

Welcome!

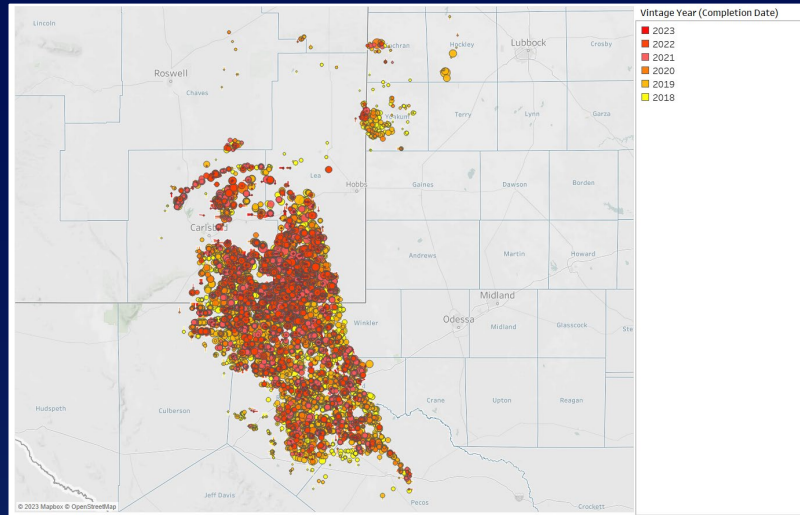
The program will begin soon.
You will not hear audio until we begin.

Unconventional Basins: Frac and Completion Trends

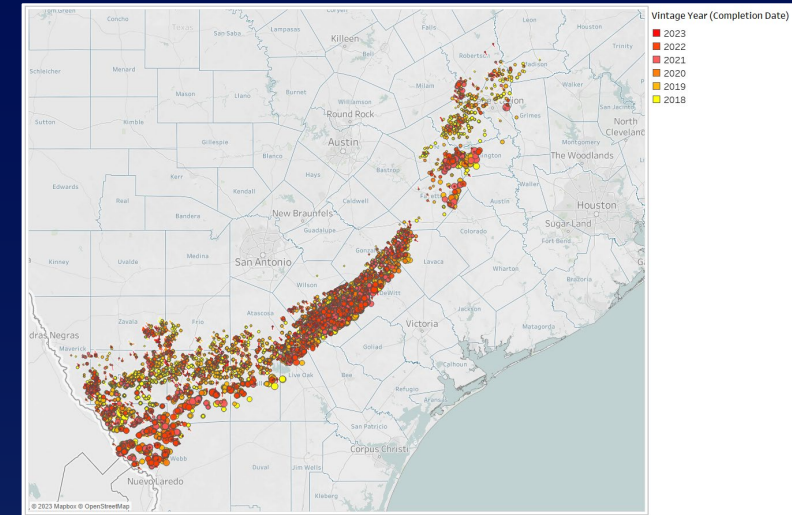
Mike Mayerhofer, Liberty Energy
January 24, 2024



