TYPE CURVE GENERATION 101

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AGENDA

- Estimating EUR & Type Curve Development
  - Understanding Your Reservoir
  - Production Analysis & Understanding Performance
  - Useful Tools
  - Using Analogy & Data Analytics
  - Big Data Applications, Important Things to Consider
- – Field Applications & Live Examples
- – Important Takeaways & Other Considerations

WHAT SMART PEOPLE SAY ABOUT UNCERTAINTY

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- "We must become more comfortable with probability and uncertainty."
  - Nate Silver (author and statistician, FiveThirtyEight.com)
- "Some people say, 'How can you live without knowing?' I do not know what they mean. I always live without knowing. That is easy. How you get to know is what I want to know."
  - Richard Feynman (Nobel prize-winning physicist)
- "The world is noisy and messy. You need to deal with the noise and uncertainty."
  - Daphne Koller (AI researcher, Stanford University)
- "Recognizing uncertainty is a sign of humility, and humility is just the ability or the willingness to learn."
  - Charlie Sheen (Two and a Half Men)

RANKING UNCERTAINTY

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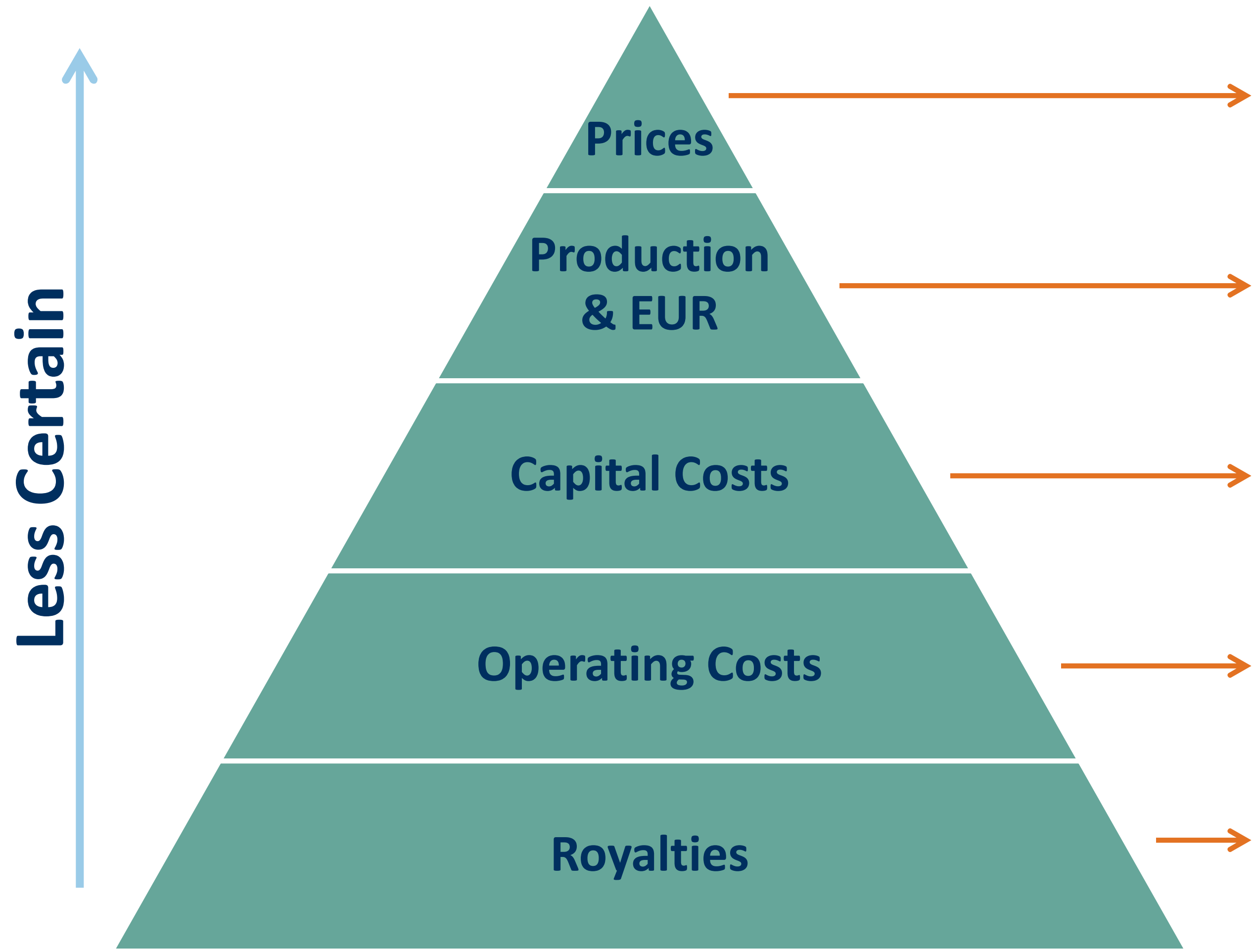
Components of a Half-Cycle Economic Analysis



- Market prices are hard to predict
- Normally predictable to ±70% with 95% confidence one year out
- Hedging can improve certainty

- Well performance
- Operational issues
- Economic factors can limit

- Usually predictable within 15%
- Uncertainty largely tied to success/failure and experimentation

- Transportation bottlenecks
- Line pressures
- Unexpected issues, maintenance
- Competition, partnerships

- Long term uncertainty in regulatory framework
- Short term is usually quite certain

STATISTICAL AGGREGATION

- It has long be recognized that adding up high confidence estimates (eg well by well reserves) results in extremely high confidence aggregate estimates (eg company reserves).
  - Put another way - Adding a bunch of low estimates results in a too low estimate
  - Similarly (but less of an issue as generally companies do not disclose high estimates) – adding all high estimates is too agressive

- Statistical techniques to account for this affect are growing in popularity

- Why would you aggregate?
  - Potentially higher Proved reserves
  - Alternate method to historical SEC step-out limitations
  - Potential for more rigorous treatment of P10 and P90 reserves definitions
  - It's new(ish) and fancy! Guidelines first published by SPEE in 2010: SPEE Monograph 3.

STATISTICAL AGGREGATION

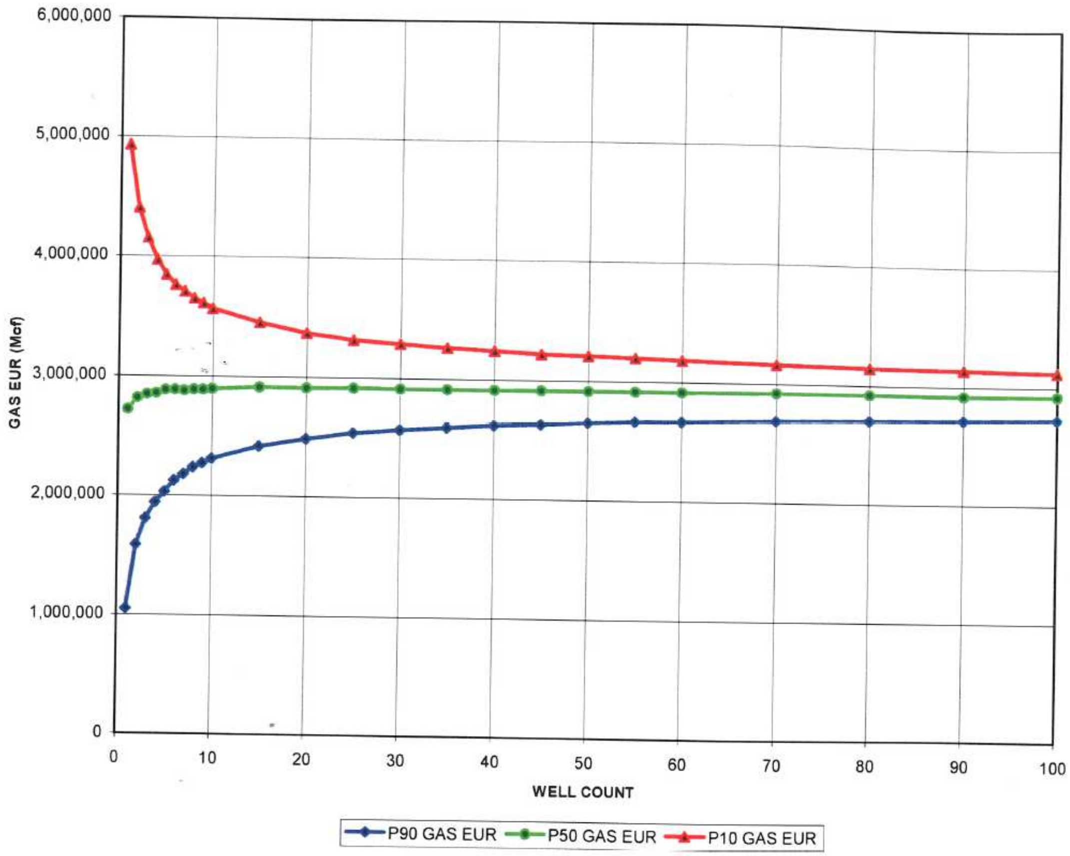


Fig. 4.14 – Probability versus Well Count

The "Trumpet Plot" shows the convergence to the mean with a higher number of wells/locations drilled.

STATISTICAL AGGREGATION

- Who is interested in aggregation
  - Parties who care mostly about P90 or Proved reserves: US clients and international clients familiar with US disclosure
  - Technical experts frustrated with a lack of statistical rigor in the oil patch

- The current governing guideline is SPEE Monograph 3 which requires
  - “Wells exhibit a repeatable statistical distribution of estimated ultimate recoveries”
  - “Offset well performance is <u>not</u> a reliable predictor of undeveloped location performance”
  - “A continuous hydrocarbon system exists that is regional in extent”
  - “Free hydrocarbons (non-sorbed) are not held in place by hydrodynamics”
  - All statistical methods presented in the Monograph assume observations are independent and follow normal or log-normal distributions.

EXAMPLE OF REPEATABLE STATISTICAL DISTRIBUTION

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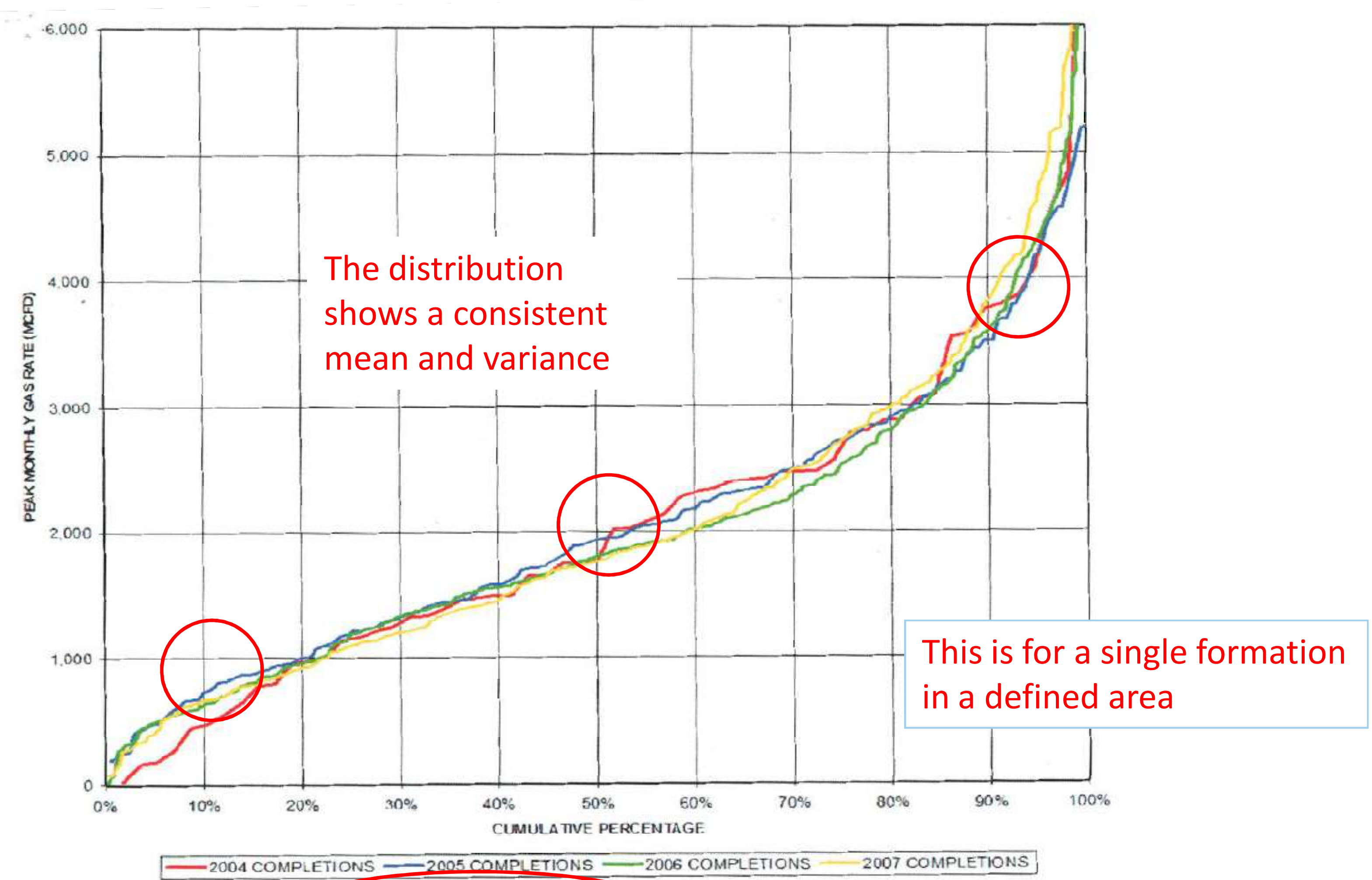
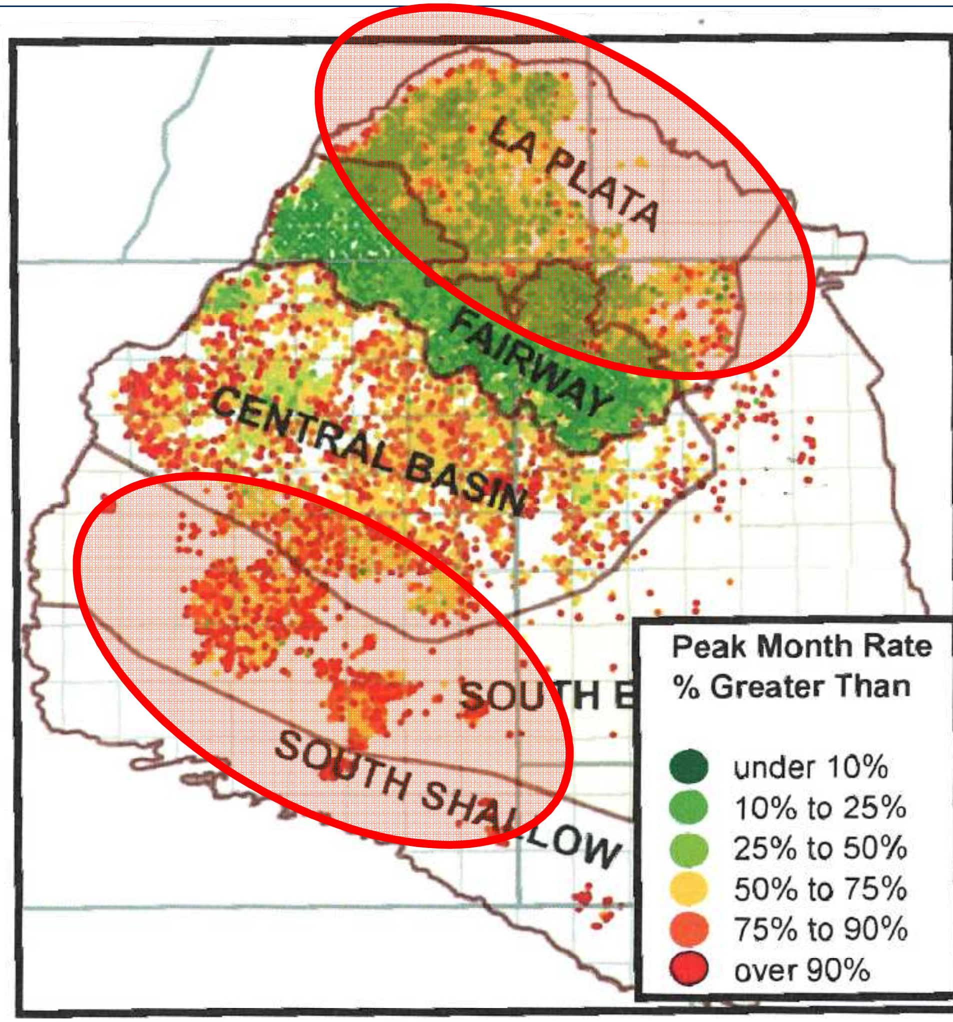


Fig. 1.1 – Barnett Shale, Johnson County, Texas Performance

EXAMPLE OF REPEATABLE STATISTICAL DISTRIBUTION

Distributions may be consistent within a given area of a play while not being consistent across the play.

Can be locally homoscedastic and globally heteroscedastic



Map 2.2 – Fruitland Coal Map - San Juan Basin

EXAMPLE OF REPEATABLE STATISTICAL DISTRIBUTION

- Monograph 3 advocates the concept of anchor wells and concentric radii.

Statistics must be consistent between radii and around every anchor well

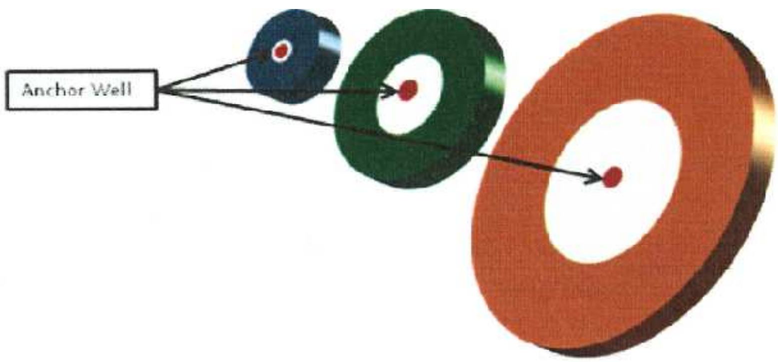


Fig. 3.15 – Example 2 – Expanding Concentric Radii (ECR) Around Anchor Wells

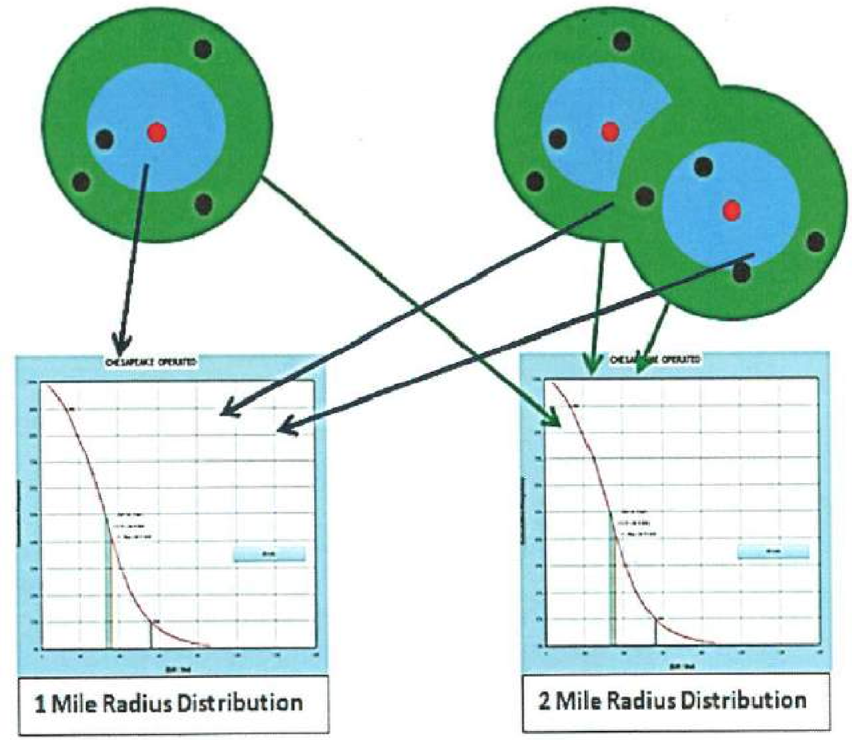
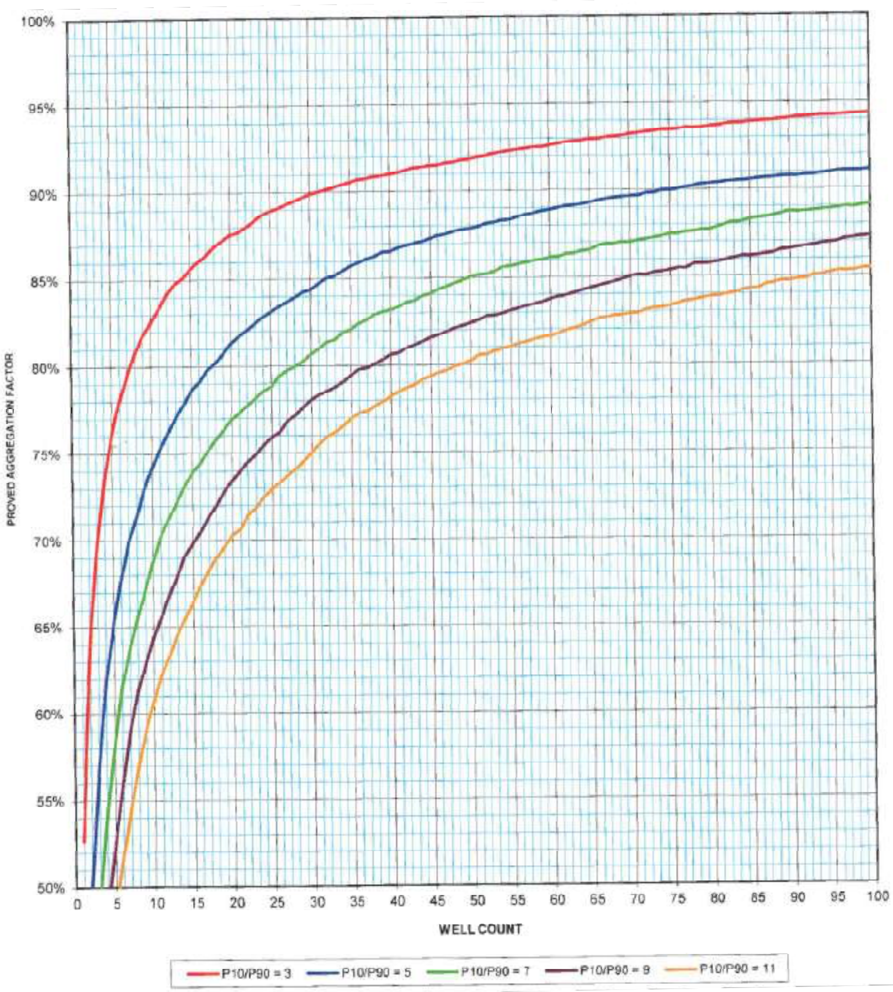


Fig. 3.16 – Example Problem 2 - EUR Statistical Distribution for Test Set Wells – Test Set 1 and Test Set 2

STATISTICAL AGGREGATION

- If all requirements are met, doing aggregation the Monograph 3 way is very easy.
  1. Calculate the ratio between your P10 and P90 EUR estimates
  2. Tally up your number of locations
  3. Look up the factor you need to multiply your P50 EUR estimate by in order to get your P90 EUR.

- Unfortunately, Monograph 3 doesn't provide detailed guidance on
  – How to calculate EUR
  – How to calculate the number of locations
  – or what to do if estimates of P10 and P90 are uncertain.



PROBLEMS WITH STATISTICAL AGGREGATION

- Most oil and gas fields show non-homoscedastic behavior

- Both the mean and variance are non-stationary. This can be in terms of exploitation methods, stratigraphic horizon, time and position

- There are non-trivial correlations between wells: expected performance is almost always a function of distance, spacing and the evaluators' assumptions.

COGEH states "The evaluator should also be aware that reserves estimates for some wells may be dependent on each other; i.e., if the estimate is incorrect for one well, it is equally incorrect for the others."

- This doesn't preclude the use of aggregation, but the analysis must be more sophisticated than the simple examples presented in Monograph 3

WHY WOULD YOU CHOOSE NOT TO STATISTICALLY AGGREGATE?

