Conventional Versus Unconventional:

**Conventional Reservoirs**
- Localized structural trap
- External HC sourcing
- Hydrodynamic influence
- Porosity important
- Permeability > 0.1 md
- Permeability \( \neq f(p) \)
- Traditional phase behavior (PVT)
- Minimal extraction effort
- Significant production history
- Often late development life-cycle
- Few wells for commerciality
- Base reserves on volumetrics
- Assess entire prospect before drilling
- Boundary-dominated flow (months)

**Unconventional Reservoirs (Shale)**
- "Continuous-type" deposit
- Self-sourced HC
- Minimal hydrodynamic influence
- Porosity may not be important
- Permeability \( << 0.1 \) md
- Permeability \( = f(p) \)
- Complex (HP/HT) PVT
- Significant extraction effort
- Limited production history
- Early development life-cycle
- Many wells for commerciality
- Base reserves on analogs
- Prospect driven by drilling
- No boundary-dominated flow

- Traditional reserves methods
- Traditional reserves methods
Reservoir Engineering Aspects of Unconventional Reservoirs — A Brief Introduction


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Slide 3

**Schematic Production Performance Plot**

- Estimated Ultimate Recovery (EUR) [The area under the hybrid (hyperbolic-exponential) rate curves]
- "Switch Point" from Hyperbolic to Exponential

**Flow Regimes — Multi-Fracture Horizontal Well**

- 1:2 Slope (high $F_{c,1}$)
- 1:4 Slope (low $F_{c,4}$)
- Formation Linear Flow Regime
- Compound Linear Flow Regime
- Elliptical Flow Regime
- Transition Regime
- Bilinear Flow Regime
- Transition Regime

**Modern Decline Analysis — Power-Law Exponential Rate**

- PLE Rate Relation:
  \[ q(t) = q_i \exp[-D_{c}t - \hat{D}_{c}t^{n}] \]
- Decline Function: $D(t)$
  \[ D(t) = \frac{1}{q} \frac{dq}{dt} \]
  \[ \approx D_{\infty} + n\hat{D}_{c}t^{(1-n)} \]
- Hyperbolic Function: $b(t)$
  \[ b(t) = \frac{d}{dt} \left[ \frac{1}{D(t)} \right] \]
  \[ \approx \frac{n\hat{D}_{c}(1-n)}{[n\hat{D}_{c} + D_{\infty}t^{(1-n)}]^2} t^{-n} \]

**Schematic — Multi-Fracture Horizontal Well**

- "Plug and Perf" System: Each STAGE has a certain number of perforation "clusters" (typically 4)
- "FracPoint" (and other such) Systems: Each STAGE is isolated and stimulated

**TD Panel • So We Frac'd the Well, Now What? • Tom Blasingame (Texas A&M U.)**

(Reservoir Engineering Aspects of Unconventionals) | PETE 631 - Petroleum Reservoir Description
**PVT: (Issues/Challenges/Solutions?)**
- Undersaturated oil, $p_b$ suppression (nano-pore volumes/distributions).
- Volatile oil/critical fluid, nano-volume effects less an issue ($IFT/p_c$).
- Gas condensates — composition issues/ variations in $p_{Crit}$ and $T_{Crit}$.
- Need molecular dynamics work to resolve/validate PVT in nano-pores.

**Critical Temperature as a Function of Pore Size**


**a. Critical point suppression due to pore size (various gases).**

**b. Phase diagrams of confined and unconfined heavy gas condensate mixture (Pedersen et al, 1989). (vertical red) line is the reservoir temperature.**

**b. The percentage of liquid drop out (% by volume) of a heavy gas condensate mixture (Pedersen et al, 1989) at 400°F. (400°F is reservoir temperature — see plot at left).**
Modeling Approach for a Horizontal Multi-Fracture Well

Modeling: (Grand Challenges)
- Fully integrated (not coupled) geomechanical/flow simulation model.
- Models may not be properly "parameterized" — no data to validate.
- Statistical versus deterministic models (system is "too complex")?
- Use models to establish/validate/bound drainage volumes.
- Use models to constrain assumptions about geomechanics/fluid flow.


b. Pressure gradient after 8 months (top) and 10 years (bottom) of production (Note times for different regimes, this is a relatively high permeability shale analog case).

b. Typical transient response where PSS is seen in the SRV (Note times for different regimes, this is a relatively high permeability shale analog case).
a. Time match of oil (green) and gas (red) rate performance. Note that the match substantially degrades after the shut-in (reservoir effect?).

b. Time match of (calculated) bottomhole pressures.

c. Cumulative oil match of oil rate using 80- and 800-acre spacings.

d. Plot of EUR versus well spacing (drainage area) for example case.

Comment:

- Left plot yields time required to estimate EUR (~12-32 months).
- The "hyperbolic" (or "constant b") flow regime is required to estimate EUR.

(all data obtained from publicly available sources — Dry Horizontal Shale Gas Wells ONLY)

[all data obtained from publicly available sources — Dry Horizontal Shale Gas Wells ONLY]
[P90/P50/P10 EUR Comparisons (Modified Hyperbolic Model with 30 year max life)]

Comment:
- Results vary when segregated by geological area, completions, spacing, etc.
- Analyses represent an attempt to quantify the RANGE of values.
What Keeps Us (Reservoir Engineers) Up at Night:

● Stimulation/Fracture Geometry:
  ■ Well spacing, reservoir model type (dual vs. single porosity), etc.?
  ■ Does the SRV change with time (specifically, does it shrink)?

● Reservoir Model:
  ■ Validity of dual $\phi/k$ models, enhanced $k$ pods, fracture networks?
  ■ Model selection has a significant impact on POTENTIAL well spacing.
  ■ Can we predict/incorporate influence of natural fractures?
  ■ Is effort on geomechanics (really) going to lead to better understanding?

● Data Collection:
  ■ Taking data to validate model, or using model to guide development?
  ■ Downhole data — expensive — but are there any viable alternatives?
  ■ Poor data $\rightarrow$ poor engineering and poor modeling.
  ■ Petrophysical data ($\phi$, $k$, $p_c$) — scale, validity, integration?
  ■ Role of "distributed" data? (temperature, pressure, rates, etc.)

● Process:
  ■ No "cowboy-ing" the choke — develop a choke plan and stick to it!
  ■ Incorporating artificial lift from inception! (including modeling)
  ■ Use modeling to interpret performance and constrain parameters.
  ■ Focus on what we can measure; use that as a basis for modeling.
  ■ Start to consider statistics in addition to mechanistics.