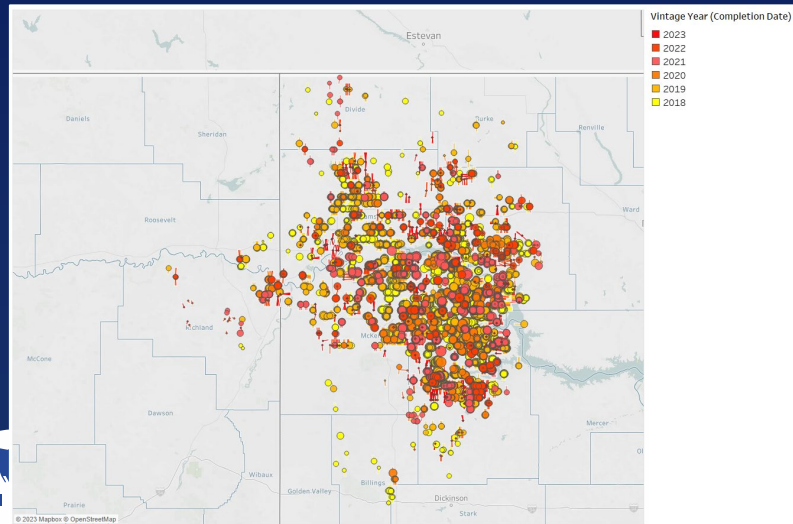
Delaware Basin



Eagleford

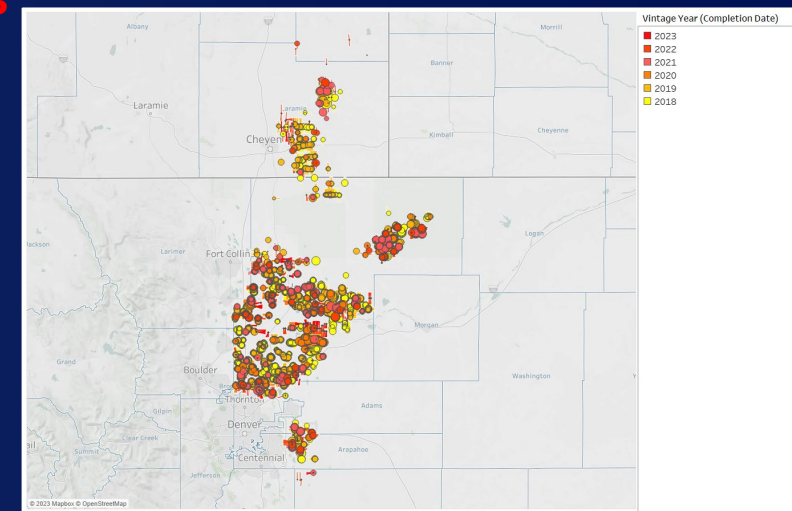


Williston

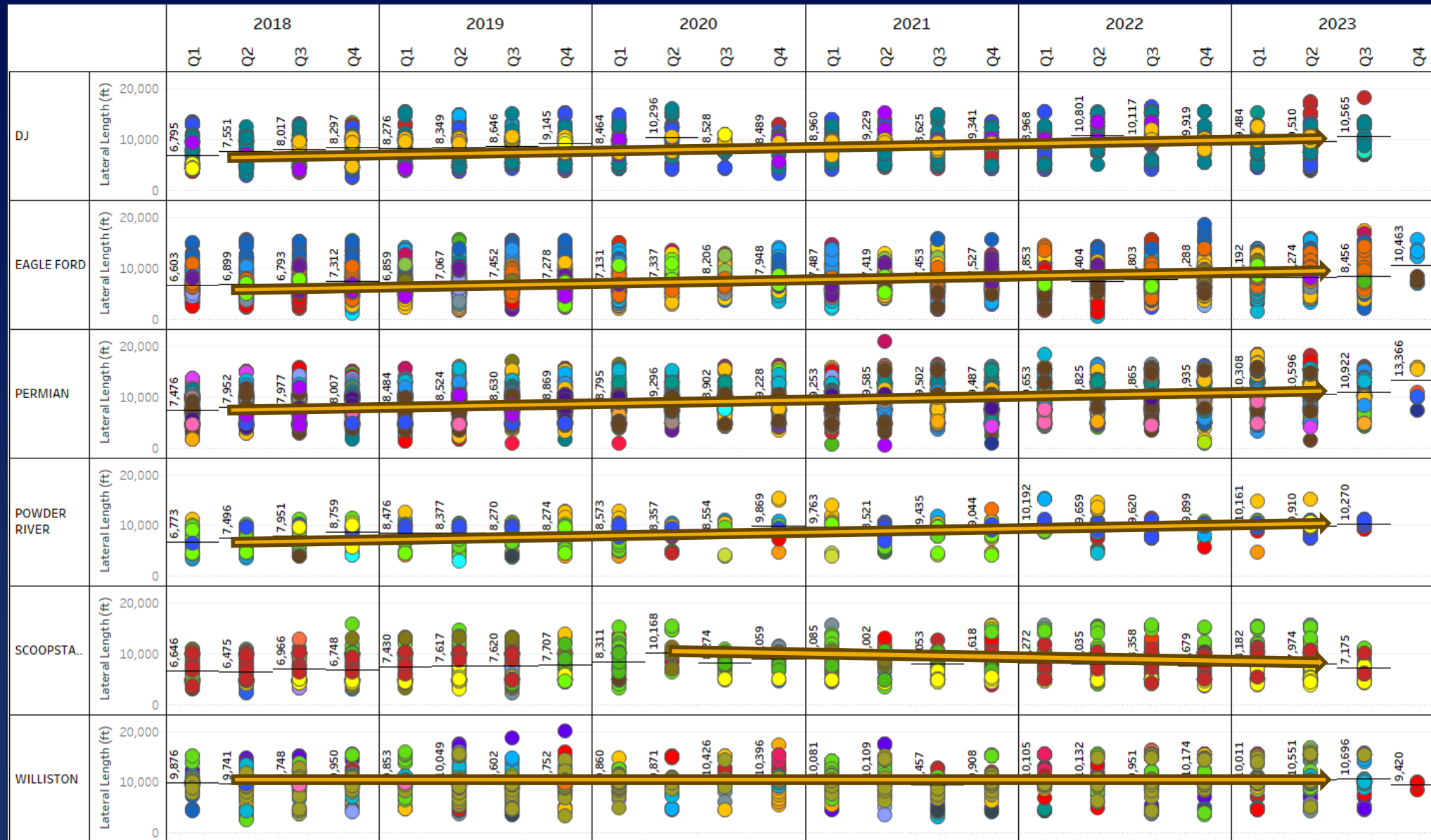


Horizontal Wells
Completed from
2018 to 2023

DJ



Unconventional Basins Horizontal Well Length Trends

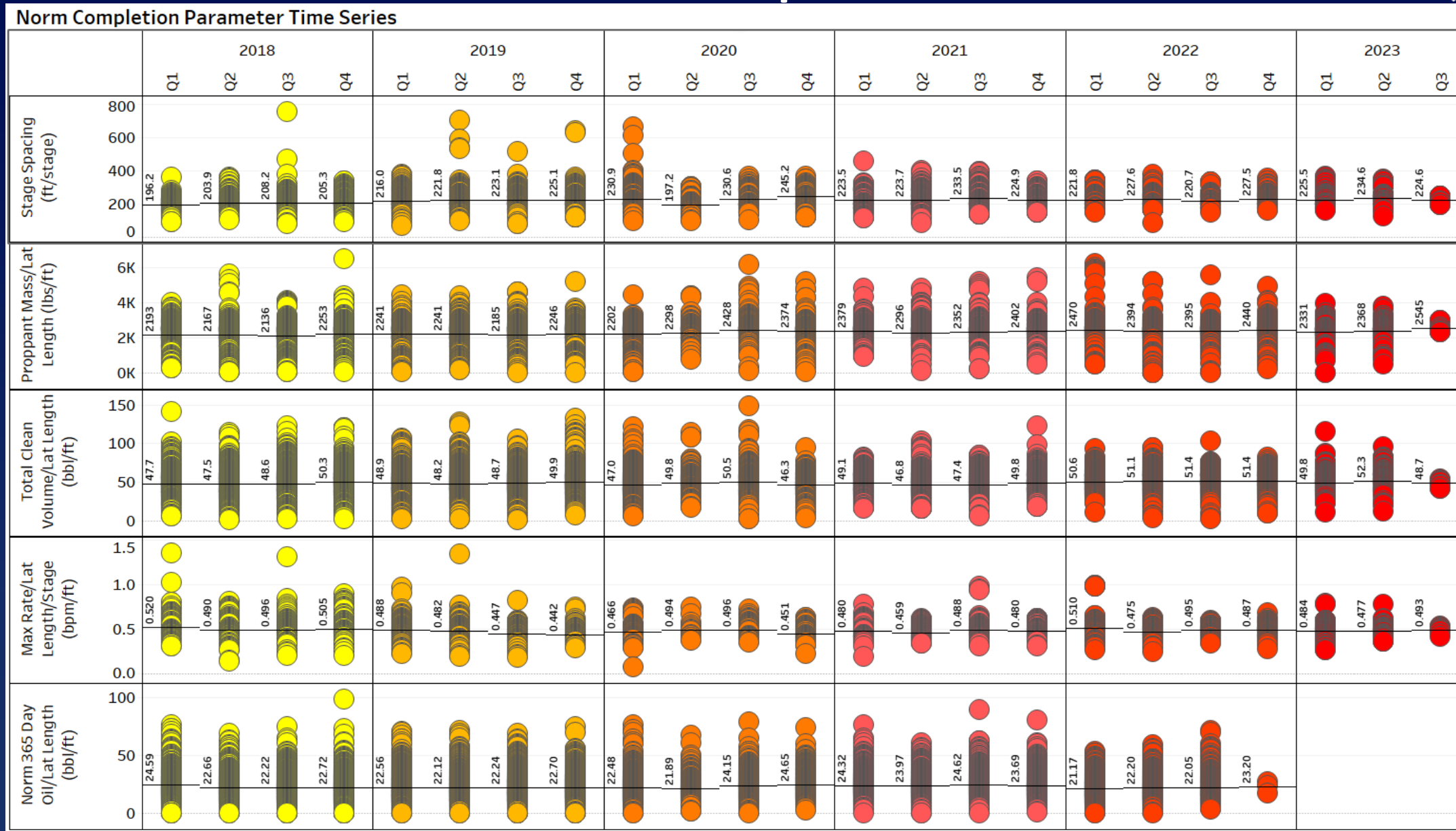


Increasing Average Lengths (7,000 ft to >10,000 ft) but large range still in 2023