- There is no need if all you and your investors care about is P50 (2P)

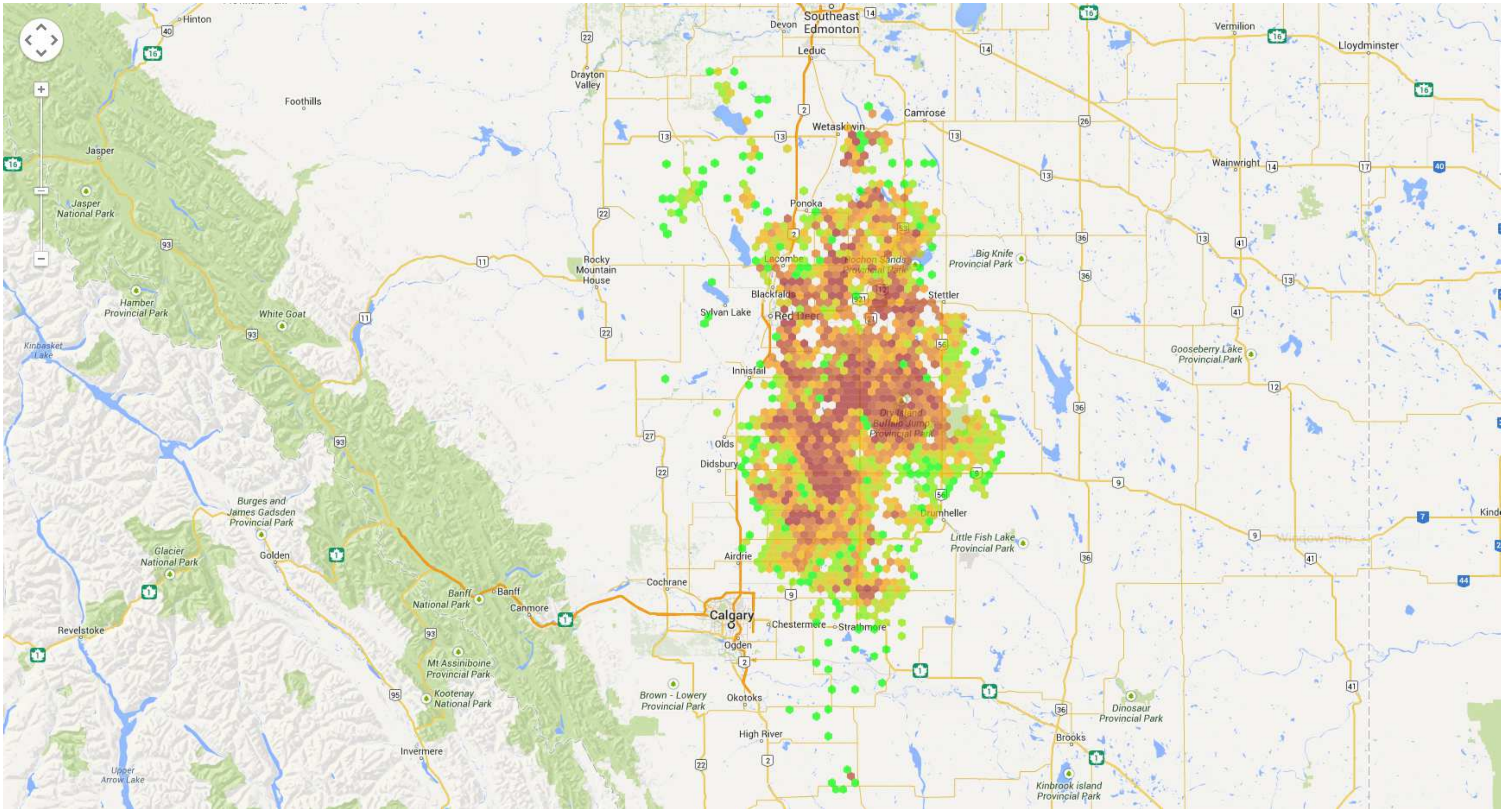
- Field data may be insufficient or contradicts the requirements of Monograph 3:
  - The statistical distribution of estimated ultimate recoveries may be inconsistent: well results may change with completion technique
  - Offset well performance may be a reliable predictor of undeveloped location performance: most fields show that offset wells do statistically influence expectations of the mean… put more simply: “reservoirs have sweet spots”
  - The hydrocarbon system my change over the region of interest: as with CGR in the Montney and Duvernay
  - Field data is sufficient and fits requirements of Monograph 3, or can be manipulated to do so, but the observations indicate dependence between variables or other statistical behaviors that don’t fit the examples in the Monograph and you are unable or unwilling to implement alternate statistical algorithms

- You would rather disclose Proved reserves with a confidence greater than 90% under current rules, remembering that reserve guidelines generally say “greater or equal” in reference to high confidence or Proved estimates.

- The imposition of the SEC’s five year rule may negate any increase in proved reserves booked

- Other risk factors may be more important, like geopolitical risk or corporate governance

“SWEET SPOT” EXAMPLES
HORSESHOE CANYON EUR



“SWEET SPOT” EXAMPLES
MILK RIVER/MEDICINE HAT EUR

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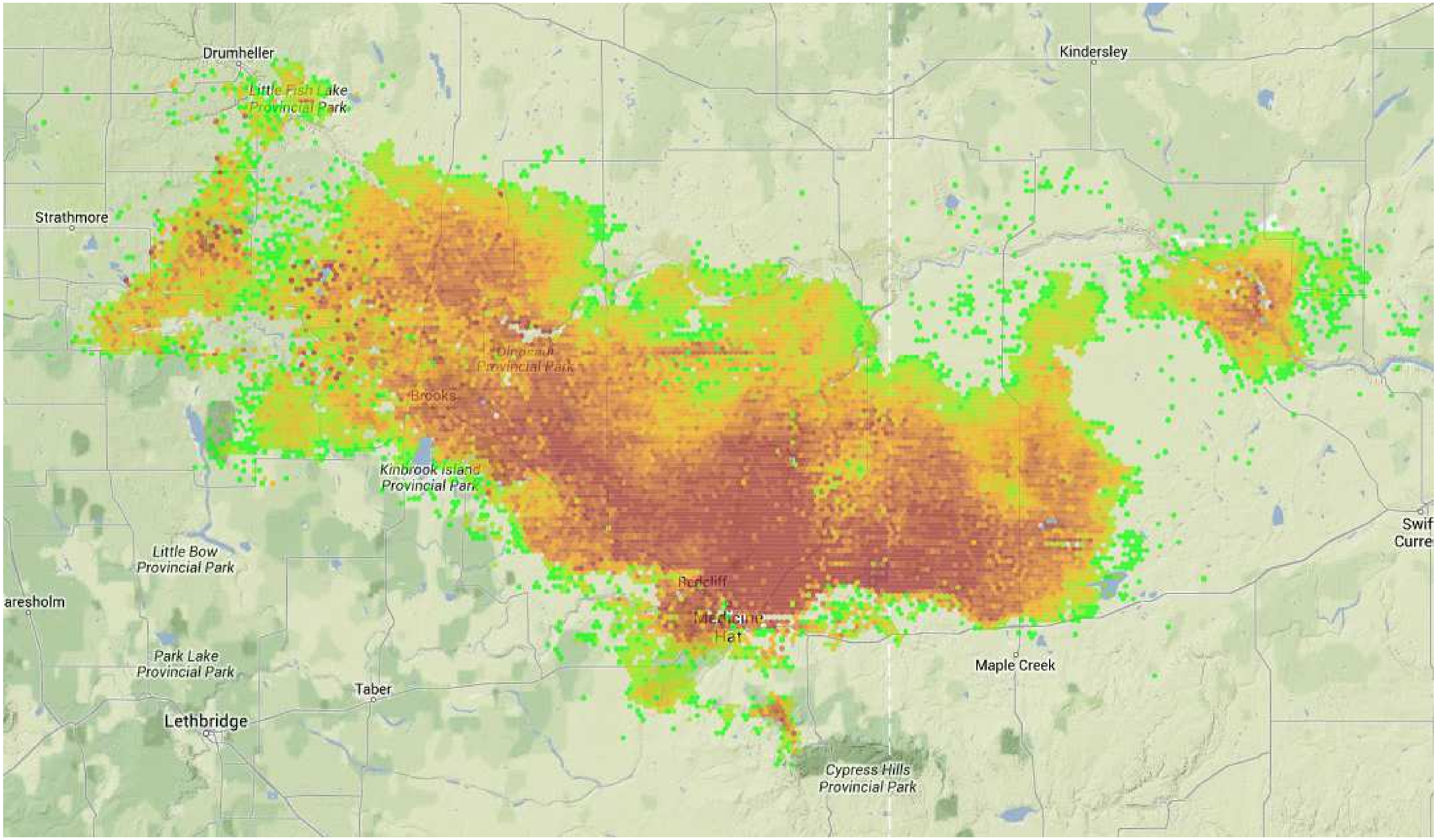
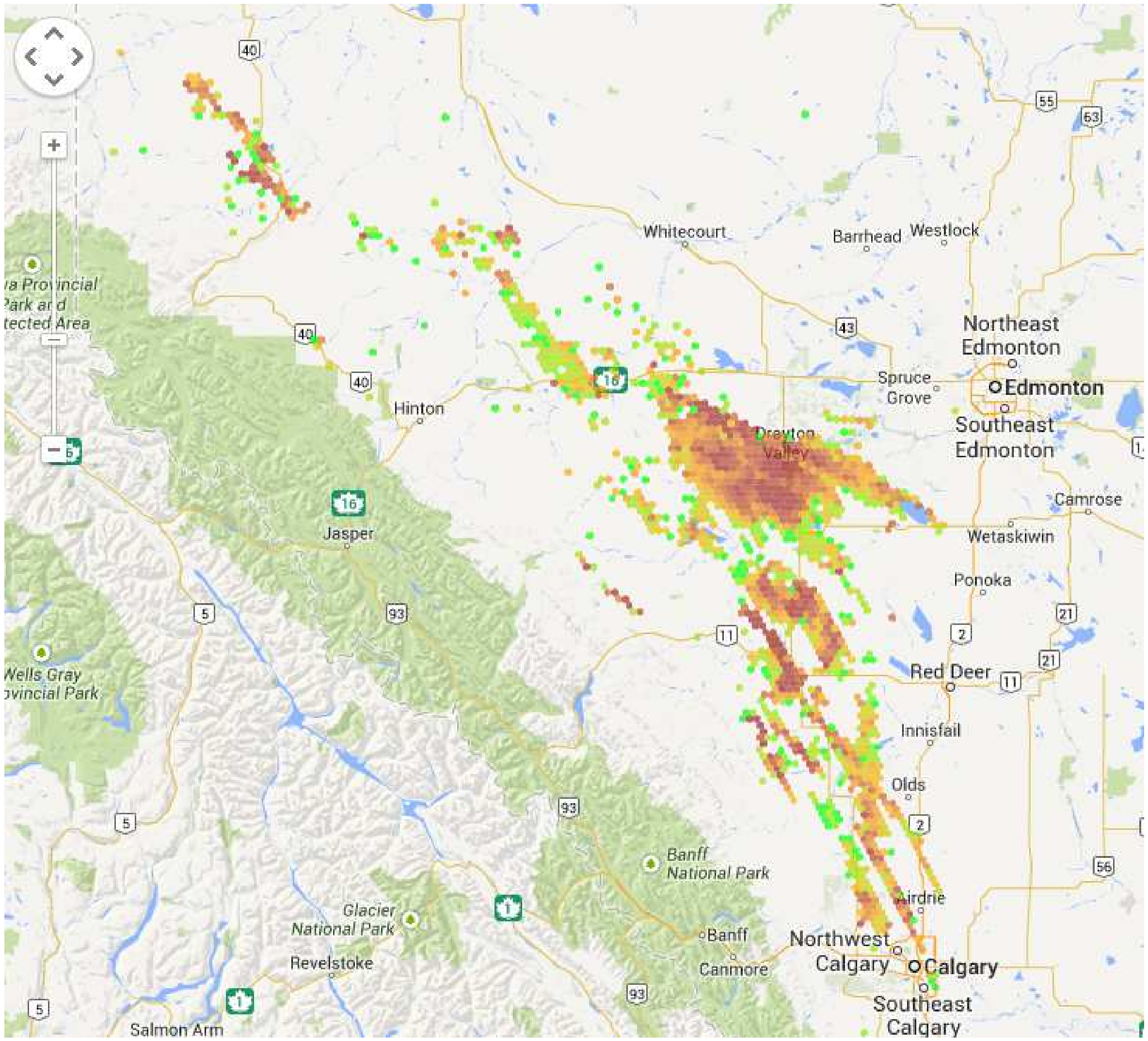


"SWEET SPOT" EXAMPLES
CARDIUM OIL EUR



EUR AND TYPE CURVE ESTIMATION

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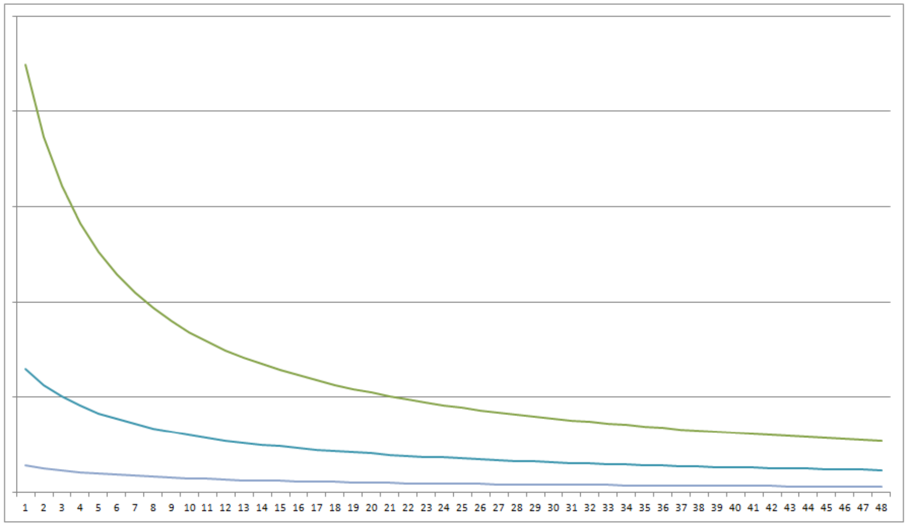
- Why are single type curves so popular?
  - Quick & Simple
  - Financial analysis/metrics (play versus play or region versus region)
  - Marketing
    - "Our 7 BCF Type Curve…" is a lot easier to digest than "Our type curves for the region vary between 4 and 10 BCF recoverable per well"

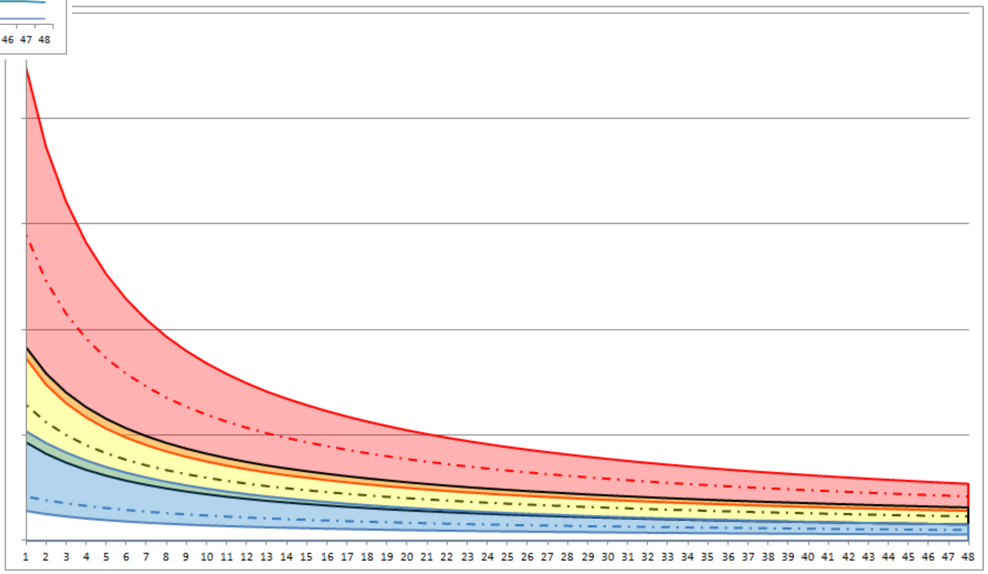
BUT…In practice, single type curves are rarely sufficient for predicting future results.

ONE IS (ALMOST) NEVER ENOUGH



- If well results have very large variance how could one curve capture enough character?
- Even a Low/Best/High can be insufficient if the asset is large enough

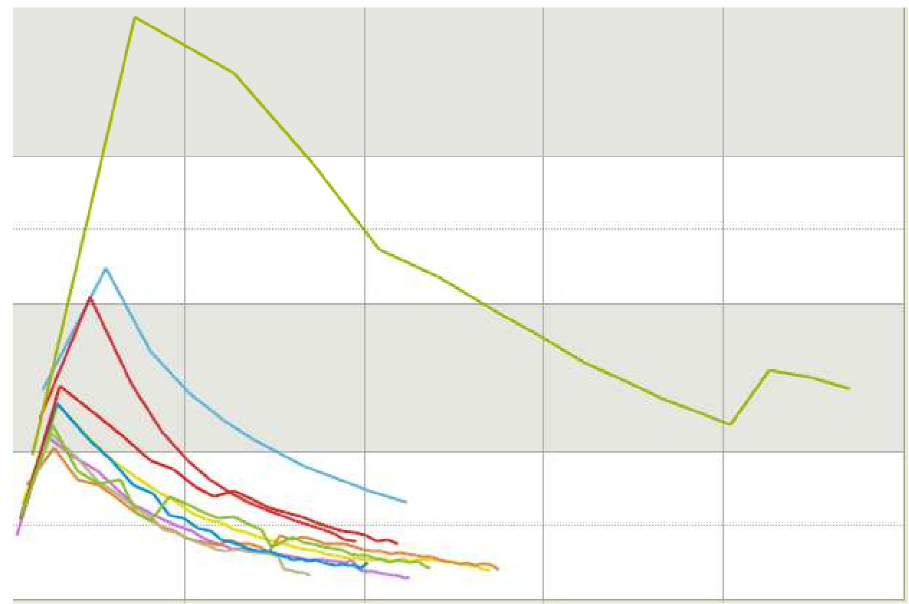
- Dividing that data by reservoir character, CGR, Normalized Peak Rate etc. can tell us a lot more
- Type Curves on groups can have overlap – it's unlikely that variations have hard borders.



WHAT IS A TYPE CURVE?

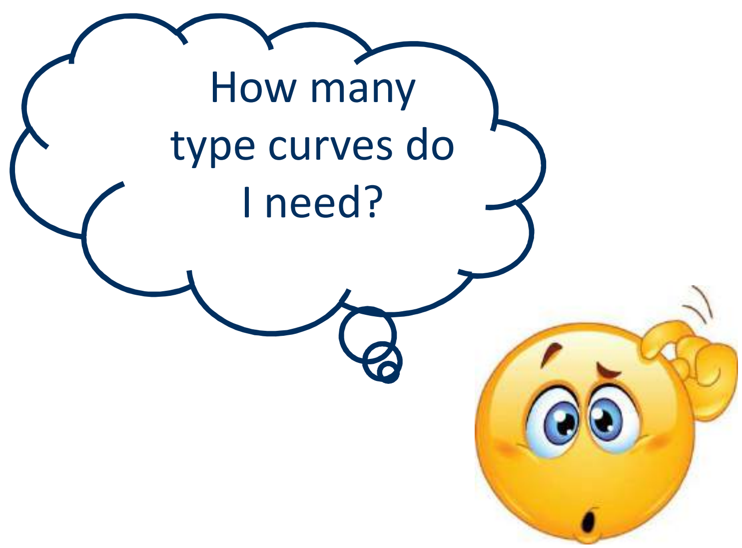
- It is a description of the production behavior we have seen/observed to date.

- Should it be considered a representative EUR that we use?.....Maybe if developed properly.



SO WHAT'S MY NUMBER?

of Type Curves ~ $f\left[\right.$ Geographical/Geological regions x Fluid Types x Well Vintage x Completions x … $\left.\right]$



DEVELOPING TYPE CURVES AND ESTIMATING EUR

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Important considerations when developing type curves:

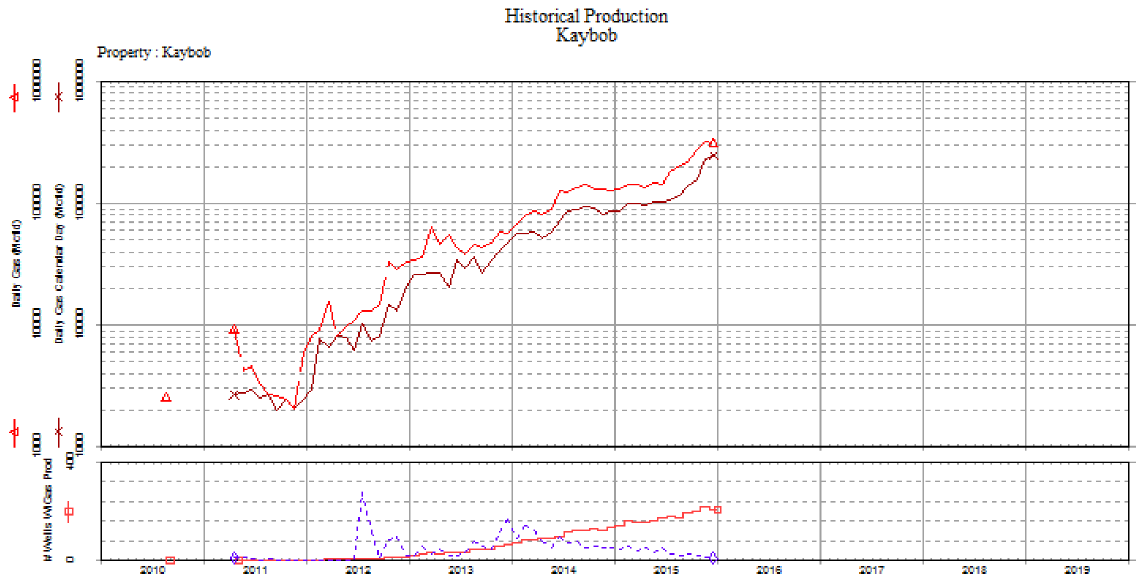
- Operator (operating conditions)
- Geographic variation (geology)
- Learning curve over time
- Well length and/or # of laterals
- Completions (# of stages, tonnes/frac, frac spacing, fluid, completion type, …)
- Cardinality (drill order)

- ……and more!

