Distinguished Lecturer Program

Primary funding is provided by

The SPE Foundation through member donations and a contribution from Offshore Europe

The Society is grateful to those companies that allow their professionals to serve as lecturers

Additional support provided by AIME

SPE International

Society of Petroleum Engineers
Distinguished Lecturer Program
www.spe.org/dl

CHARACTERIZING SHALE PLAYS

The Importance of Recognizing What You Don't Know

SPE 2013-2014 Distinguished Lecturer Series

Brad Berg

SPE International

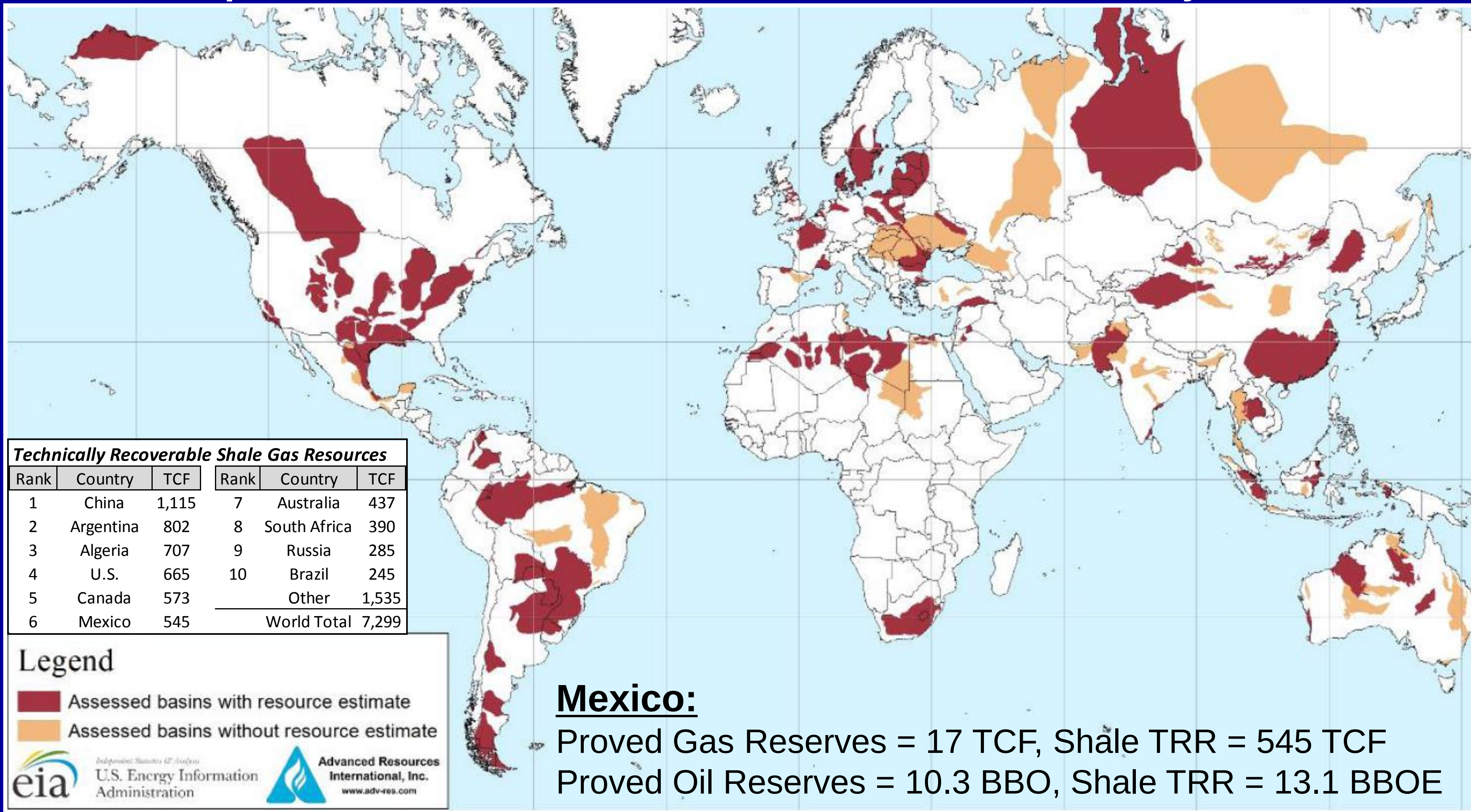
Anadarko Petroleum Corporation

Outline

- Huge Global Resource
- Shale Play Characterization Challenges
- Incorporating Uncertainty into Assessments
- The Impact of Decision Behavior
- Conclusions

Global Shale Gas Resource: 7,300 TCF (~200 TCM)

Map of basins with assessed shale formations, as of May 2013



Technically Recoverable Shale Gas Resources

Rank	Country	TCF	Rank	Country	TCF
1	China	1,115	7	Australia	437
2	Argentina	802	8	South Africa	390
3	Algeria	707	9	Russia	285
4	U.S.	665	10	Brazil	245
5	Canada	573		Other	1,535
6	Mexico	545		World Total	7,299

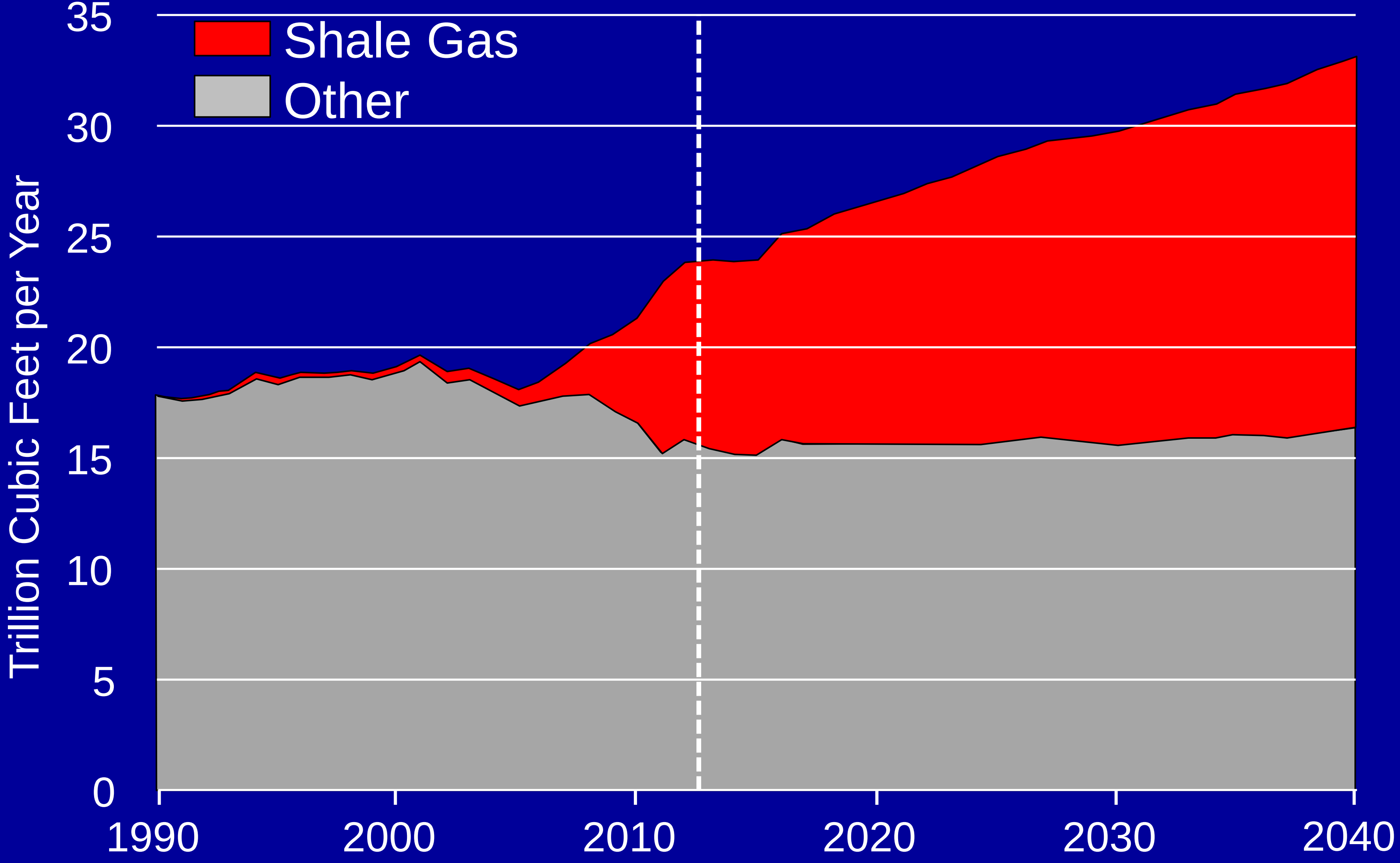
Mexico:

Proved Gas Reserves = 17 TCF, Shale TRR = 545 TCF

Proved Oil Reserves = 10.3 BBO, Shale TRR = 13.1 BBOE

Source: United States basins from U.S. Energy Information Administration and United States Geological Survey; other basins from ARI based on data from various published studies.

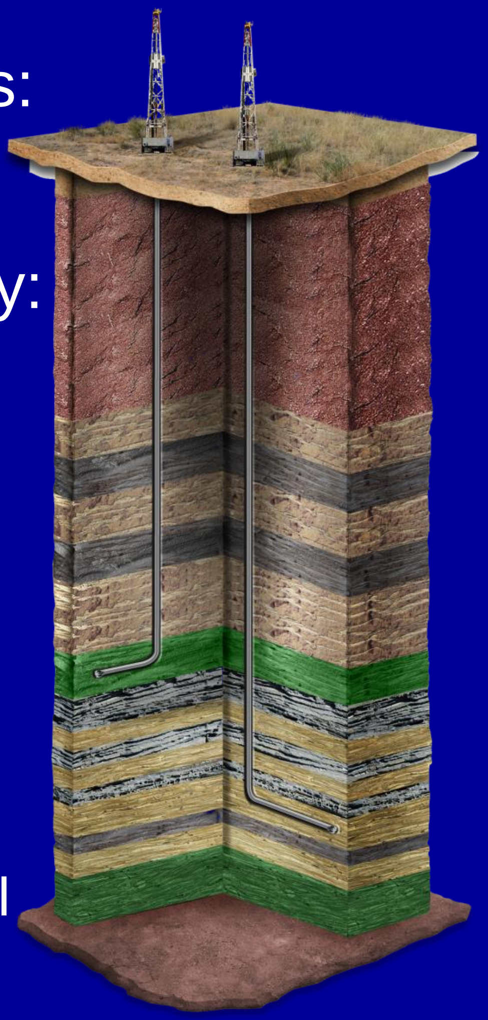
U.S. Natural Gas Production Forecast



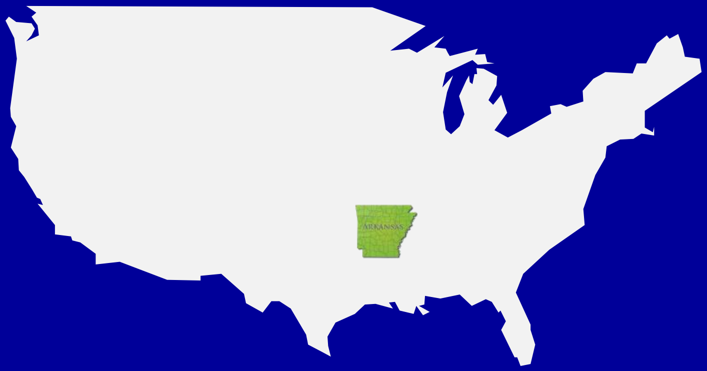
Source: EIA 2013 Early Release Overview

Characterizing Shale Plays - Challenges

- No industry standard for evaluating shale plays:
  - Most attention has been in the last 5-10 years
- Reservoir characteristics are difficult to quantify:
  - Low matrix porosity & permeability
  - Presence of fractures is critical
  - Horizontal drilling and hydraulic fracturing required
  - Effective drainage area is hard to define
  - Commercial boundary is flexible
  - Cost reduction is critical
- Measuring success:
  - Geologic information alone is a poor predictor of well performance
  - Success is judged on well production
  - **With well production comes a lot of uncertainty**

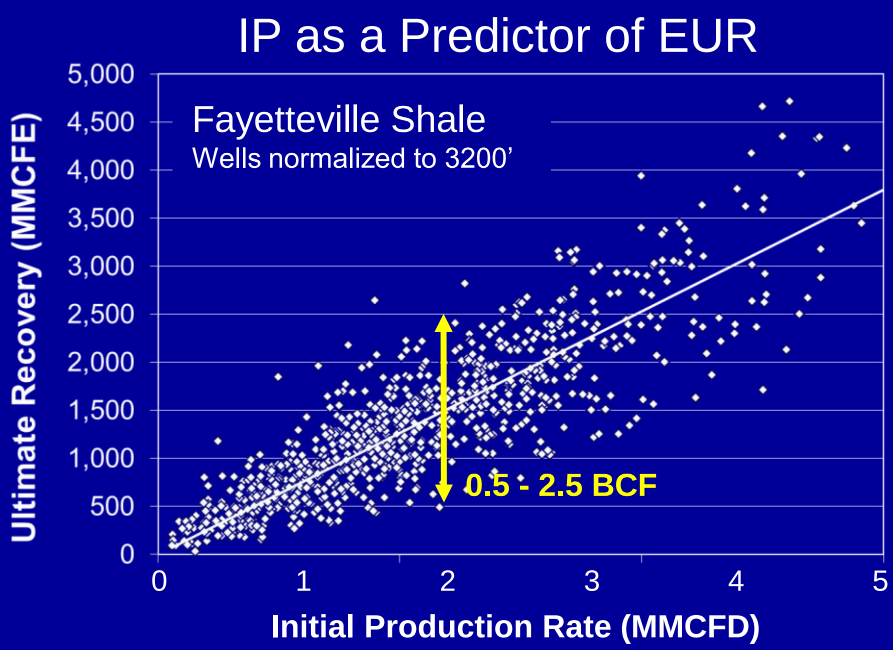


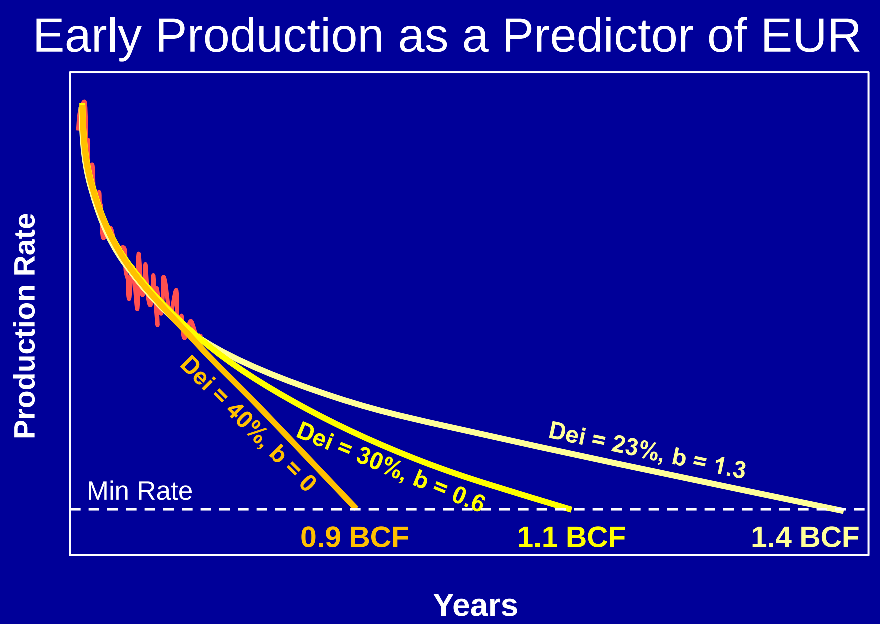
Fayetteville Shale Play



- One of the oldest shale targets, drilling began in 2004
- Mississippian-age shale at 1,500 to 6,500 foot depth
- Over 4000 wells drilled
- Examined 933 wells with extended production history
- Production forecasts 'normalized' to same completed horizontal length

Challenges to Forecasting Production



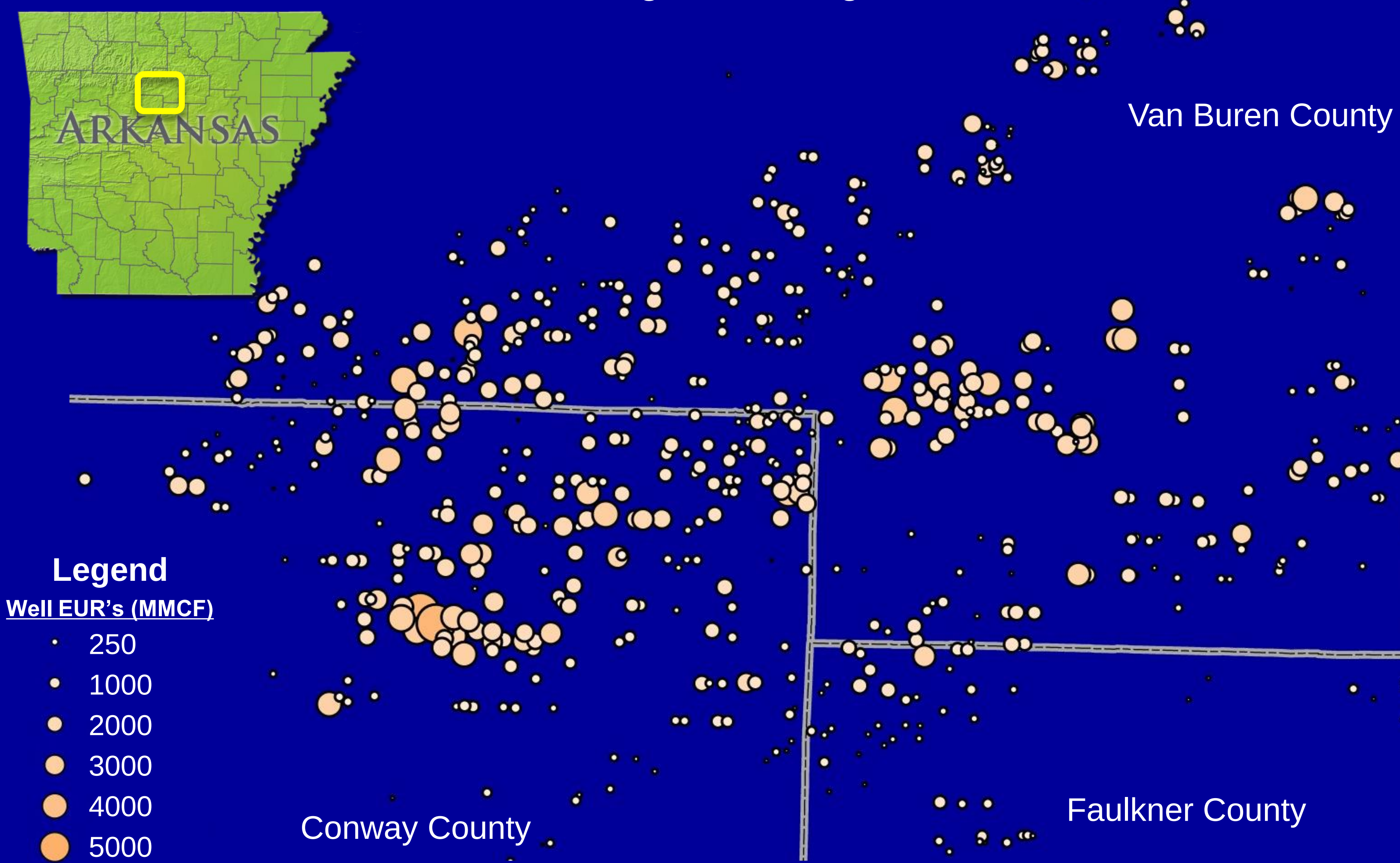


- **How long of a production period do we need from each well?**
  - **3 - 6 months after cleanup to estimate initial decline rate**
  - **12 - 36 months after cleanup to estimate hyperbolic behavior (b factor)**