Decrease from 2020 to 2023

Flat at 10,000 ft average

Delaware Basin Completion Trends



Flat trend
225 ft/stage

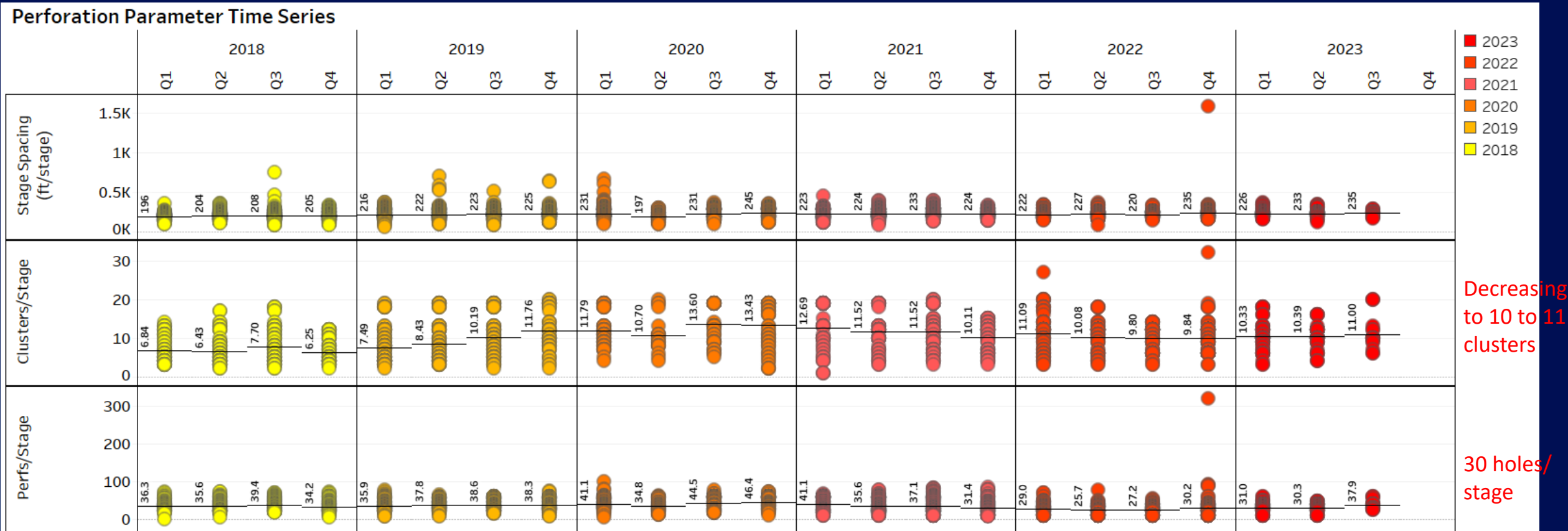
Flat trend
2,400 lbs/ft

Flat trend
50 bbls /ft

Flat trend
0.5 bpm /ft

Decrease of
BO/ft in 2022

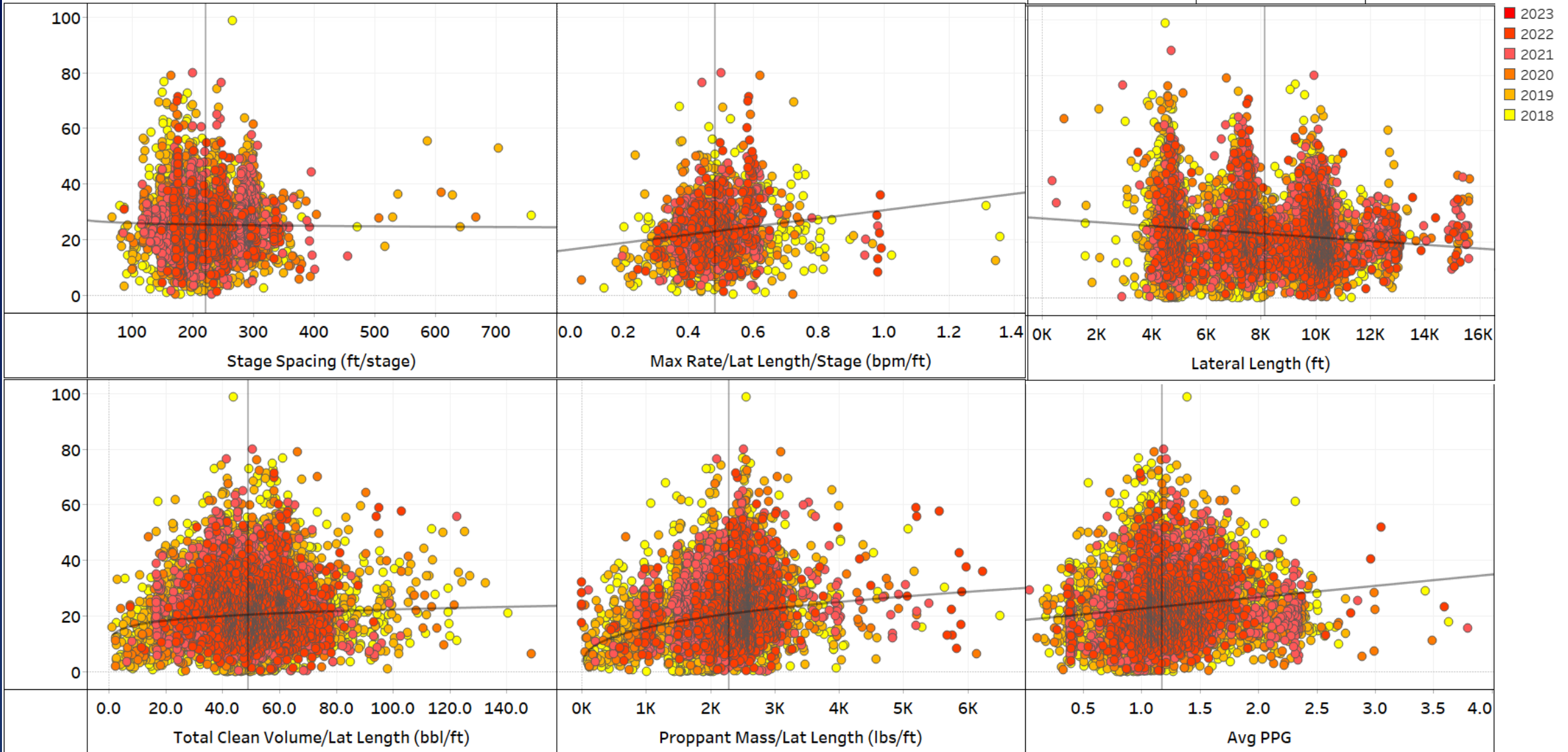
Delaware Basin Completion Trends



Delaware Basin Completion Trends



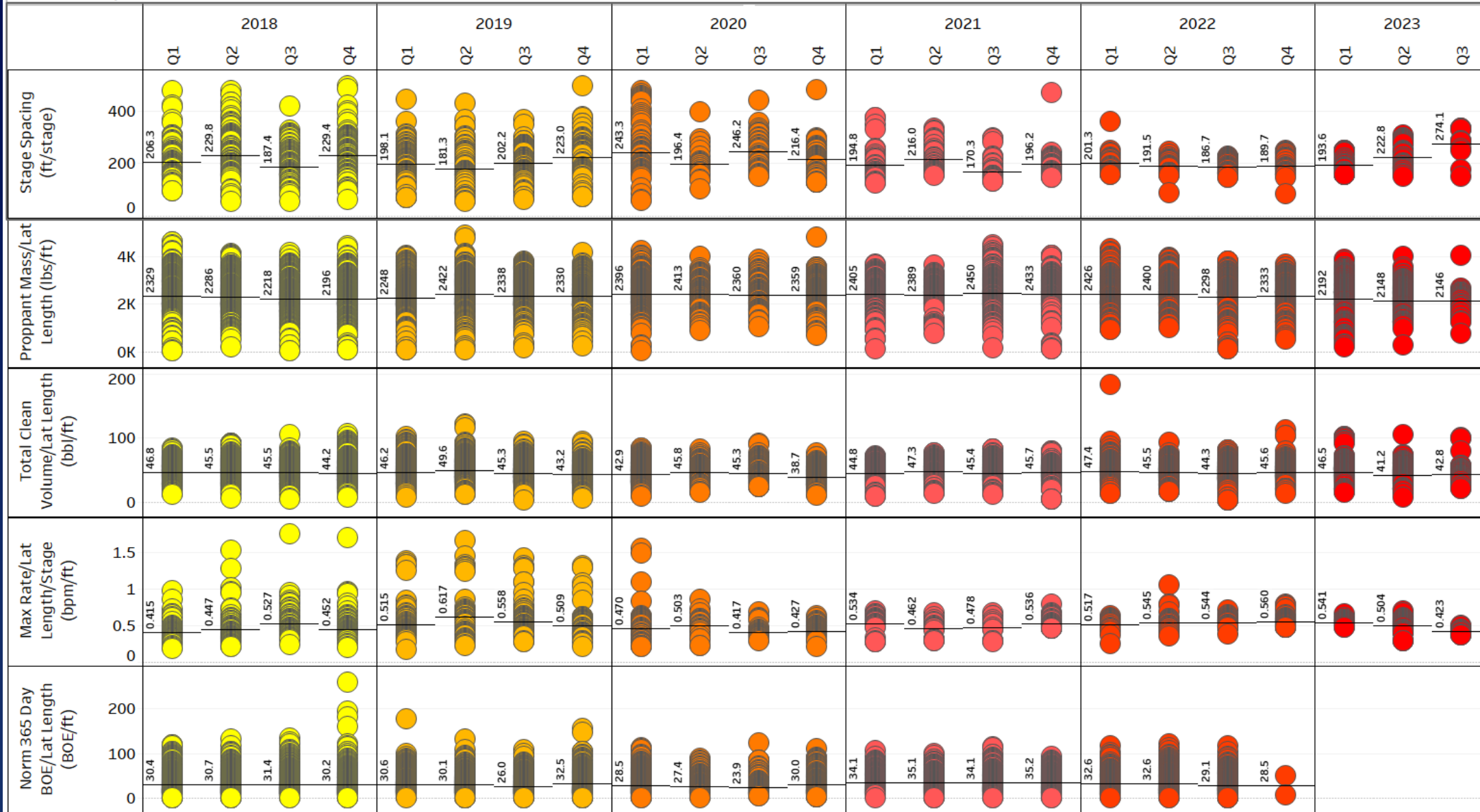
Norm 365 Day Oil/Lat Length (bbl/ft) vs. General Completions Parameters