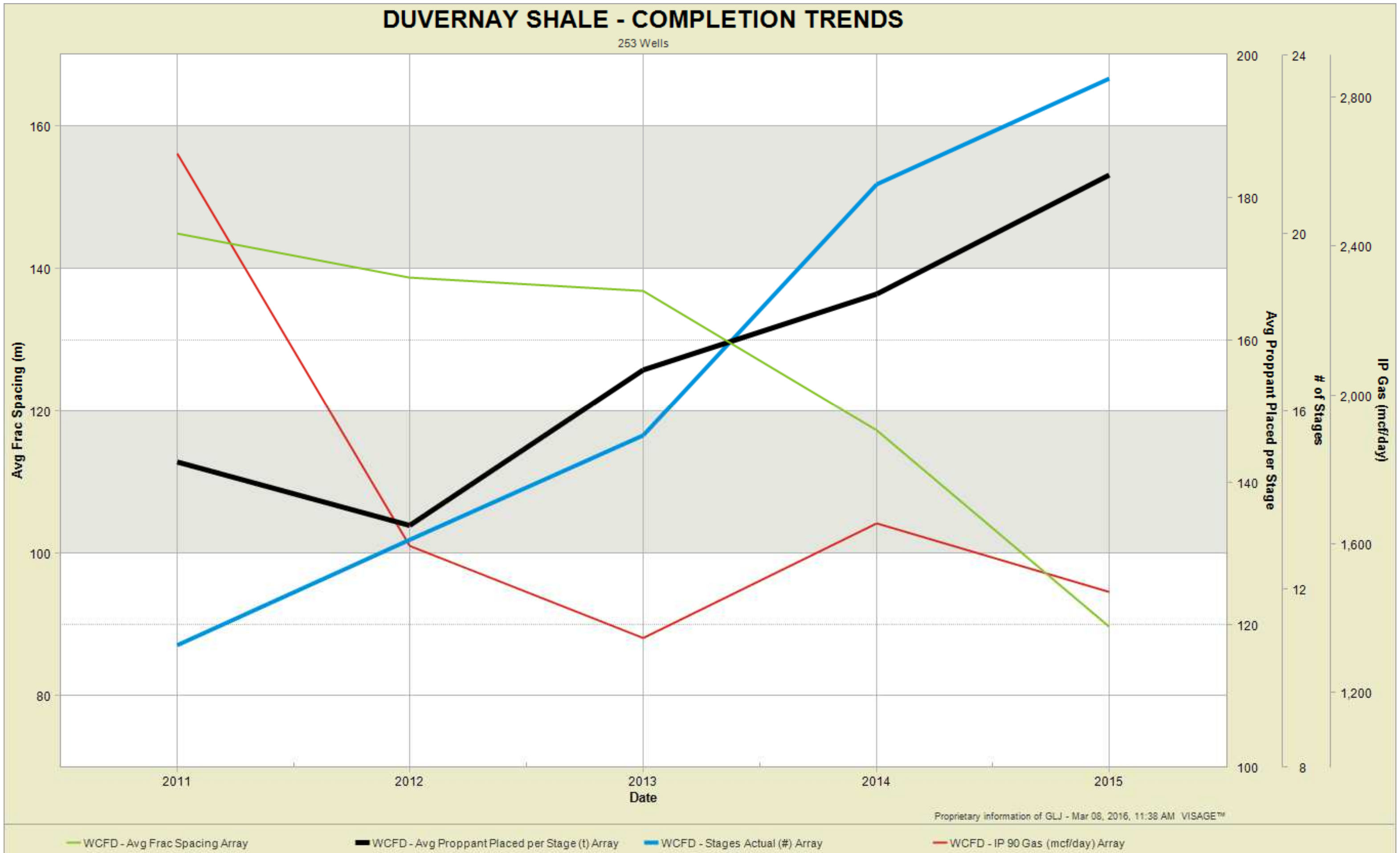
KAYBOB DUVERNAY EXAMPLE

KNOW THY FLUID – DUVERNAY EXAMPLE

- The Duvernay is a Thermogenetic shale
  - Higher temperature reached by source rock the more hydrocarbon cracking, higher gas content and lower liquid yields
- Development started in 2010 and reached ~250-300* mmcf/d as of December 31, 2016

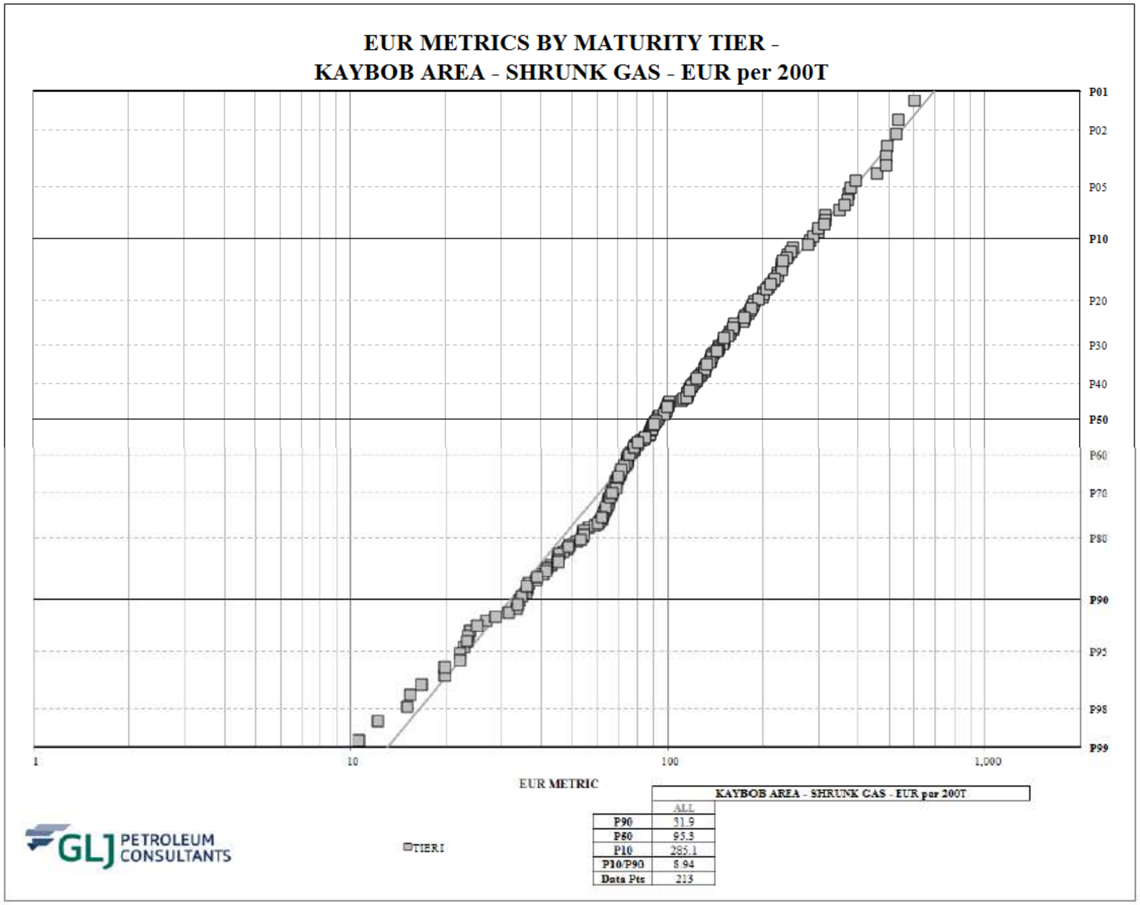


NORMALIZATION – COMPLETION TRENDS



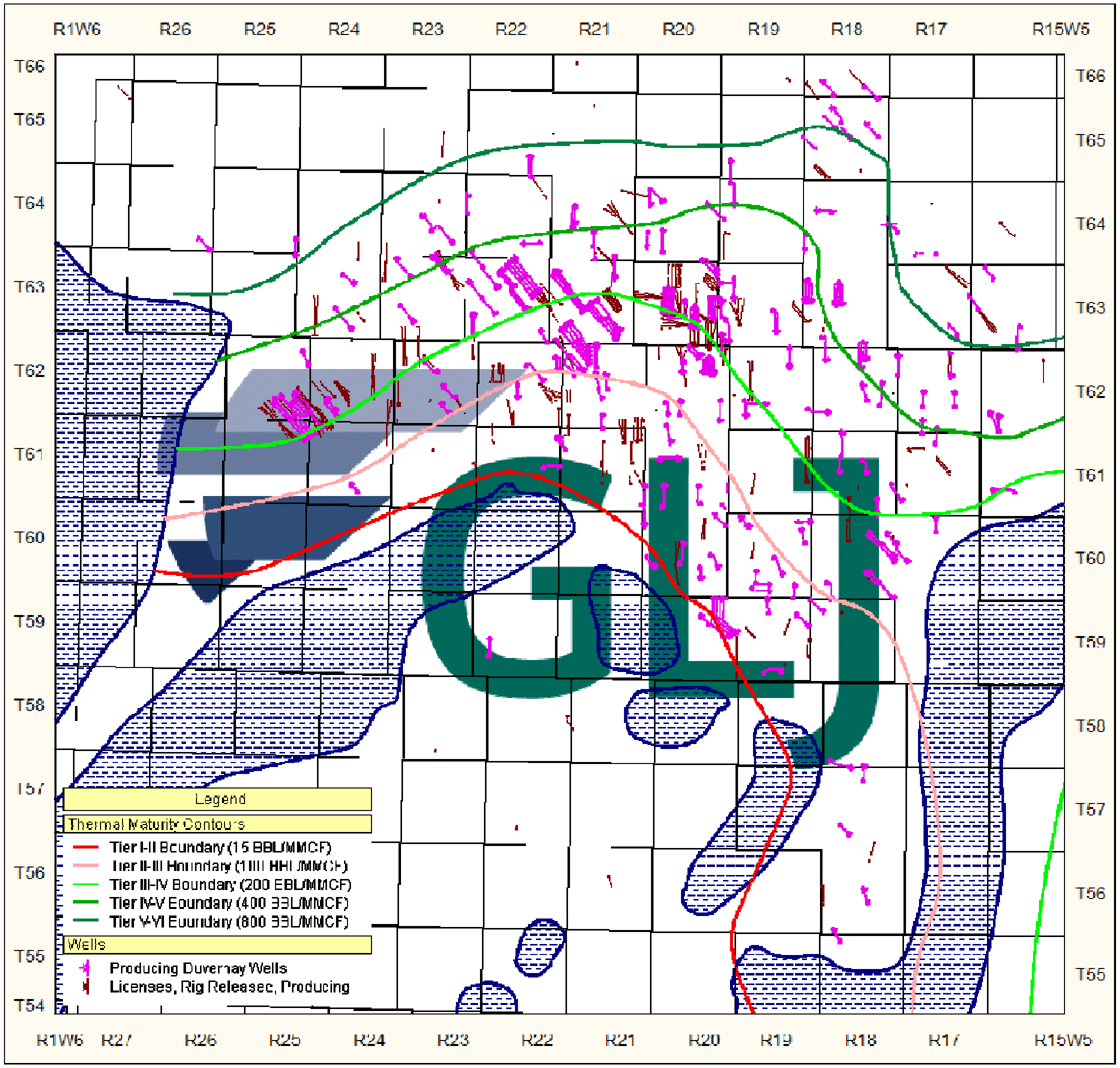
	2011	2012	2013	2014	2015
WCFD - IP 90 Gas (mcf/day) Array	2,648	1,594	1,346	1,656	1,470
WCFD - Stages Actual (#) Array	11	13	15	21	23
WCFD - Avg Proppant Placed per Stage (t) Array	143	134	156	167	183
WCFD - Avg Frac Spacing Array	145	139	137	117	90

NOT THAT ANYONE WOULD DO THIS…RIGHT?



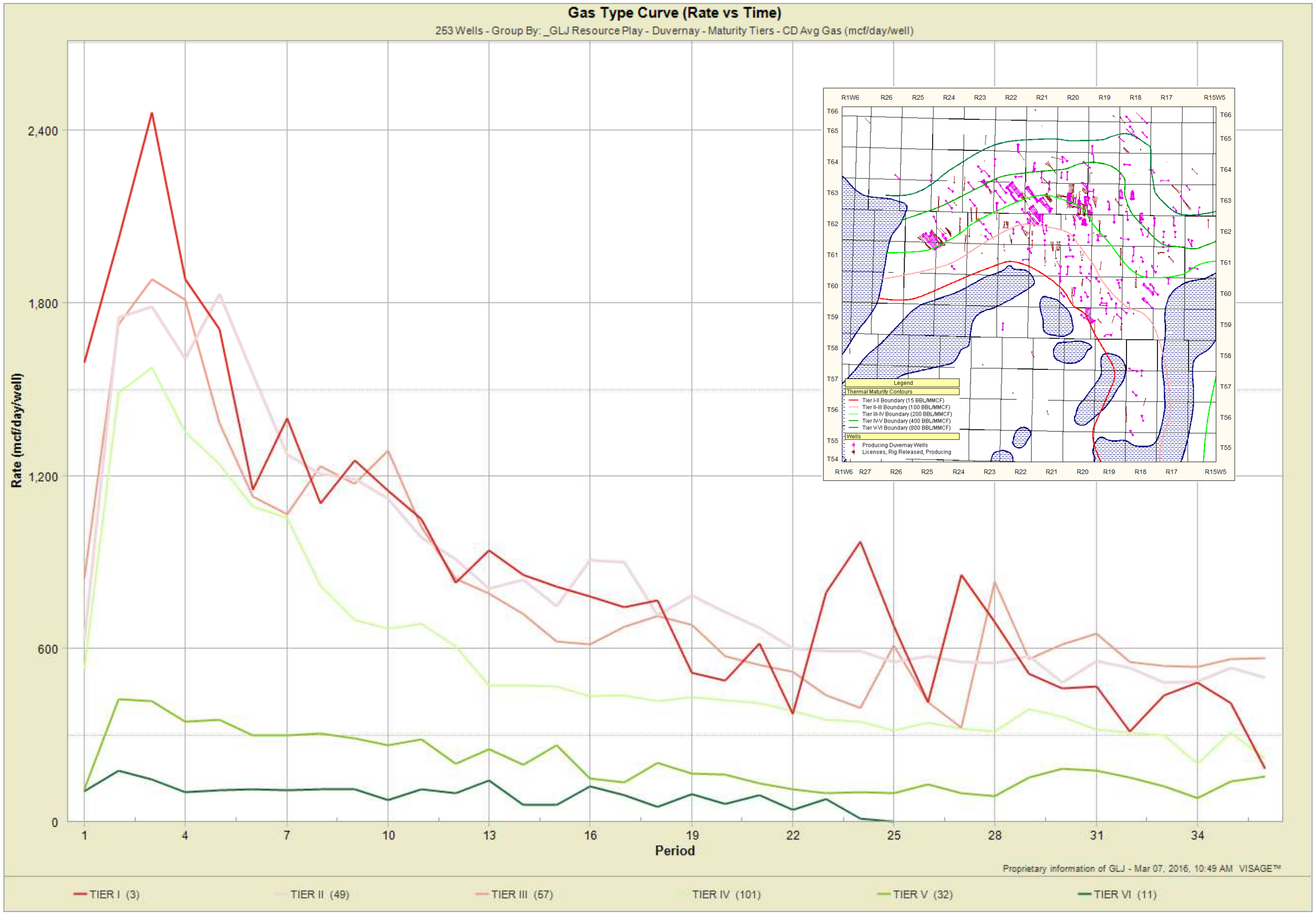
- Probit distribution of gas EUR per 200T placed for ALL duvernay
- Suggests P50~100 mmcf/200T stage
- But is this really a reasonable representation of the Duvernay?

KAYBOB DUVERNAY THERMAL MATURITY

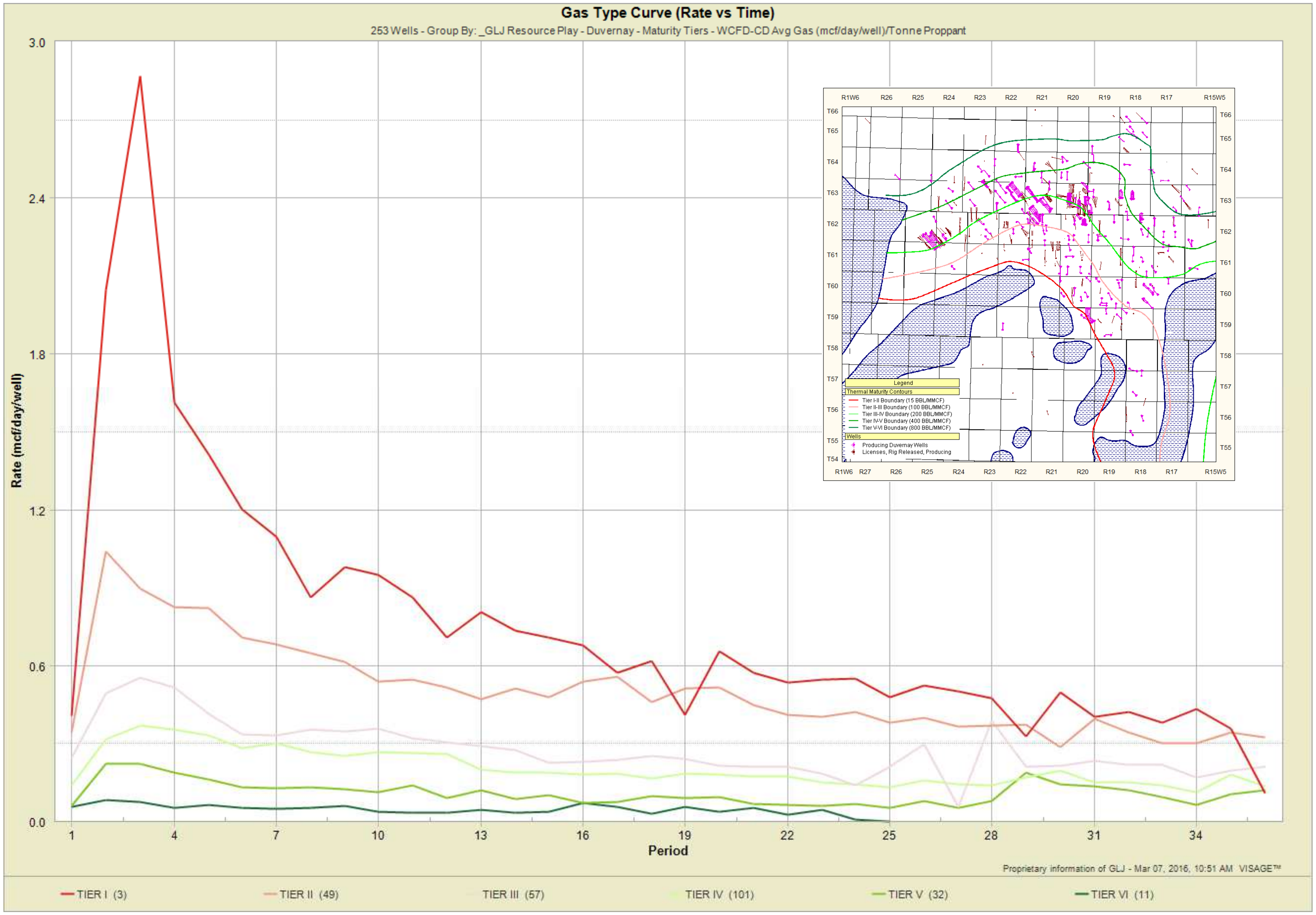


- Logic would dictate that more mature regions (lower liquids) would produce higher gas rates because of…
  - Fluid mobility
  - Higher TOC based porosity
  - Higher pressure gradients

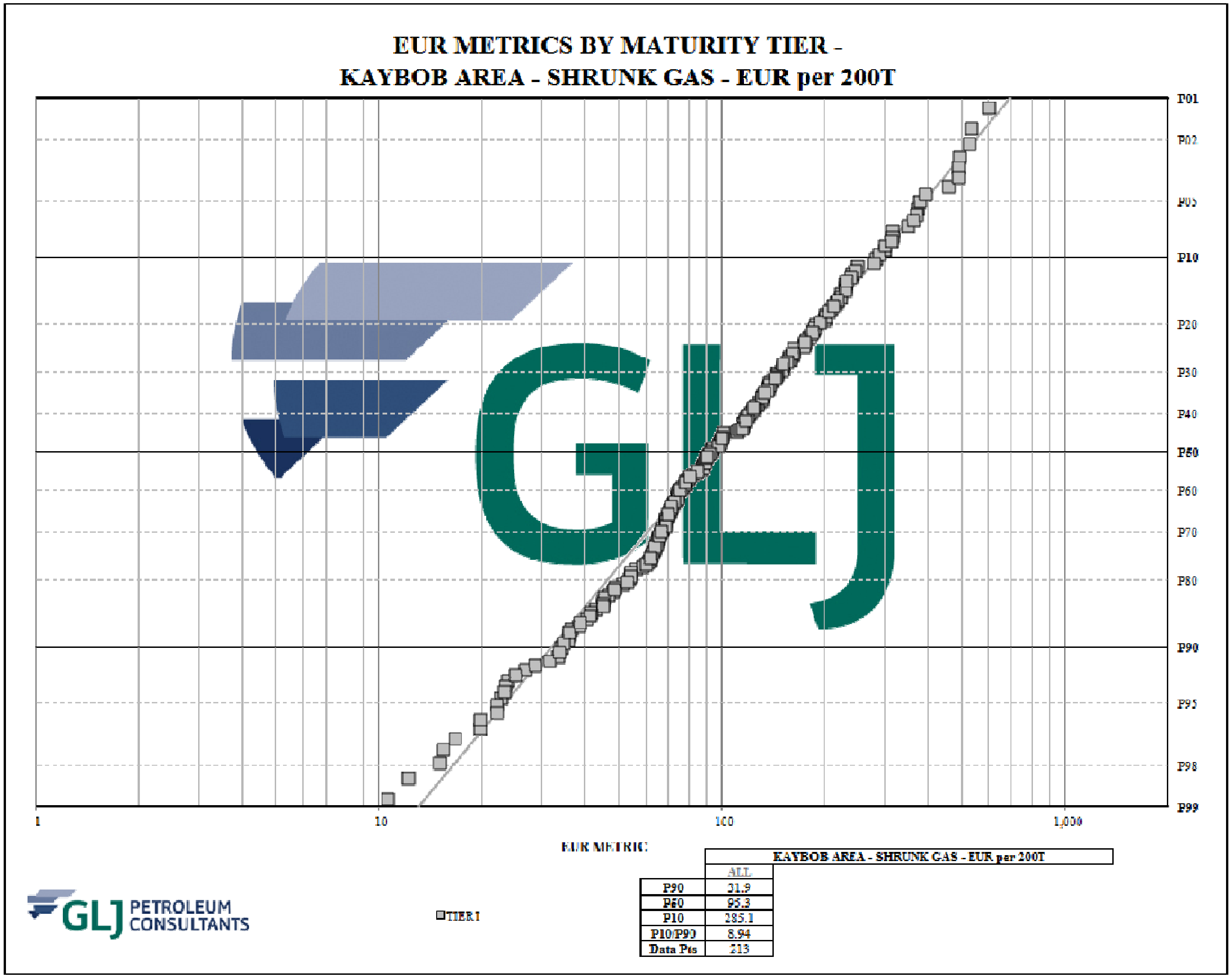
GAS RATE PER WELL



GAS RATE PER TONNE PLACED

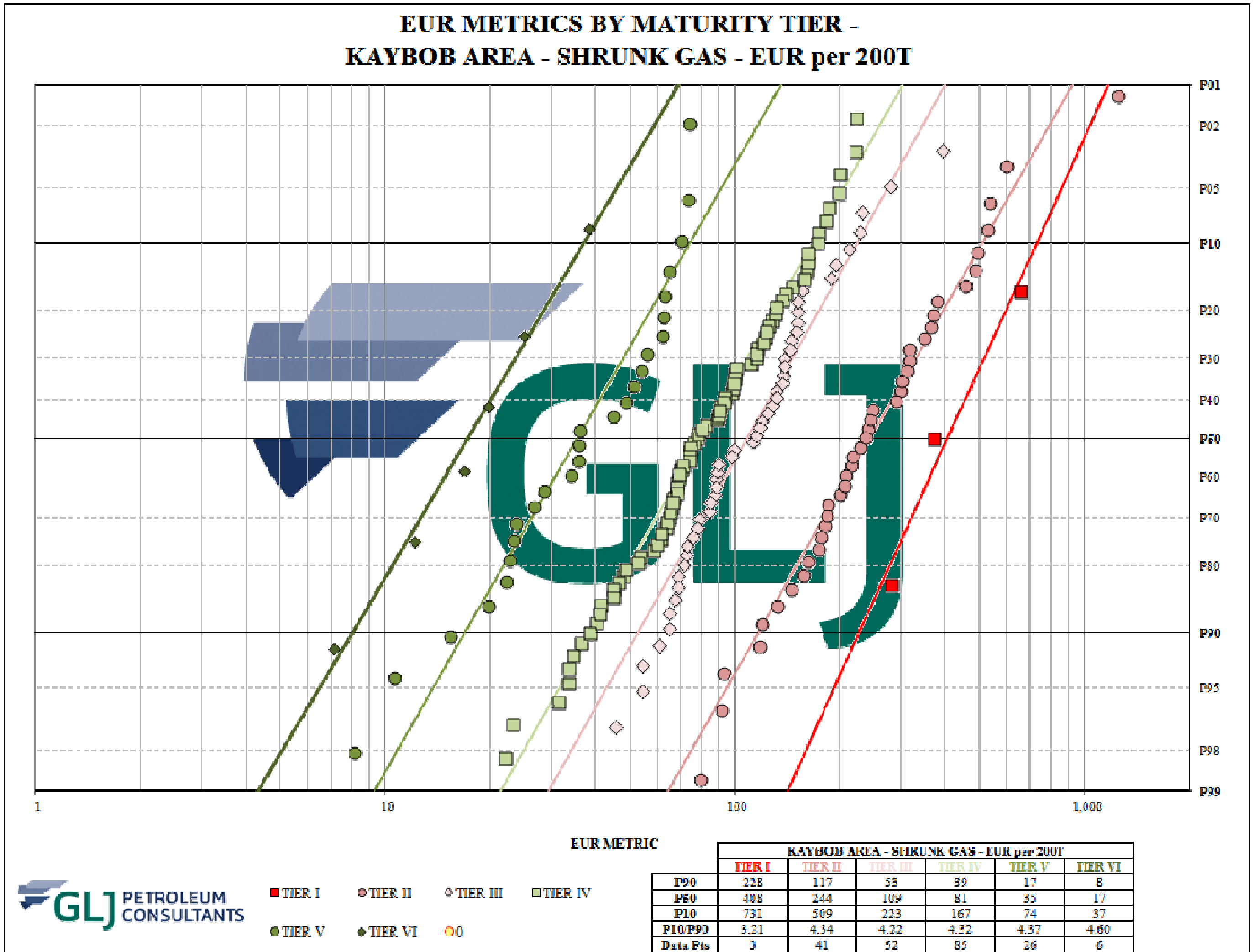


REMINDER…P10/P90~10



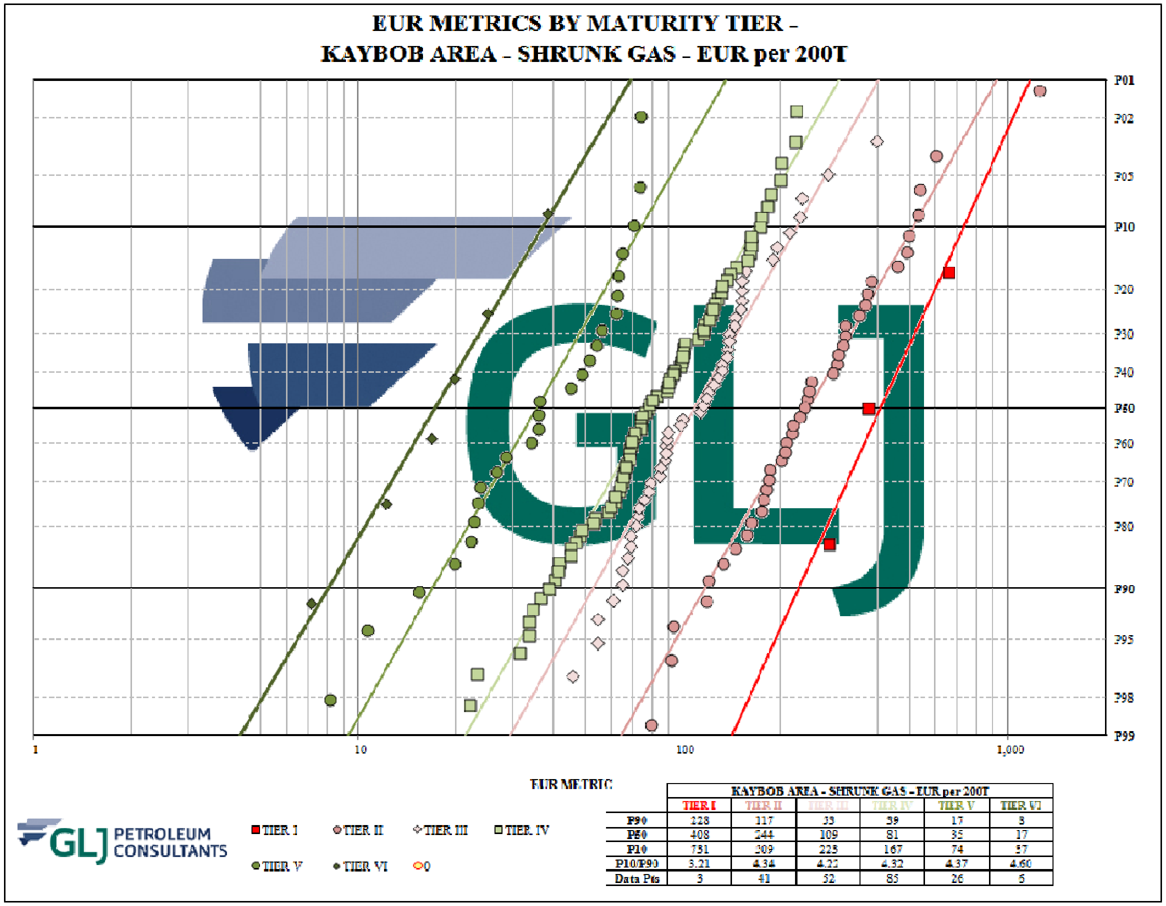
KAYBOB AREA - SHRUNK GAS - EUR per 200T	ALL
P90	31.9
P50	95.3
P10	285.1
P10/P90	8.94
Data Pts	213