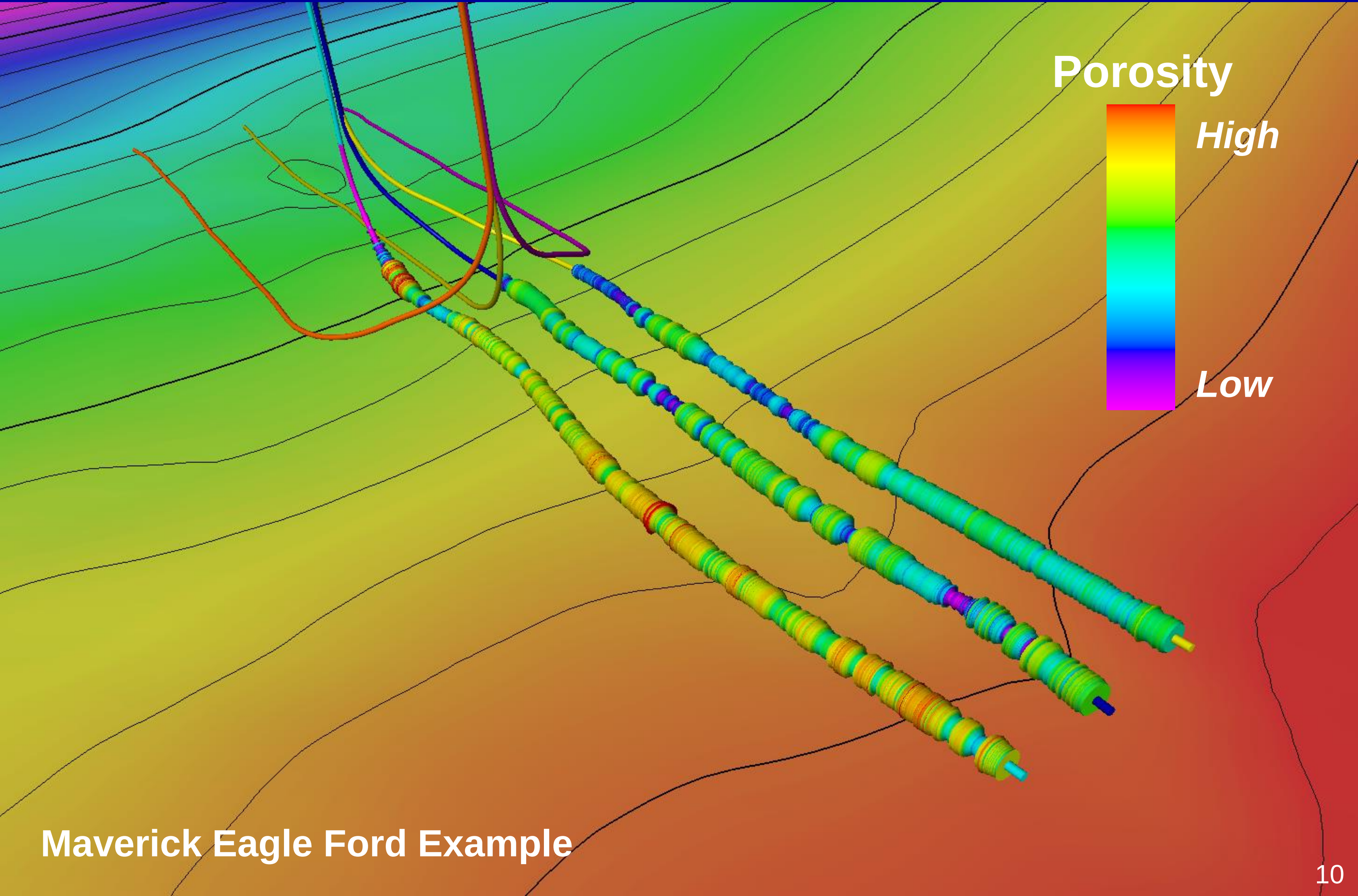
Challenges to Predicting Reservoir Performance

Fayetteville Shale Play

Well EUR's normalized to 3200' average lateral length



Challenges to Predicting Reservoir Performance

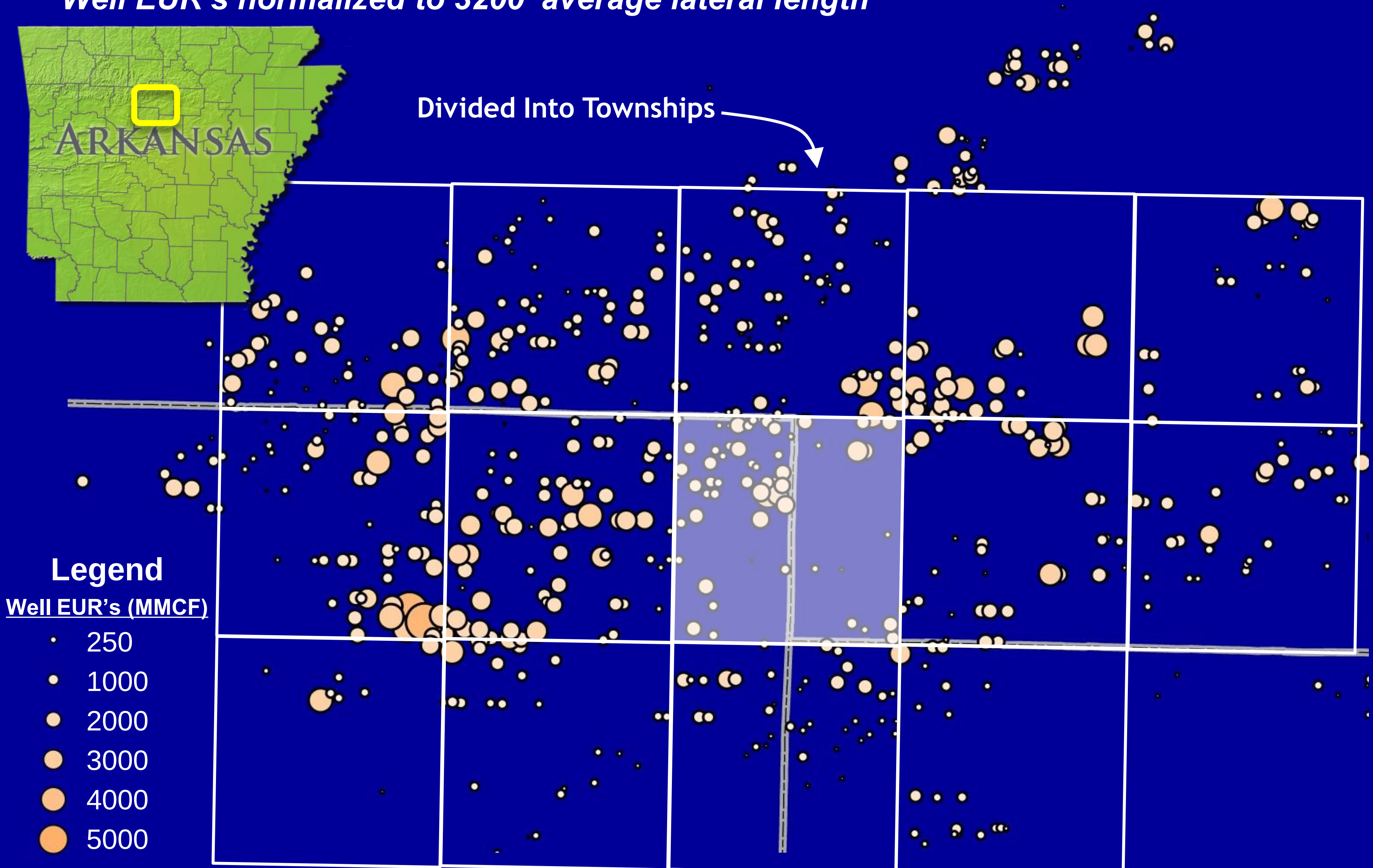


Maverick Eagle Ford Example

Challenges to Predicting Reservoir Performance

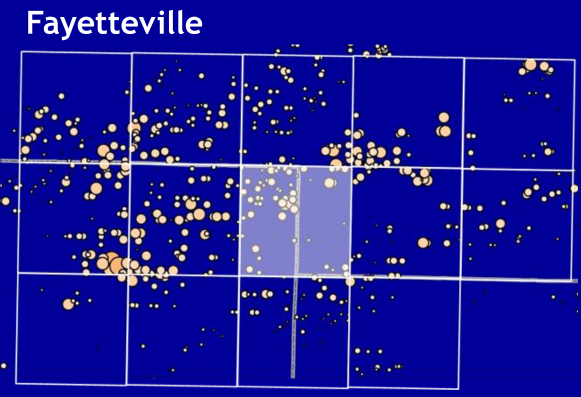
Fayetteville Shale Play

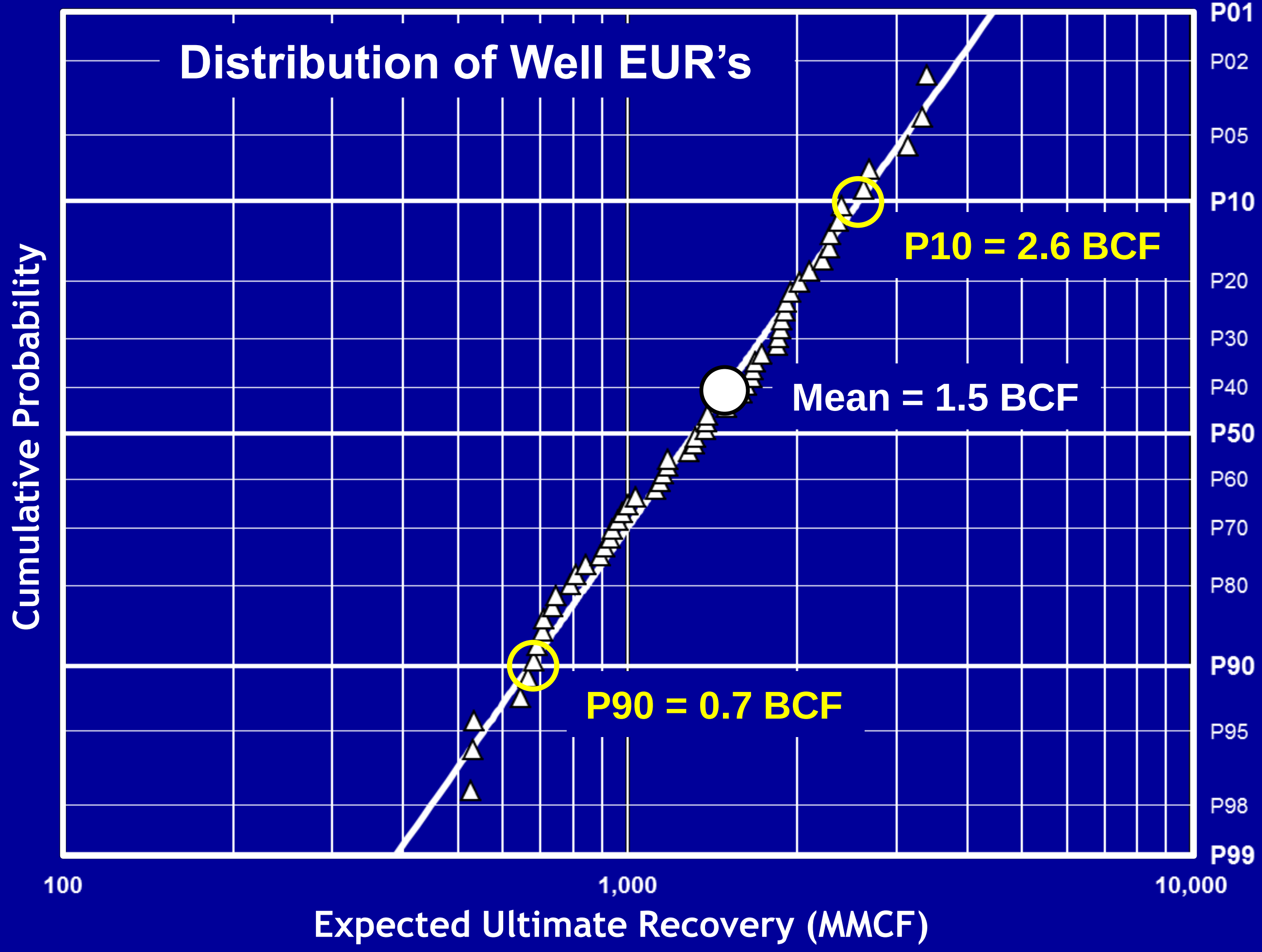
Well EUR's normalized to 3200' average lateral length



Measuring Uncertainty in Well Performance

- The uncertainty range, or variance, of the distribution is measured as P10/P90 ratio.