Eagleford Completion Trends



Norm Completion Parameter Time Series



Increasing trend to over 220 ft/stage

Decreasing trend to 2,100 lbs/ft

Flat trend 45 bbls /ft

Flat trend 0.5 bpm /ft

Decrease of BOE/ft in 2022

Eagleford Completion Trends

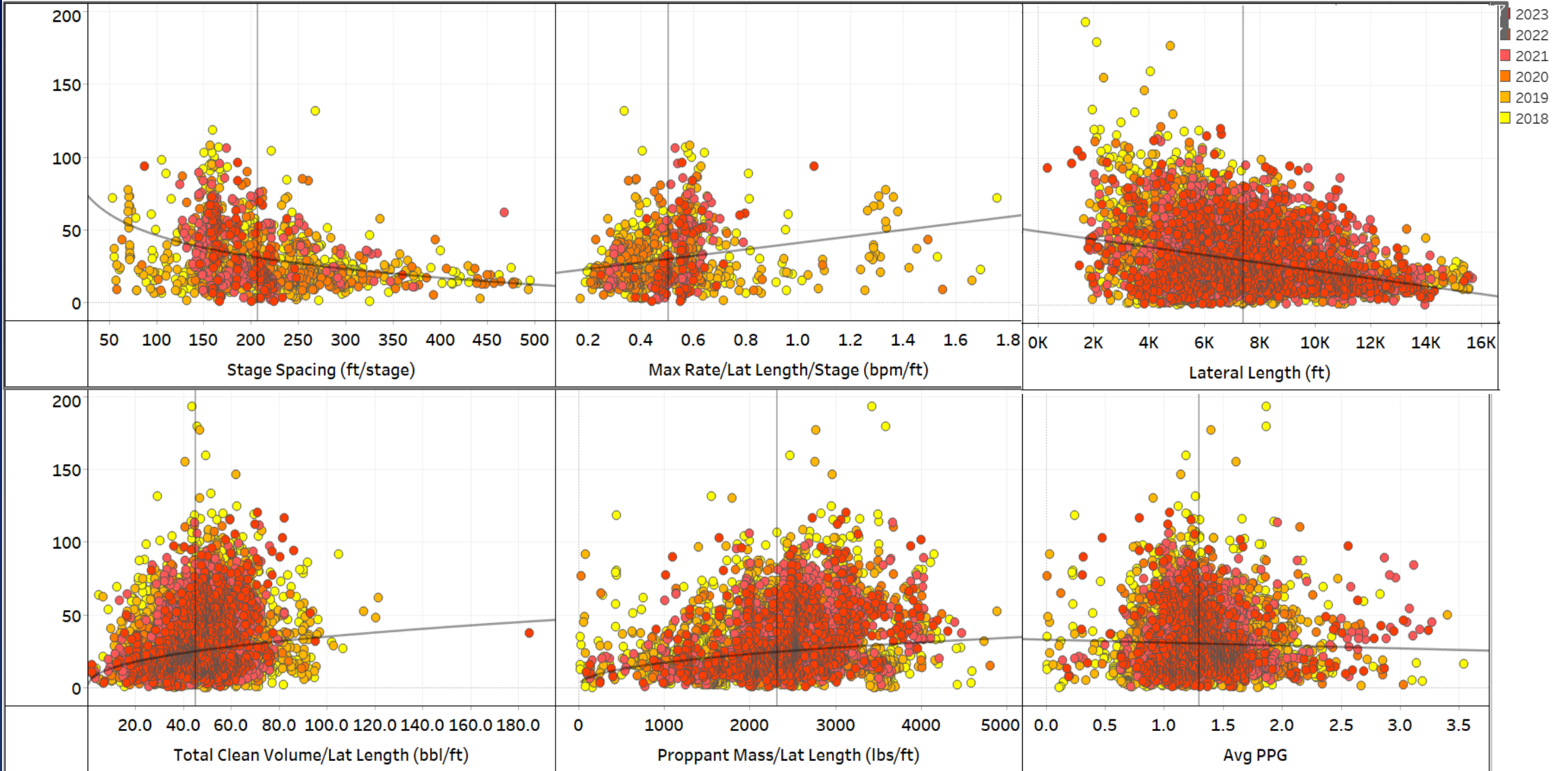


Perforation Parameter Time Series



Eagleford Completion Trends

Norm 365 Day BOE/Lat Length (BOE/ft) vs. General Completions Parameters

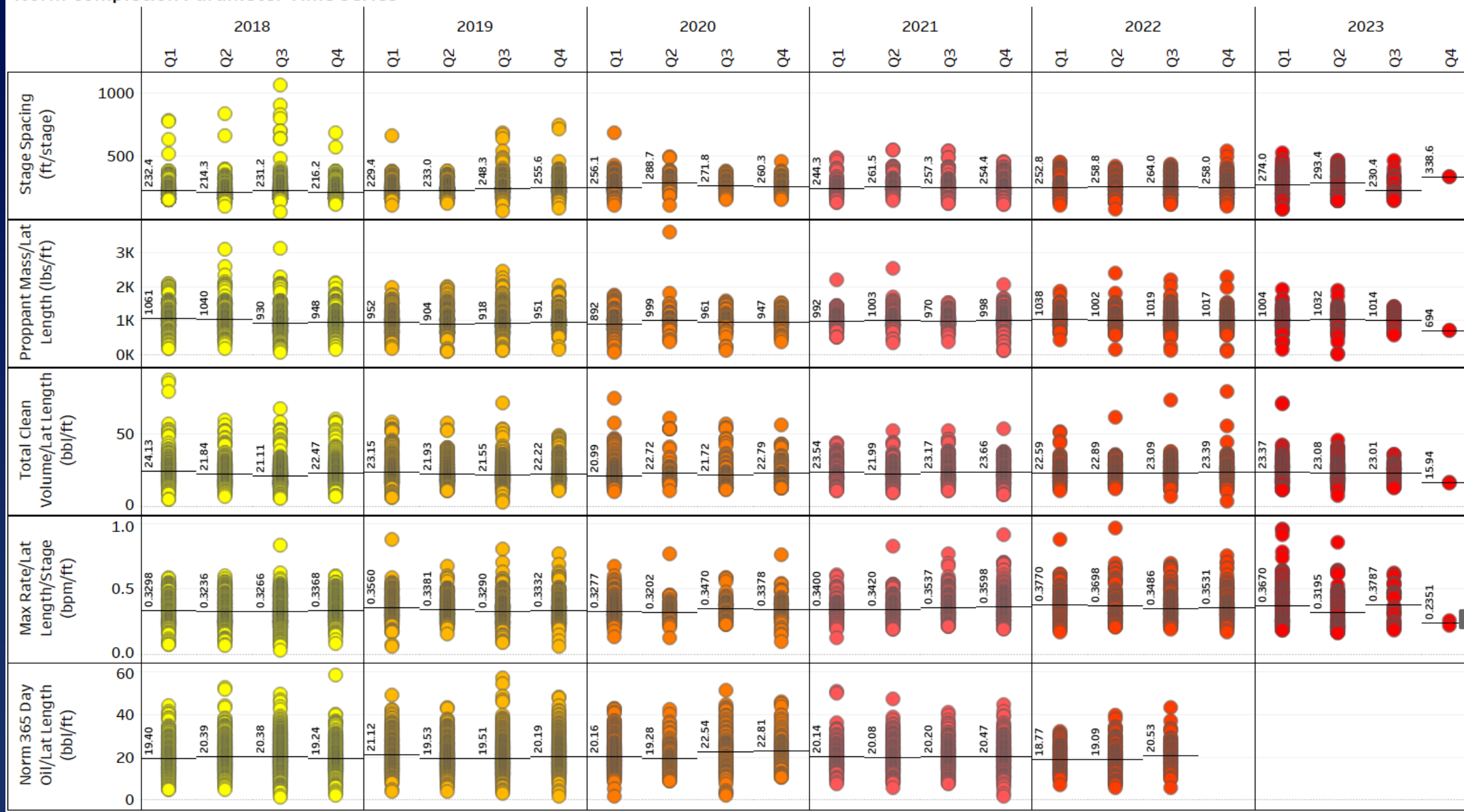