DIVIDING THE RESULTS BASED ON CGR



	KAYBOB AREA - SHRUNK GAS - EUR per 200T					
	TIER I	TIER II	TIER III	TIER IV	TIER V	TIER VI
P90	228	117	53	39	17	8
P50	408	244	109	81	35	17
P10	731	509	223	167	74	37
P10/P90	3.21	4.34	4.22	4.32	4.37	4.60
Data Pts	3	41	52	85	26	6

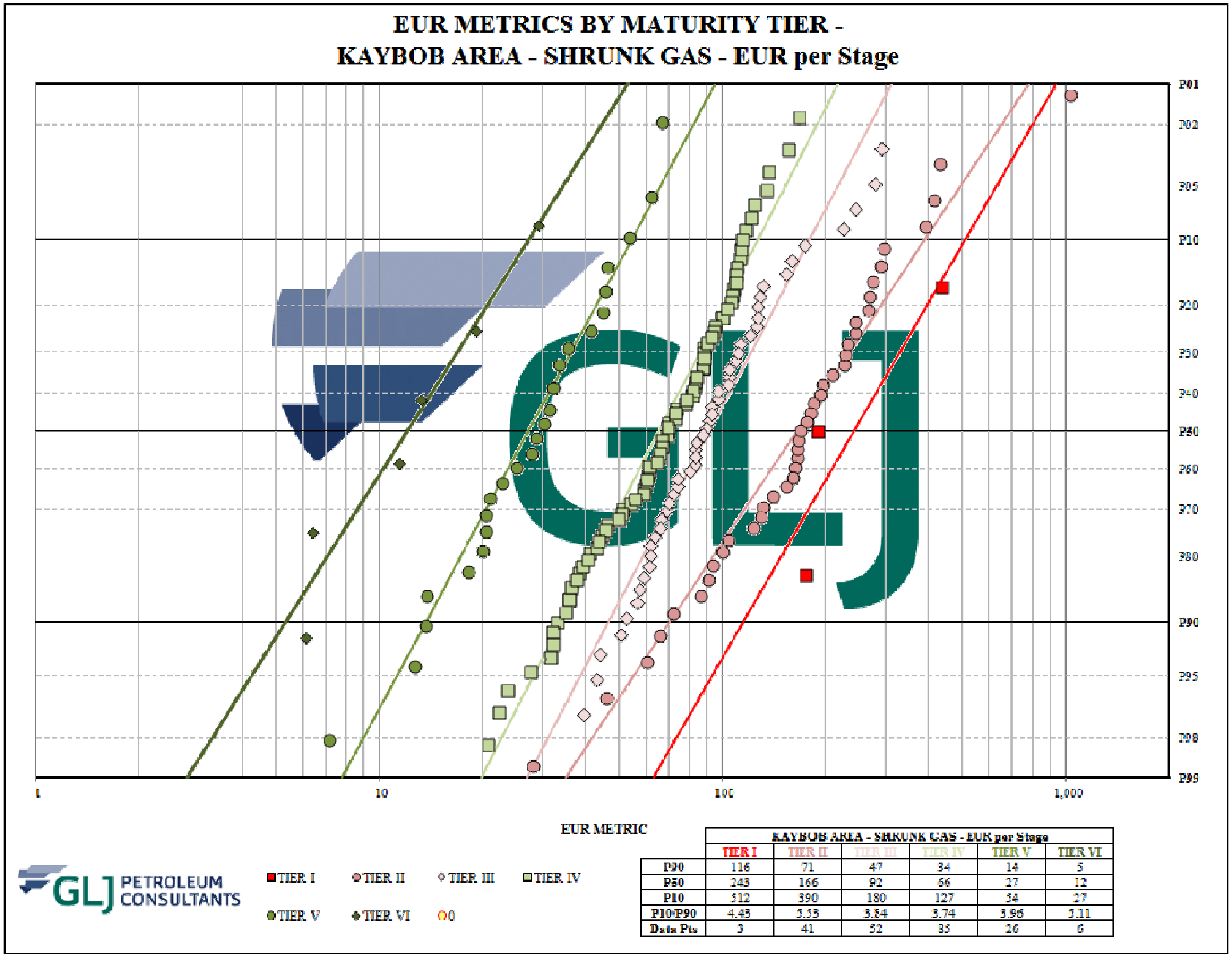
WELL THAT'S BETTER



	KAYBOB AREA - SHRUNK GAS - EUR per 200T					
	TIER I	TIER II	TIER III	TIER IV	TIER V	TIER VI
P90	228	117	53	39	17	8
P50	408	244	109	81	35	17
P10	731	509	225	167	74	37
P10/P90	3.21	4.34	4.25	4.32	4.37	4.60
Data Pts	3	41	52	85	26	5

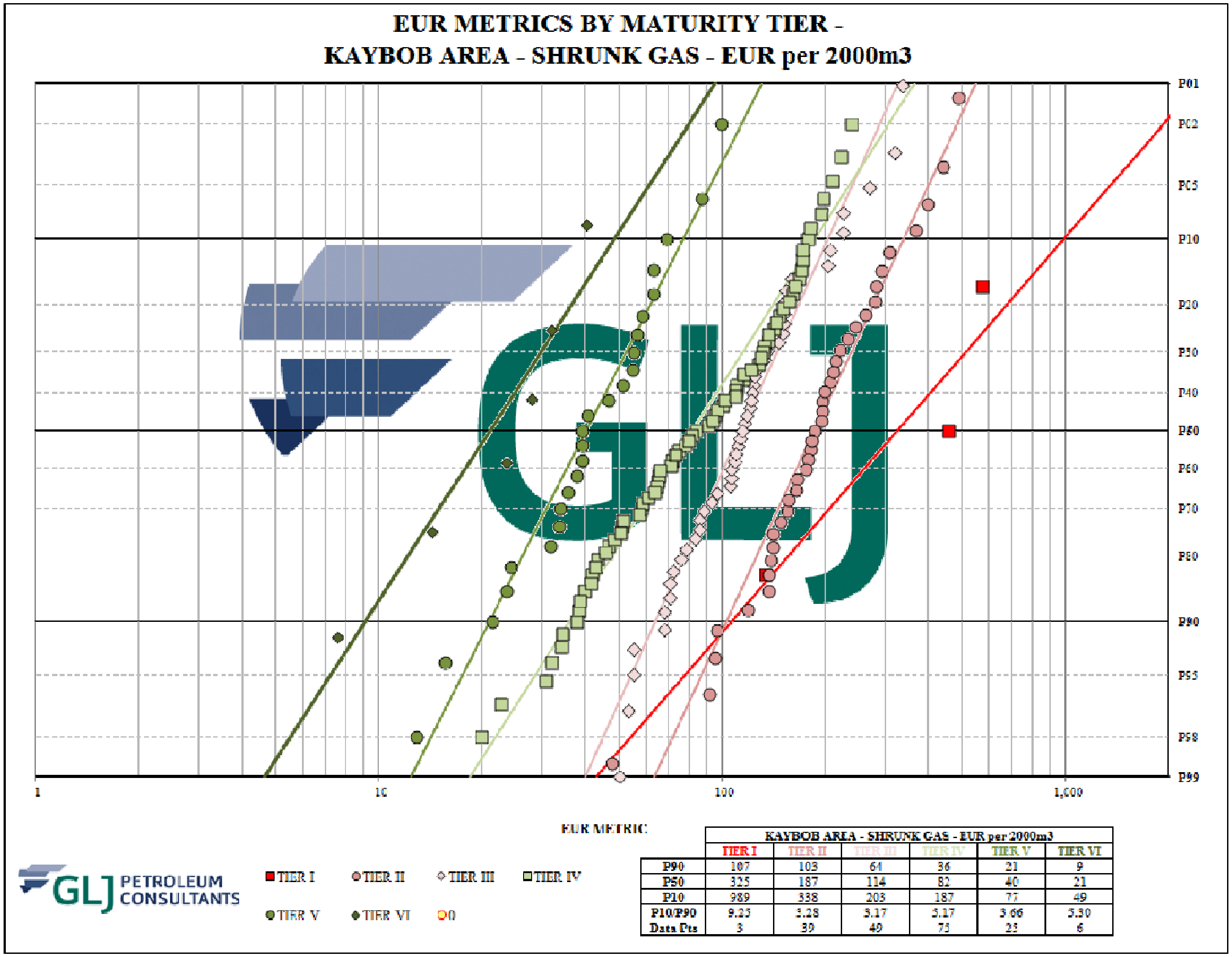
- Best Estimate EUR could vary from 20 to 400 mmcf per 200T!
- Interpretations with corresponding liquid production has obvious NPV implications

IMPORTANT TO CONSIDER OTHER COMPLETION CHARACTERISTICS



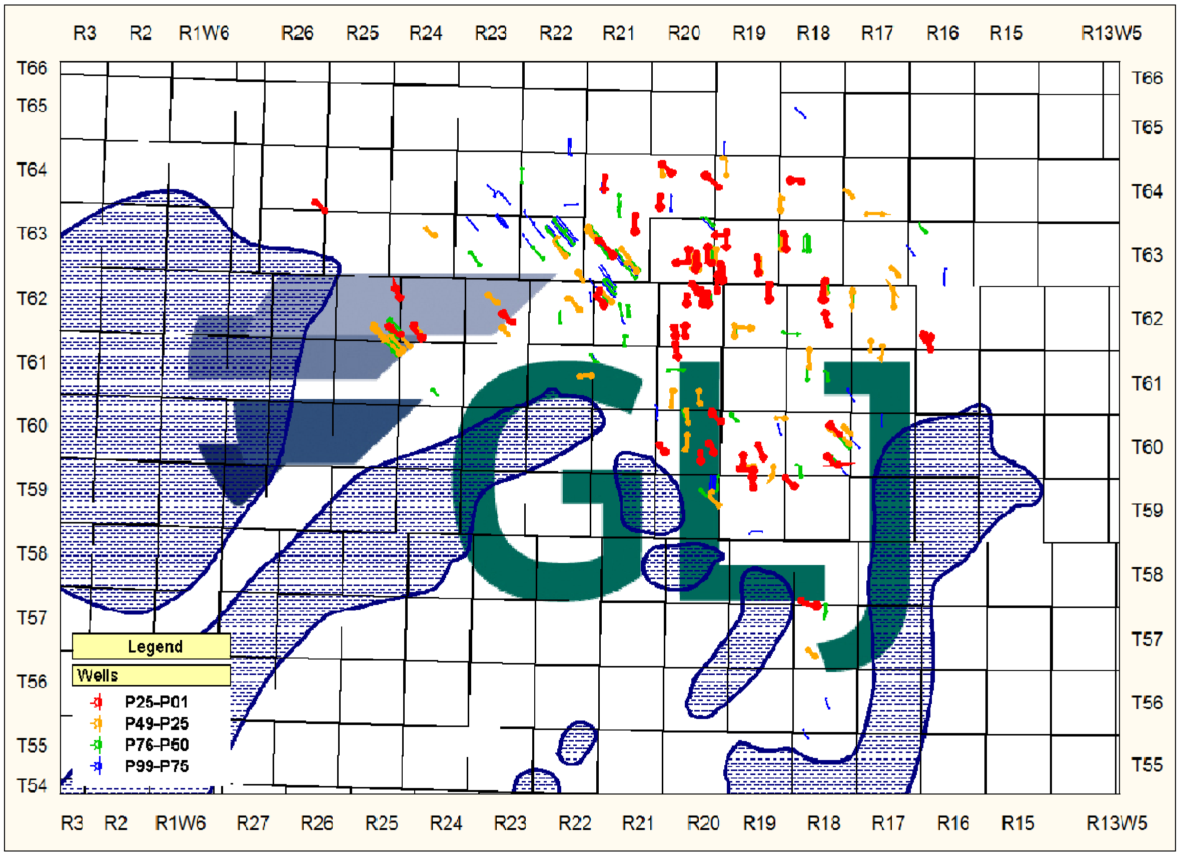
KAYBOB AREA - SHRUNK GAS - EUR per Stage	TIER I	TIER II	TIER III	TIER IV	TIER V	TIER VI
P90	116	71	47	34	14	5
P50	243	166	92	66	27	12
P10	512	390	180	127	54	27
P10/P90	4.43	5.53	3.84	3.74	3.96	5.11
Data Pts	3	41	52	35	26	6

IMPORTANT TO CONSIDER OTHER COMPLETION CHARACTERISTICS



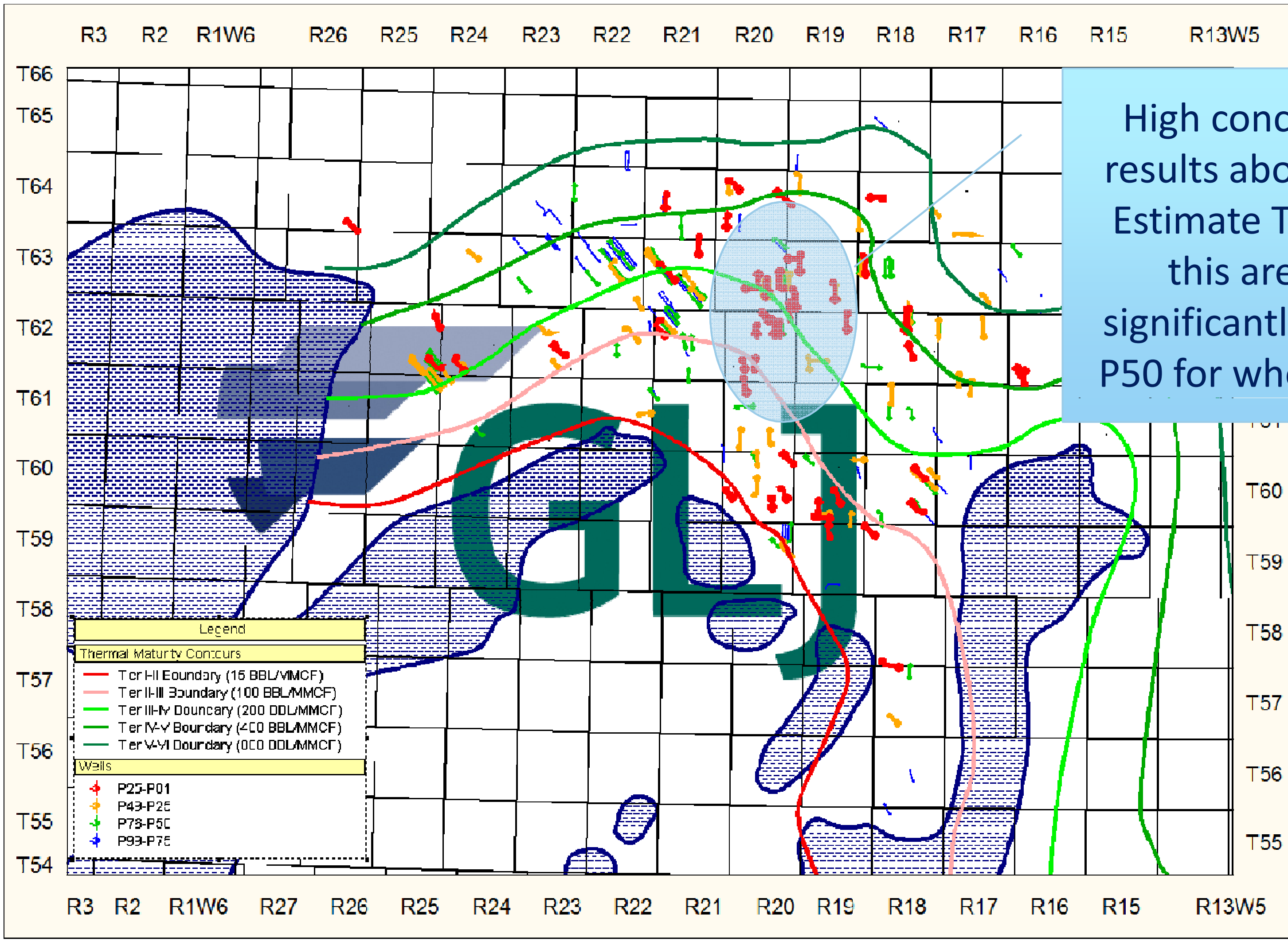
	KAYBOB AREA - SHRUNK GAS - EUR per 2000m3					
	TIER I	TIER II	TIER III	TIER IV	TIER V	TIER VI
P90	107	103	64	36	21	9
P50	325	187	114	82	40	21
P10	989	338	203	187	77	49
P10/P90	9.25	3.28	3.17	5.17	3.66	5.30
Data Pts	3	39	49	75	25	6

TAKEN FLUIDS INTO ACCOUNT – WHAT ABOUT THE ROCK?



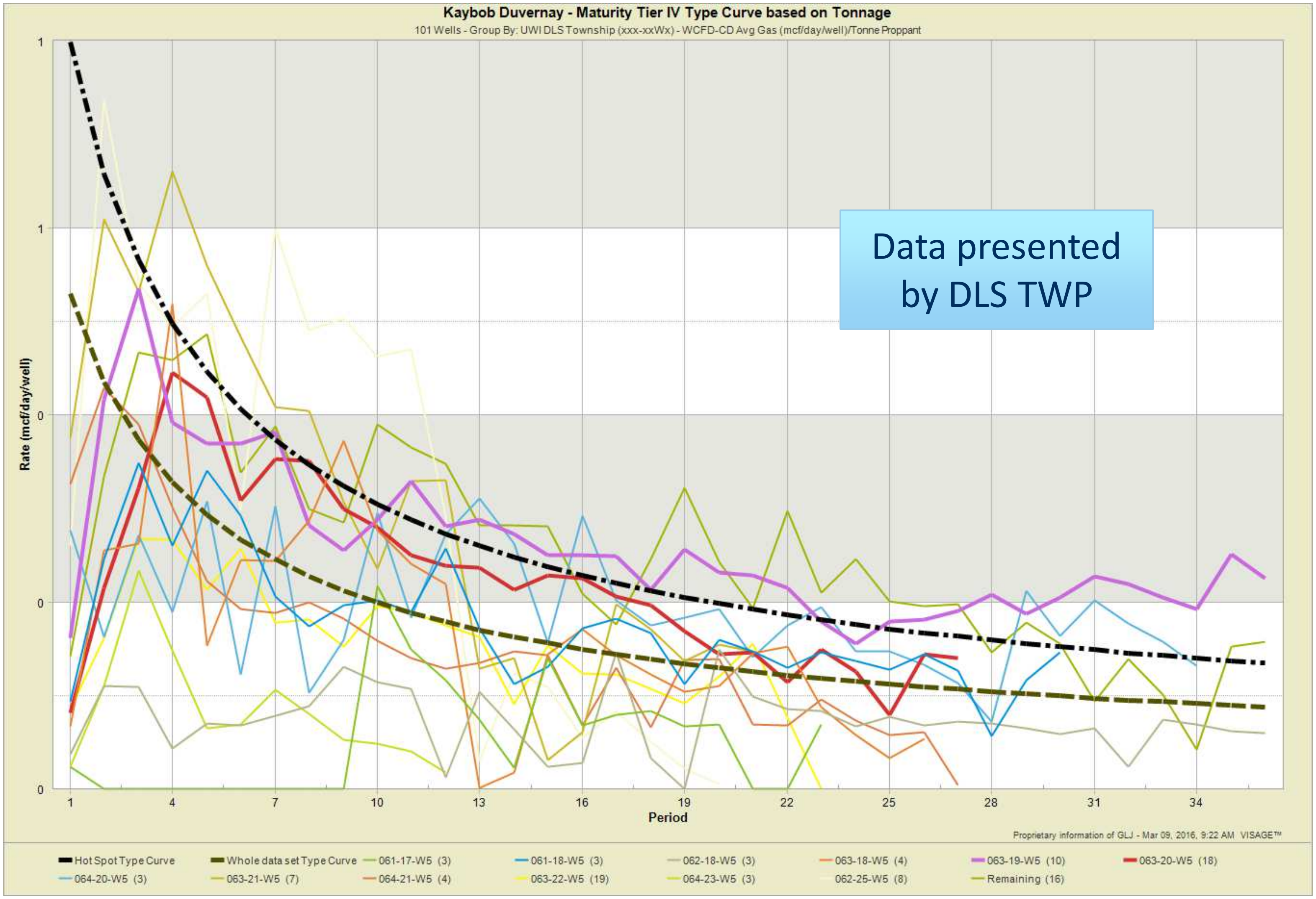
- If the data is grouped appropriately we can start to see reservoir characteristics if all completions are comparable…
  - Of if completions are highly varied you might see that too

REPEATED RESULTS ABOVE/BELOW P50...