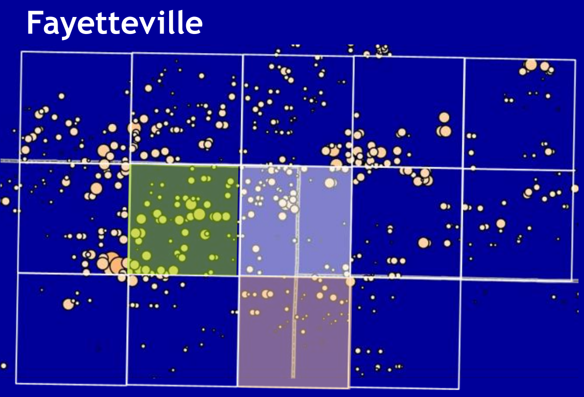


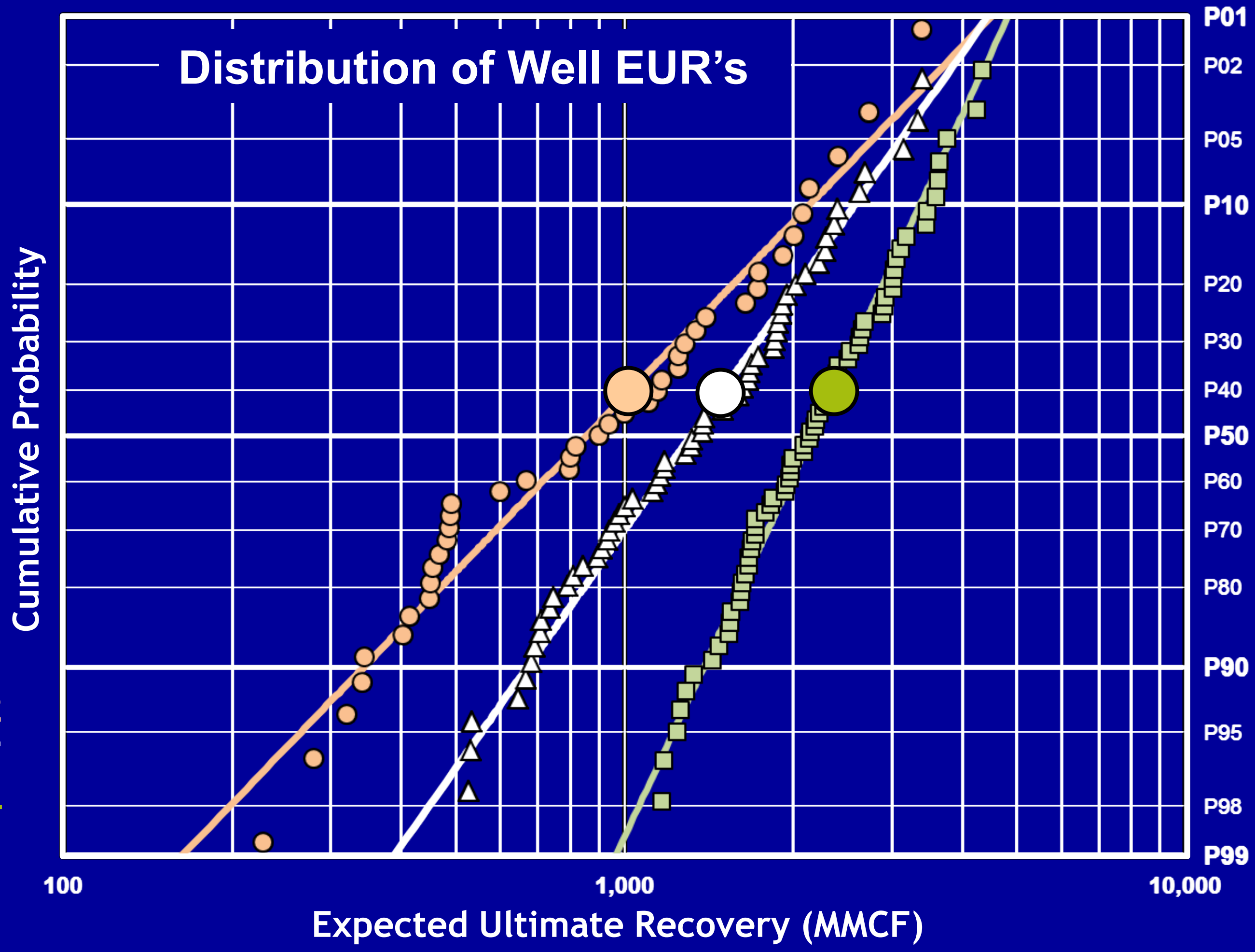


P10/P90 = 2.6 / 0.7 = 3.7

Measuring Uncertainty in Well Performance

- Average well performance by area



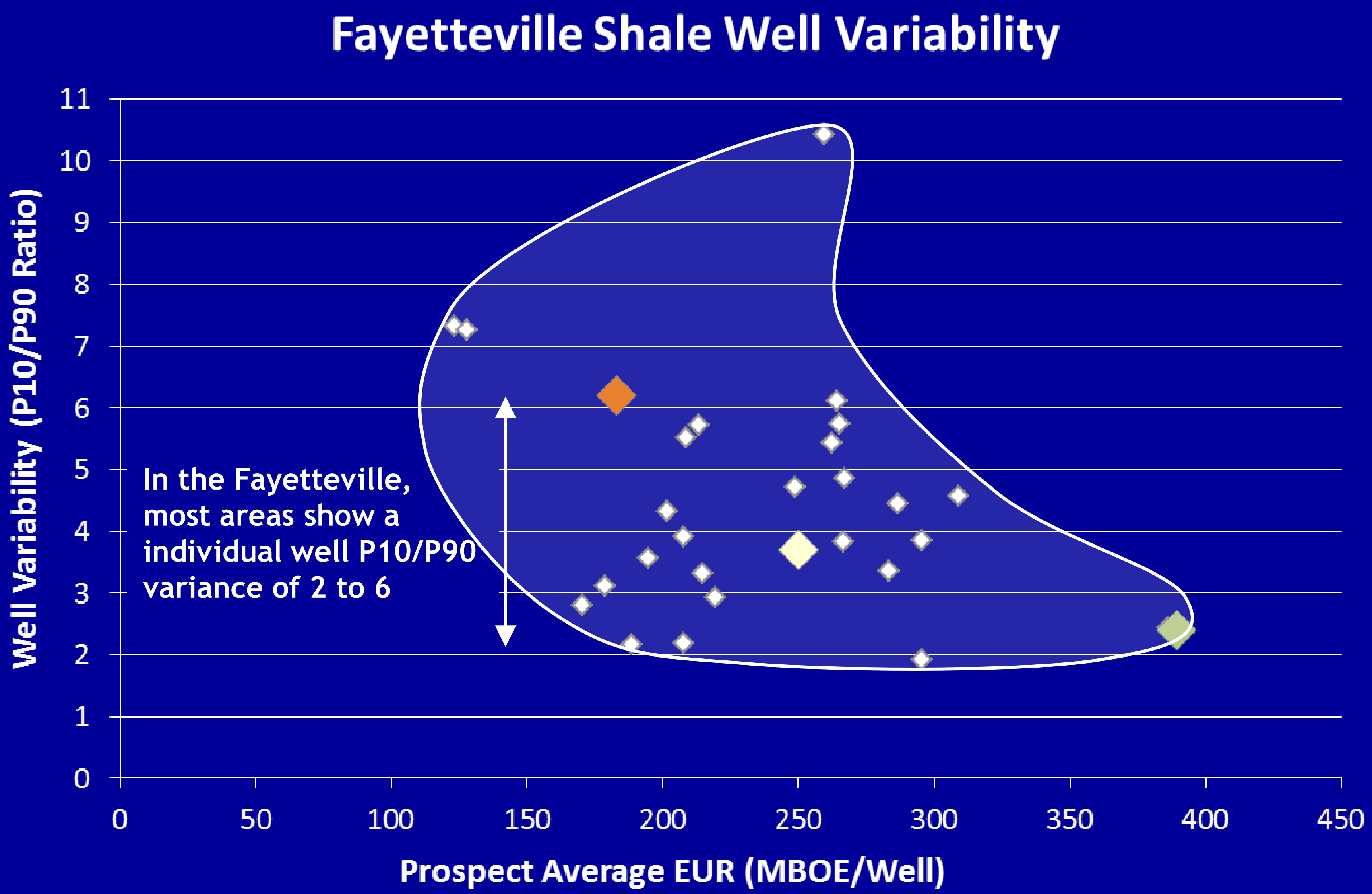


Mean = 1.1 BCF, P10/P90 = 6.2

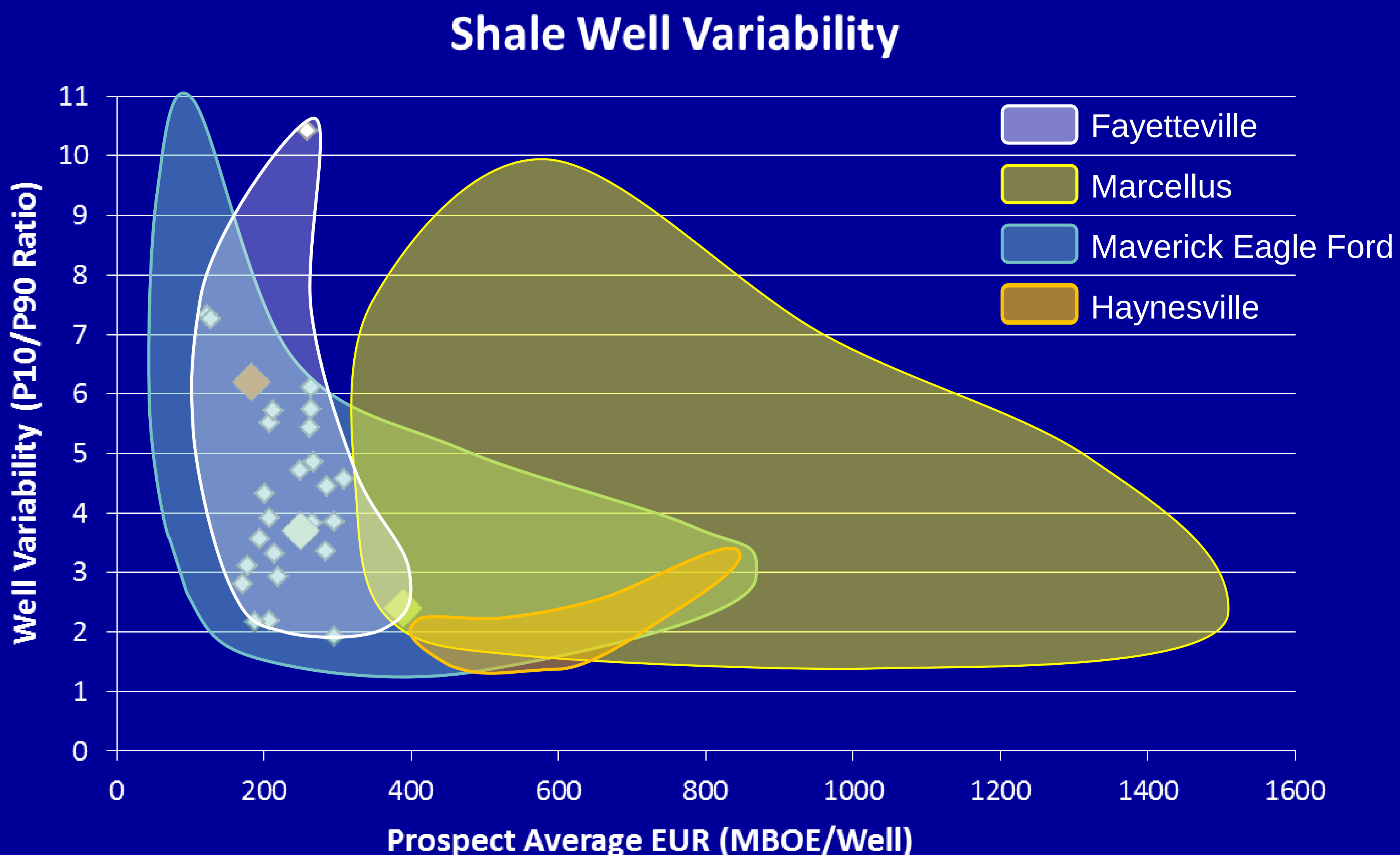
Mean = 1.5 BCF, P10/P90 = 3.7

Mean = 2.3 BCF, P10/P90 = 2.4

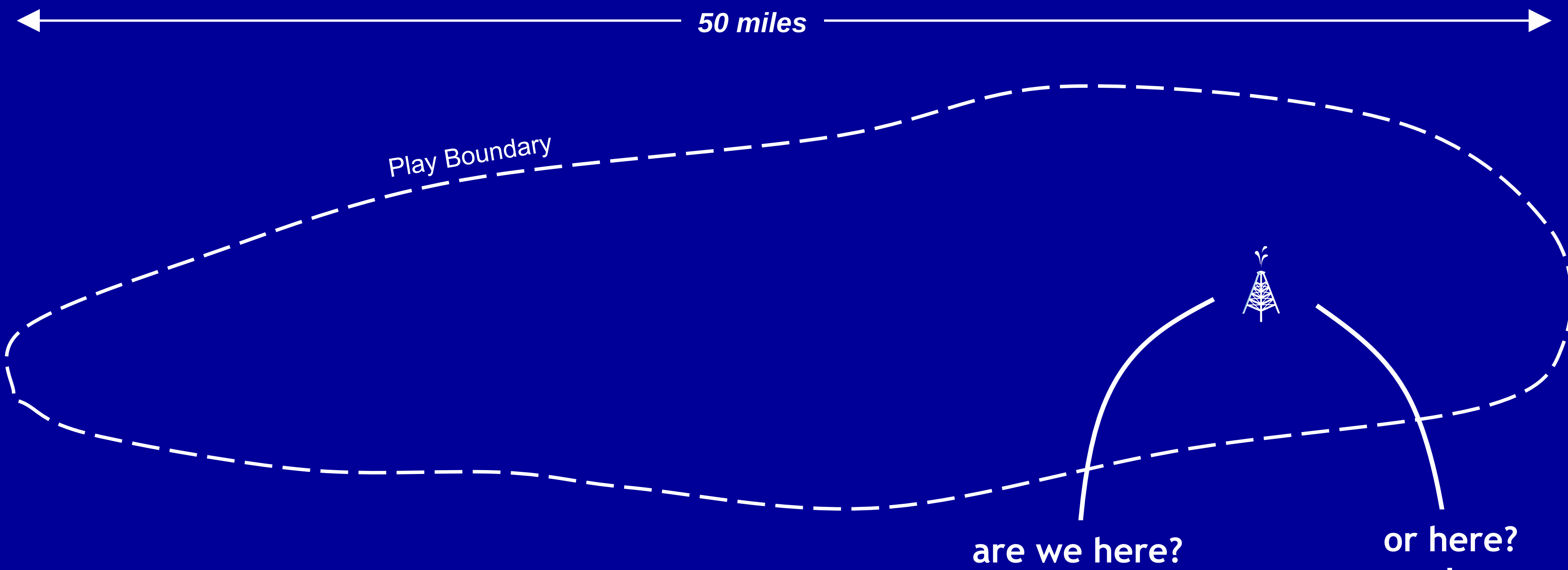
Well Performance Uncertainty in Shale Plays

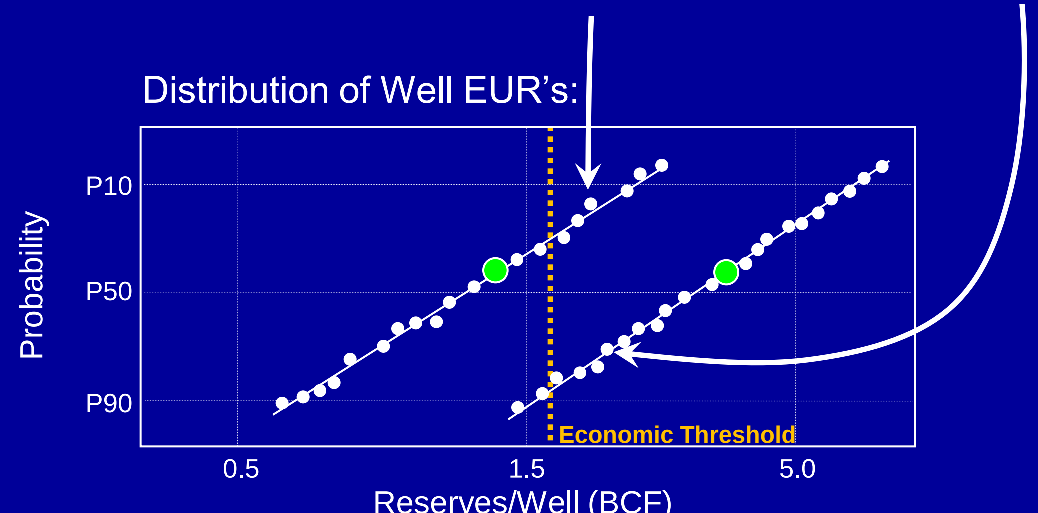


Well Performance Uncertainty in Shale Plays



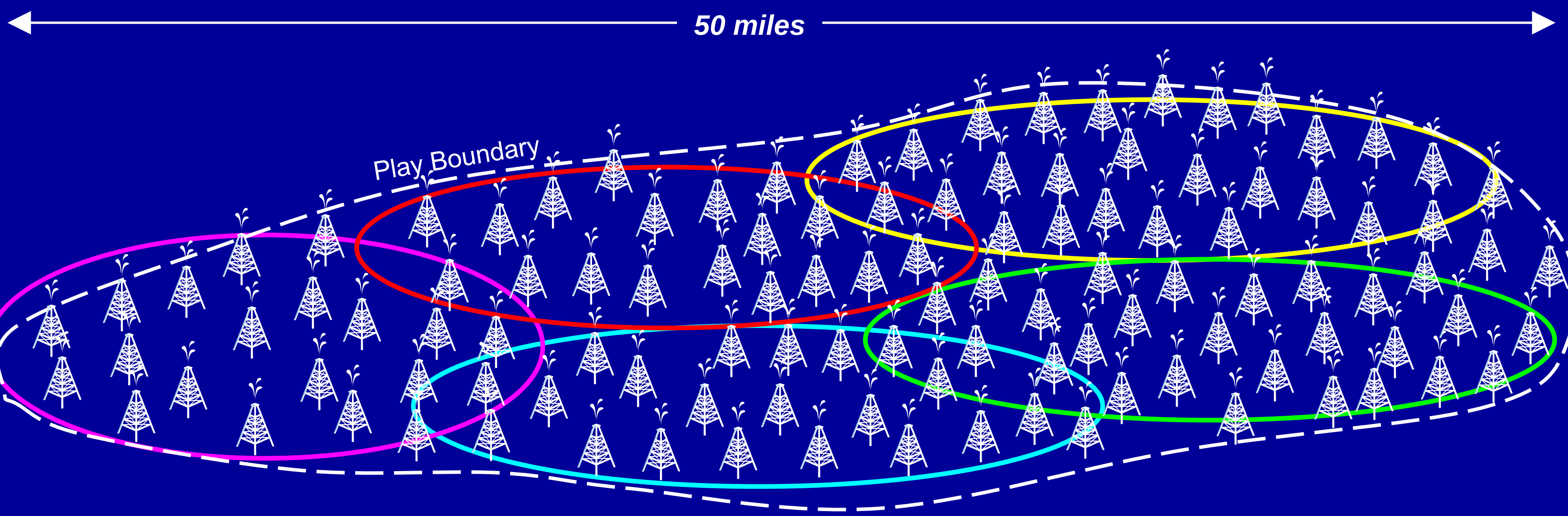
Characterizing a Shale Play

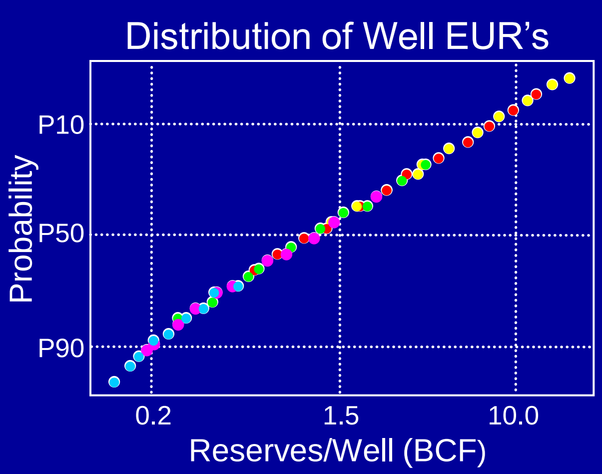


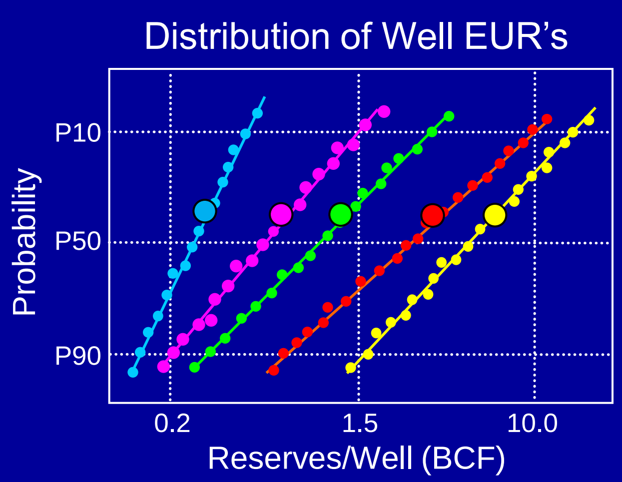


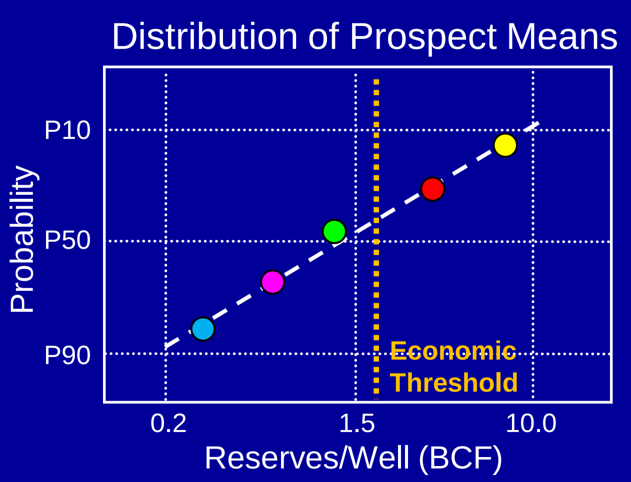
A single well won't provide the productivity information you need.

Characterizing a Shale Play







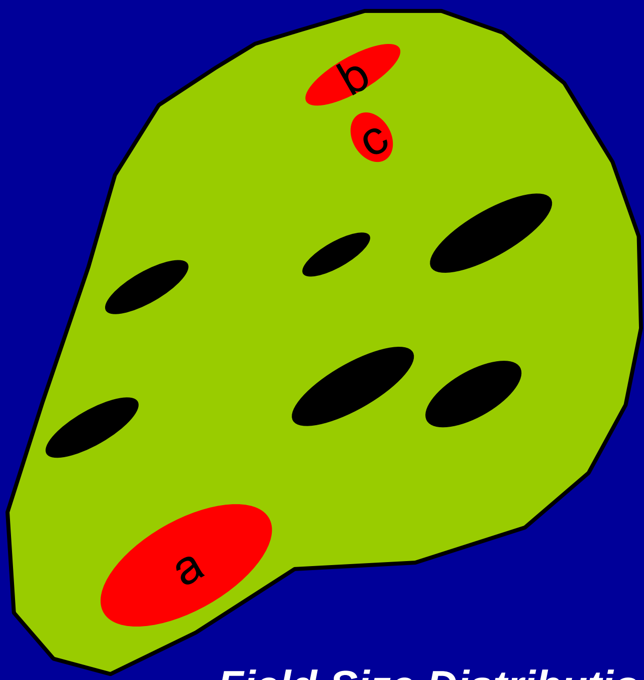


Planning an Exploration Program

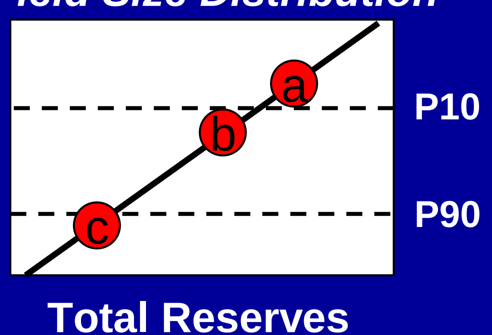
- What defines a prospect area?
- What variability should I use to predict well performance?
- How many wells should I drill in each prospect area?
- What defines the "encouragement" needed to continue drilling?

What Defines a Prospect Area?

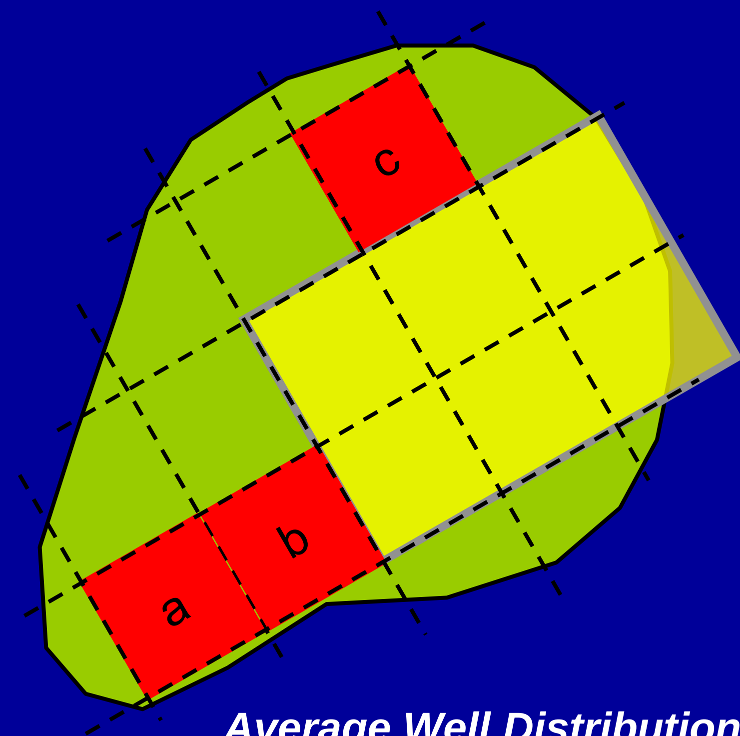
Conventional



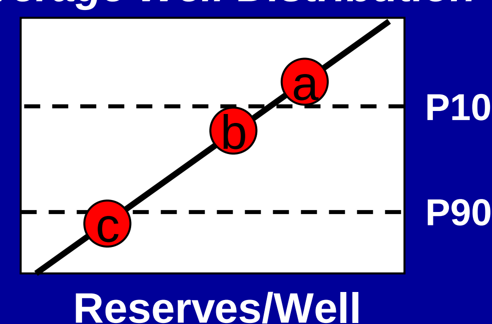
Field Size Distribution



Unconventional



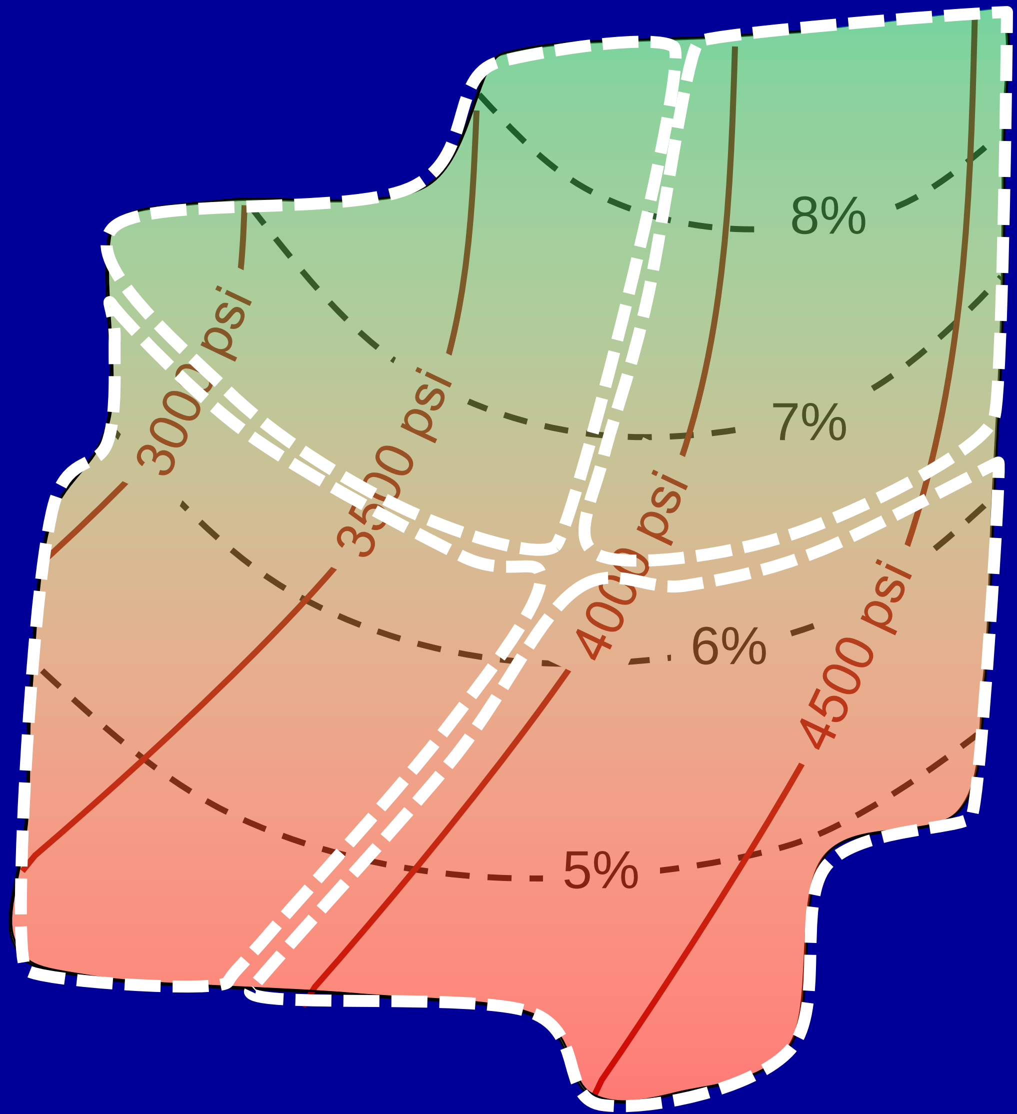
Average Well Distribution



What Defines a Prospect Area?