Williston Basin Completion Trends



binars

Norm Completion Parameter Time Series



Fairly flat
>250 ft/stage

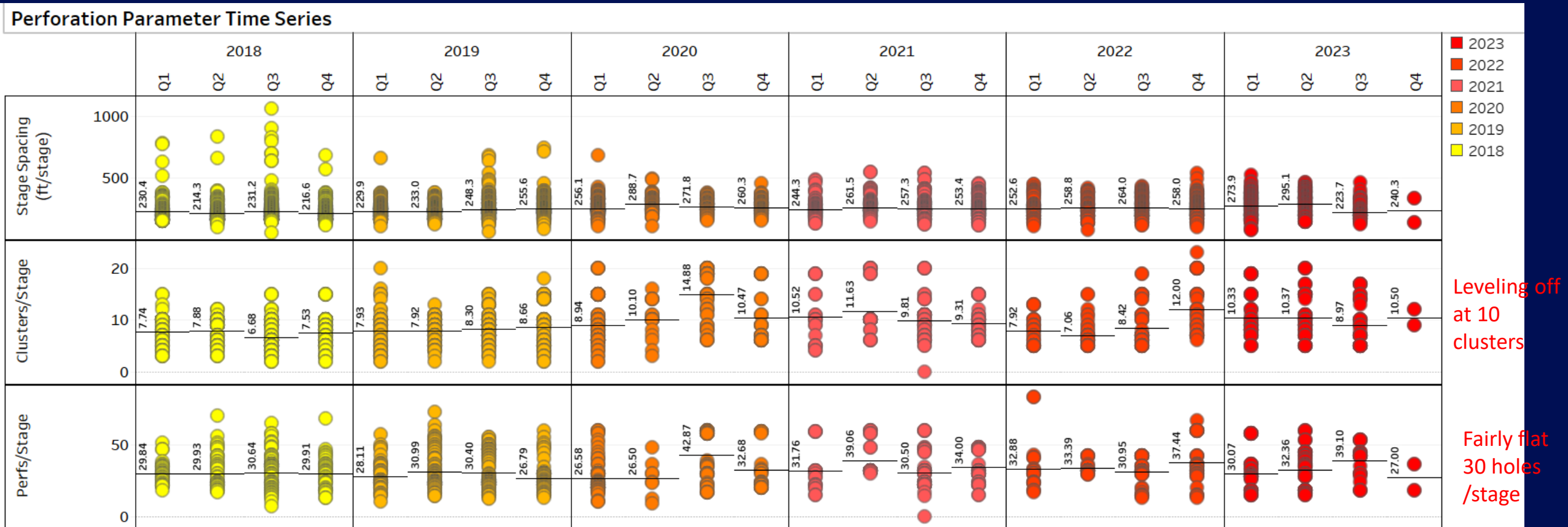
Leveled off
at 1,000
lbs/ft

Flat trend
23 bbls /ft

Flat trend
0.37 bpm /ft

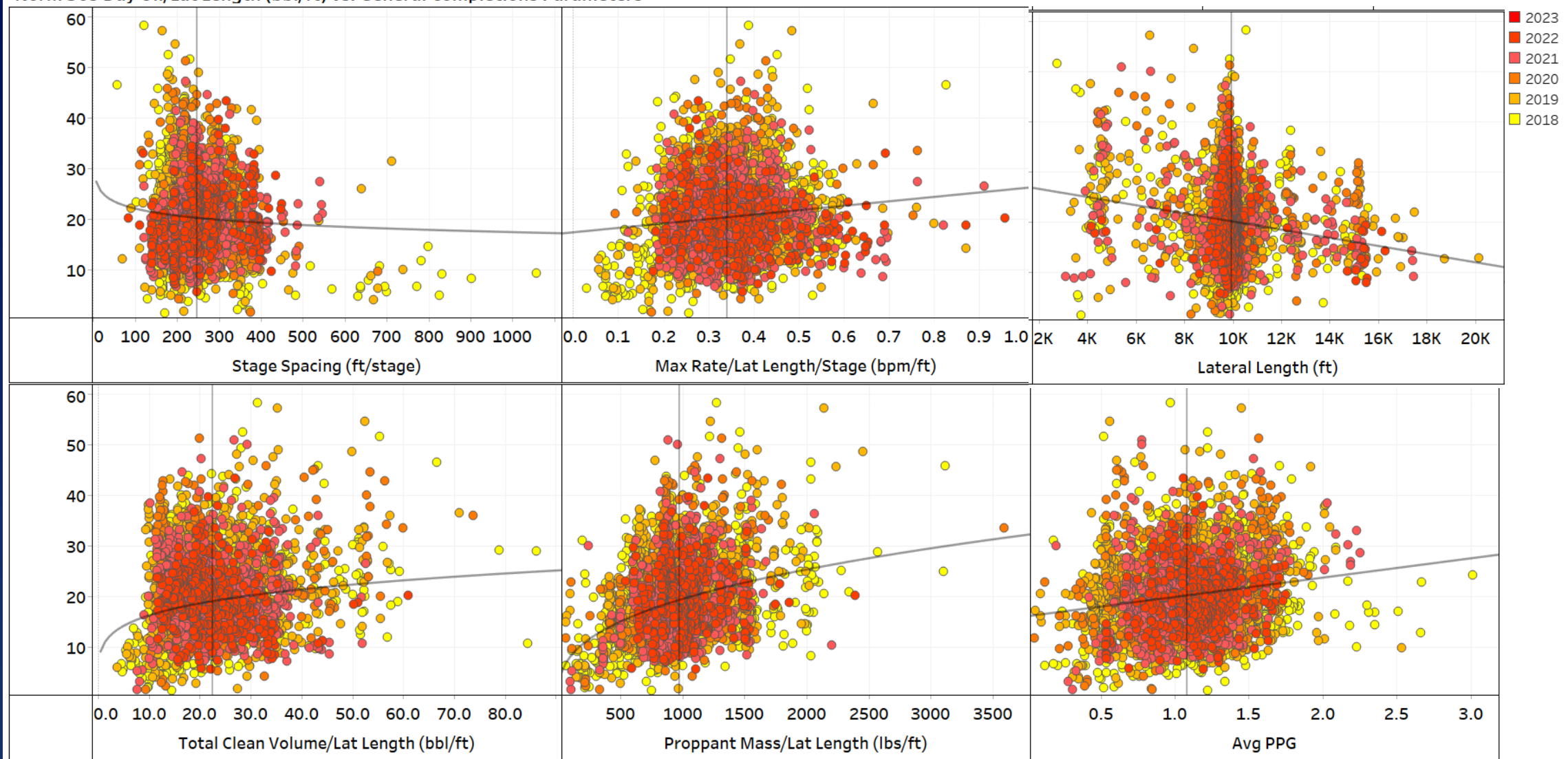
Decrease in
2021 and 2022

Williston Basin Completion Trends



Williston Basin Completion Trends

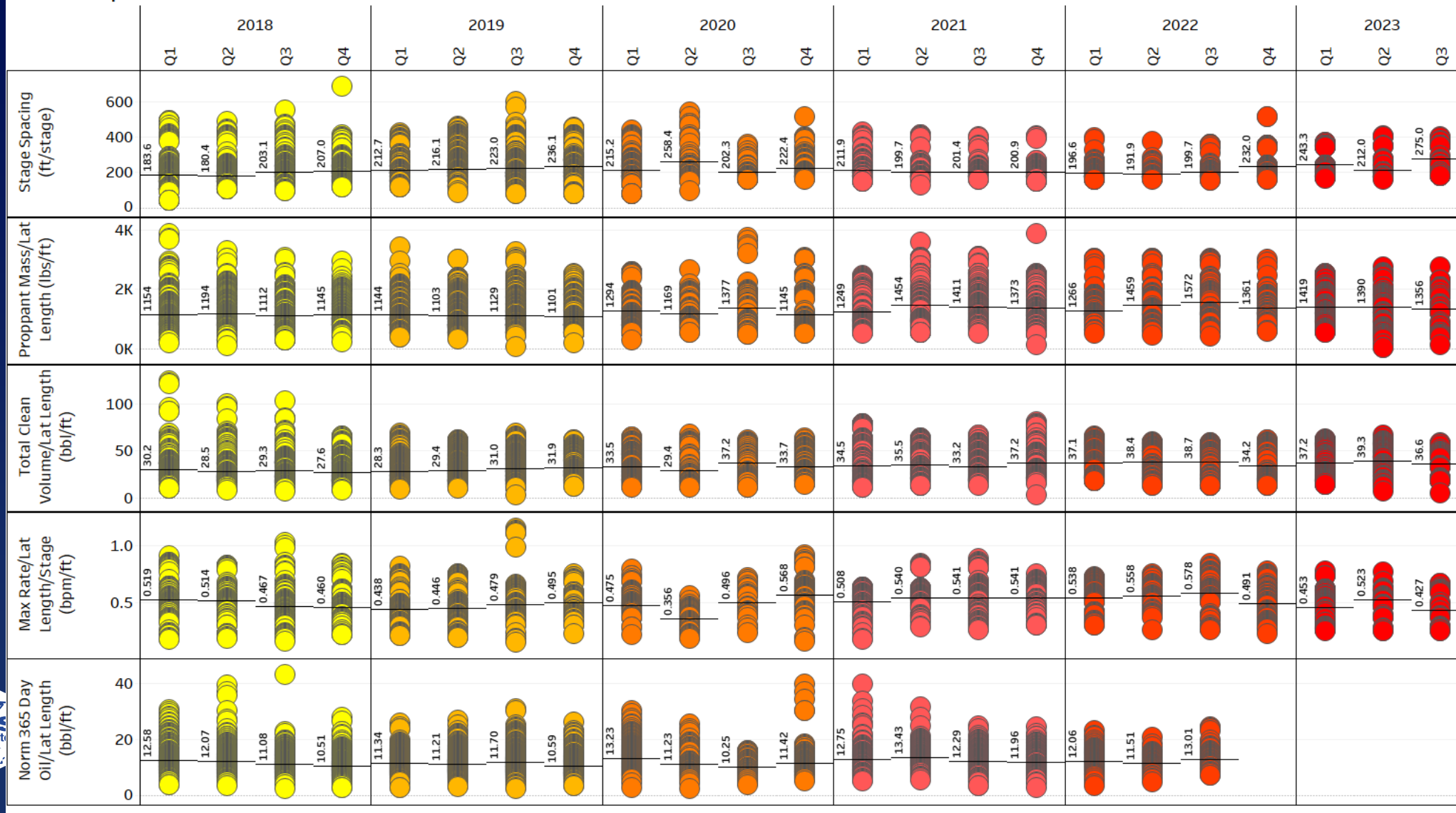
Norm 365 Day Oil/Lat Length (bbl/ft) vs. General Completions Parameters