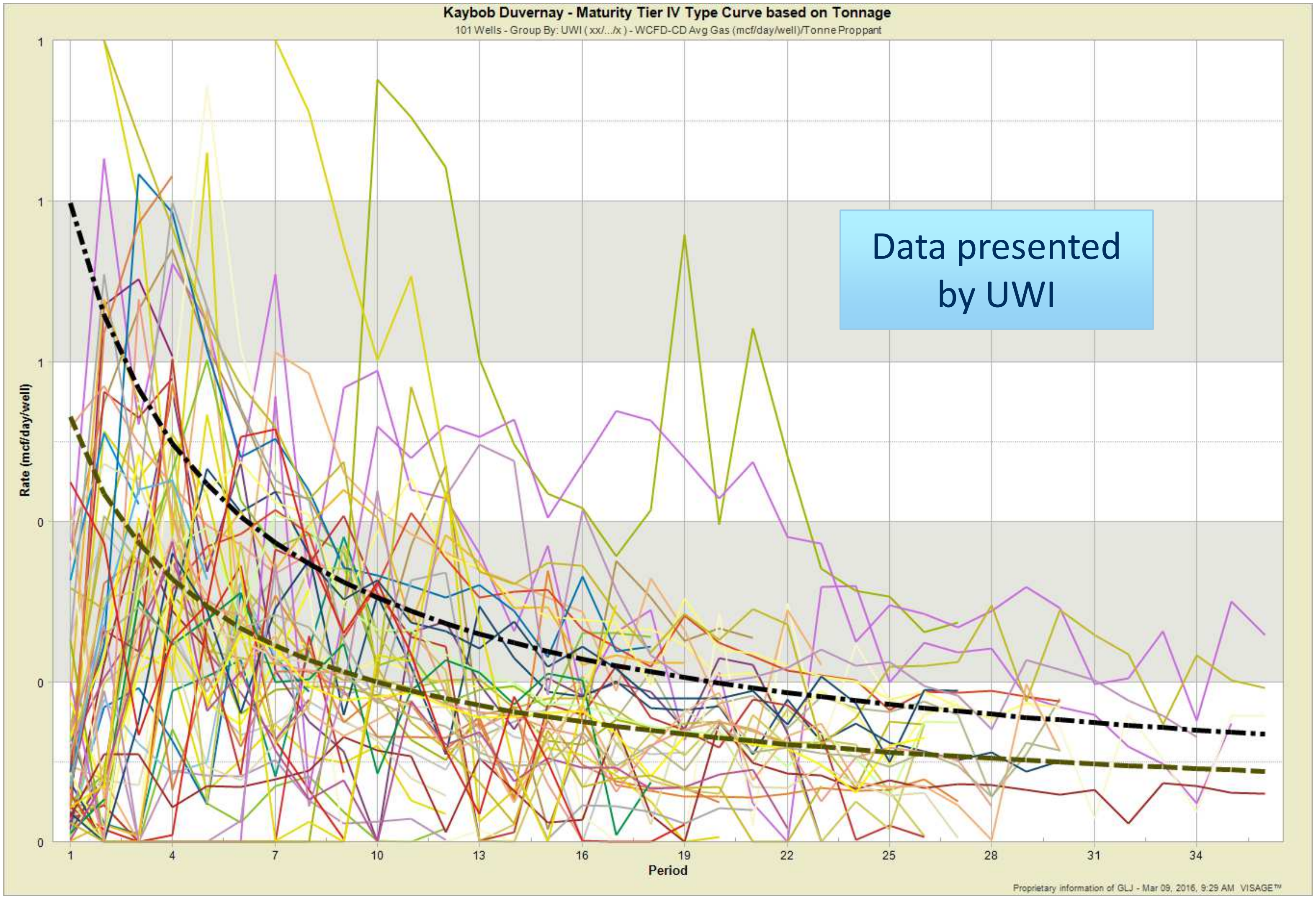


High concentration of results above P50...Best Estimate Typecurve for this area may be significantly higher than P50 for whole of Kaybob

TYPE CURVE EXAMPLE



TYPE CURVE EXAMPLE



TYPE CURVE PITFALLS

A QUICK ASIDE ON ‘CARDINALITY‘

Cardinality (i.e. drill order)

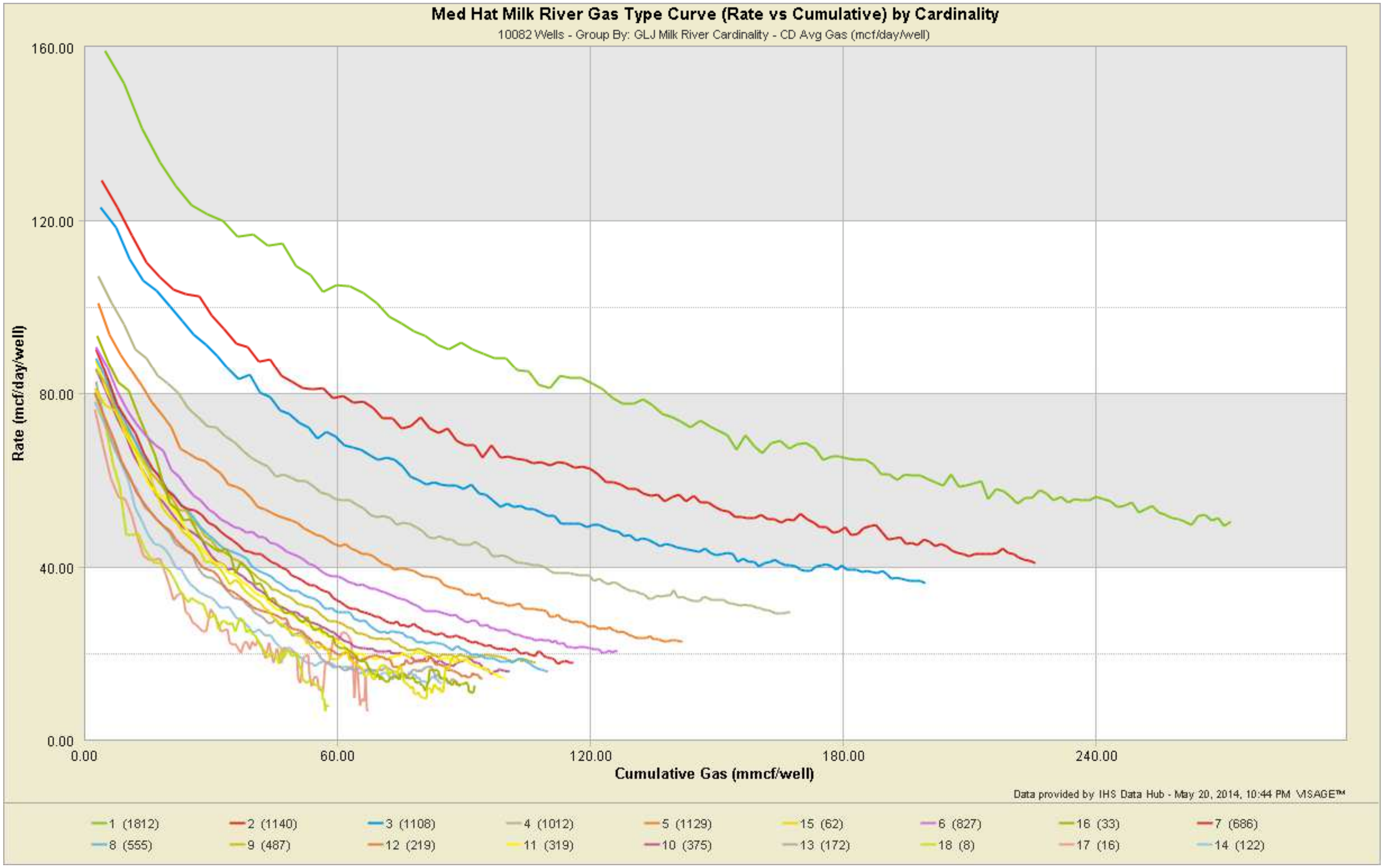
- Should we expect the same results with additional drilling? Does the old type curve still apply?

Comparison between 2 Plays:

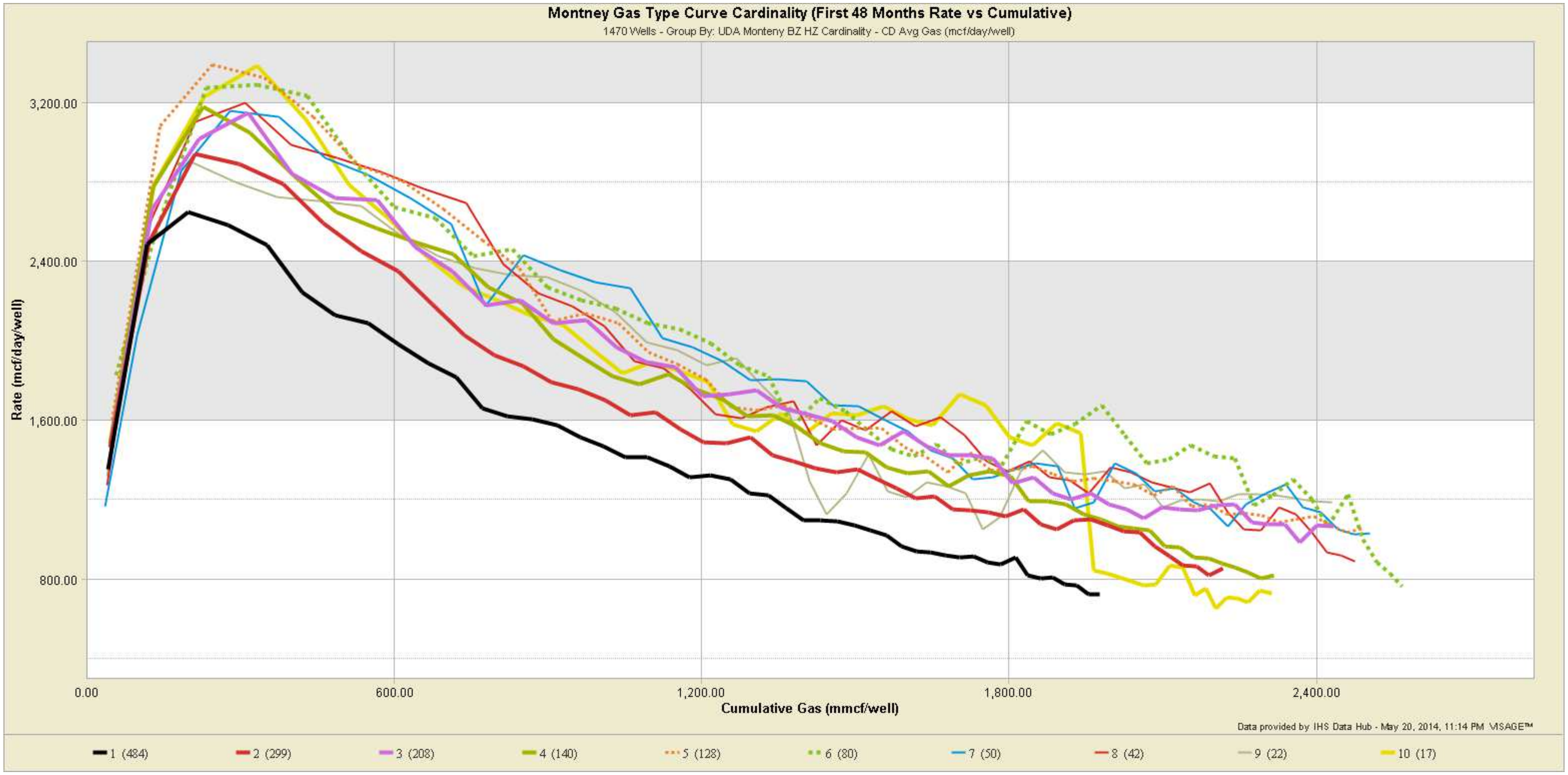
- Milk River vs Montney

This is of particular importance in the ‘more conventional’ Spirit River, where higher permeability and downspacing can lead to diminishing returns not yet observed (particularly in late life)

MED HAT/MILK RIVER CARINALITY



MONTNEY CARDINALITY



MONTNEY CARDINALOGY PER STAGE

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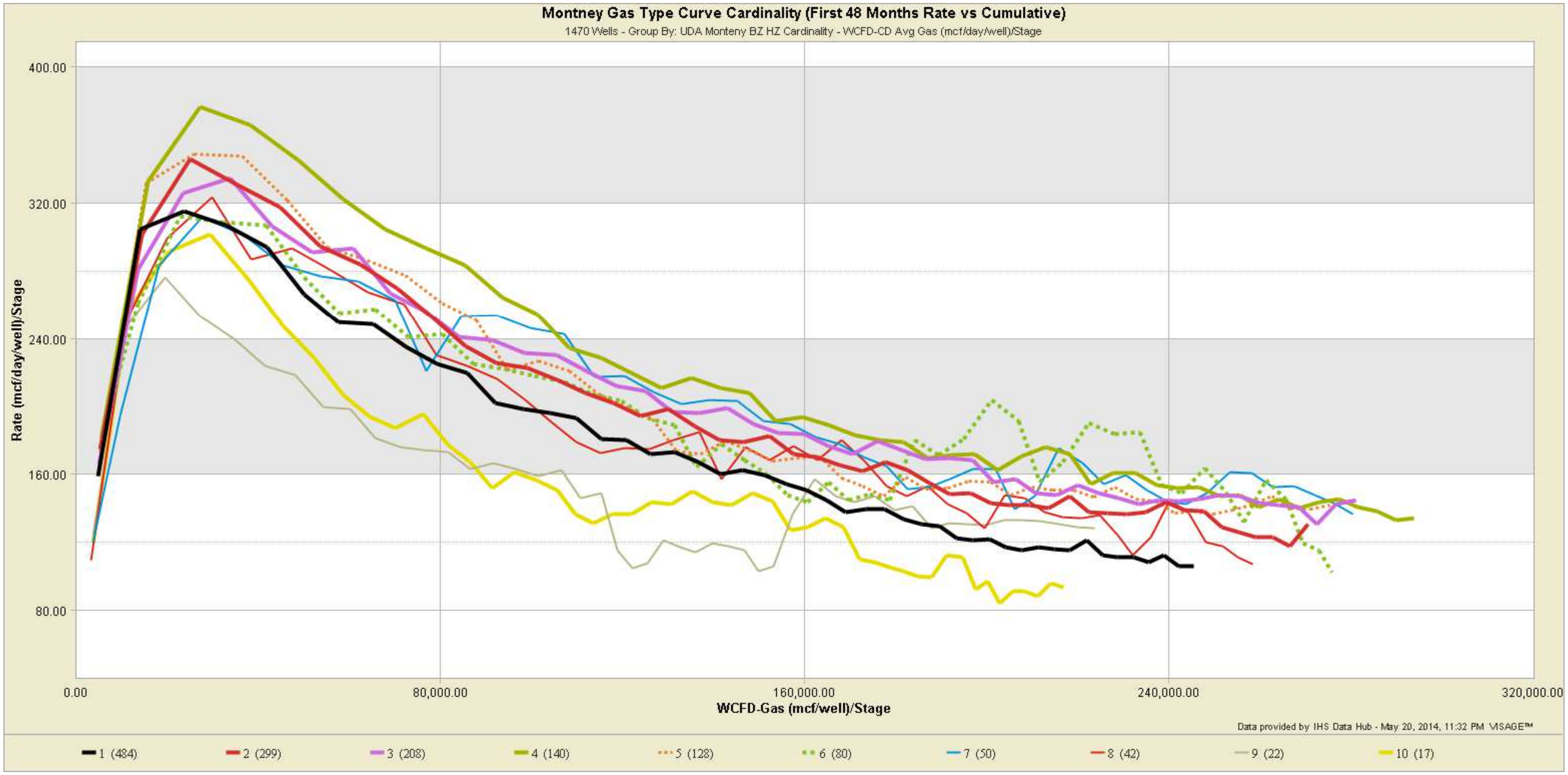


DEVELOPING WELL EXPECTATIONS

- You need to understand your reservoir!

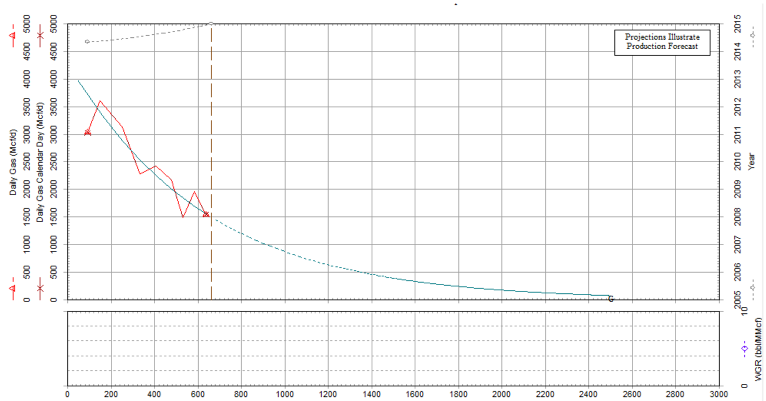
- Fundamentally, you need an underlying knowledge of :
  - Geology: Petrophysics (Phi, Sw, Sor etc.)
  - Reservoir Fluid & Flow Dynamics (governing performance data)
  - 3Ps: PVT, Pressure and Permeability

- Performance Differences:
  - It's not just completions….try to separate reservoir from completions (if you can, and you can't always do this).
  - Small Changes in reservoir properties can make a big difference in production!

COMMON PITFALLS

ACTIVITY!

WELLS 1-4



Decline Analysis Summary At 2015/01/01

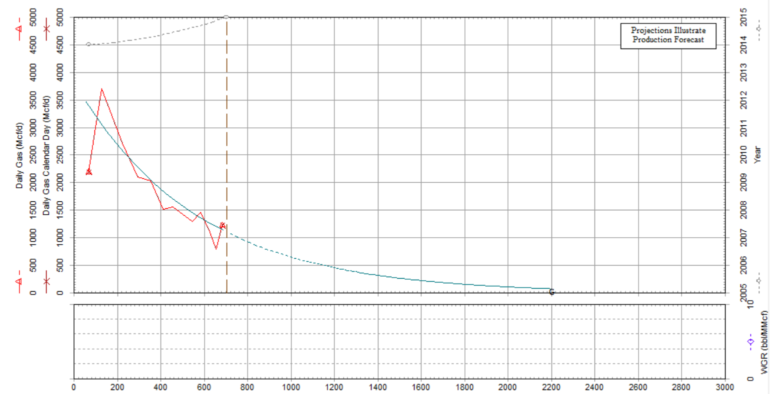
Reserves Classification	Raw Gas (MMcf) Ultimate	Raw Gas (MMcf) Cum Prd	Raw Gas (MMcf) Remain	Rates (Mcf/d) Initial	Rates (Mcf/d) Final	Decline Initial	Decline Expont	Decline Term
P + P Prd — G	2500	661	1839	1500	75	46.7	1.00	6.0

Average Production Rates (Last 12 months ending 2014/12/31)

Gas :	2406.1 Mcf/d	2403.6 Mcf/cd	WGR :	0.0 bbl/MMcf
Oil :	0.0 bbl/d	0.0 bbl/cd	GOR :	0.0 scf/stb
On Prod :	0.0 days		WC :	0.0 %

Cumulative Production

Oil : 0.0 Mbbl Gas : 661.0 MMcf Water : 0.0 Mbbl



Decline Analysis Summary At 2015/01/01

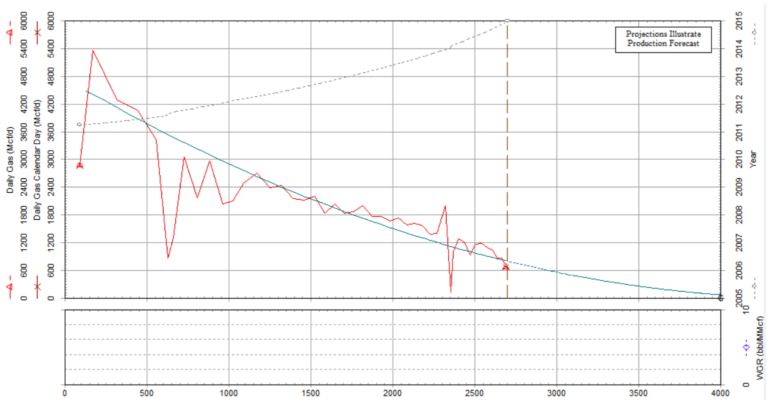
Reserves Classification	Raw Gas (MMcf) Ultimate	Raw Gas (MMcf) Cum Prd	Raw Gas (MMcf) Remain	Rates (Mcf/d) Initial	Rates (Mcf/d) Final	Decline Initial	Decline Expont	Decline Term
P + P Prd — G	2200	703	1497	1100	75	41.6	1.00	6.0

Average Production Rates (Last 12 months ending 2014/12/31)

Gas :	1744.6 Mcf/d	1739.7 Mcf/cd	WGR :	0.0 bbl/MMcf
Oil :	0.0 bbl/d	0.0 bbl/cd	GOR :	0.0 scf/stb
On Prod :	0.0 days		WC :	0.0 %

Cumulative Production

Oil : 0.0 Mbbl Gas : 703.0 MMcf Water : 0.0 Mbbl



Decline Analysis Summary At 2015/01/01

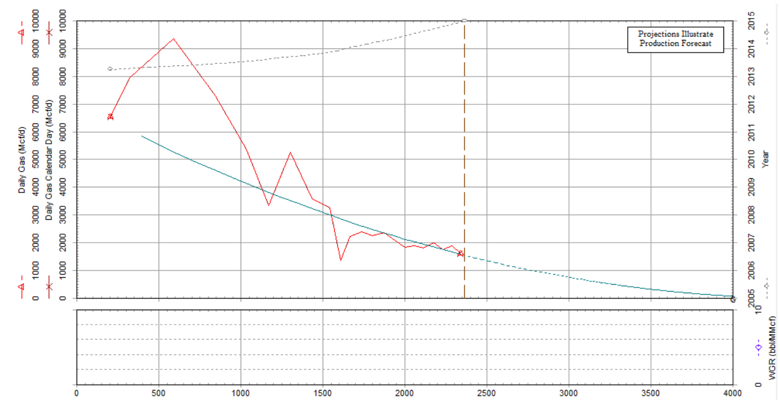
Reserves Classification	Raw Gas (MMcf) Ultimate	Raw Gas (MMcf) Cum Prd	Raw Gas (MMcf) Remain	Rates (Mcf/d) Initial	Rates (Mcf/d) Final	Decline Initial	Decline Expont	Decline Term
P + P Prd — G	4000	2699	1301	800	75	25.1	0.50	6.0

Average Production Rates (Last 12 months ending 2014/12/31)

Gas :	955.0 Mcf/d	953.4 Mcf/cd	WGR :	0.0 bbl/MMcf
Oil :	0.0 bbl/d	0.0 bbl/cd	GOR :	0.0 scf/stb
On Prod :	0.0 days		WC :	0.0 %

Cumulative Production

Oil : 0.0 Mbbl Gas : 2699.0 MMcf Water : 0.0 Mbbl



Decline Analysis Summary At 2015/01/01

Reserves Classification	Raw Gas (MMcf) Ultimate	Raw Gas (MMcf) Cum Prd	Raw Gas (MMcf) Remain	Rates (Mcf/d) Initial	Rates (Mcf/d) Final	Decline Initial	Decline Expont
P + P Prd — G	4000	2364	1636	1550	75	38.0	0.50

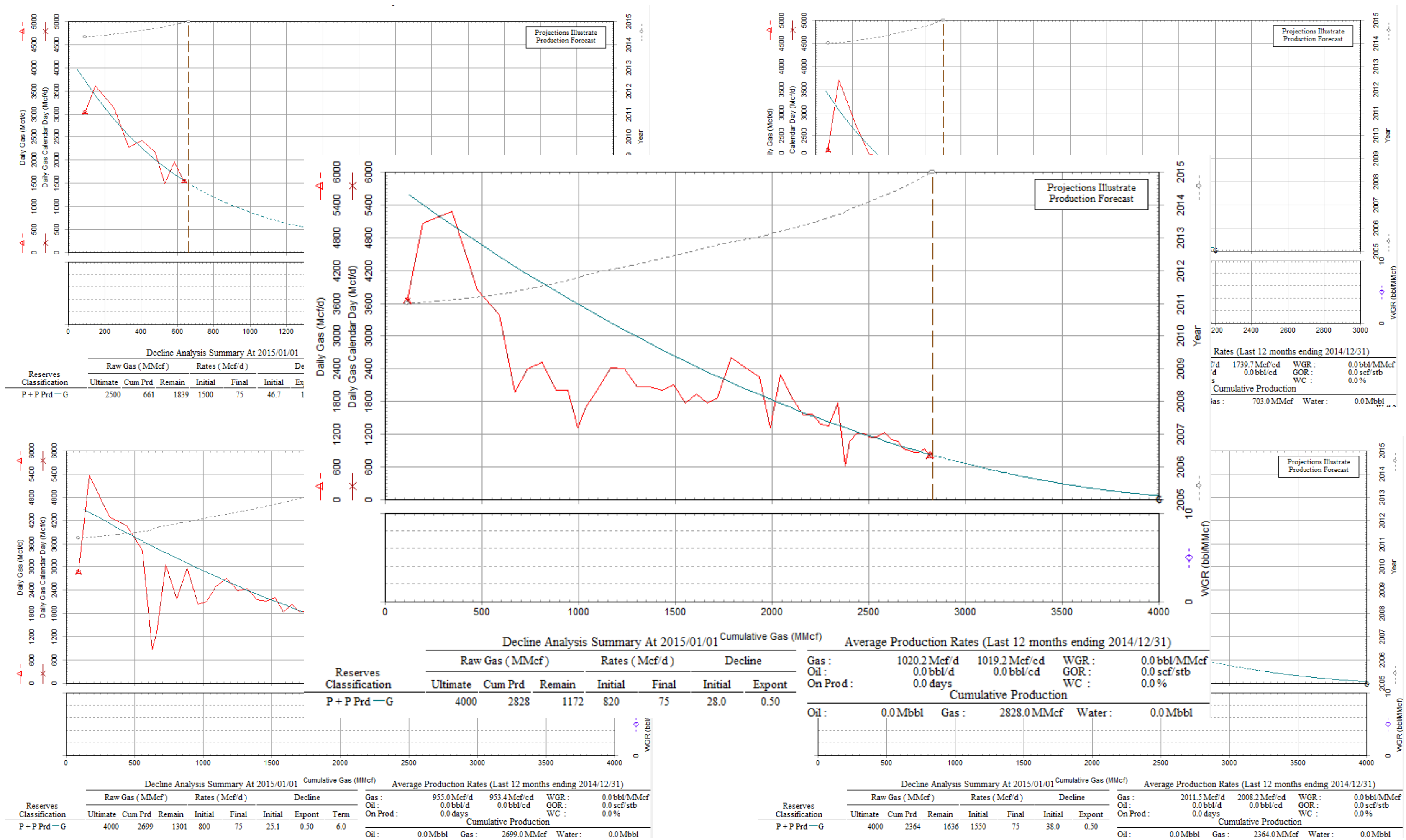
Average Production Rates (Last 12 months ending 2014/12/31)

Gas :	2011.5 Mcf/d	2008.2 Mcf/cd	WGR :	0.0 bbl/MMcf
Oil :	0.0 bbl/d	0.0 bbl/cd	GOR :	0.0 scf/stb
On Prod :	0.0 days		WC :	0.0 %

Cumulative Production

Oil : 0.0 Mbbl Gas : 2364.0 MMcf Water : 0.0 Mbbl

WELL 5 WAS THE AVERAGE?!?