Productivity Drivers:

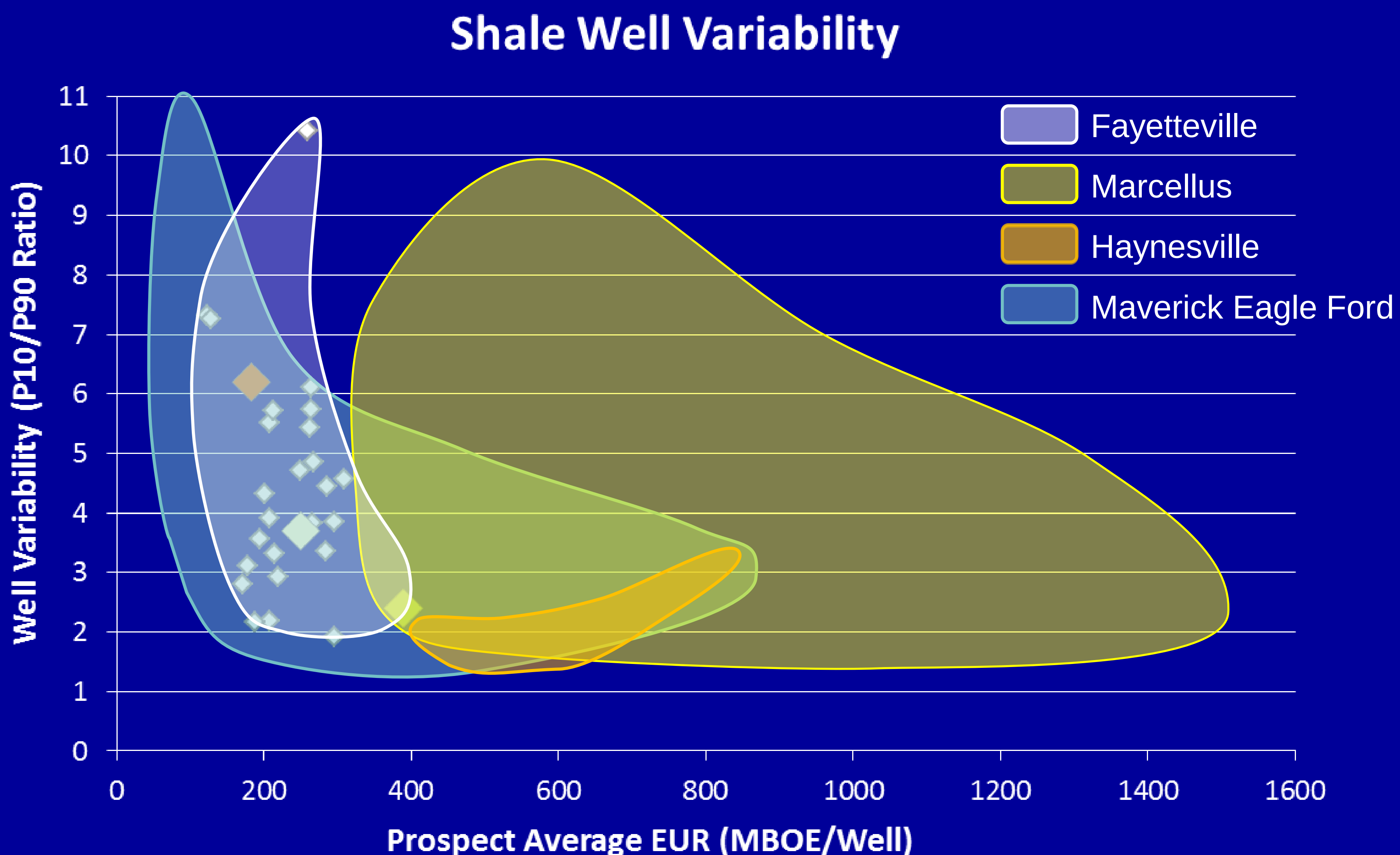
- Reservoir Quality
  - Porosity
  - Matrix Permeability
  - Water Saturation
  - Natural Fractures
- Pressure
- Fluid Type
  - Maturity



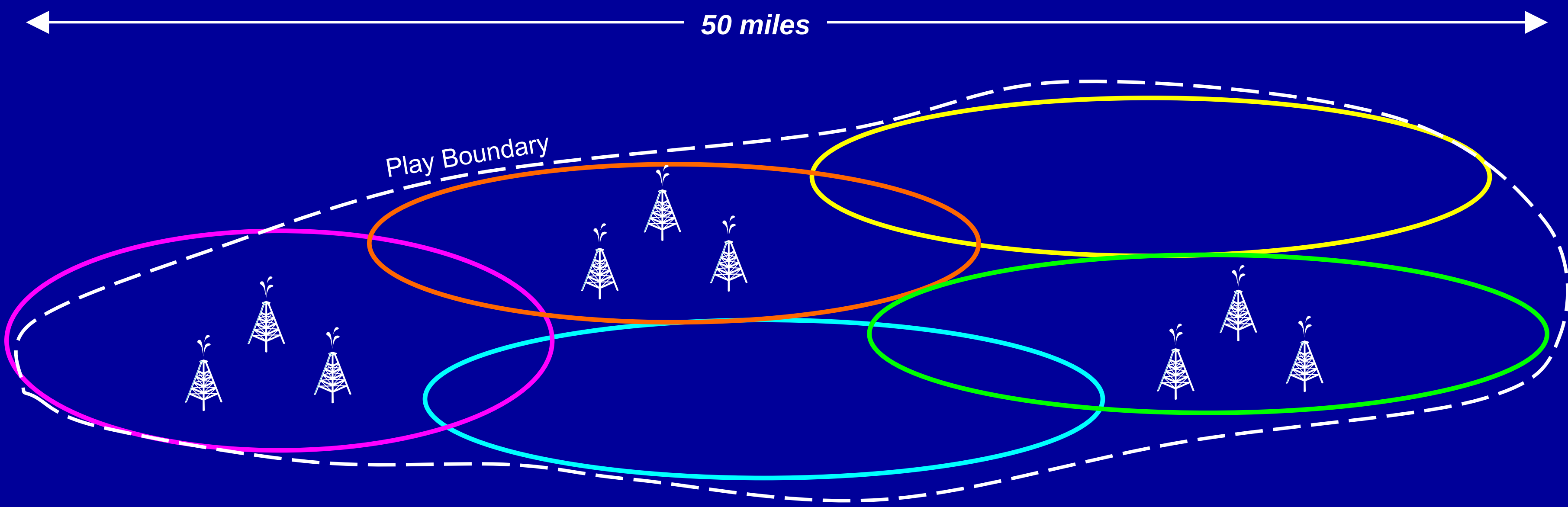
Planning an Exploration Program

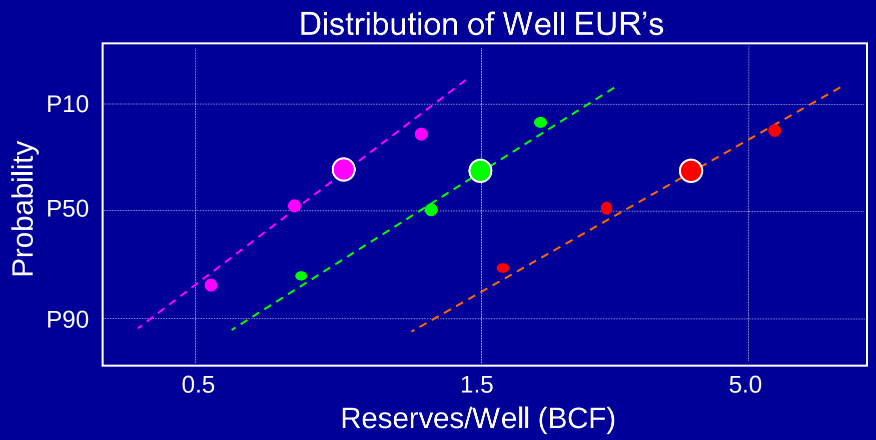
- What defines a prospect area?
- What variability should I use to predict well performance?
- How many wells should I drill in each prospect area?
- What defines the "encouragement" needed to continue drilling?

Analog Well Performance Uncertainty



Testing a Shale Play





Planning an Exploration Program

- **What defines a prospect area?**
- **What variability should I use to predict well performance?**
- **How many wells should I drill in each prospect area?**
- **What defines the “encouragement” needed to continue drilling?**

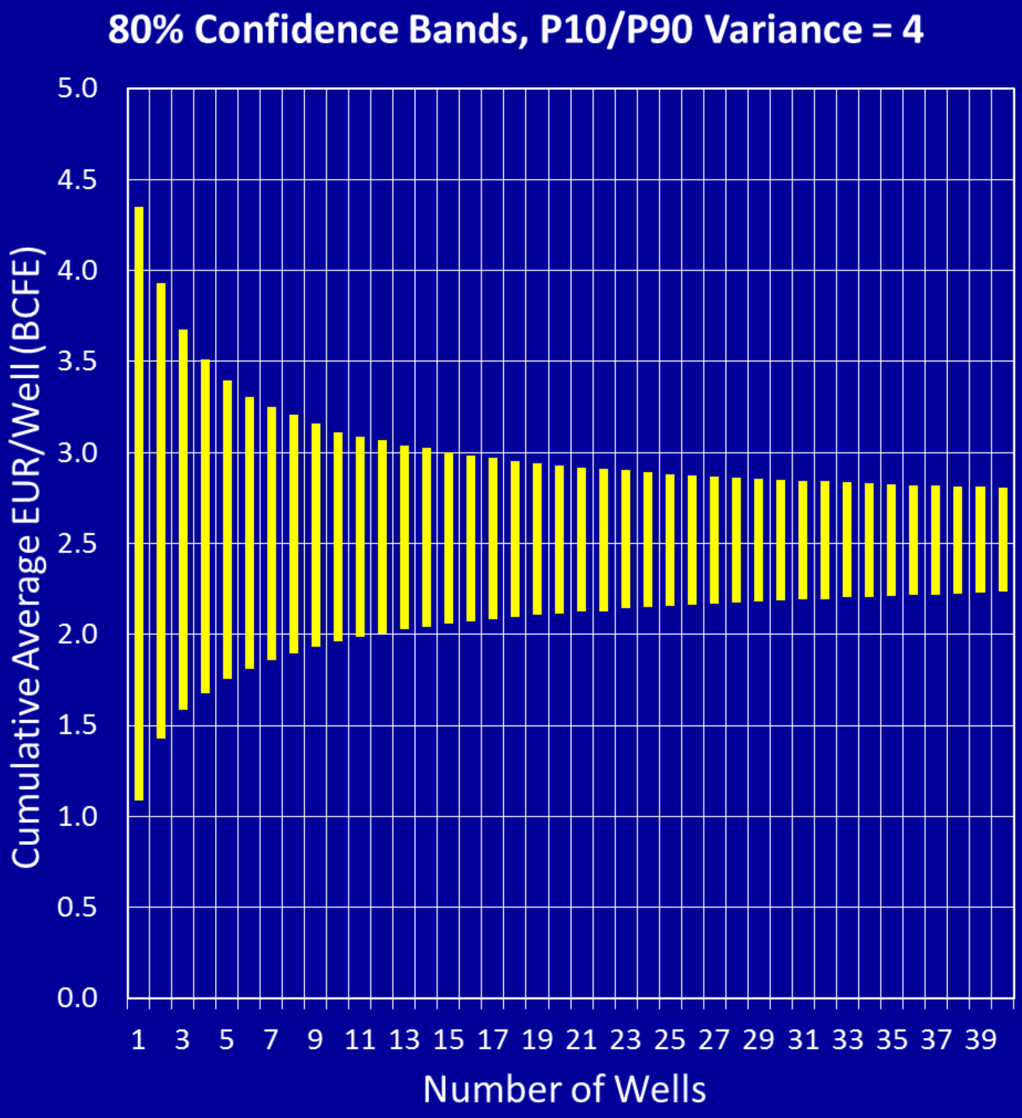
Confidence Range Versus Well Count

- The more wells you drill, the more confidence you'll have that the wells will represent the average reservoir performance.

Predicting EUR's:

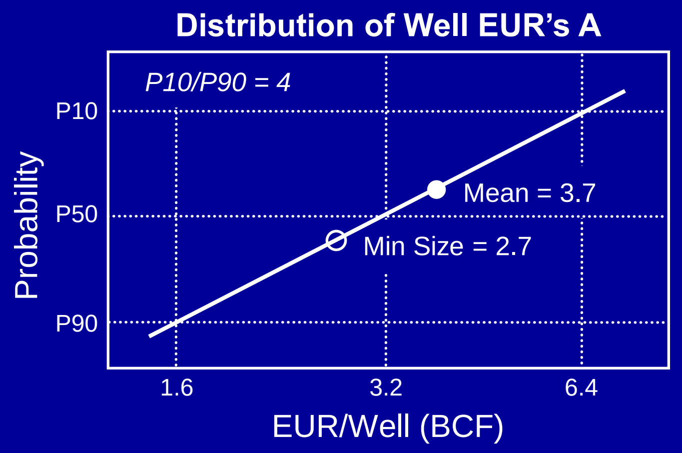
- Modeled wells from prospect:
  - Average EUR/well = 2.5 BCF
  - P10/P90 = 4
  - Sampled the distribution 10,000 times

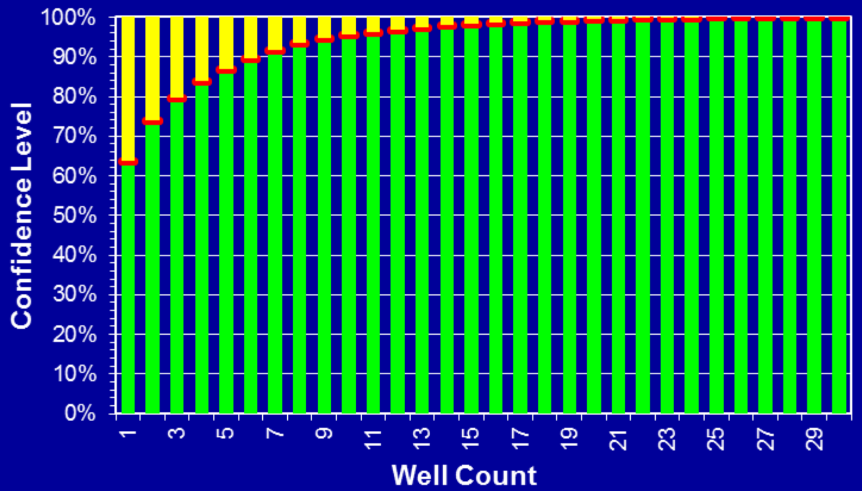
- For P10/P90 = 4:
  - ➢ 1 Well = 1.1 - 4.3 BCF/well
  - ➢ 3 Wells = 1.6 – 3.7 BCF/well
  - ➢ 10 Wells = 2.0 – 3.1 BCF/well

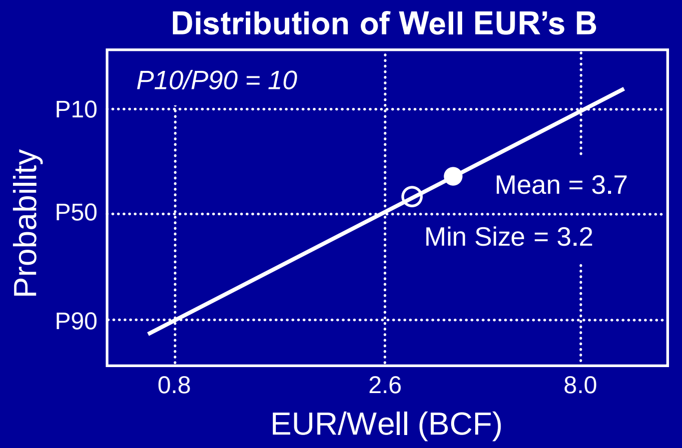


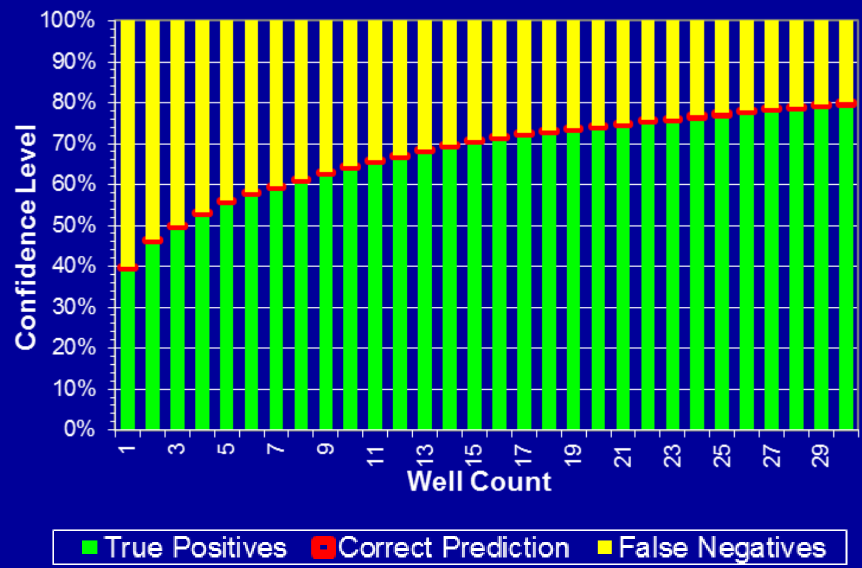
Designing An Exploration Pilot

- The number of wells needed depends primarily on:
  - Uncertainty range of the reserves distribution
  - Proximity of the minimum commercial size to the mean of the distribution









Planning an Exploration Program

- What defines a prospect area?
- What variability should I use to predict well performance?
- How many wells should I drill in each prospect area?
- What defines the "encouragement" needed to continue drilling?

What Defines Encouragement?

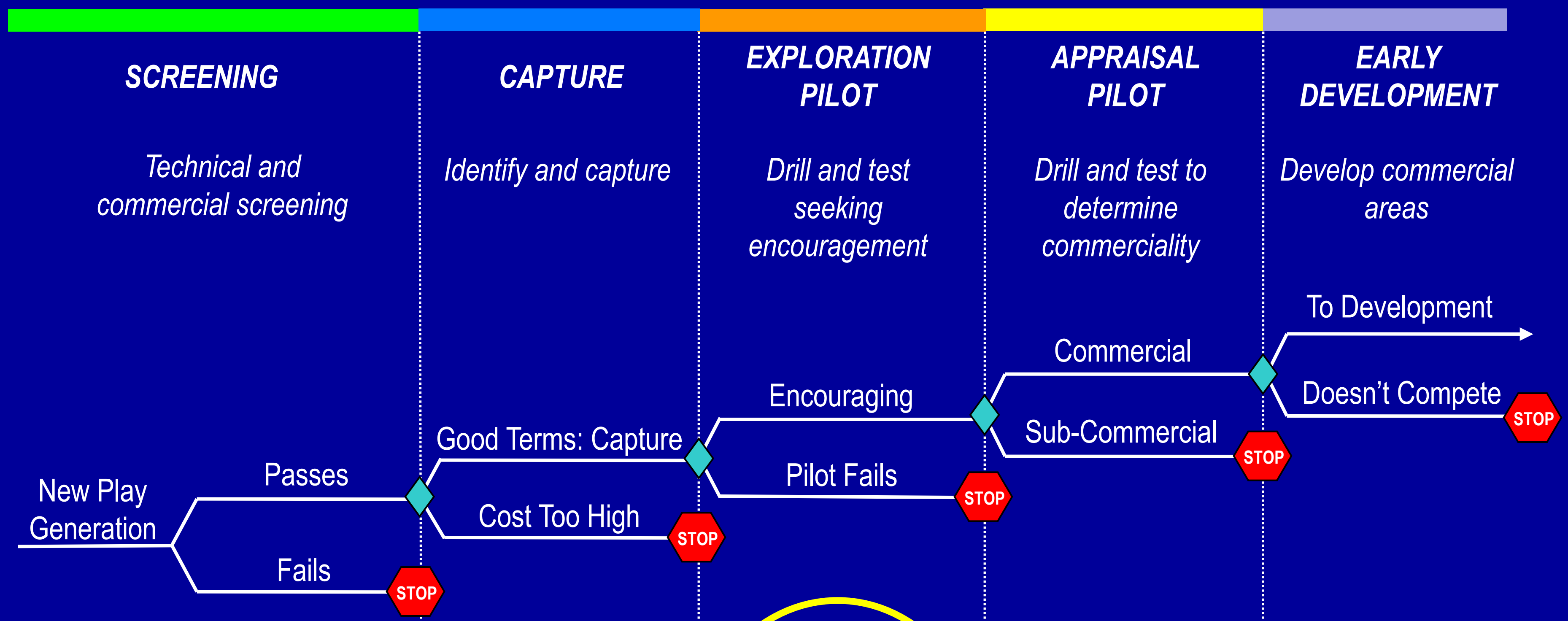
En·cour·age·ment [en-**kur**-ij-m*uh*nt]

noun

1. Available data indicates that the play has the **potential** to be economically viable.
2. A threshold that recognizes the uncertainty in the data.
3. Results that motivate you to keep drilling.