DJ Basin Completion Trends



Norm Completion Parameter Time Series



Increasing trend to over 240 ft/stage

Leveled off at 1,400 lbs/ft

Flat trend 38 bbls /ft

Flat trend 0.54 bpm /ft

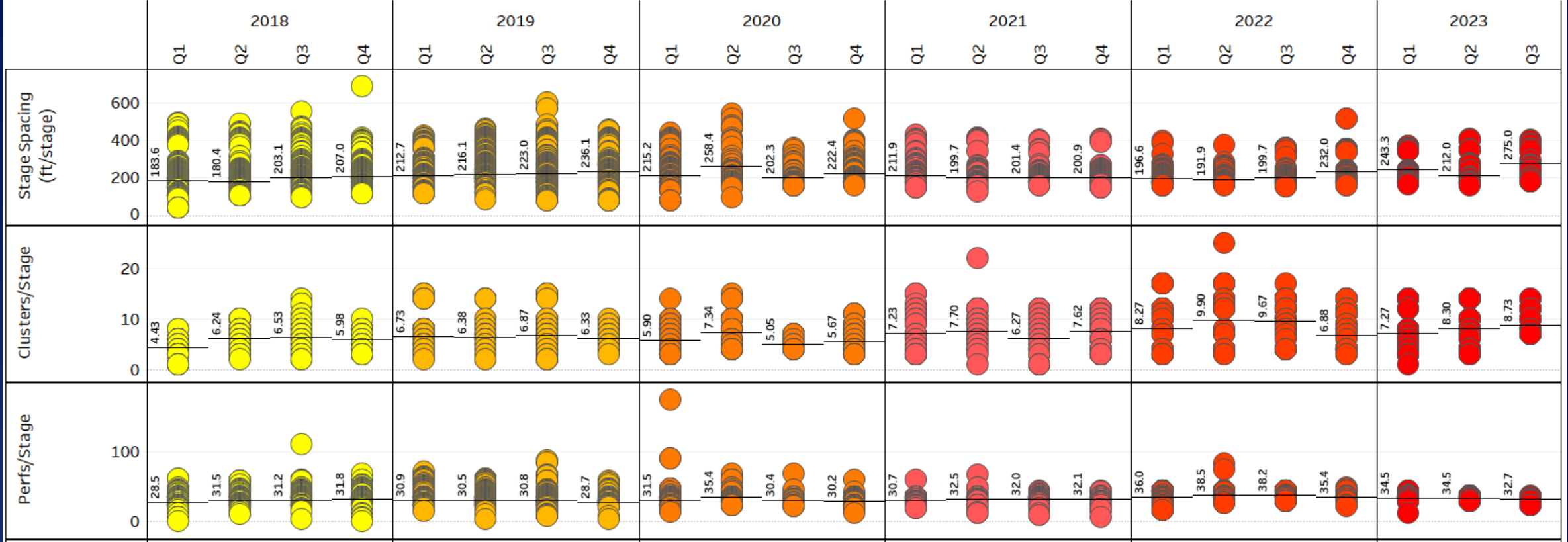
Fairly flat



DJ Basin Completion Trends