COMMON PITFALLS – AVERAGES

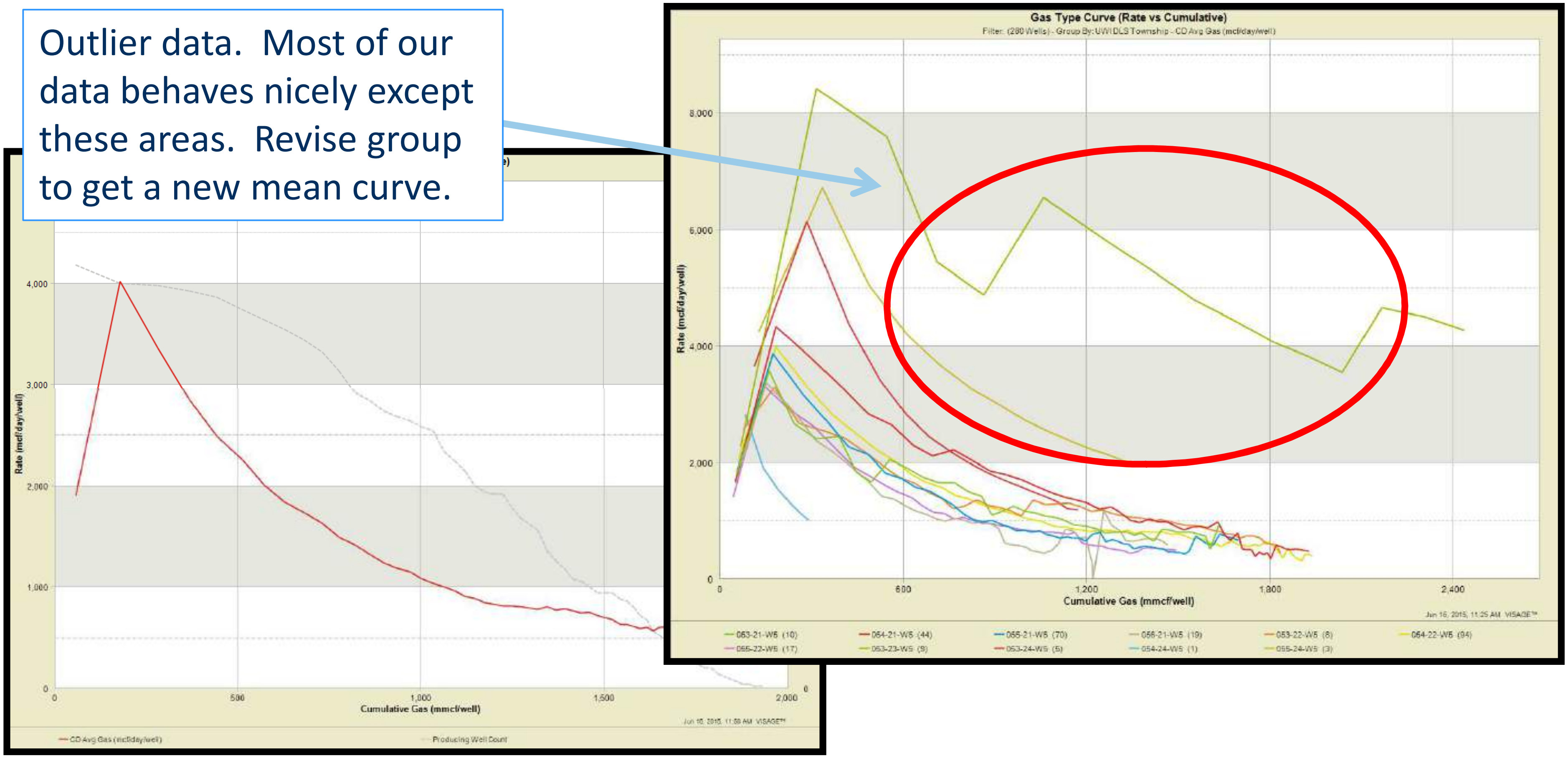
- Common ‘malpractice’ is to complete decline analysis on the average well performance.
- Wells with atypical well production profiles can have dramatic effects on average well profile

IMPORTANT POINTS TO CONSIDER: PRESSURE INFLUENCES

- Additional back pressure/drawdown can behavior changes that cannot be quantified when evaluating based on rates alone.
- This can also appear as a different flow regime prior to linear flow in early time data
- Often when estimating reserves by decline alone, the back pressure causes a flattening of behavior
- Conversely, increasing drawdown cause an artificial inflation of rates, can falsely appears as better productivity
- Can lead to over/under estimation of reserves/EUR
- Need to recognize “false” reservoir energy

MEAN CURVES ARE CONDENSED DATA

Outlier data. Most of our data behaves nicely except these areas. Revise group to get a new mean curve.



- Always review the underlying data set.
- Move between a mean representation and examine outlier data

UNDERLYING DATA: UNDERSTAND WHAT IS IN YOUR MEAN CURVE

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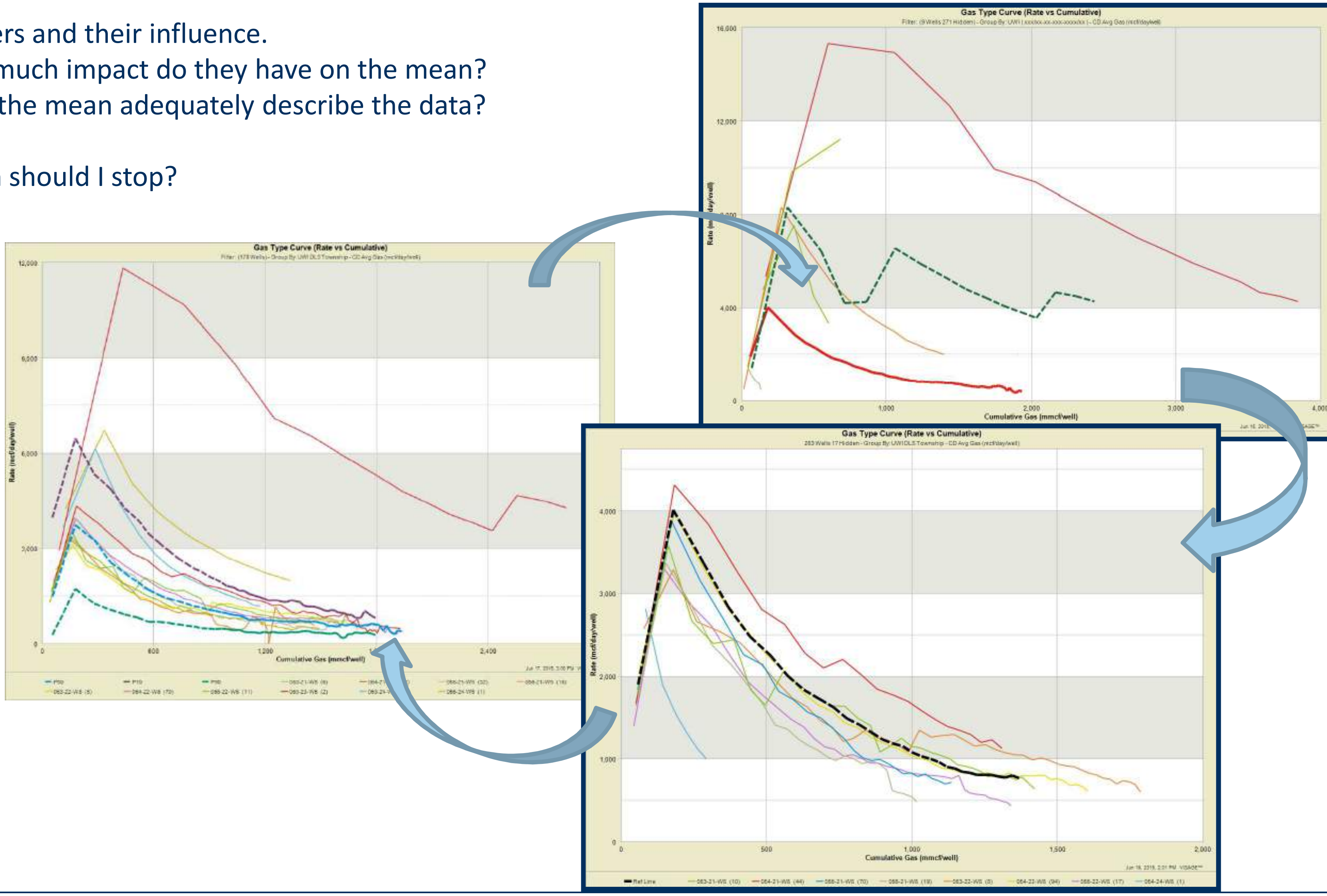
Outliers and their influence.
How much impact do they have on the mean?
Does the mean adequately describe the data?

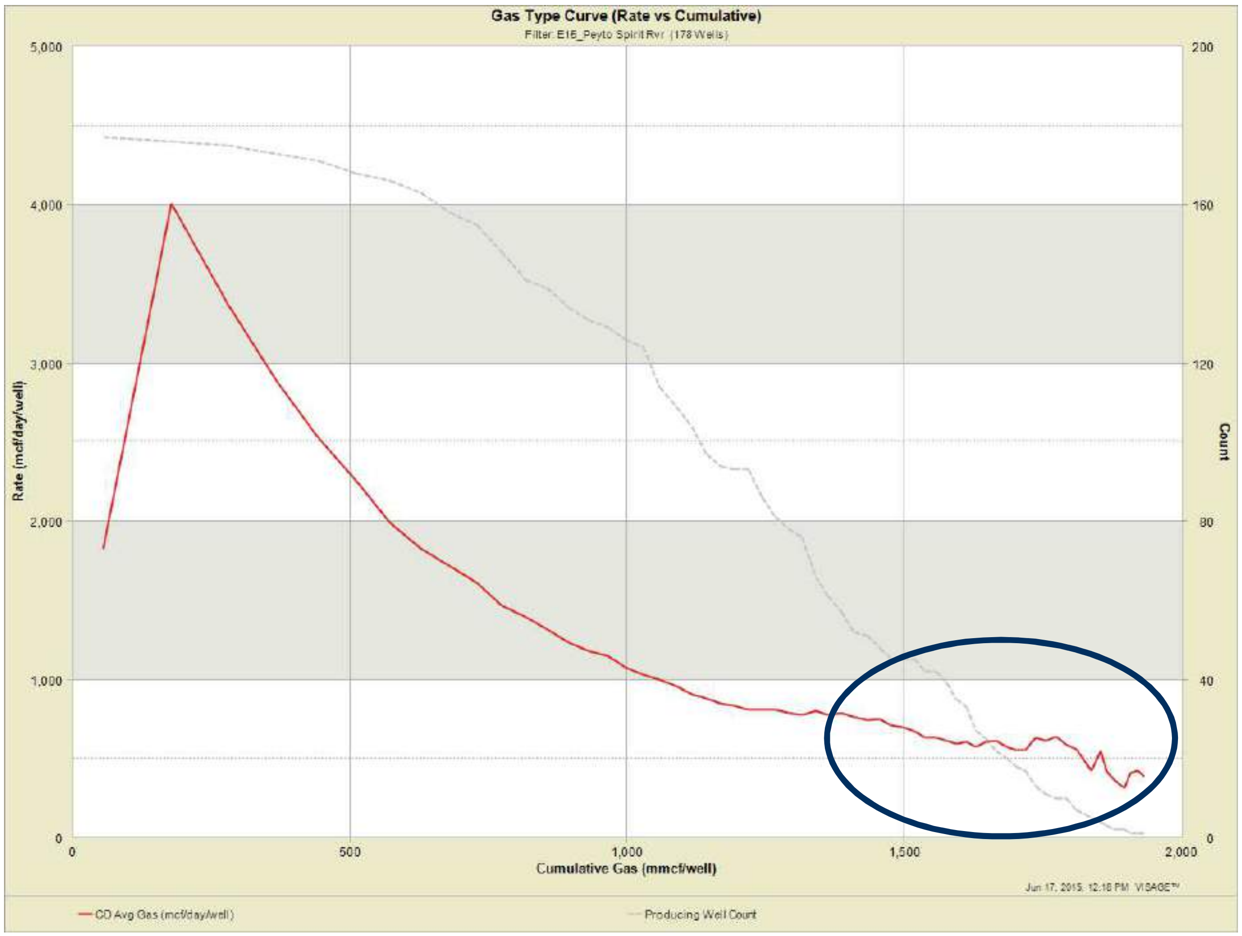
When should I stop?



COMMON PITFALLS – SURVIVOR BIAS

- Strongest wells produce at higher rates for longer
  - Are you surprised?
- The poor outliers can disappear prematurely from the data set if shut-in for economic reasons
  - Poor wells drop out – that helps my average!
- If the highest rate wells produce at higher rates longer what does that do to our “average” well profile?

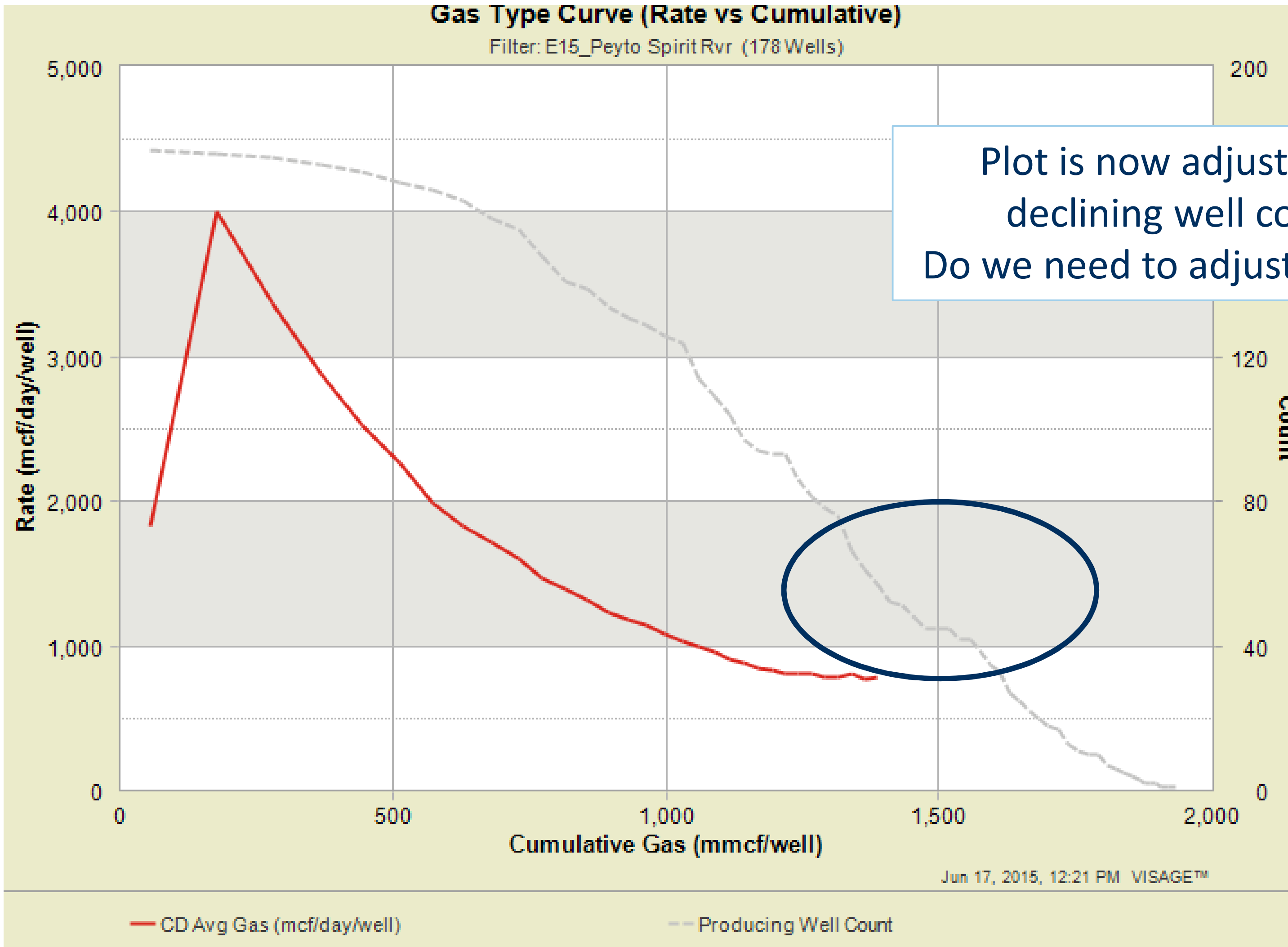
PROPERTY MEAN CURVE & SURVIVOR BIAS…



Decreasing well count has a significant impact on the curvature of this mean curve.

Note the well count. Can mislead your type curves!

ADJUSTING FOR SURVIVOR BIAS



Plot is now adjusted for declining well count.
Do we need to adjust further?

COMMON PITFALLS – LATE LIFE ASSUMPTIONS

- Transient Flow Behaviour
  - Appears as a period of shallow decline on log(q) vs log(t) plot
  - Appears as a slope less than -1 on log(q) vs log(tMB) plot
  - DCA in this flow period is theoretically justified, but only for the duration of transient flow, and can have an Arps exponent between 0 and 2.
  - Have we actually observed this behavior?
  - Of course… it is currently the dominate flow regime for most wells in shale gas resource plays (eg Marcellus, Eagleford, Montney, Horn River)
- Very easy to over estimate late life behaviour with very shallow declines beyond type curve history

FIRST ORDER MATERIAL BALANCE – KAKWA SPIRIT RIVER WELLS

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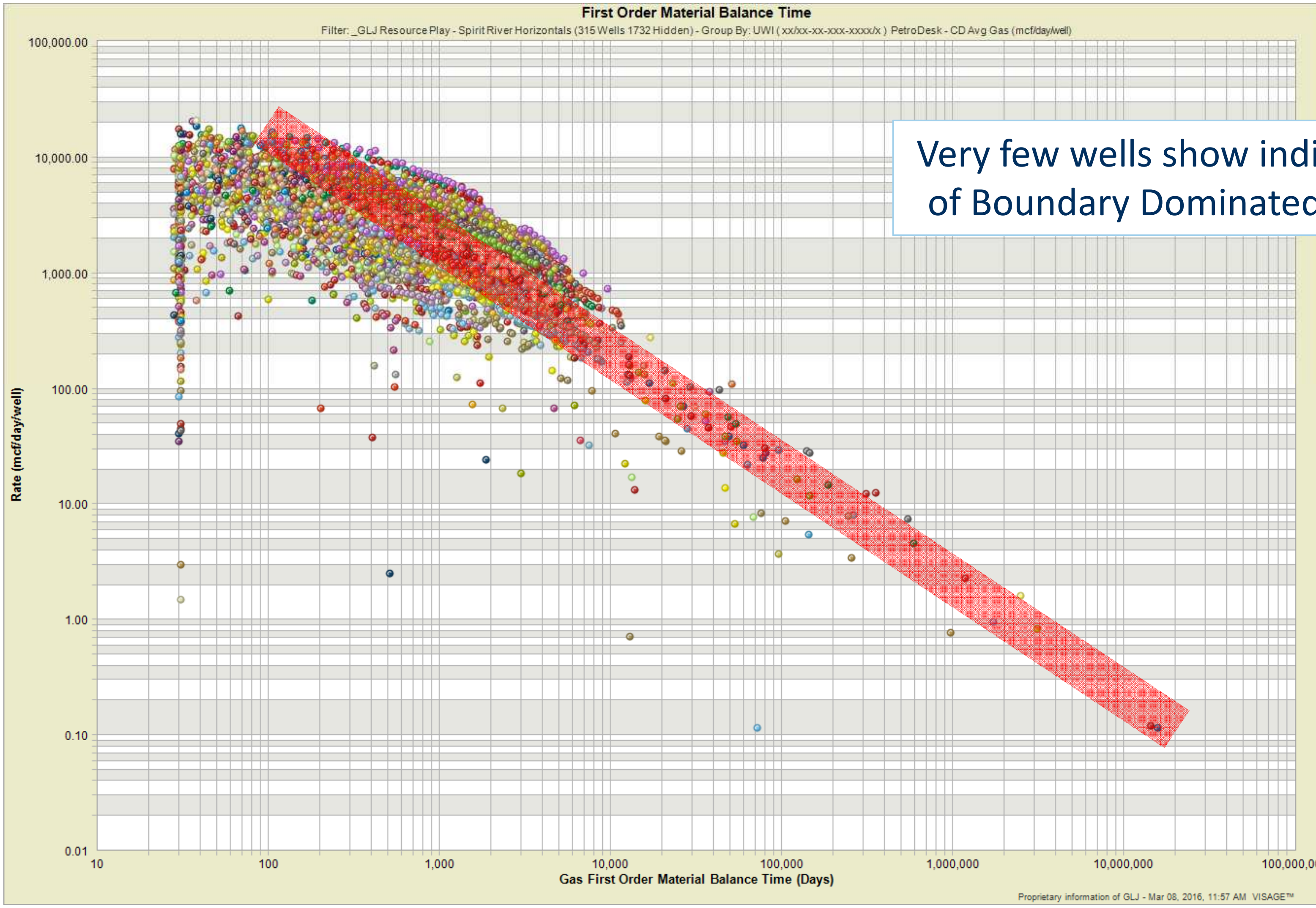