- The less data you have, the lower your threshold should be.
- Example thresholds
  - During the exploration phase: < Breakeven
  - During the appraisal phase: Breakeven
  - During the development phase: Competitive with other opportunities

Modeling Decision Behavior



Play Description:

- 500,000 acres (~2000 km^2)
- 10 Prospect Areas
- EUR potential 1 to 6 BCF/well
- Individual Well P10/P90 = 4
- Breakeven EUR = 2.3 BCF/well
- Competitive EUR = 2.8 BCF/well

	Exploration Pilot	Appraisal Pilot	Early Development
Drilling Program:	• **Drill 3 wells in 3 prospects (9 wells)**	• **Drill 5 more wells in each "good" prospect** • **Test additional prospects.**	• **Drill 12 more wells in each "good" prospect.** • **Test additional prospects.**
Economic Hurdle:	**50% of Breakeven**	**Breakeven**	**Competitive**

The Impact of Decision Behavior

Anticipated Behavior

Base Case

- Drill 3 Wells in 3 Prospects
- Threshold: ½ NPV10 = 0

Stricter Behavior

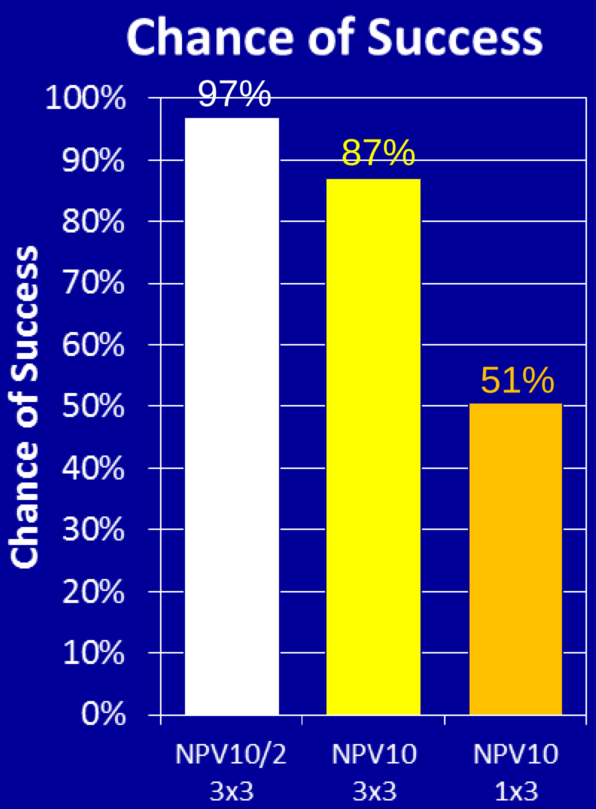
Raise threshold

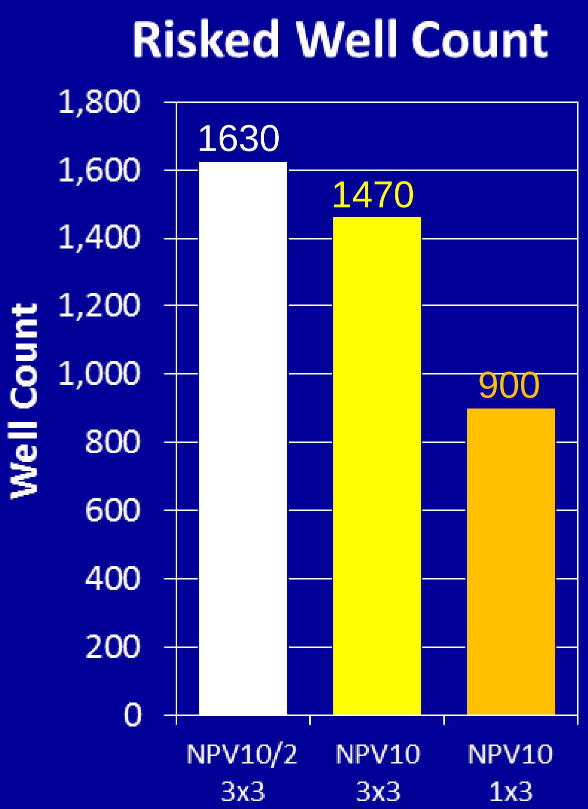
- Drill 3 wells in 3 Prospects
- Threshold: NPV10 = 0

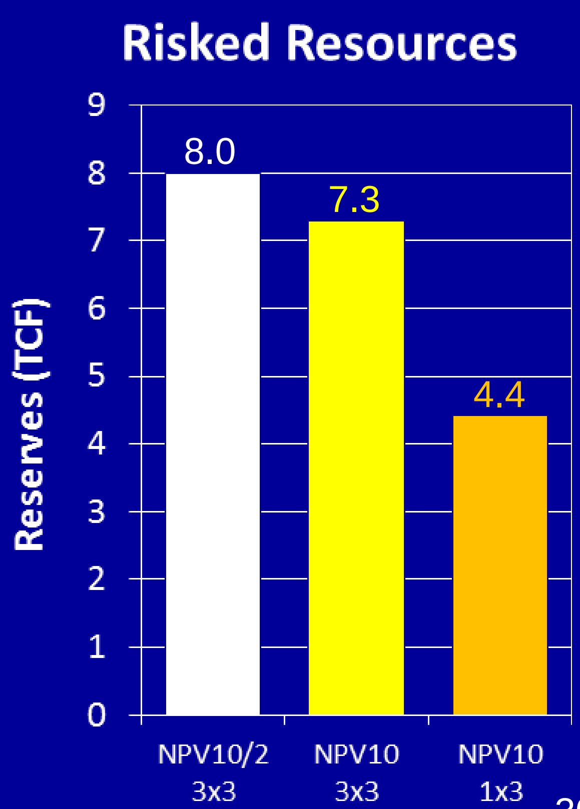
Harsh Behavior

Cut well count

- Drill 3 wells in 1 Prospect
- Threshold: NPV10 = 0







Conclusions

- Shale play potential is measured through long term production performance. This takes time. Using early production estimates requires that forecast uncertainty be quantified.
- Wells in the same area, drilled and completed the same way, can and do perform quite differently from one another.
- Natural variance in well performance can easily fool you into making bad decisions. You can only overcome this if you drill enough wells to achieve statistical significance.
- Decision behavior can have a substantial effect on the chance of success. It's important to model how you'll actually behave.
- There are many challenges associated with evaluating shale reservoirs. Perseverance, and an understanding of the uncertainties associated with these plays is needed in order to successfully explore for them.

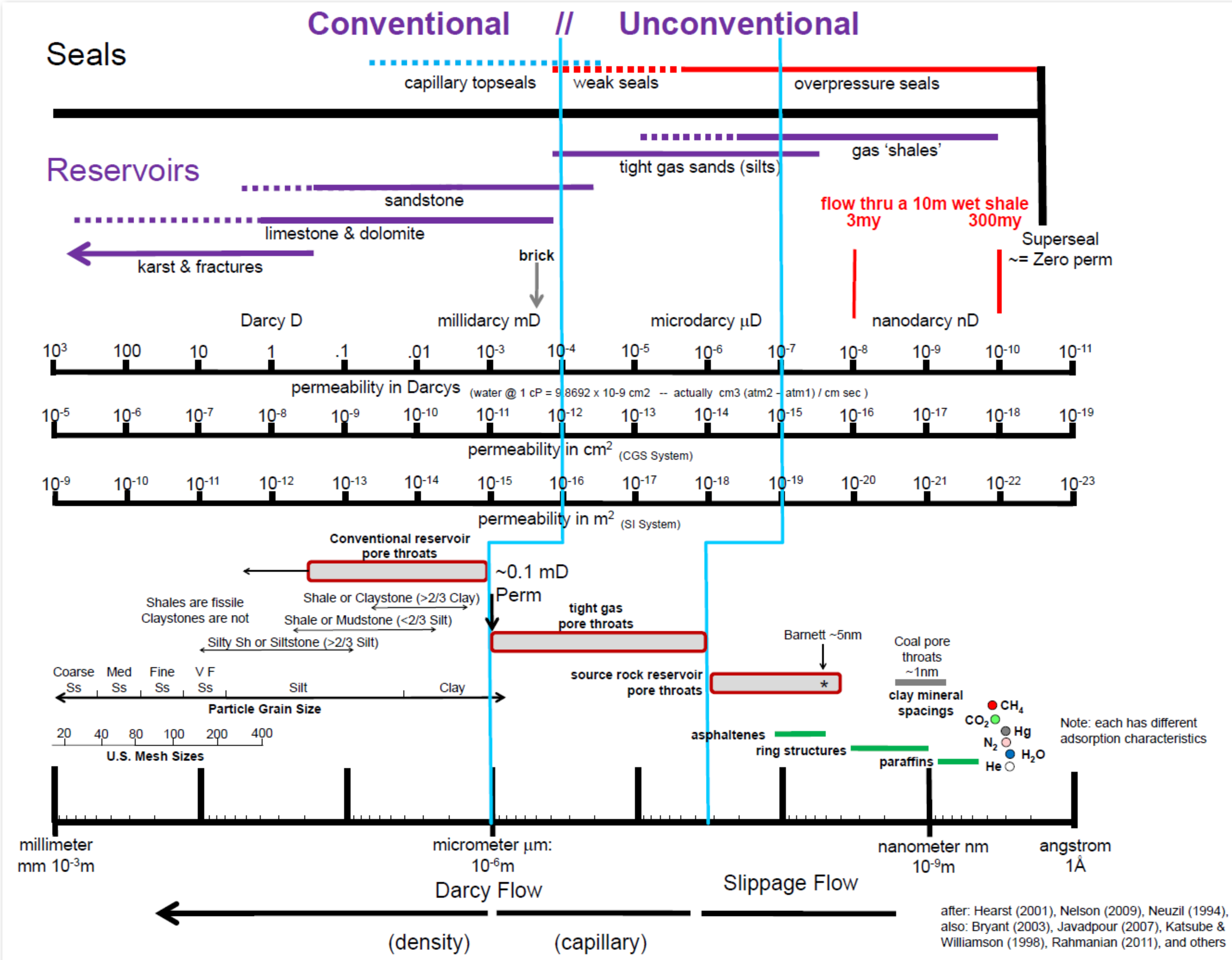
Distinguished Lecturer Program

Your Feedback is Important

Enter your section in the DL Evaluation Contest by completing the evaluation form for this presentation

http://www.spe.org/dl/

Thank You



Conventional // Unconventional
Seals
capillary topseals
weak seals
overpressure seals
Reservoirs
gas 'shales'
tight gas sands (silts)
sandstone
limestone & dolomite
karst & fractures
brick
flow thru a 10m wet shale
3my
300my
Superseal
~= Zero perm
Darcy D
millidarcy mD
microdarcy µD
nanodarcy nD
10^3 100 10 1 .1 .01 10^{-3} 10^{-4} 10^{-5} 10^{-6} 10^{-7} 10^{-8} 10^{-9} 10^{-10} 10^{-11}
permeability in Darcys (water @ 1 cP = 9.8692 x 10-9 cm2 -- actually cm3 (atm2 - atm1) / cm sec)
10^{-5} 10^{-6} 10^{-7} 10^{-8} 10^{-9} 10^{-10} 10^{-11} 10^{-12} 10^{-13} 10^{-14} 10^{-15} 10^{-16} 10^{-17} 10^{-18} 10^{-19}
permeability in cm^2 (CGS System)
10^{-9} 10^{-10} 10^{-11} 10^{-12} 10^{-13} 10^{-14} 10^{-15} 10^{-16} 10^{-17} 10^{-18} 10^{-19} 10^{-20} 10^{-21} 10^{-22} 10^{-23}
permeability in m^2 (SI System)
Conventional reservoir pore throats
~0.1 mD Perm
Shales are fissile
Claystones are not
Shale or Claystone (>2/3 Clay)
Shale or Mudstone (<2/3 Silt)
Silty Sh or Siltstone (>2/3 Silt)
tight gas pore throats
Barnett ~5nm
Coal pore throats ~1nm
source rock reservoir pore throats
clay mineral spacings
Coarse Ss
Med Ss
Fine Ss
V F Ss
Silt
Clay
Particle Grain Size
20 40 80 100 200 400
U.S. Mesh Sizes
asphaltenes
ring structures
paraffins
CH_4
CO_2
Hg
N_2
H_2O
He
Note: each has different adsorption characteristics
millimeter mm 10^{-3}m
micrometer µm: 10^{-6}m
nanometer nm 10^{-9}m
angstrom 1Å
Darcy Flow
Slippage Flow
(density)
(capillary)
after: Hearst (2001), Nelson (2009), Neuzil (1994), also: Bryant (2003), Javadpour (2007), Katsube & Williamson (1998), Rahmanian (2011), and others

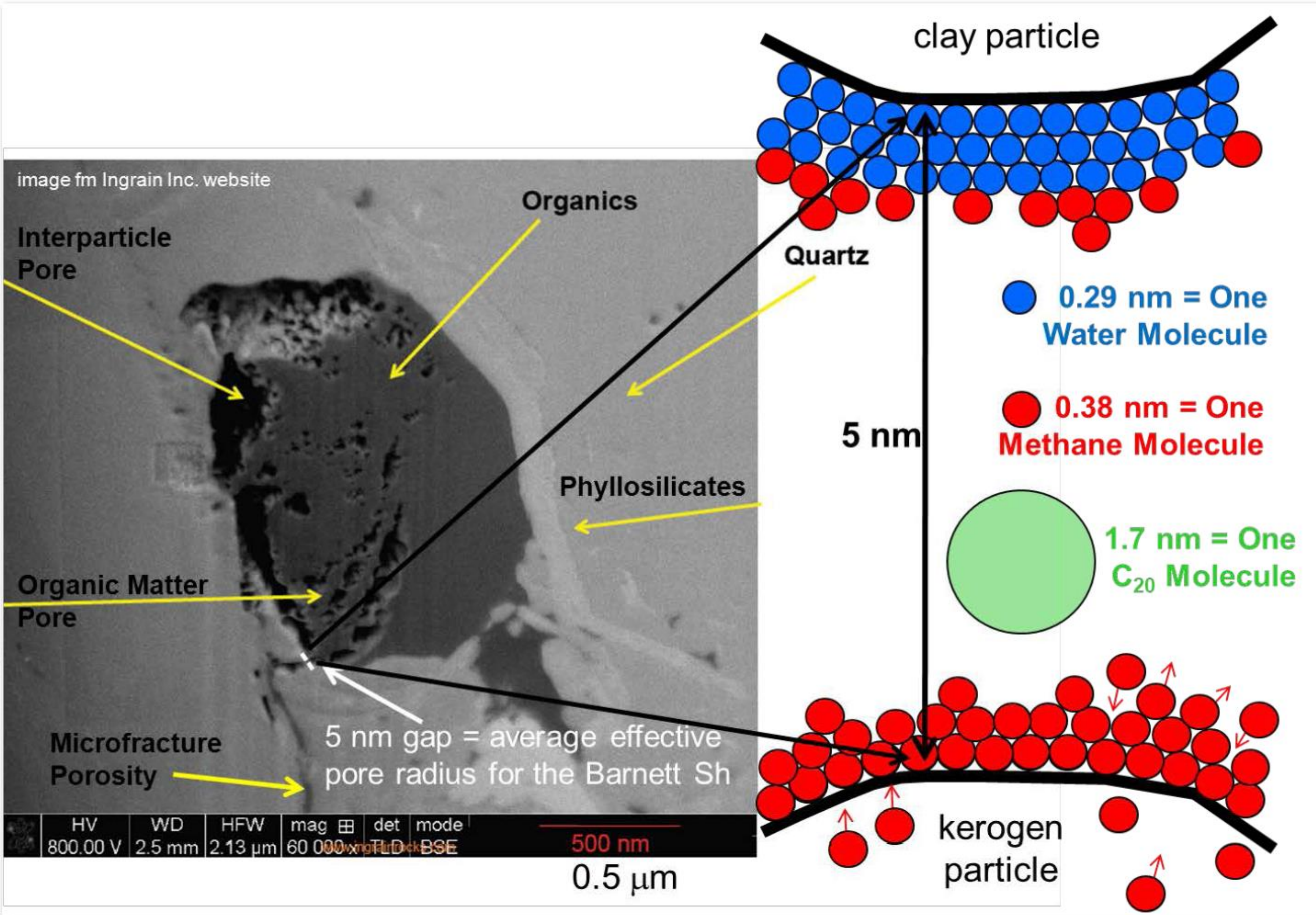


image fm Ingrain Inc. website
Interparticle Pore
Organics
Quartz
Phyllosilicates
Organic Matter Pore
Microfracture Porosity
5 nm gap = average effective pore radius for the Barnett Sh
HV 800.00 V
WD 2.5 mm
HFW 2.13 µm
mag 60 000 x
det TLD
mode BSE
500 nm
0.5 µm
clay particle
5 nm
0.29 nm = One Water Molecule
0.38 nm = One Methane Molecule
1.7 nm = One C_{20} Molecule
kerogen particle

Abstract
Permeability of rocks in the subsurface varies over many orders of magnitude from too high to be a useful concept to too low to be measurable. The division between conventional petroleum systems and continuous accumulations is approximately 0.1 millidarcy. At that point, relative permeability and capillary pressures create the trapping seal. Weak barostratigraphic seals become common in the microdarcy range. Good overpressure seals are modeled to be in the 10 to 100 nanodarcy range. The flow of water is slow enough at these permeabilities so that the interstitial water bears a portion of the overburden load and is overpressured (undercompaction disequilibrium).

Source rock reservoirs (SRR) are present in 'shales' with permeabilities that are also in the 10 to 100 nanodarcy range and are capable of producing gas at commercial flow rates. This apparent paradox is addressed by examination of the geologic history of the SRR. Generation, maturation (including the cracking of oil to gas) and the expulsion of hydrocarbons creates high internal overpressures sufficient to fracture the host rock, so that the hydrocarbons can be expelled through a microfracture network. The generation of hydrocarbons also creates pore space within the kerogen grains themselves. After expulsion ceases, cementation and diagenesis occludes the larger fractures and primary migration routes in the SRR, and isolates the kerogen and microfracture system. Hydraulic fracturing reopens the natural fractures and connects to the oil-wet, gas filled porosity in the SRR kerogens. The remaining unexpelled free and adsorbed gas is then available to be produced.