Perforation Parameter Time Series

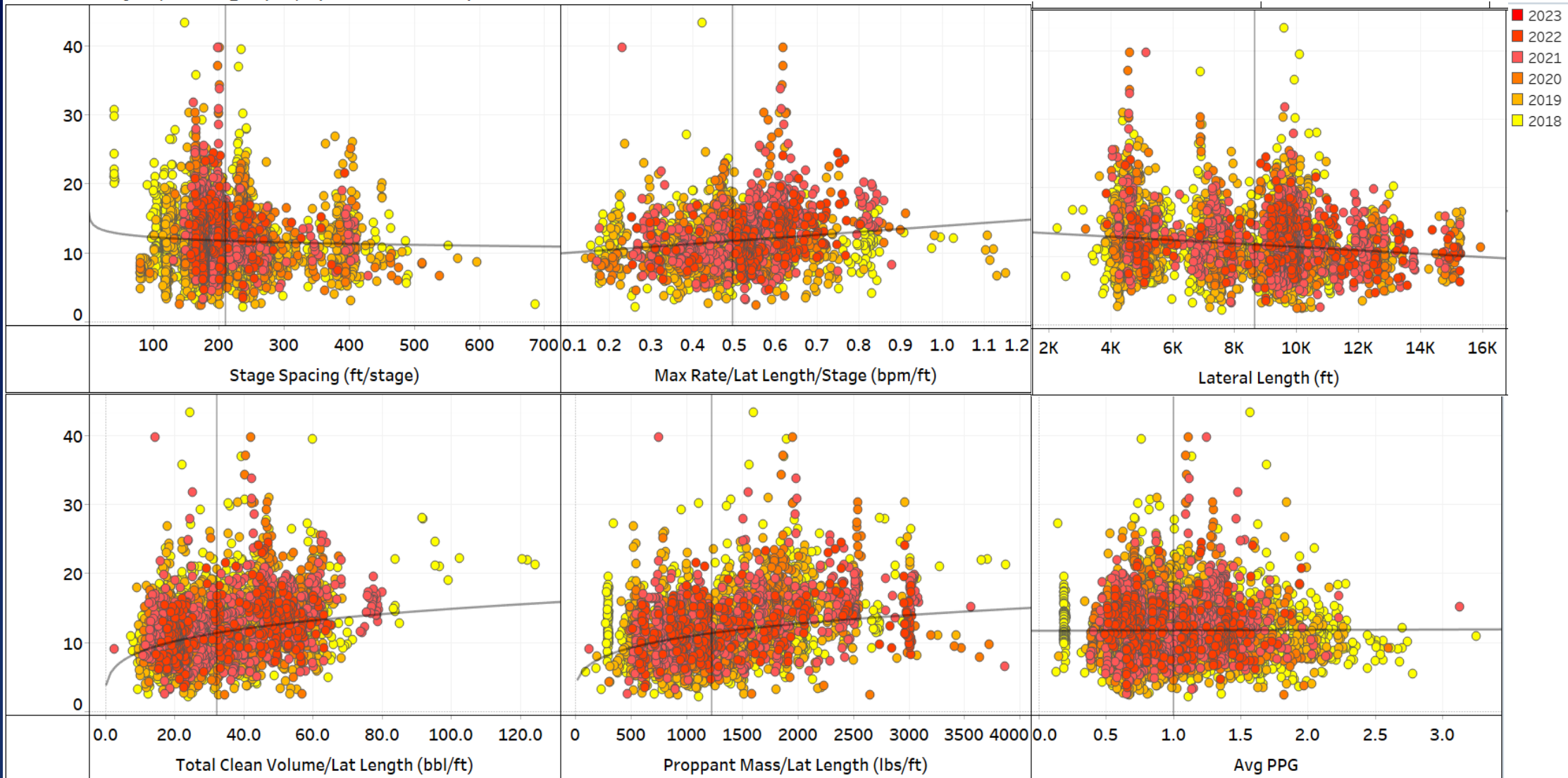


Leveling off
at 7 to 9
clusters

Fairly flat
34 holes/
stage

DJ Basin Completion Trends

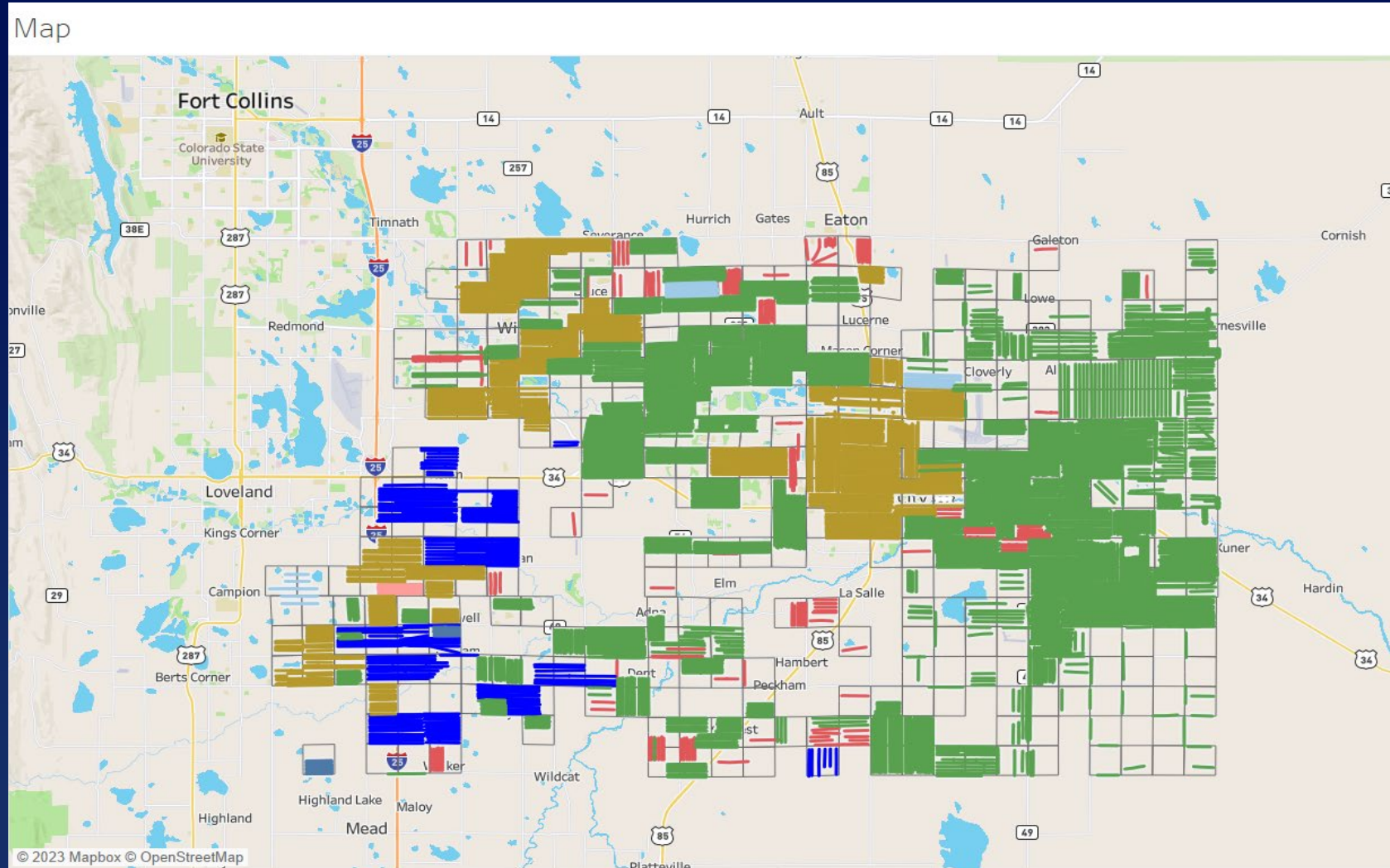
Norm 365 Day Oil/Lat Length (bbl/ft) vs. General Completions Parameters