Very few wells show indication of Boundary Dominated Flow

FIRST ORDER MATERIAL BALANCE
KAKWA SPIRIT RIVER WELLS

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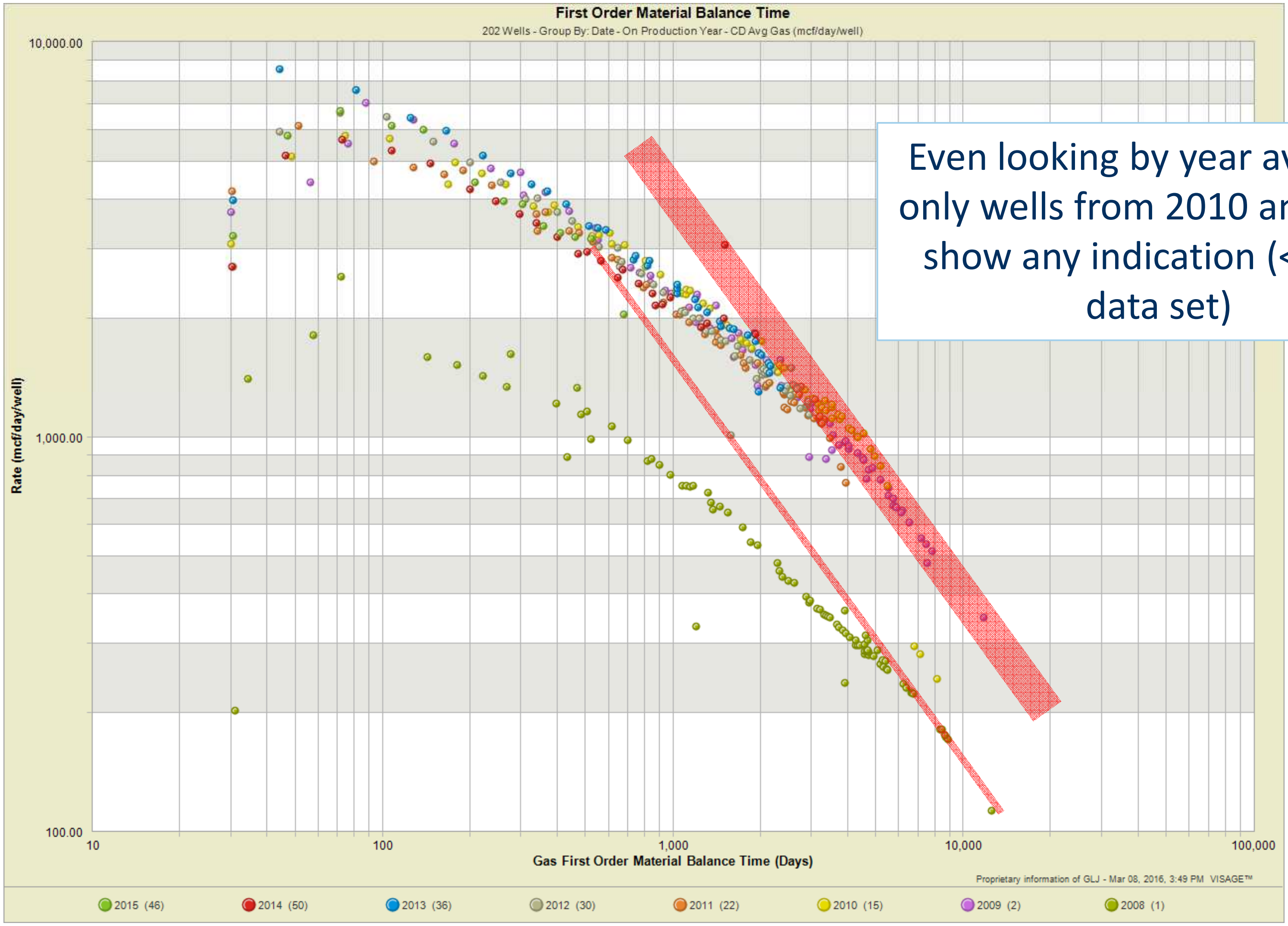


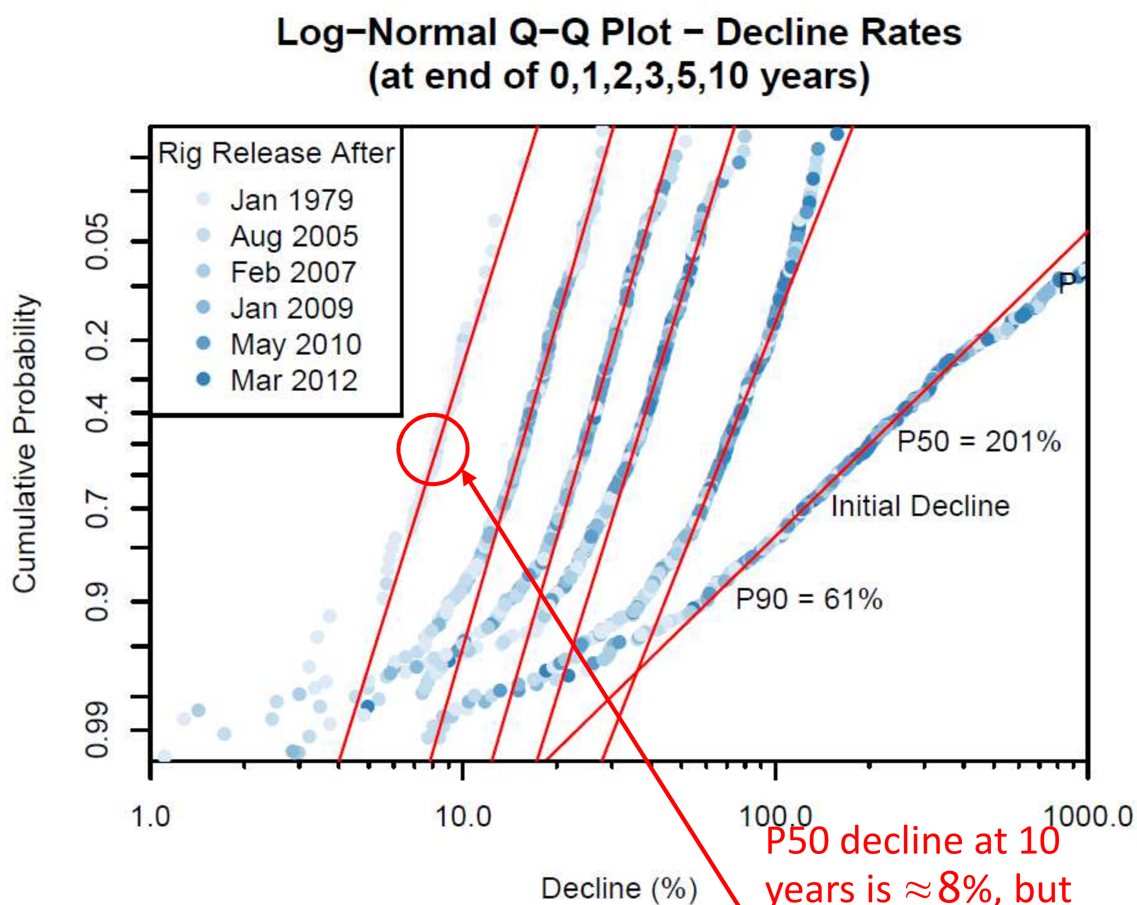
Even looking by year averages only wells from 2010 and older show any indication (<5% of data set)

SO, NO BDF PERIOD EVIDENT YET?

- If reservoir is unconventional there many only be a few examples of BDF
- What do we use?
  - Often, wells in these reservoirs produce majority of their hydrocarbons within the first 3-4 years and have paid out over this time. You could restrict your forecast to this time period and not worry about EUR.
  - You could estimate permeability from the few wells that entered BDF and use models help to predict long term behavior for a typical well still in transient flow
  - Long term producing vertical wells can give us some clues and rough estimates of what to do… they may be in radial flow which would allow us to estimate perm
  - You could assume a long-term final decline based on what has been observed to date, at least until the time to BDF becomes clear.

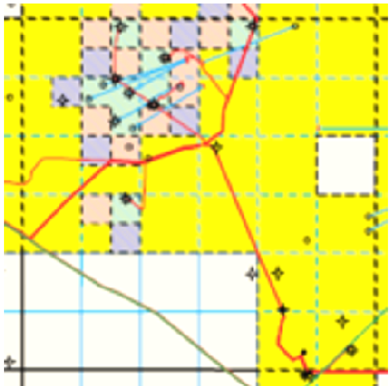
LATE LIFE ASSUMPTIONS

- By default, for late life assumptions on horizontal wells we look to longer history Vertical Wells
- Plot shows decline rate for Deep Basin Verticals in Kakwa
- Spacing of 80-160 acres for verticals is one thing...what about a frac stage every 100 meters?
  - 10-20 acres / stage



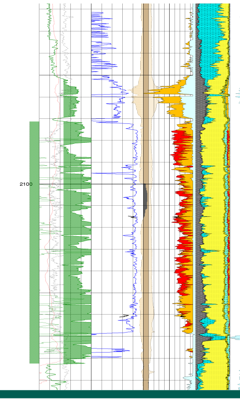
P50 decline at 10 years is ≈8%, but these are widely spaced verticals

RESERVES & RESOURCE EVALUATION PROCESS



Estimated PIIP

- Assumed petrophysics cutoffs
- Kerogen density assumptions

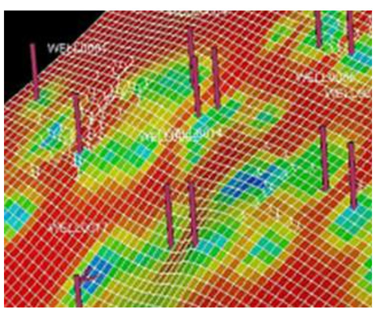


Undeveloped Reserve/Resource Assignments

- Assign reserves and resources offsetting performance using volumetrics and analogy

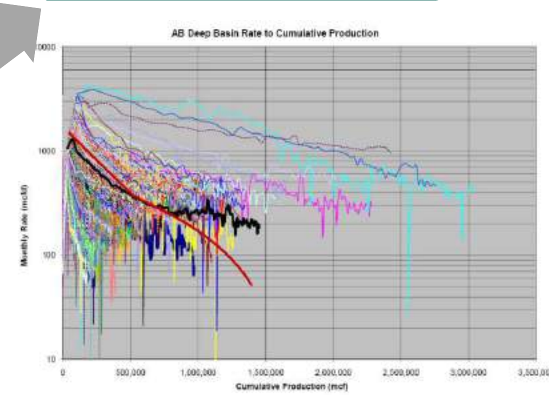
Performance Data

- Initial Rate assumption
- Typecurves (Arps eqn)
- Terminal Declines



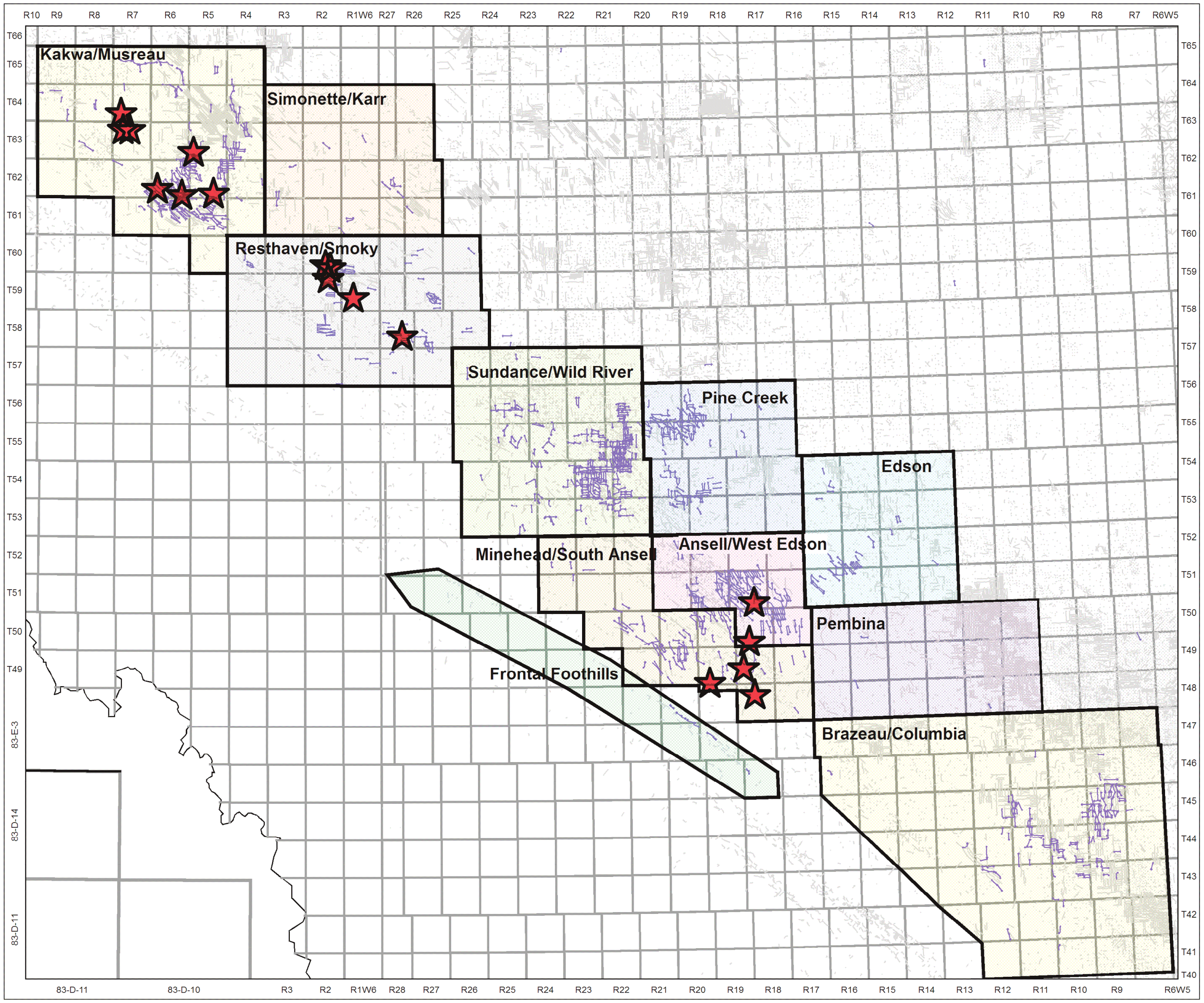
Recovery Factors

- Check performance / decline analysis versus PIIP estimates
- Do these make sense based on produced fluid encountered?



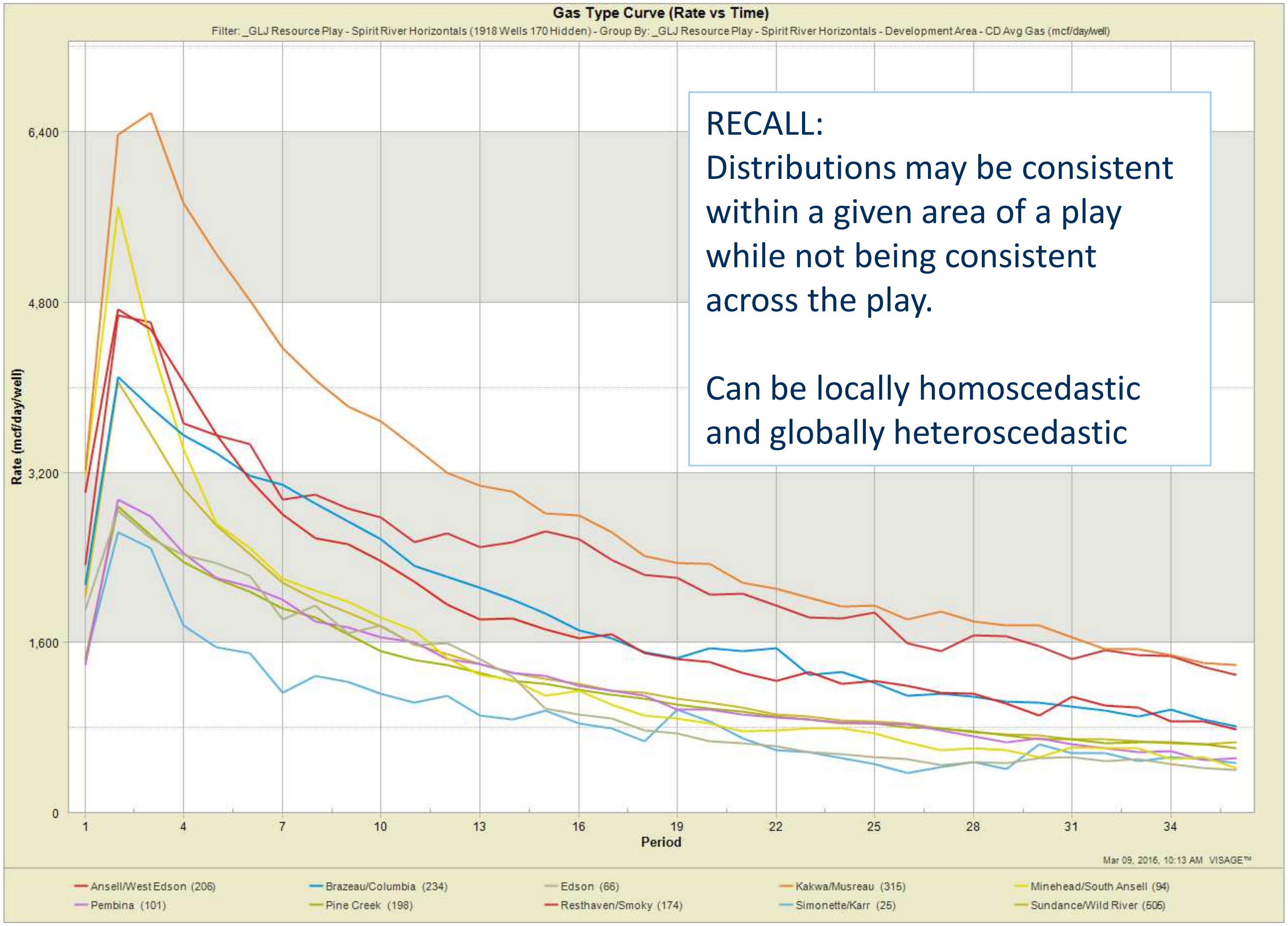
KAKWA SPIRIT RIVER EXAMPLE

SPIRIT RIVER FAIRWAY
CORE/PETROPHYSICS REVIEW MAP



Cores used:
100/01-28-048-18W5/00
100/05-17-049-18W5/00
100/01-05-049-19W5/00
102/12-04-050-18W5/00
100/16-03-051-18W5/00
100/13-11-058-27W5/00
100/01-17-059-01W6/00
100/01-34-059-02W6/00
100/03-10-060-02W6/00
100/13-02-060-02W6/00
100/01-07-063-05W6/00
100/08-02-062-06W6/00
100/08-07-062-06W6/00
100/10-29-063-07W6/00
100/06-08-064-07W6/00
100/10-28-063-07W6/00
100/09-03-062-05W6/00

SPIRIT RIVER PRODUCTION PROFILES



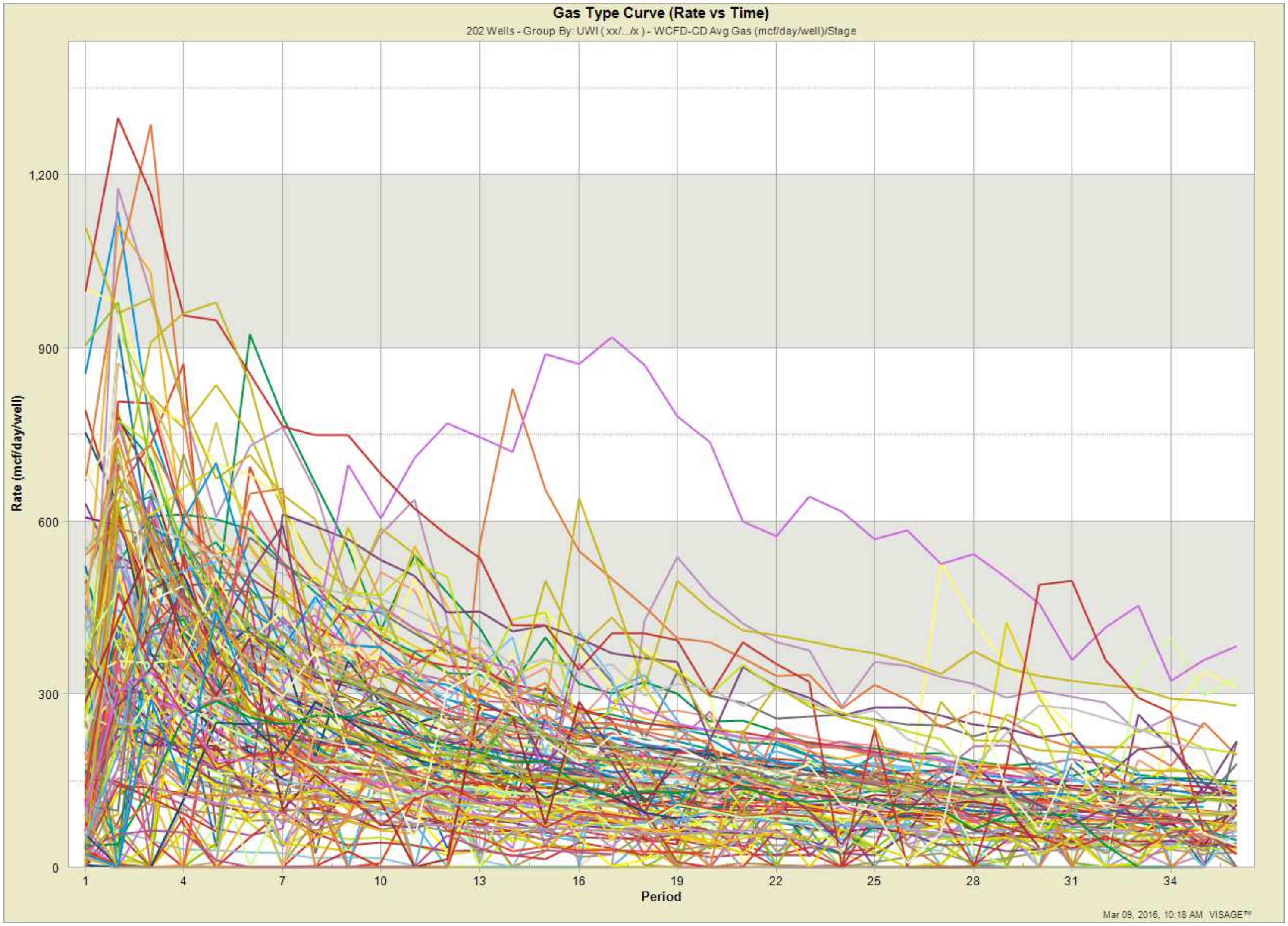
RECALL:
Distributions may be consistent within a given area of a play while not being consistent across the play.

Can be locally homoscedastic and globally heteroscedastic

KAKWA AVERAGE PROFILE

The shape of this curve looks pretty familiar...so one type curve should suffice.