Due to the expulsion of hydrocarbons and associated water, SRRs may not be water-wet, but may be hydrophobic. Furthermore, the laminated nature of many source rock shales and the presence of oil and gas in the pore space creates a relative permeability reduction to the flow of water and also facilitates the formation of capillary seals. SRRs may be an effective pressure seal. The separate gas filled microporosity system is isolated within the matrix of the SRR and can be accessed through artificial fracturing. The conventional interstitial and interparticle porosity is water-wet and may be gas-filled, and produces by Darcy flow. The kerogen and microporosity system is oil-wet and gas filled with an adsorbed gas component. It produces by diffusion flow. The combination of the two systems is what is seen at the wellbore

Pore-Scale: *Nelson Pore/Molecule Size Chart*

Question(s):

- How small are pores in shale gas? ***Note that the size of the pores is on the order of 5-10 times the size of the fluid molecule.***

AAPG Bulletin, v. 93, no. 3 (March 2009)

Pore-throat Sizes In Sandstones, Tight Sandstones, and Shales

P.H. Nelson, USGS

← **Each green line is x10 *SMALLER* scale.**

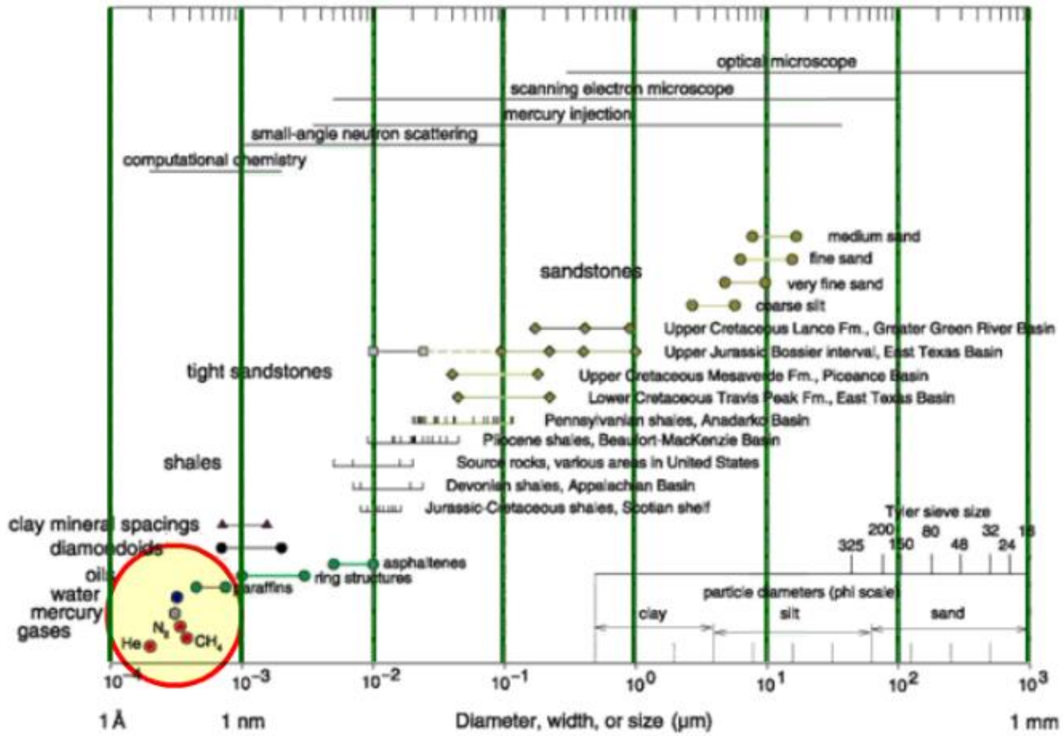


Figure 2. Sizes of molecules and pore throats in siliciclastic rocks on a logarithmic scale covering seven orders of magnitude. Measurement methods are shown at the top of the graph, and scales used for solid particles are shown at the lower right. The symbols show pore-throat sizes for four sandstones, four tight sandstones, and five shales. Ranges of clay mineral spacings, diamondoids, and three oils, and molecular diameters of water, mercury, and three gases are also shown. The sources of data and measurement methods for each sample set are discussed in the text.

Perspective:

- ***The concept of pores and pore throats begins to break down at these scales.***
- ***The flow path can be as small as 10-20 molecular diameters (or less).***

Issues:

- ***How do the fluids move?***
  - — ***Darcy flow?***
  - — ***Dispersion (gases)?***
  - — ***Knudsen flow?***
- ***How are the fluids stored?***
  - — ***In the organic matter?***
  - — ***Adsorbed?***
  - — ***Another mechanism?***

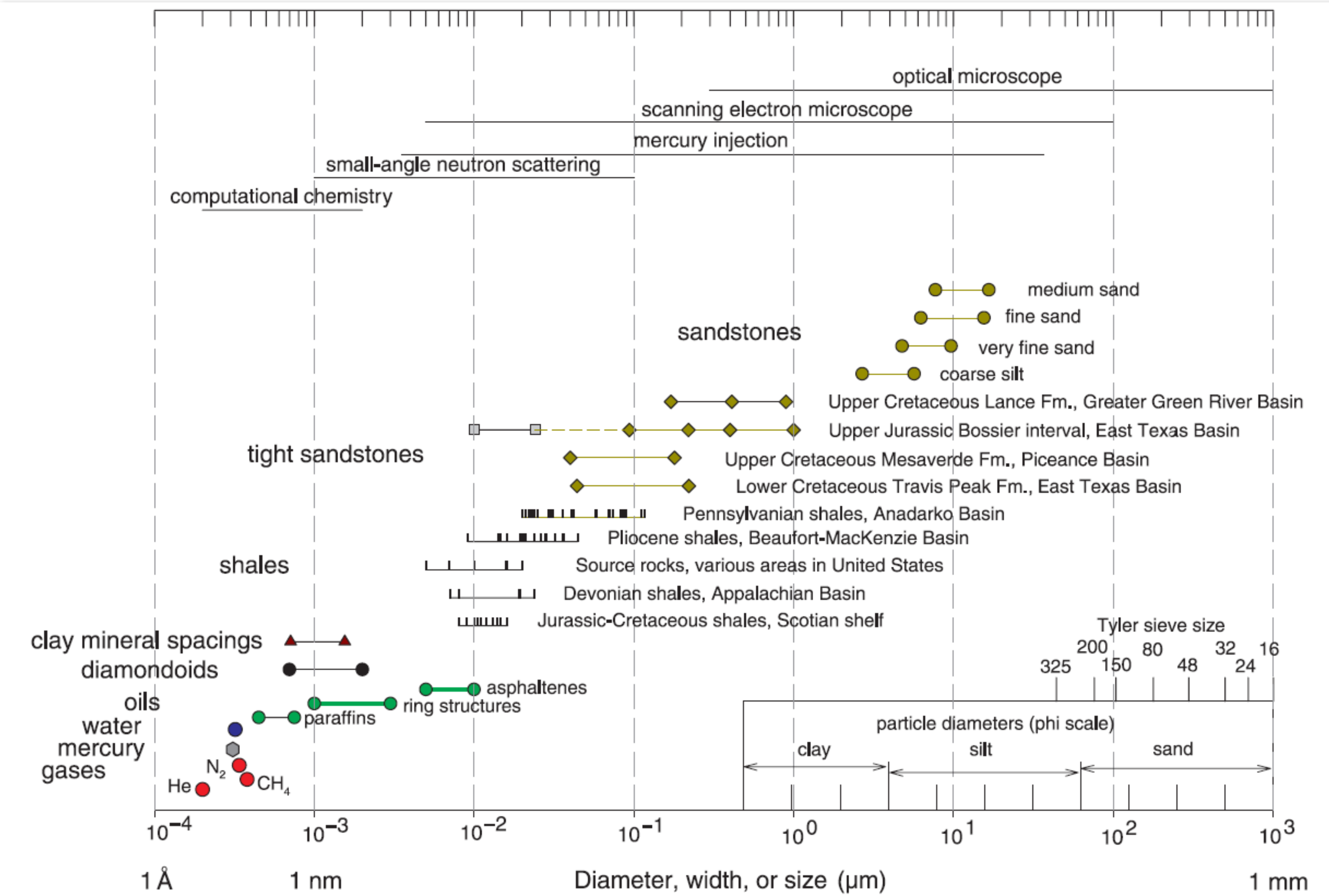
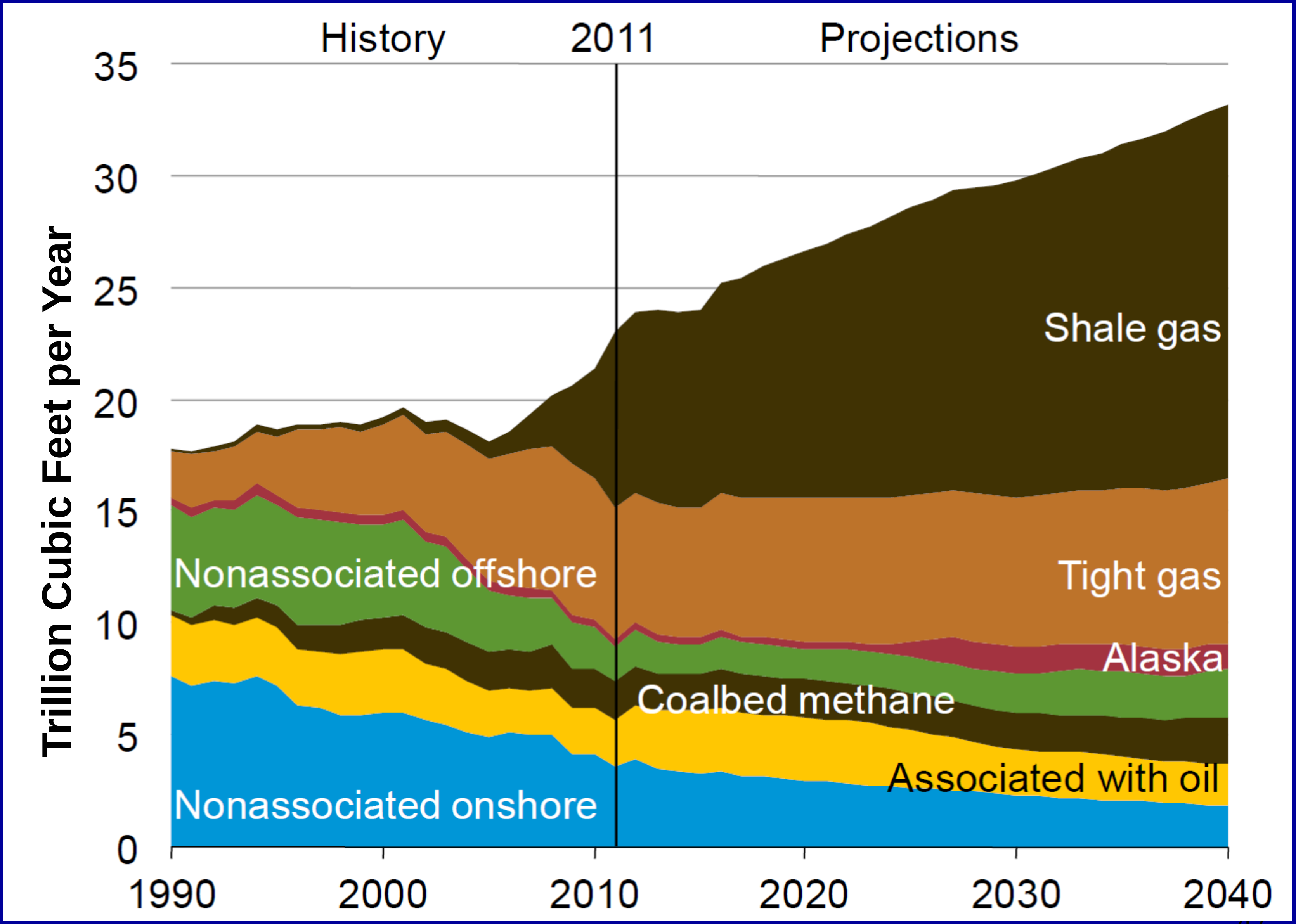


Figure 2. Sizes of molecules and pore throats in siliciclastic rocks on a logarithmic scale covering seven orders of magnitude. Measurement methods are shown at the top of the graph, and scales used for solid particles are shown at the lower right. The symbols show pore-throat sizes for four sandstones, four tight sandstones, and five shales. Ranges of clay mineral spacings, diamondoids, and three oils, and molecular diameters of water, mercury, and three gases are also shown. The sources of data and measurement methods for each sample set are discussed in the text.

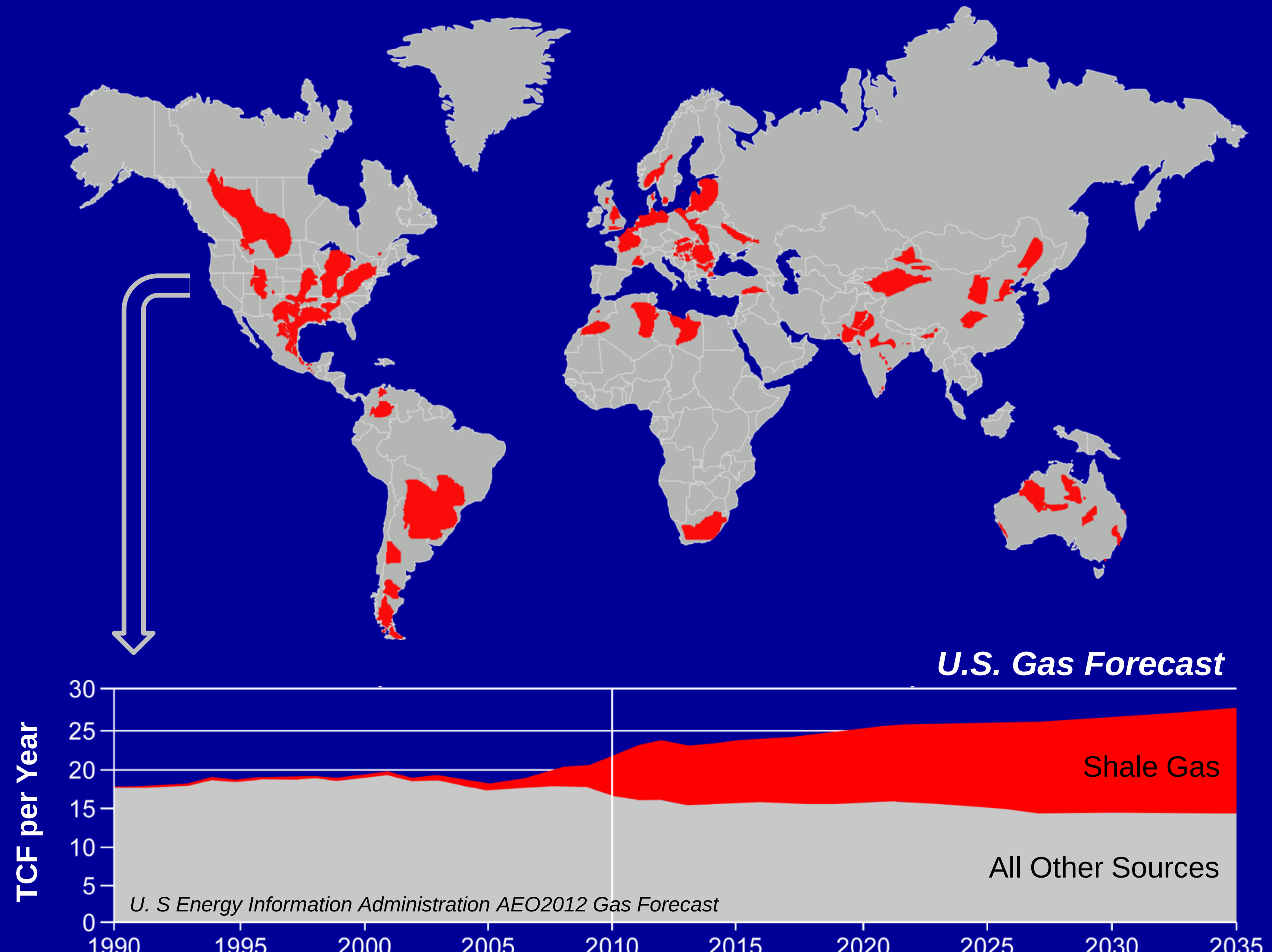
AAPG Bulletin , V 95, No 3 (March 2009), pp. 329-340
Pore-throat sizes in sandstones, tight sandstones, and shales

U.S. Natural Gas Production Forecast



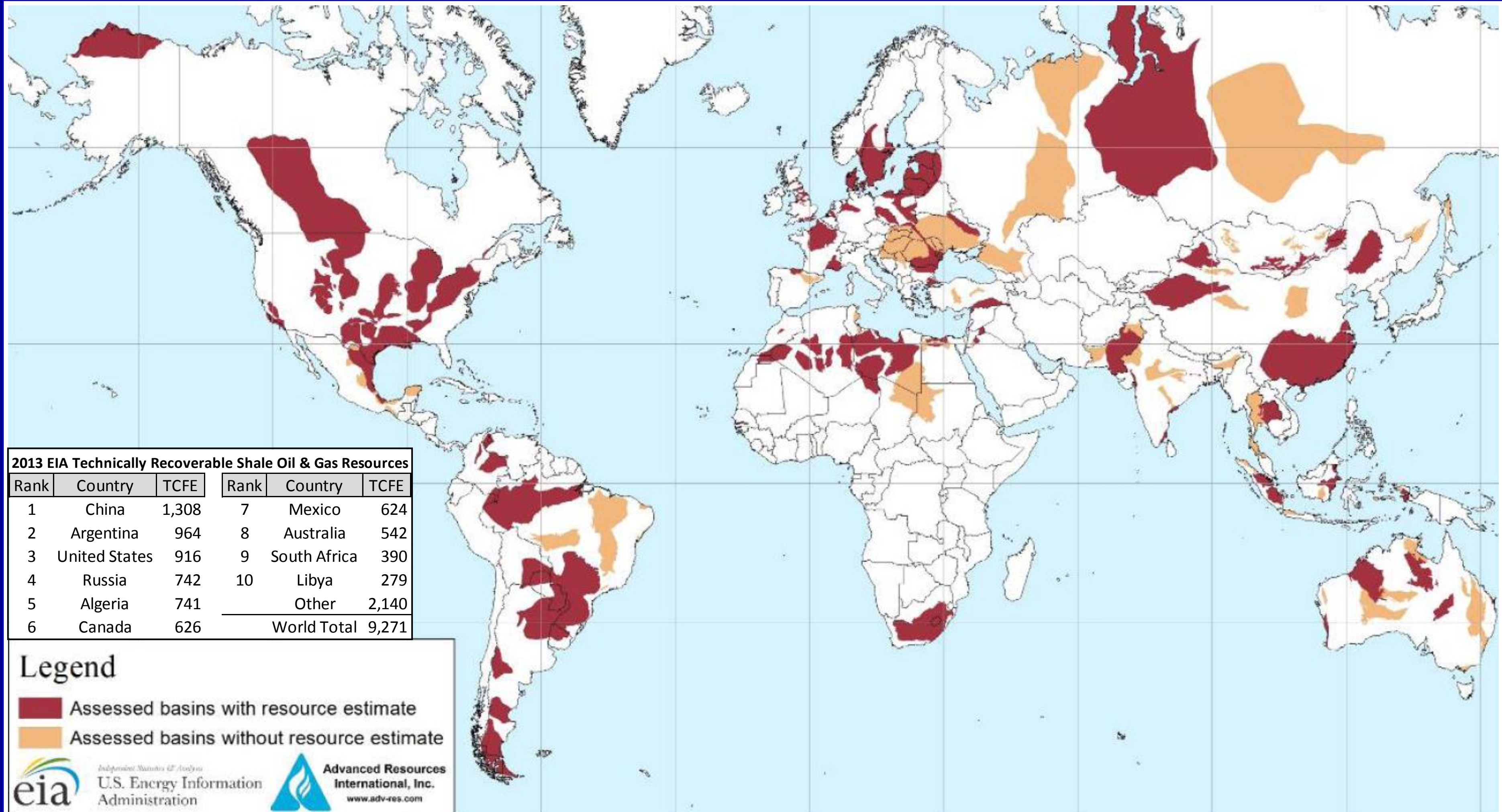
Source: AEO 2013 Early Release Overview

Global Shale Resource: ~6,000 TCF (~170 TCM)



Global Shale Resource: 7,200 TCF & 345 BBO (~200 TCM & ~50 Million Tonnes)

Map of basins with assessed shale oil and shale gas formations, as of May 2013



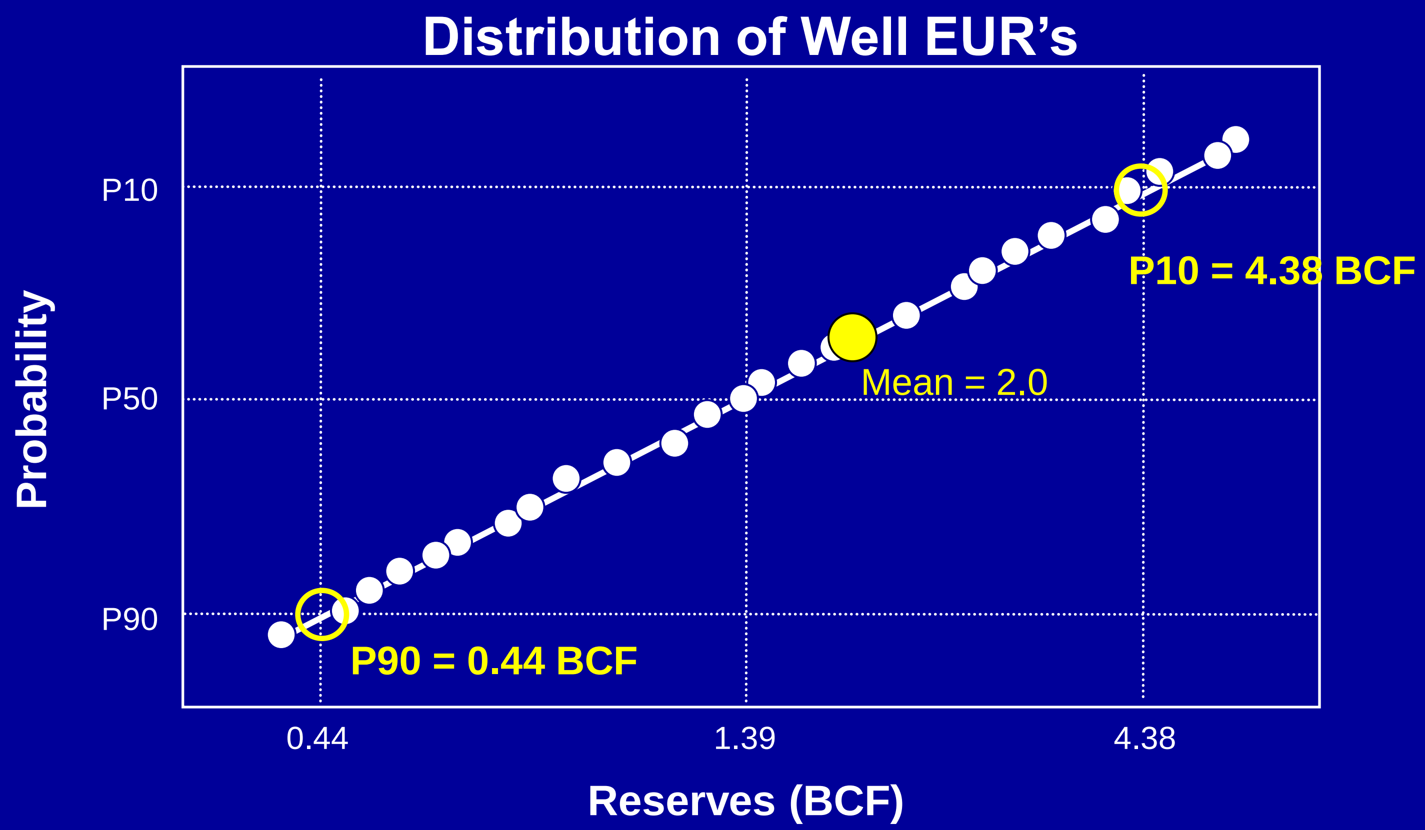
2013 EIA Technically Recoverable Shale Oil & Gas Resources

Rank	Country	TCFE	Rank	Country	TCFE
1	China	1,308	7	Mexico	624
2	Argentina	964	8	Australia	542
3	United States	916	9	South Africa	390
4	Russia	742	10	Libya	279
5	Algeria	741		Other	2,140
6	Canada	626		World Total	9,271

Source: United States basins from U.S. Energy Information Administration and United States Geological Survey; other basins from ARI based on data from various published studies.

