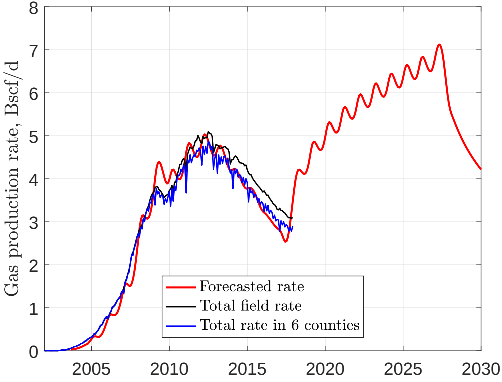




Source: Patzek et al., Submitted, August 15, 2018

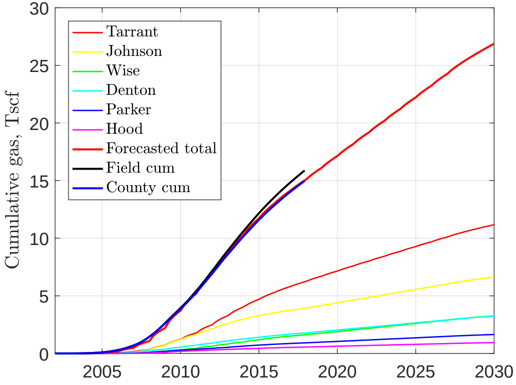
Now a forecast with 12,600 future wells over next 10 years

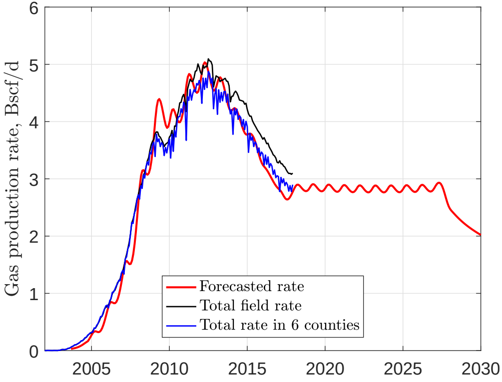




Source: Patzek et al., Submitted, August 15, 2018

And a forecast with 3,570 future wells over next 10 years



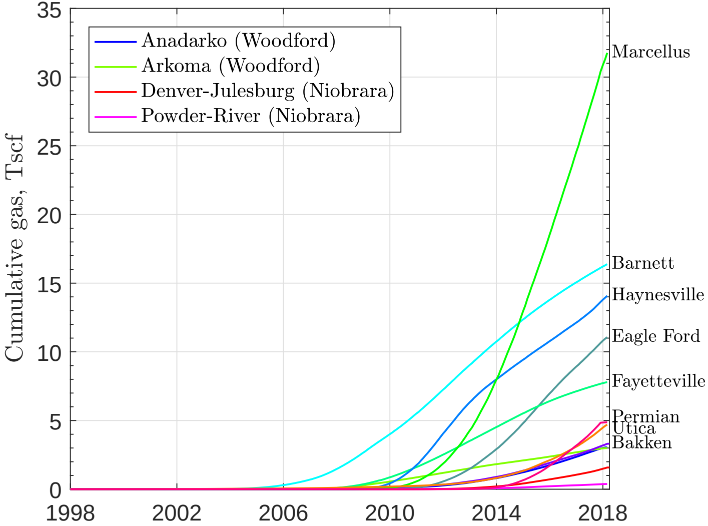


Source: Patzek et al., Submitted, August 15, 2018

Time-lapse photo by a KAUST student **Vinicius Lube**, Jan 24, 2018

Cumulative gas production by play

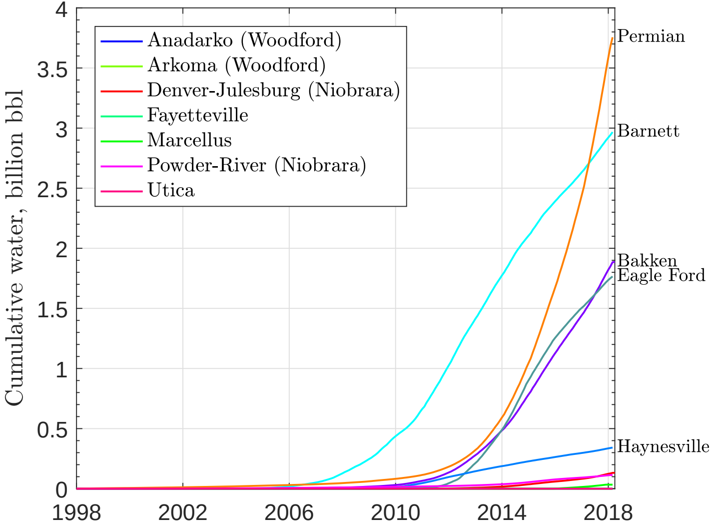
Marcellus produced twice as much gas as Barnett



Wardana et al., DrillingInfo, Unpublished, August 2018

Cumulative water production by play

Permian produced most water, but Barnett is a close second



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