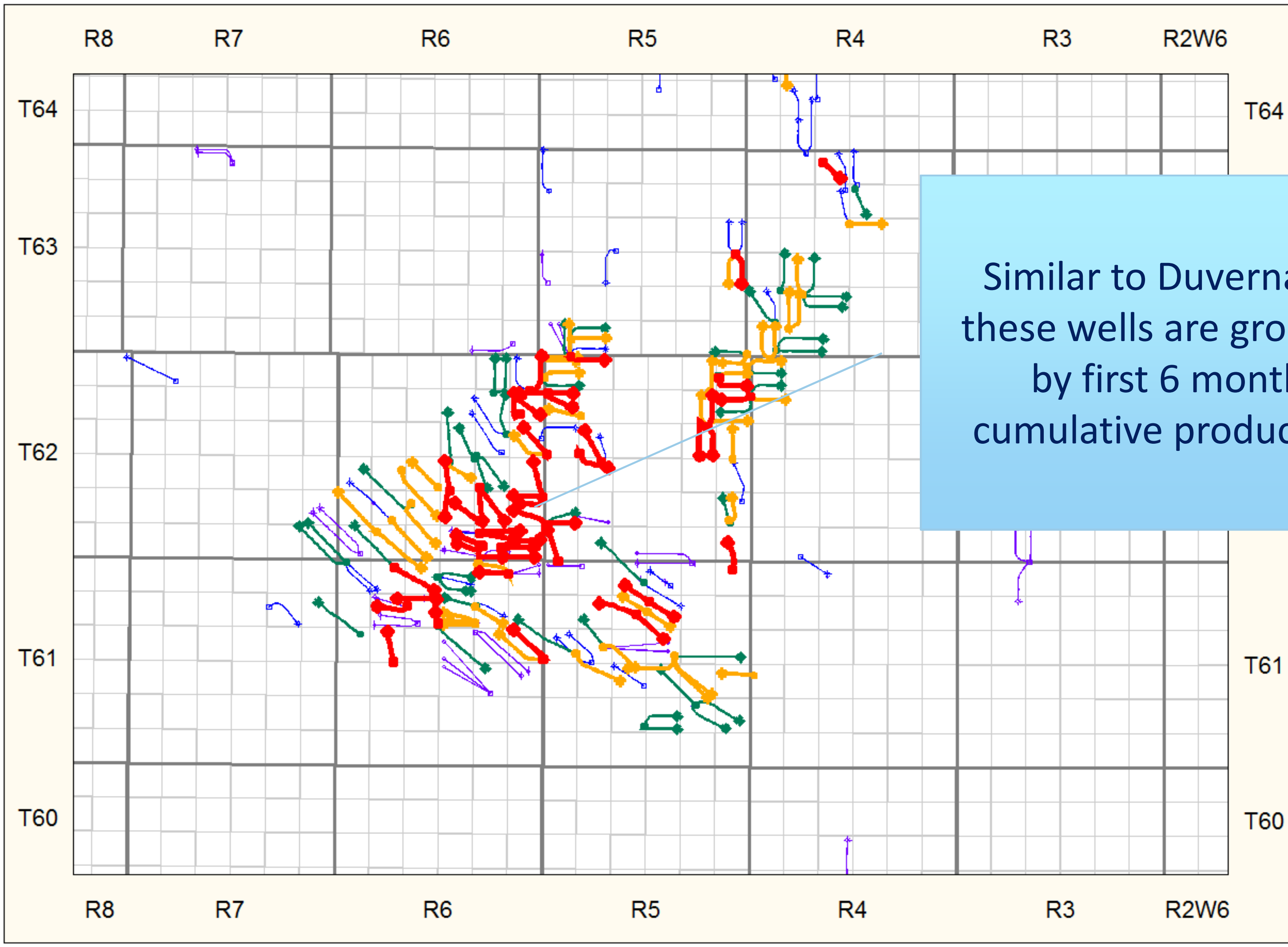
KAKWA SPIRIT RIVER WELLS



SPLITTING UP WELL RESULTS

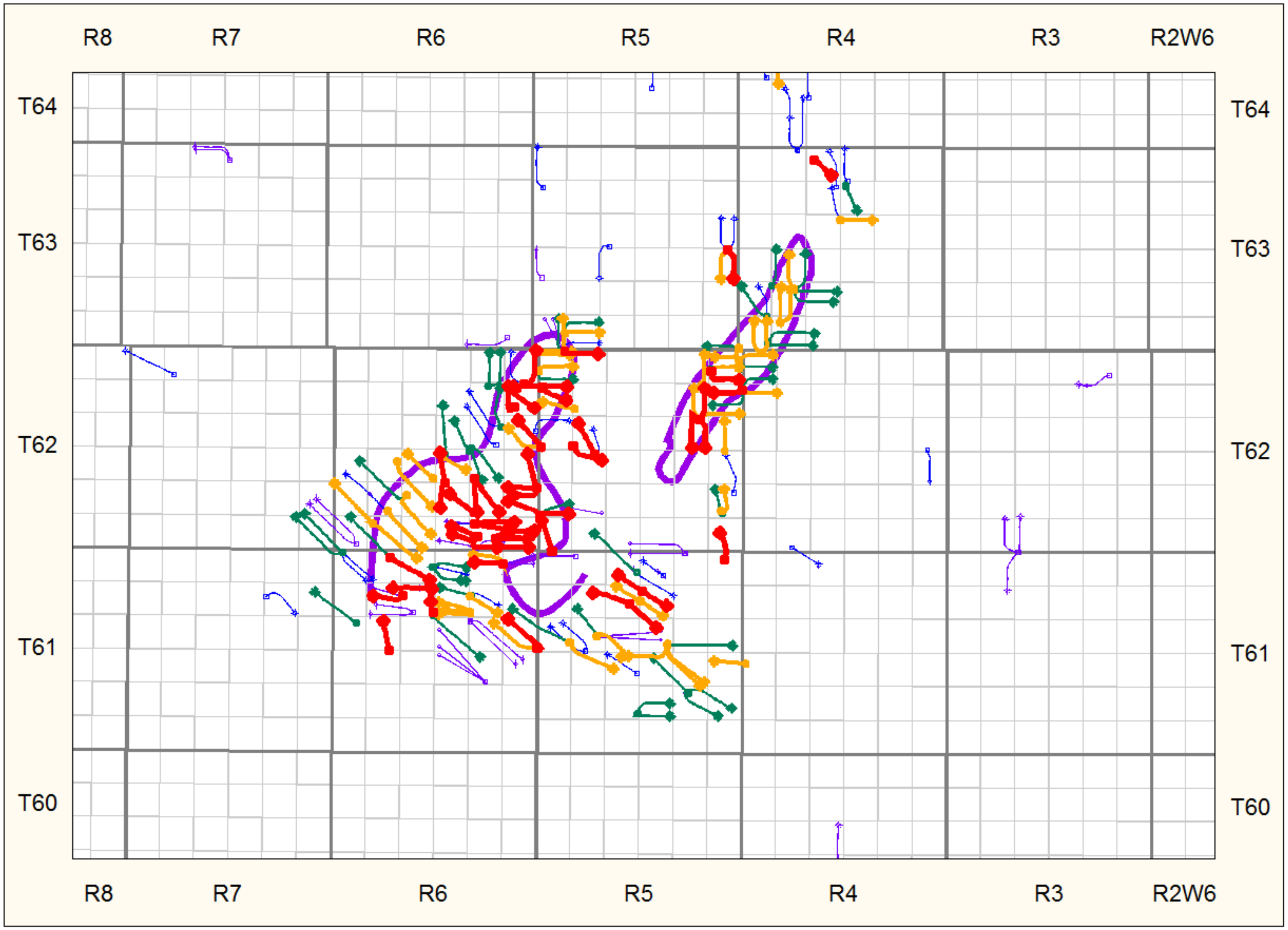
- Performance from the Spirit River is guided more by OGIP than other “resource plays”
- Since core areas tend to be drilled up first can we take historical development and apply the same type curve moving out of the fairway?

TIERED PERFORMANCE DATA

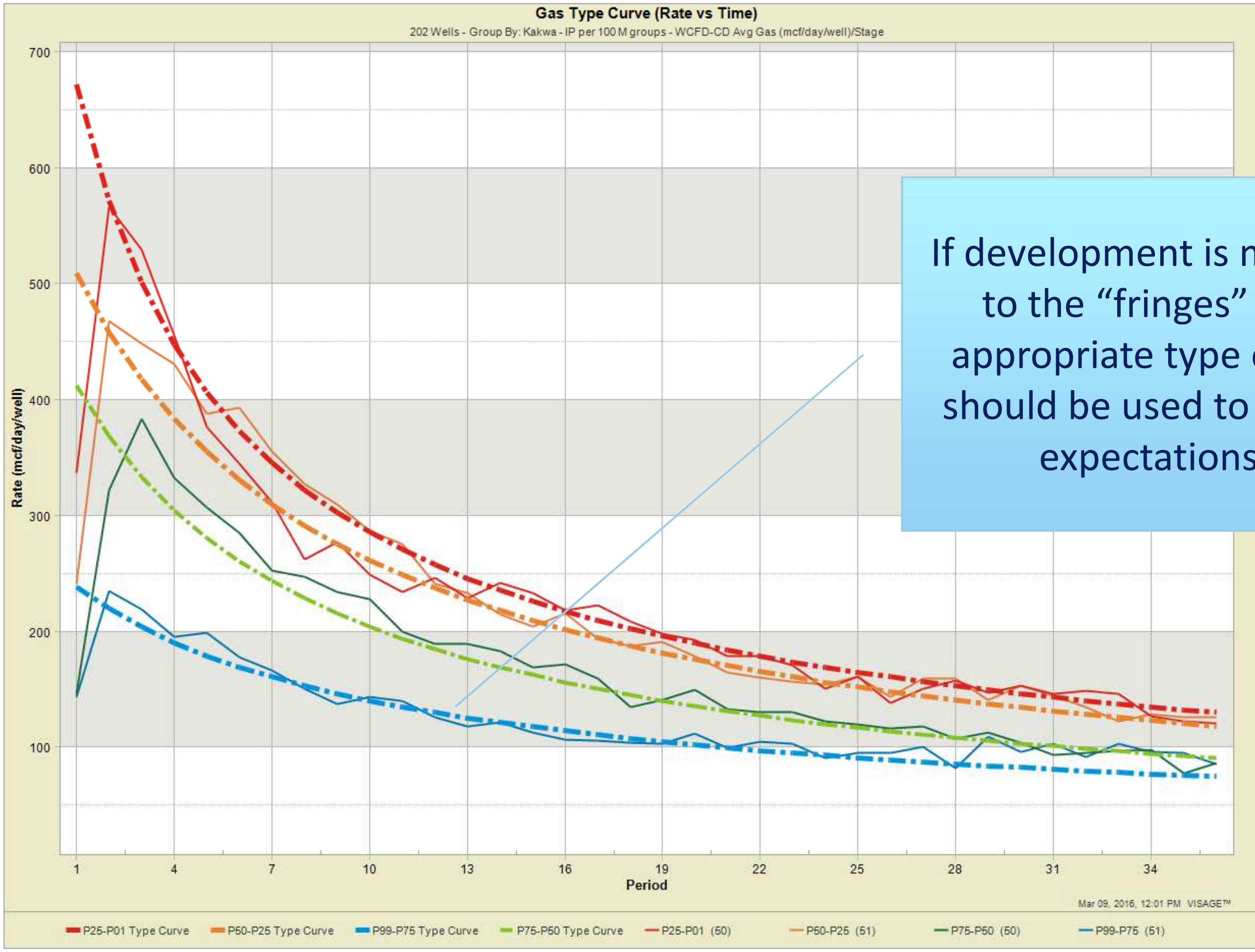


Similar to Duvernay – these wells are grouped by first 6 month cumulative production

SWEET SPOTS EMERGE

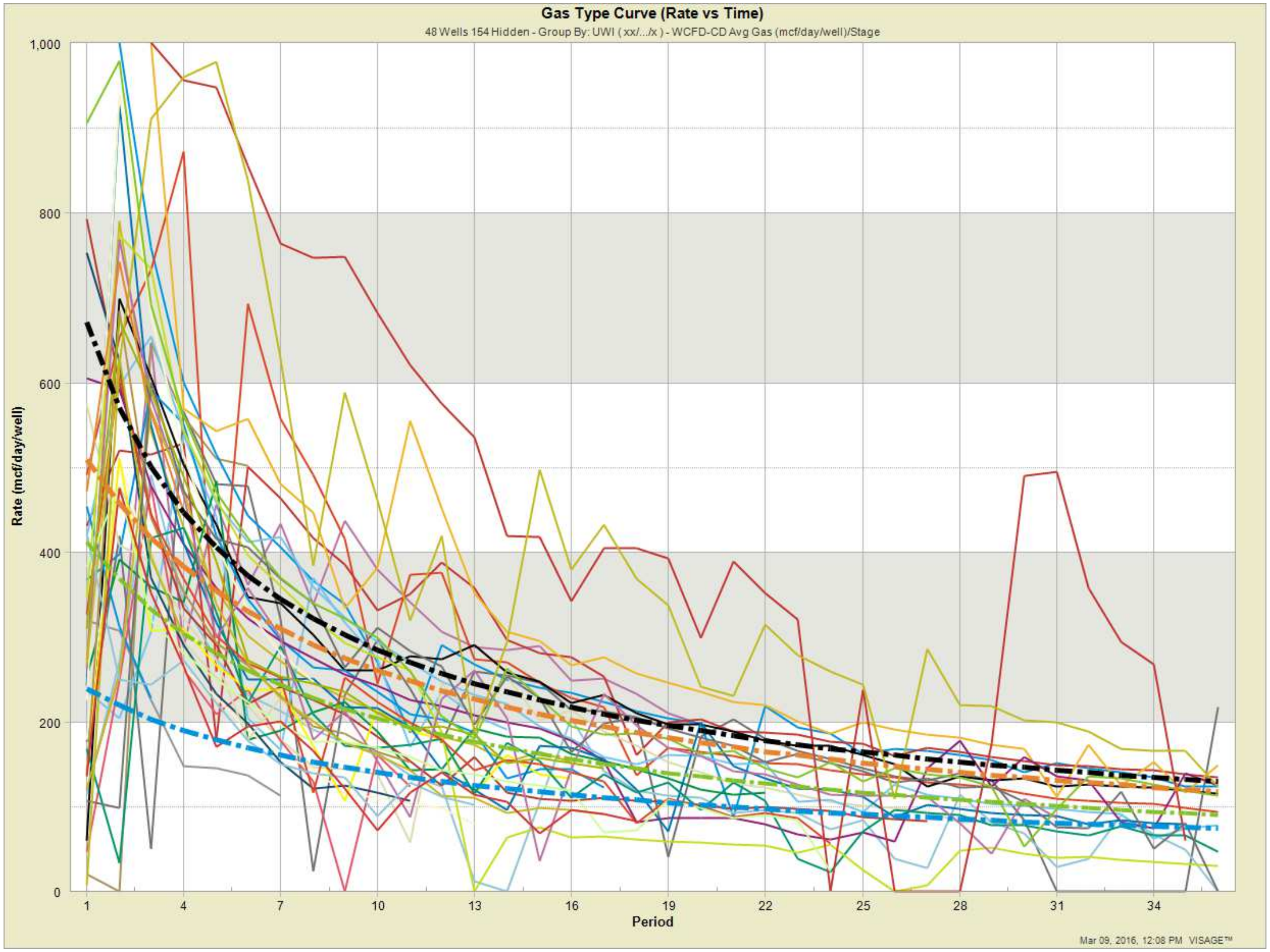


TYPE CURVES ON RESPECTIVE GROUPS

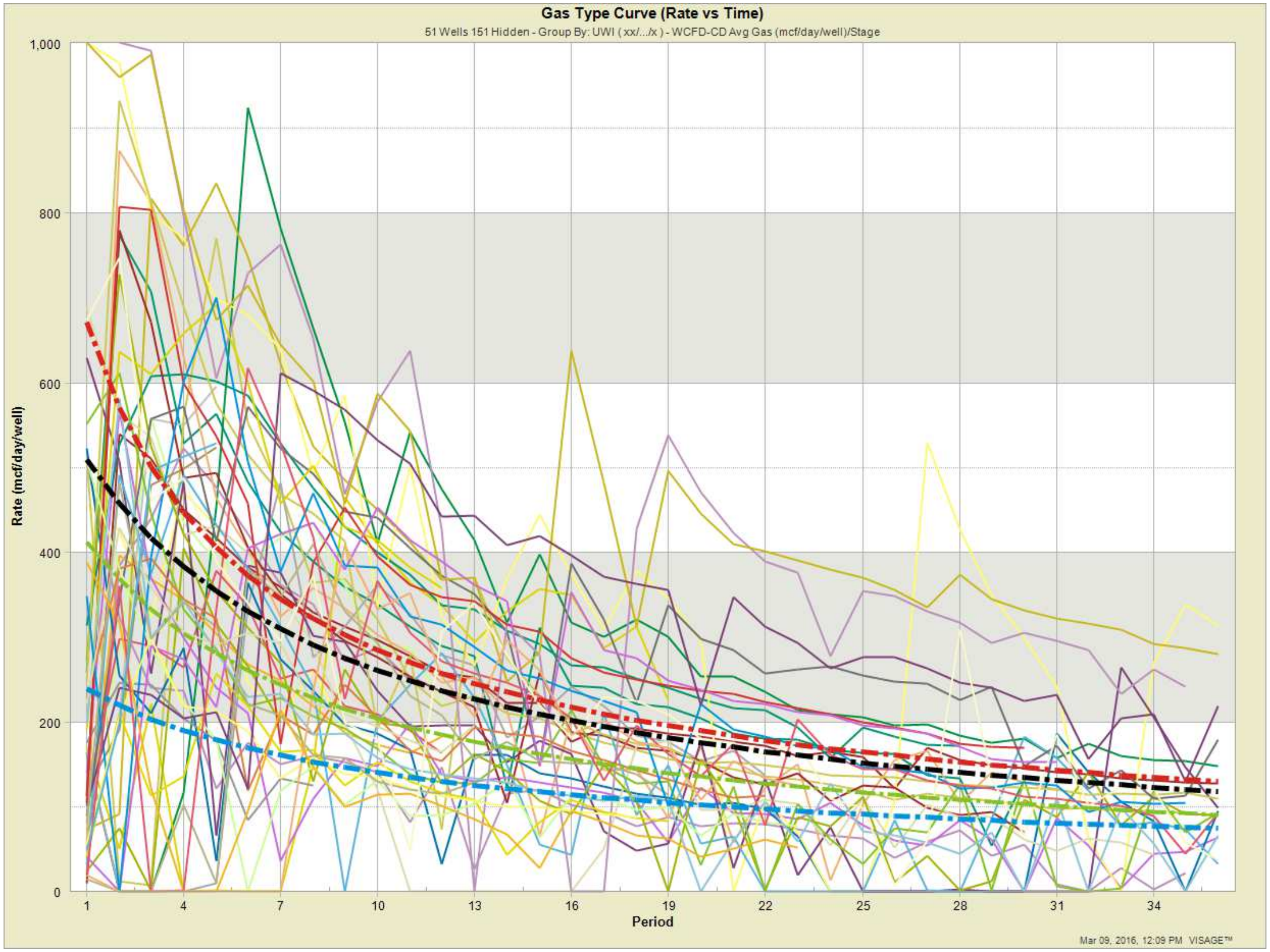


If development is moving to the “fringes” the appropriate type curve should be used to guide expectations

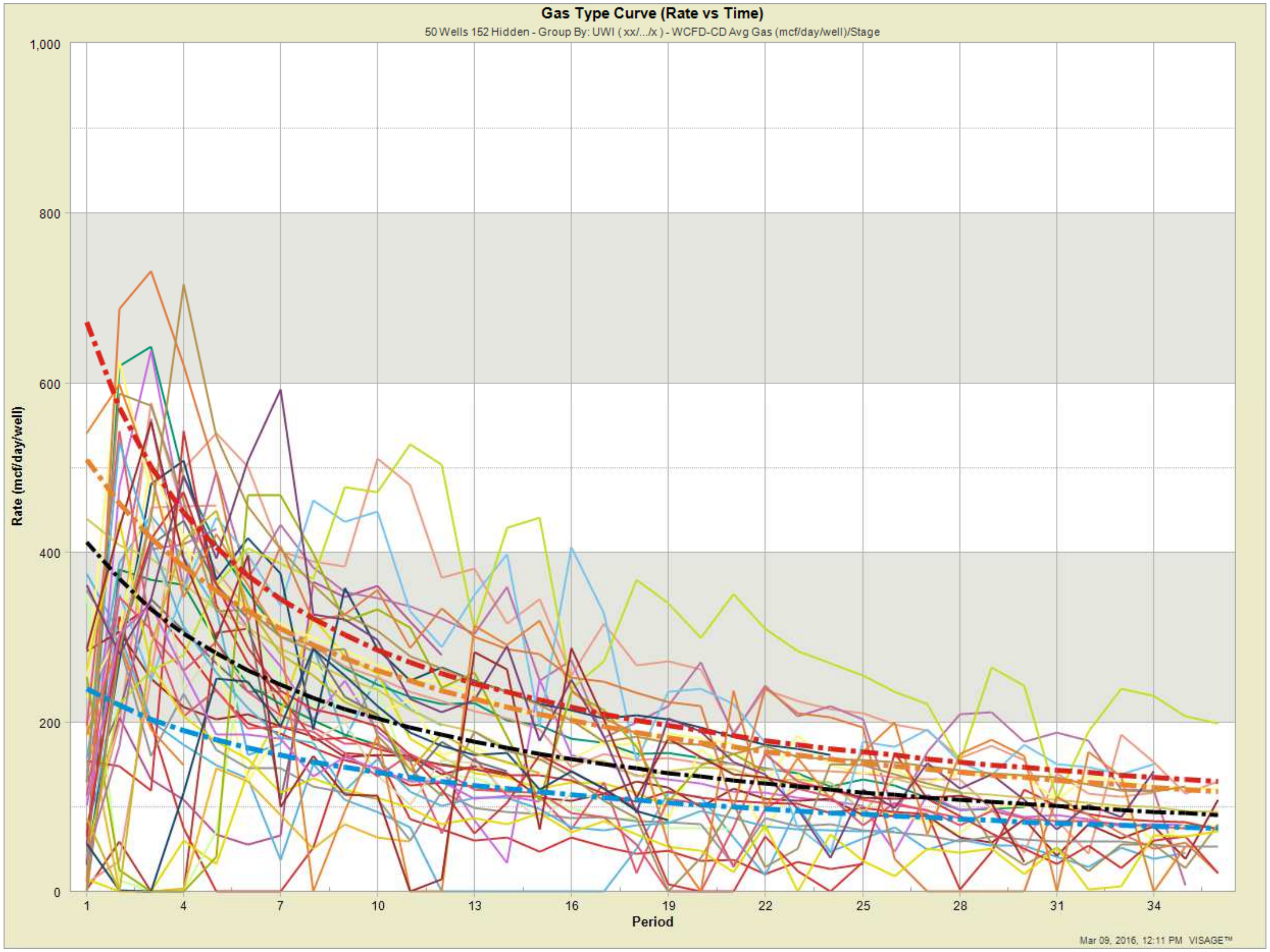
P25-P01 GROUP



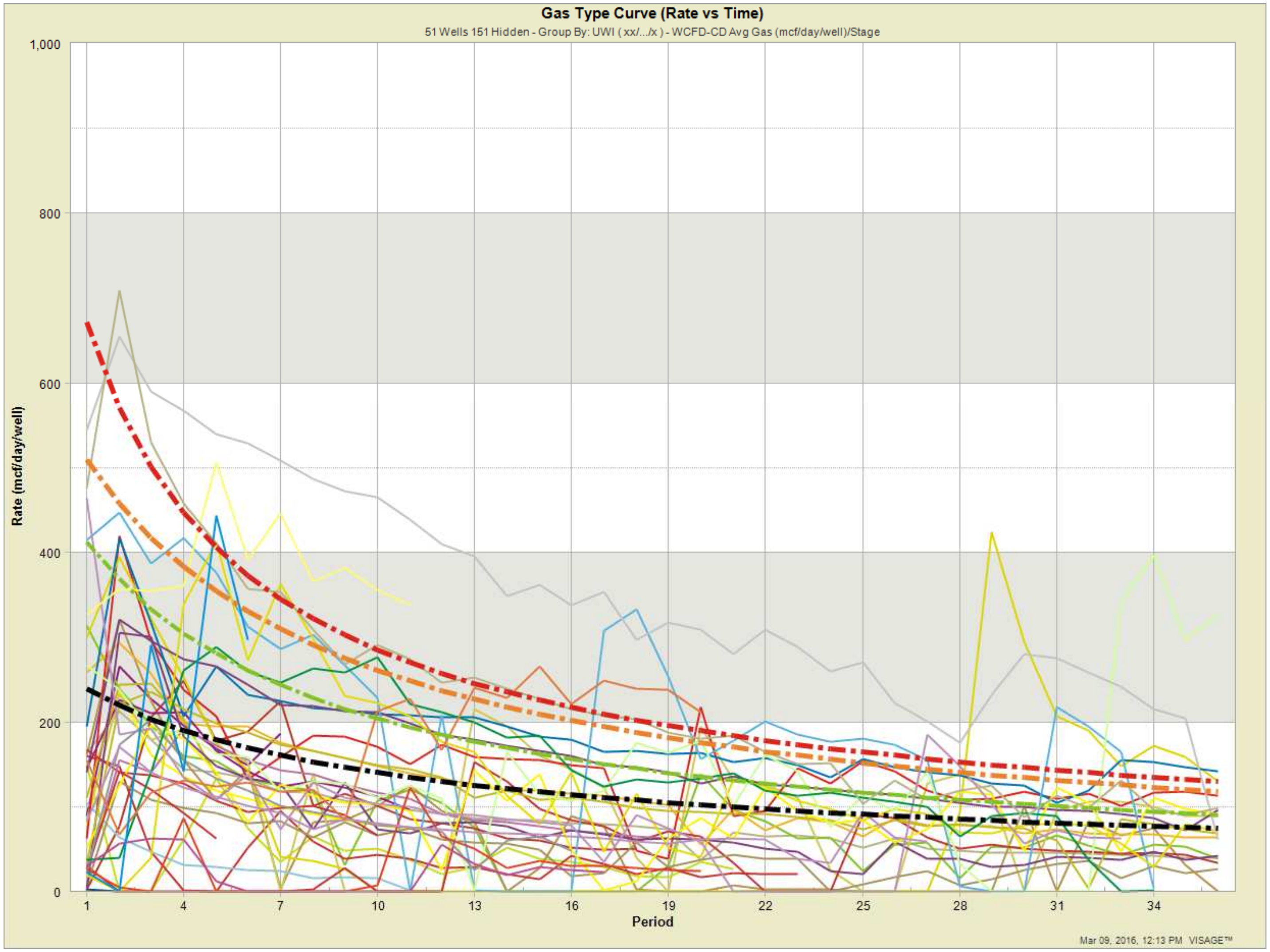
P50-P25 GROUP



P75-P50 GROUP



P99-P75 GROUP



MAJOR CONCLUSIONS

- There will be significant pressure from financial markets and management to simplify the analysis. This has the dangers of condensing varied reservoir performance (multiple type curves) into a single “representative” type curve.
- Many current plays are still in infinite acting flow and so it is difficult to verify DPIIP assumptions from production data.
- Good areas are developed first and will be drilled until there is enough interference, hopefully not too much!
- Typical long term decline rates may be steeper than you expect: median decline rates for gas wells after 30 years of production are approximately 5-10%. A minority of wells have much shallower declines.
- Know your reservoir before you start down type curves...what is the most important variable that effects performance?
  - Fluid, Phi-h, Facies?
- Many important parameters, such as EUR and decline rates, can be neither normally nor log-normally distributed.

THANK YOU!

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