Measuring Uncertainty

- *The uncertainty range, or variance, of the distribution is measured as P10/P90 ratio.*



P10/P90 = 4.38 / 0.44 = 10

So, What Uncertainty Range Should I Assume?

Shale Reservoir Performance Drivers

First-order Drivers

Reservoir Quality, Maturity & Pressure

Second-order Drivers

Drilling | **Completion** | **Production**

Reservoir Quality
- Porosity
- Permeability
- Lithology
- Mineralogy
- Thickness
- Water Saturation
- TOC
- Natural Fractures
- Structural Complexity

Maturity & Pressure
- GOR
- Viscosity
- Gas Composition (BTU)
- Thermal History
- Hydrocarbon Phase
- Normal vs Over Pressure
- Pressure Gradient Variances
- Critical Point (Dew/Bubble)
- Overburden
- Burial history

Drilling
- In Target Zone
- Well Tortuosity
- Horizontal Length
- Well Azimuth

Completion
- # Stages
- Stage Spacing
- # Perf Clusters
- Volume of Fluid
- Type of Fluid
- Volume of Proppant
- Type of Proppant
- Concentration
- Injection Rates
- Frac Gradient
- Zipper Fracs
- Microseismic

Production
- Choke Management
- Imbibition
- Artificial Lift
- Pressure
- Maintenance

So, What Uncertainty Range Should I Assume?

- The uncertainty range you use to make predictions should be based on the best geologic analogs available.
- Characteristics to consider when picking an analog:

SETTING
Reservoir Type
Geologic Interval
Depth (ft TVD)

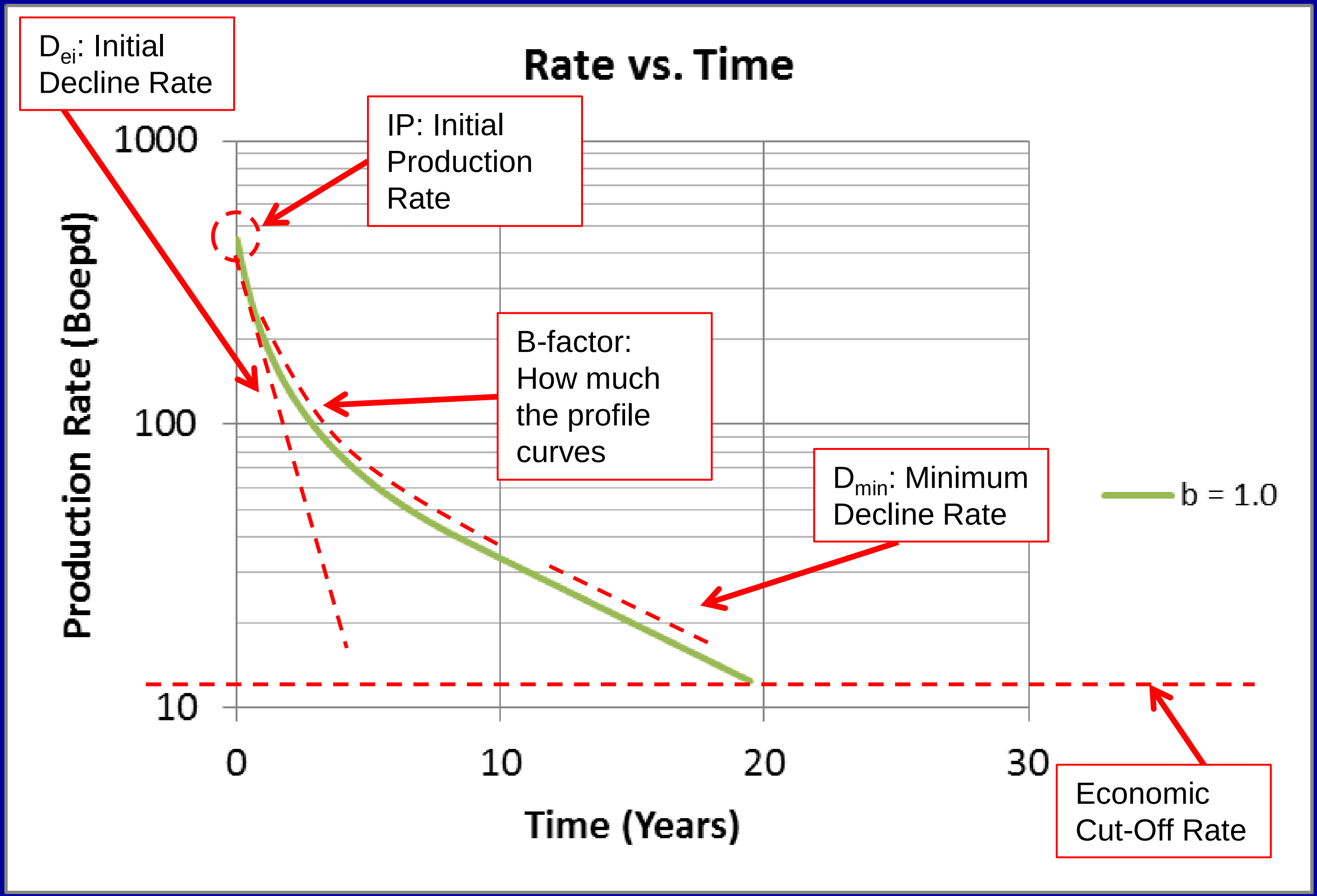
RESERVOIR
Net Pay Thickness (ft)
Hydrocarbon Thickness
Effective Porosity (%)
Water Saturation (%)
Matrix Permeability (nd)
Natural Fracture Density
Reservoir Pressure (psi)
Pressure Gradient (psi/ft)
HC In Place (MMBOE/Sec.)

ROCK CHARACTER
Clay Volume (%)
Quartz Volume (%)
Calcite Volume (%)
Static Young's Modulus
Dynamic Young's Modulus
Poisson's Ratio
Brittleness (high, mod, low)
Fabric (layering, anisotropy)
Frac Barriers
Structural Complexity

SOURCE ROCK
Thickness
Organic Richness (TOC)
Thermal Maturity (%Ro)
Kerogen Type (oil or gas?)
Gas Content (scf/ton)

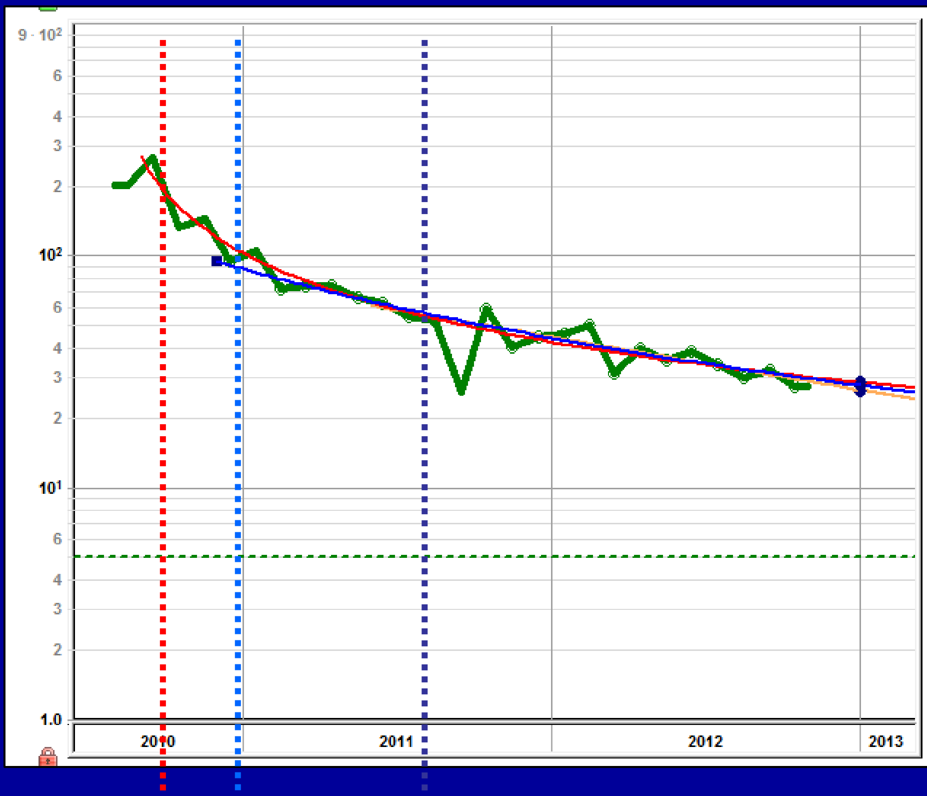
FLUID CHARACTER
Wellhead Gas Quality
Condensate Yield
Processed NGL Yield
Oil Gravity (deg API)

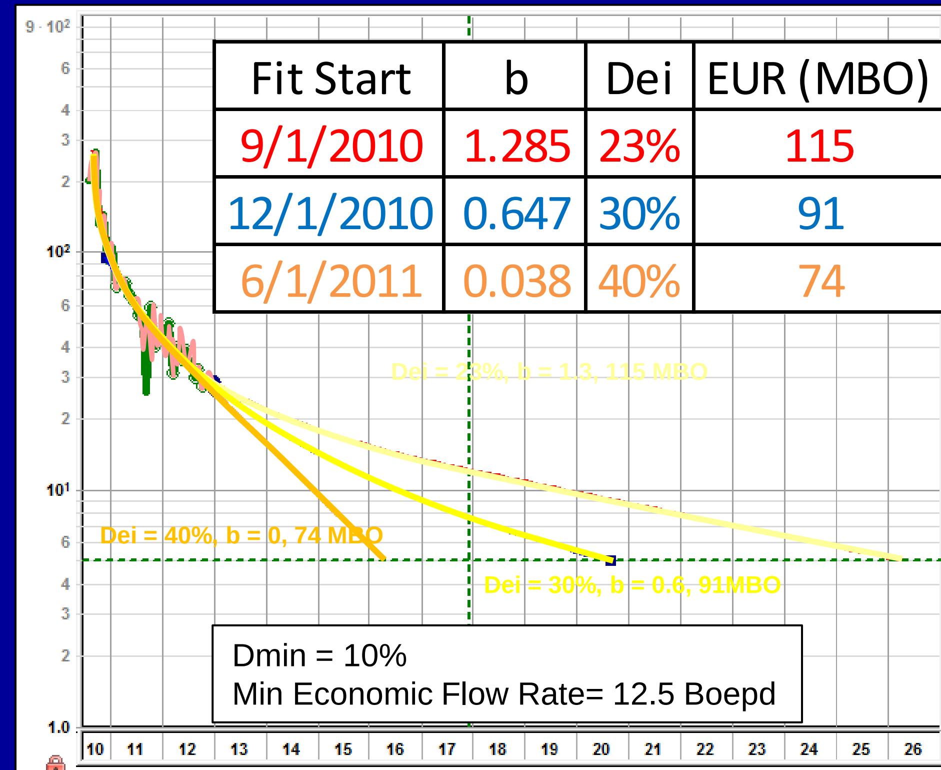
How Real Wells Behave



- Logs, core, fluid data are all important, but to estimate EUR you need production data.
- How long of a production period do we need from each well?

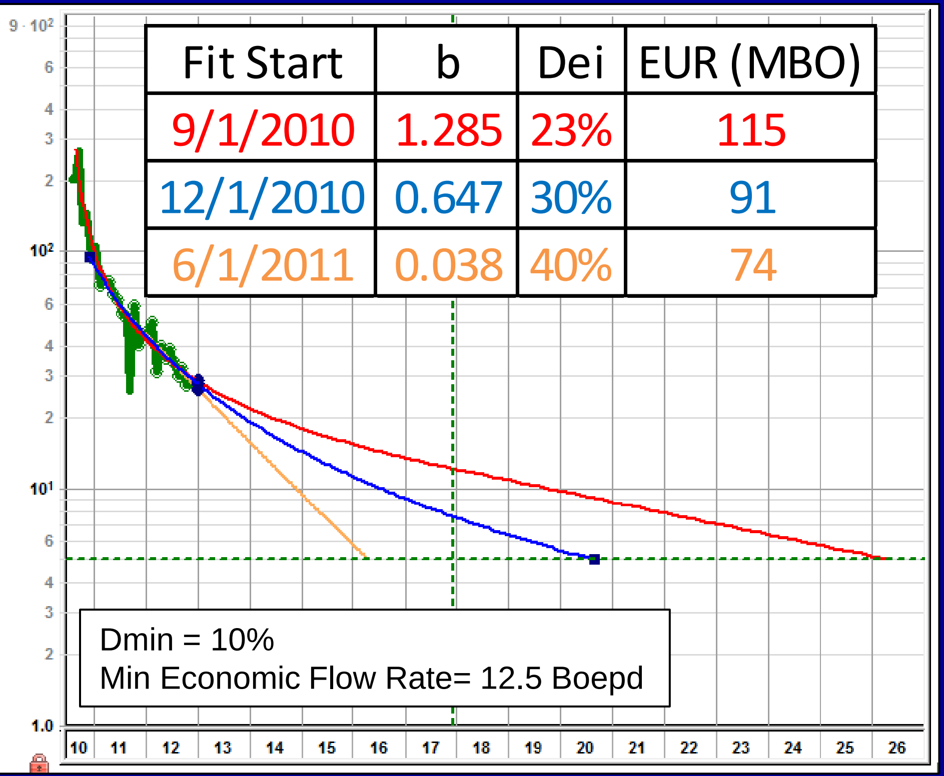
How Real Wells Behave – Fayetteville Shale Play



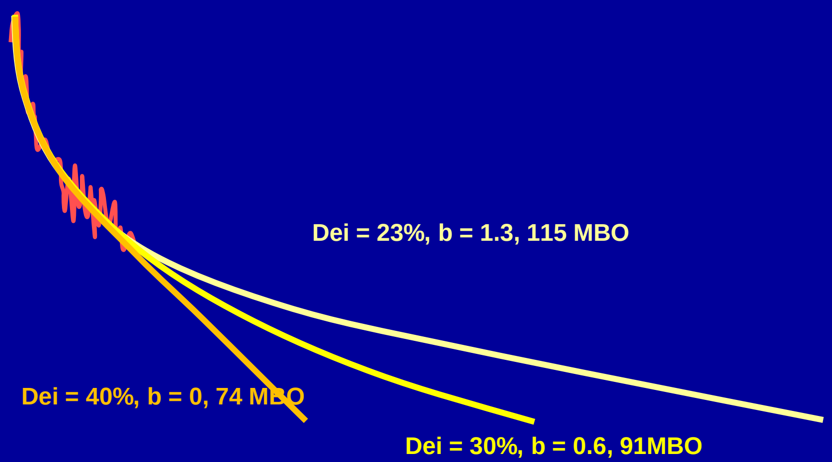


- **Logs, core, fluid data are all important, but to estimate EUR you need production data.**
- **How long of a production period do we need from each well?**

How Real Wells Behave – Fayetteville Shale Play

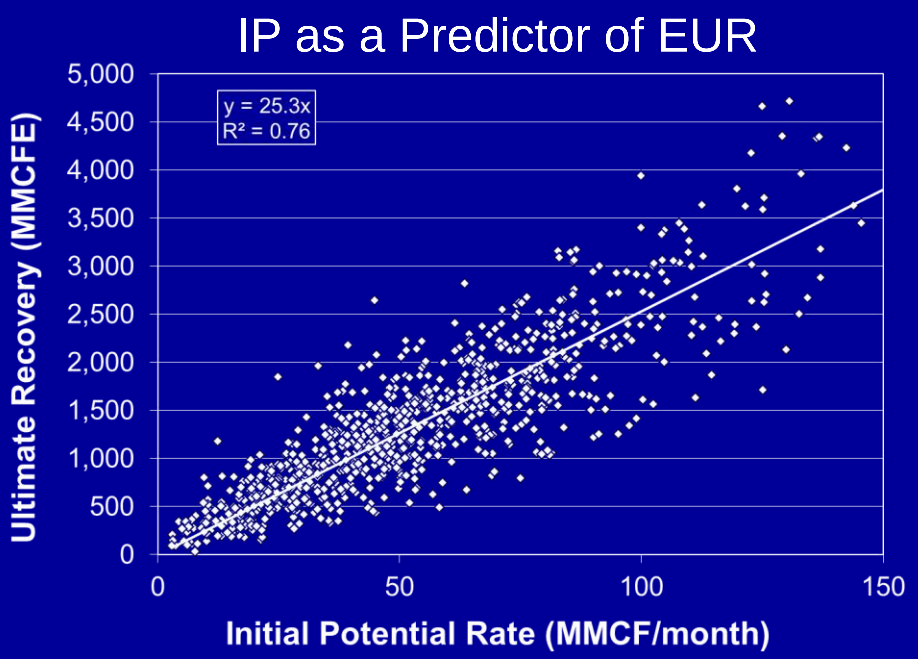


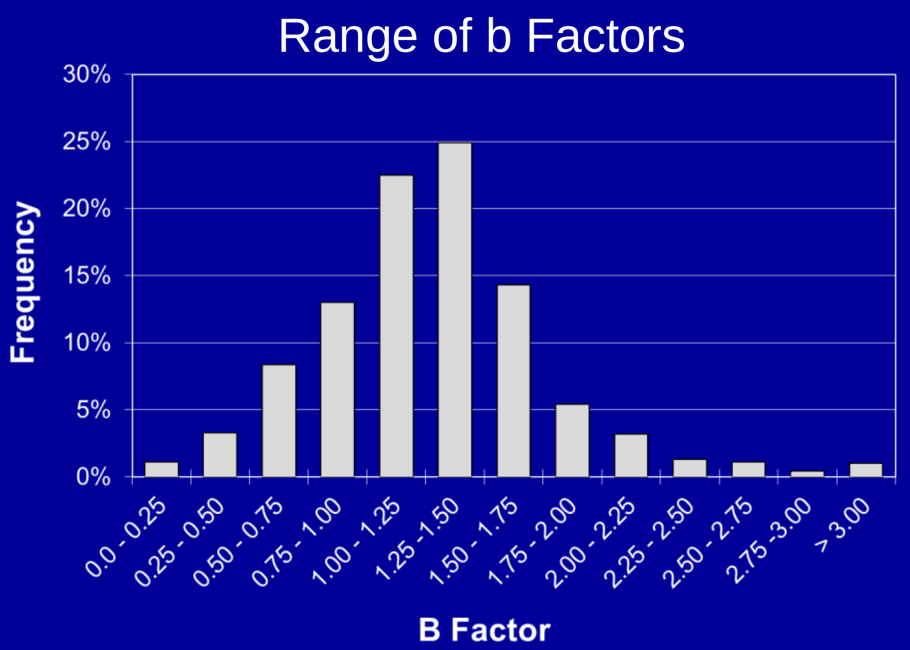
Fit Start	b	Dei	EUR (MBO)
9/1/2010	1.285	23%	115
12/1/2010	0.647	30%	91
6/1/2011	0.038	40%	74



- Logs, core, fluid data are all important, but to estimate EUR you need production data.
- How long of a production period do we need from each well?

How Real Wells Behave – Fayetteville Shale Play





- **Logs, core, fluid data are all important, but to estimate EUR you need production data.**
- **How long of a production period do we need from each well?**
  - **3 - 6 months are typically needed after cleanup to reasonably estimate decline rate**
  - **12 - 36 months are needed to reasonably estimate hyperbolic behavior (b factor)**

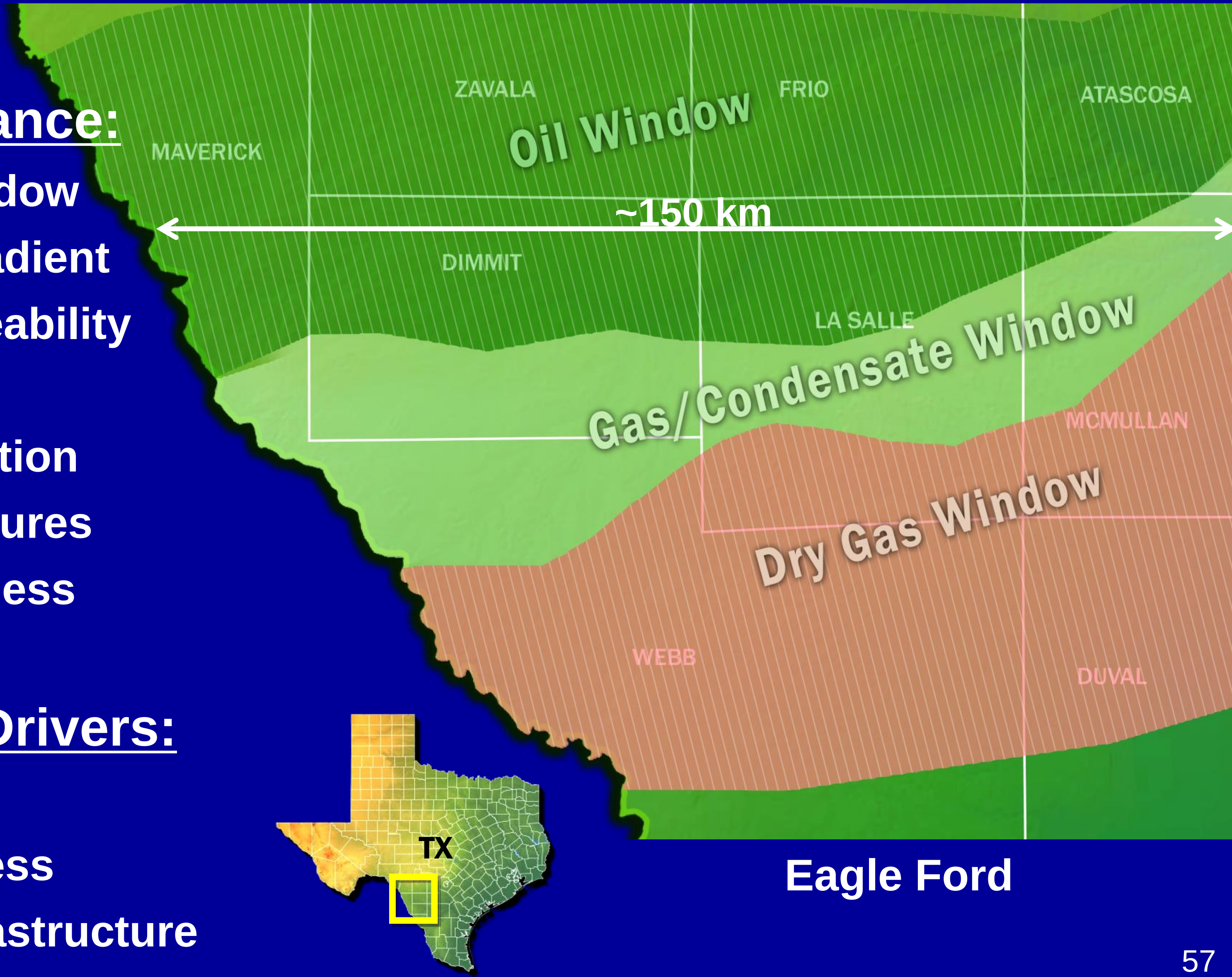
What Defines a Prospect Area?

Well Performance:

- Maturity Window
- Pressure Gradient
- Matrix Permeability
- Porosity
- Water Saturation
- Natural Fractures
- Rock Brittleness

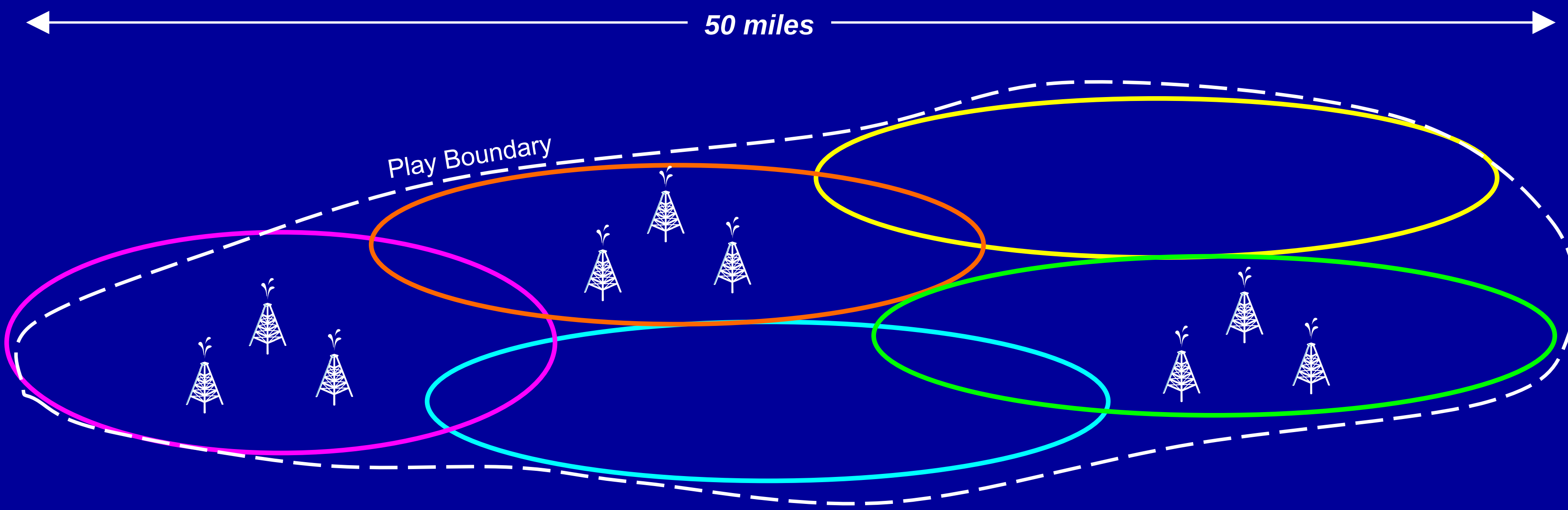
Cost/Timing Drivers:

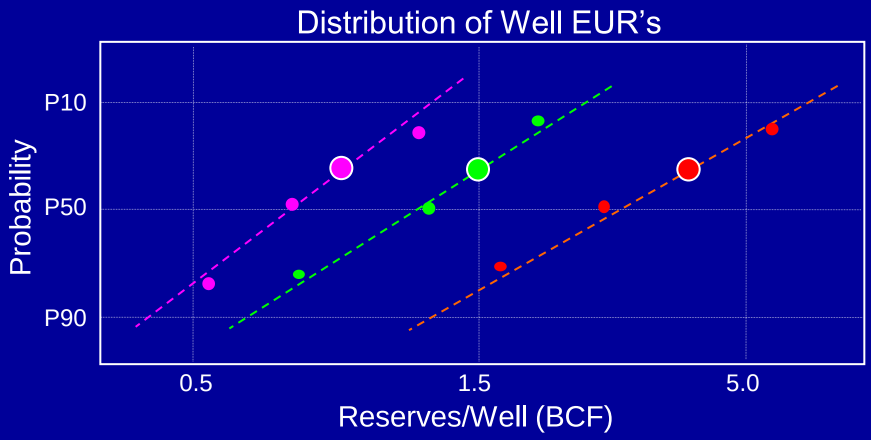
- Target Depth
- Surface Access
- Existing Infrastructure

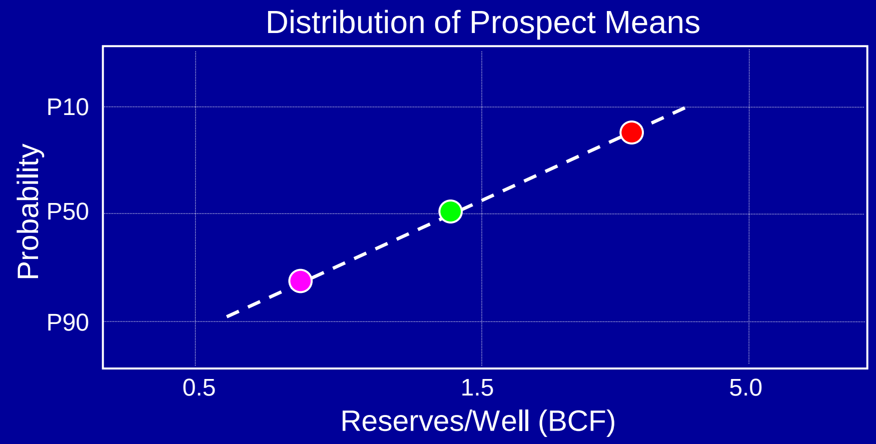


Eagle Ford

Testing a Shale Play







The Impact of Decision Behavior

Anticipated Behavior

Base Case

- Drill 3 Wells in 3 Prospects
- Threshold: ½ Disc. NPV = 0

Stricter Behavior

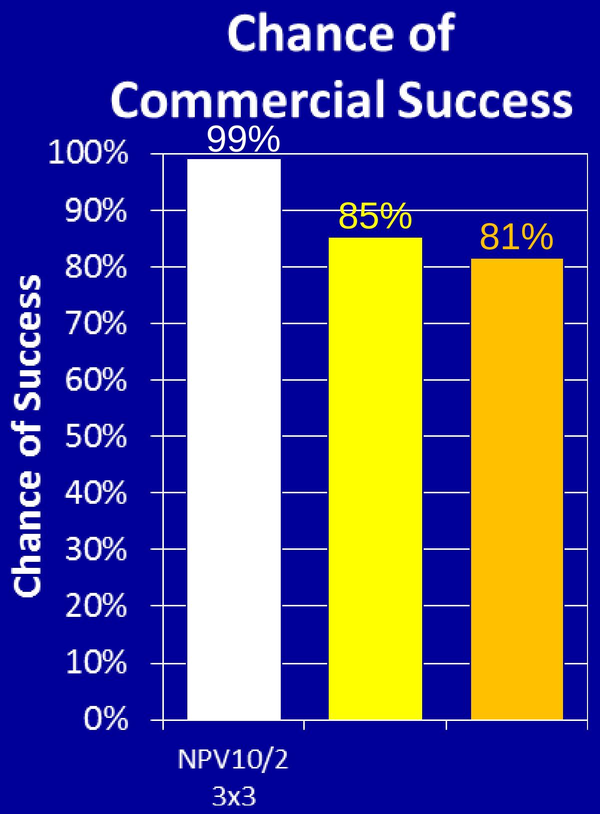
Raise threshold

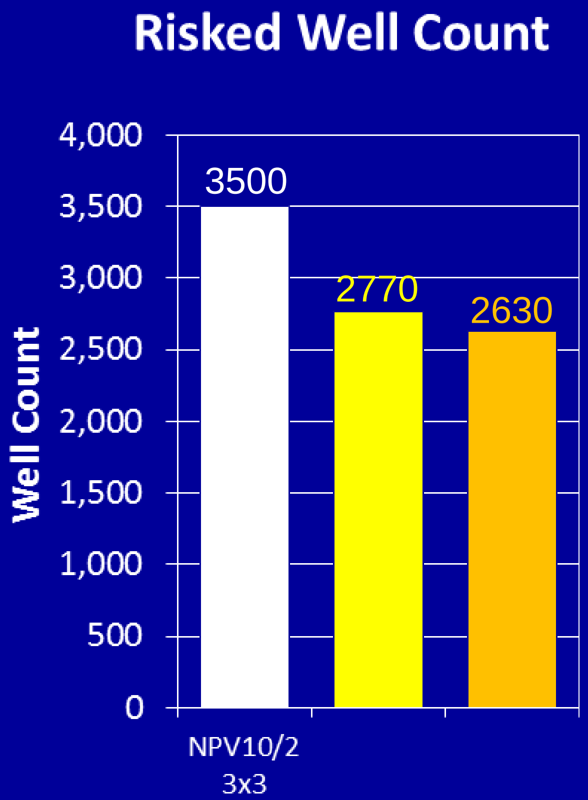
- Drill 3 wells in 3 Prospects
- Threshold: Disc. NPV = 0

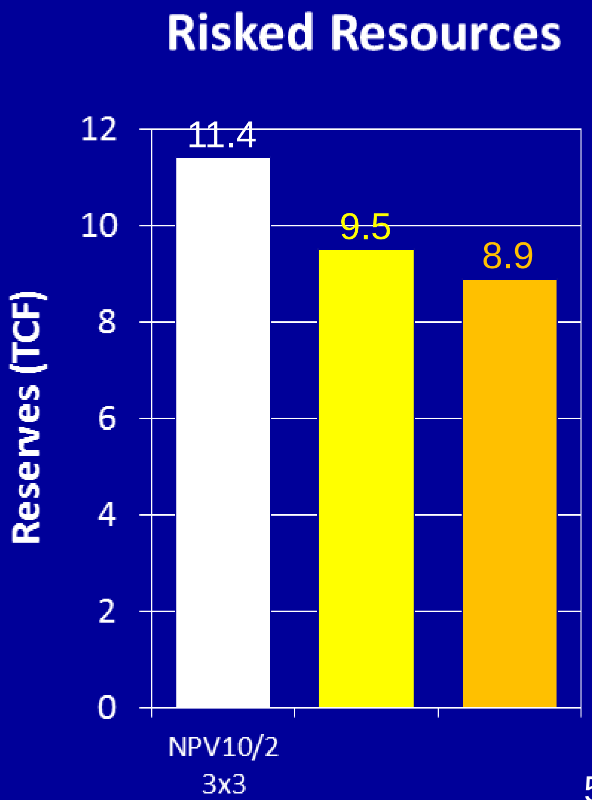
Harsh Behavior

Cut well count

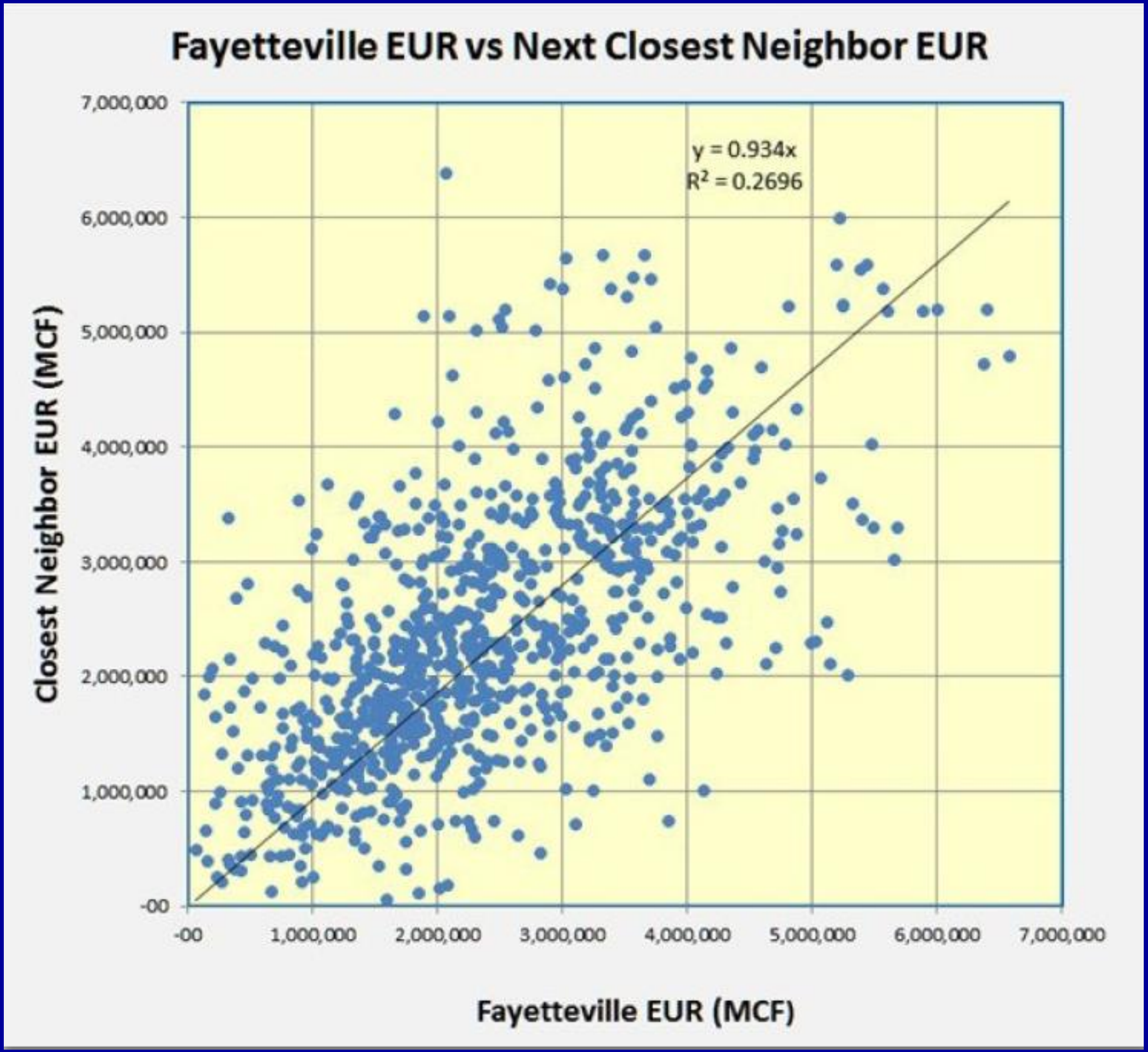
- Drill 1 well in 3 Prospects
- Threshold: Disc. NPV = 0





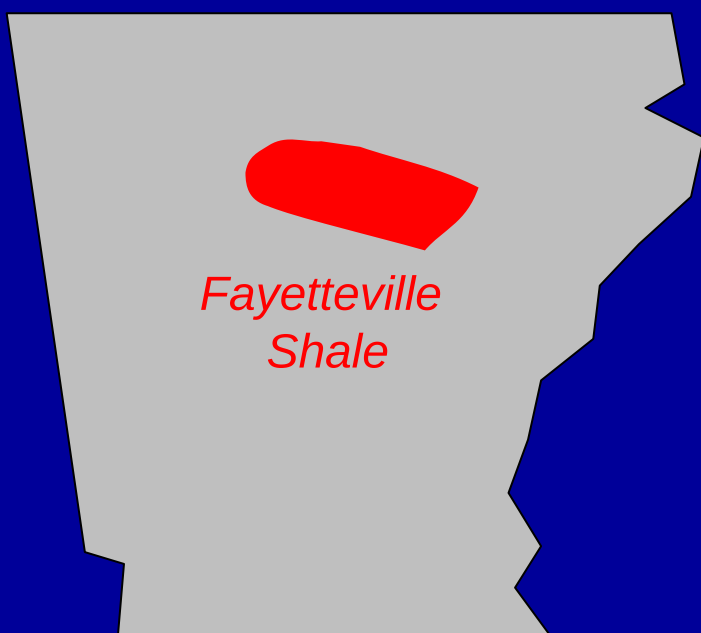


How Real Wells Behave – Fayetteville Shale Play



From Evaluating the Fayetteville Shale, Case Study using the guidelines of SPEE Monograph III

Fayetteville Shale Play



- One of
  drilling
- Mississ
  1,500 t
- Over 4
- Examin
  extend
- Produc
  'norma
  horizon