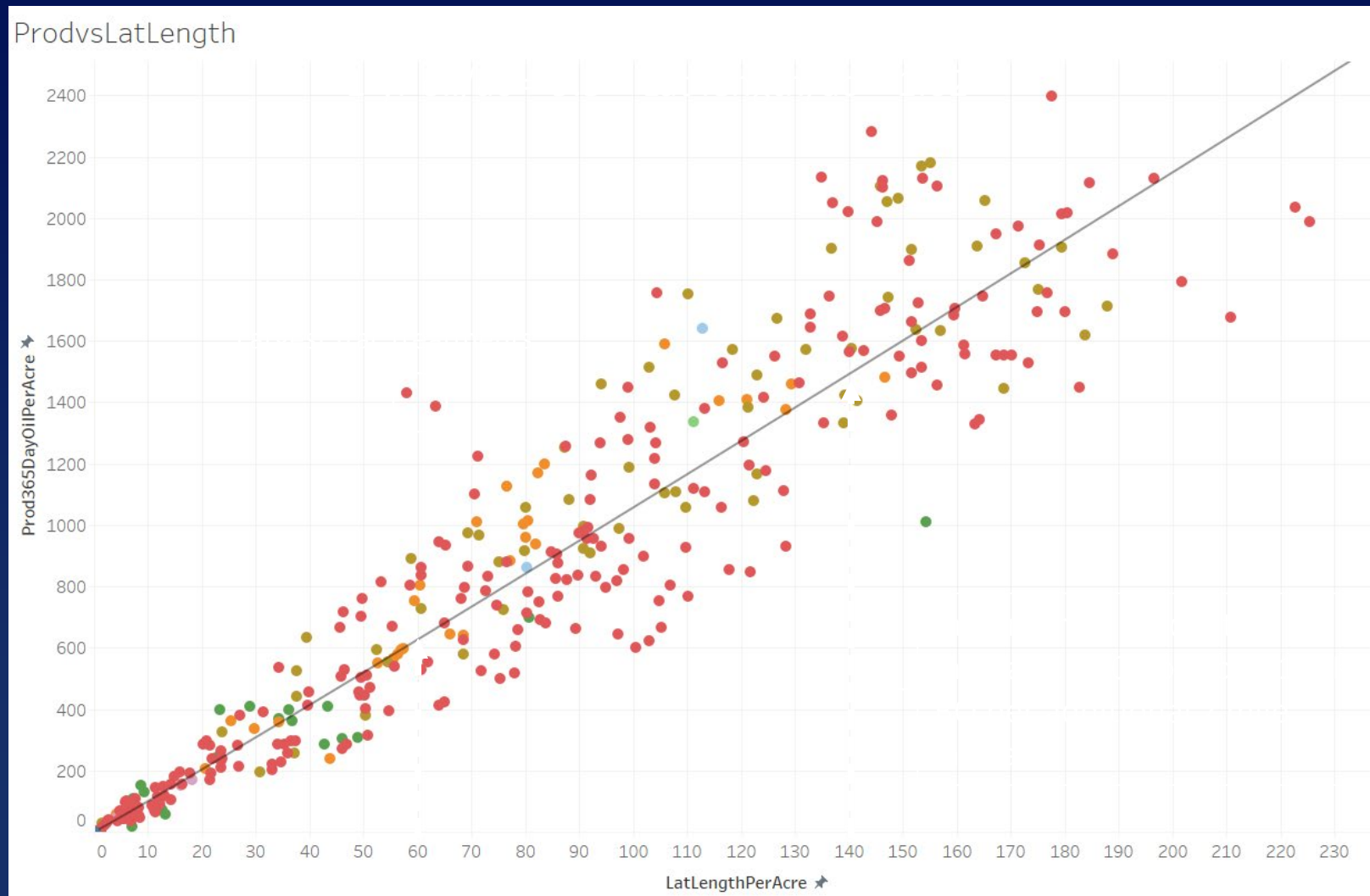
Main Takeaways

- All Basins except Scoop/Stack show increasing average horizontal well lengths (3 milers are common and 4 milers are being tested in the DJ). This leads to higher average well production.
- On average most completion parameters are “locked in” but some experimentation is still going on.
- Average stage lengths are fairly consistent at 200 to 250 ft in all basins but companies are evaluating longer stage lengths using more clusters and better perforation strategies to reduce cost.
- Due to larger formation thicknesses larger treatments are pumped in Texas Basins (2,100 to 2,400 lbs/ft and 45 to 50 bbls/ft) than in the Rockies (1,000 to 1,400 lbs/ft and 23 to 38 bbls/ft).

DJ Basin Section Analysis Example



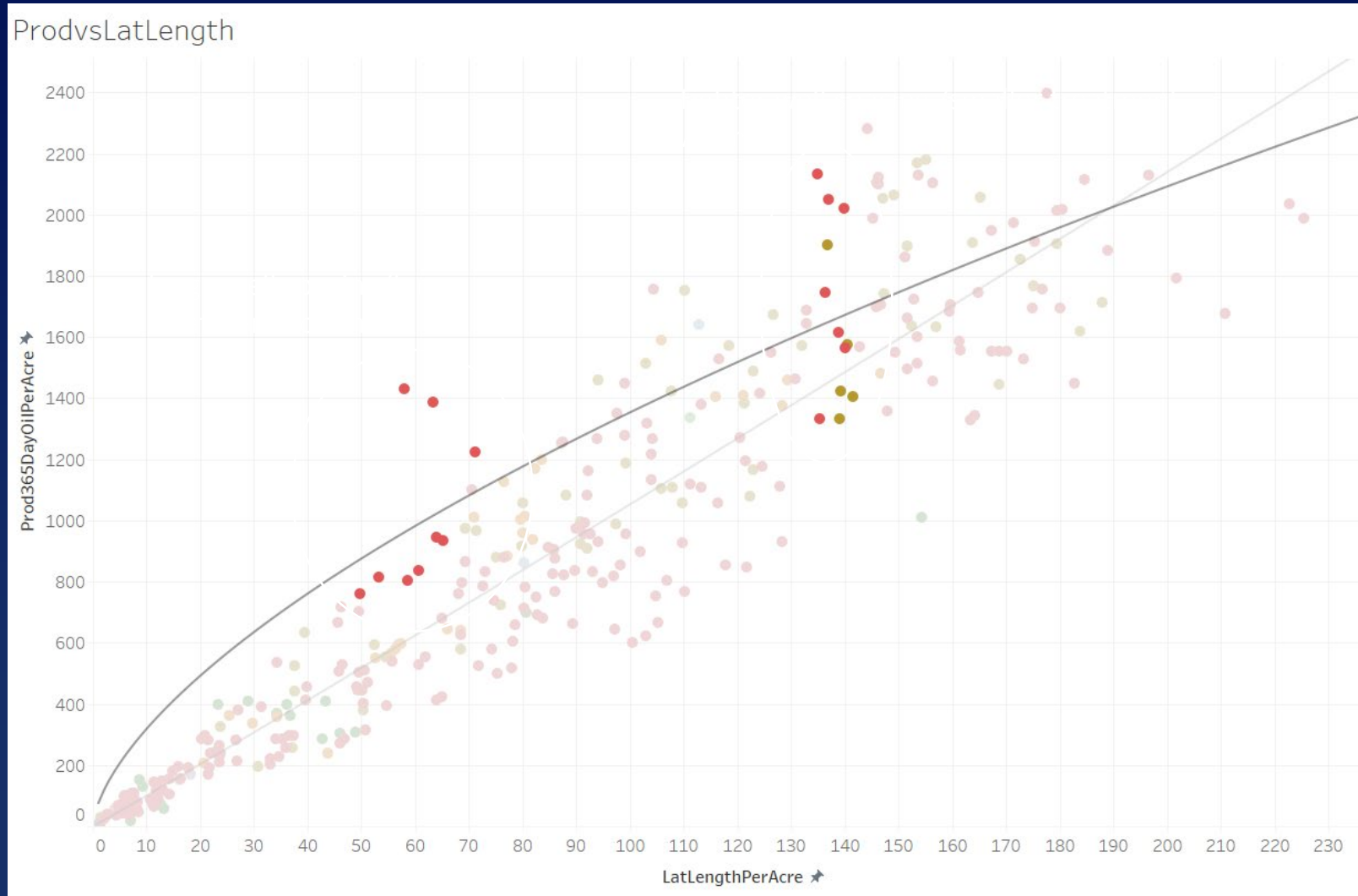
365 Day Oil per Acre vs Lat Length per Acre (WPS) (All Landing Zones)



\$ 59,500/ac in additional revenue
(at \$70 oil) when going from 8
WPS to 18 WPS

One-Year payout if D&C are
below \$743/ft (\$59,500 divided
by incremental 80 ft/ac)

365 Day Oil per Acre vs Lat Length per Acre (Highlighting Different Development Strategies)



\$ 42,000/ac in additional revenue
(at \$70 oil) when going from 8
WPS to 18 WPS

One-Year payout if D&C are
below \$525/ft (\$42,000 divided
by incremental 80 ft/ac)

Production as a Diagnostic Tool

Stephen Schubarth

1-24-2024



Production as a Diagnostic Tool



- How a well produces and the behavior of the production decline can be interpreted to determine the configuration of the stimulated reservoir and the characteristics of the reservoir being drained
- Interpreting the production behavior can be complicated, but the data is “free” and there are several Unconventional Reservoir characteristics that help uncomplicate things



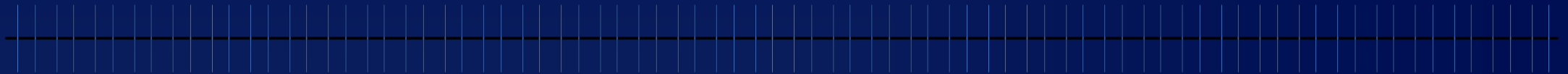
Examples of Fracture Spacing along 10k Lateral



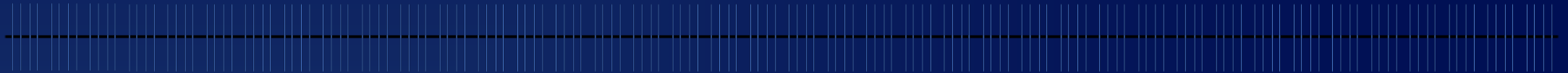
Fractured Area = SRV



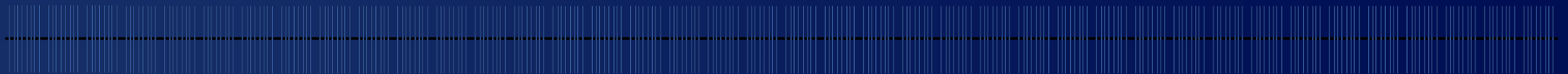
40 Created Fracs – 250' between fracs – $L_f = 250$ feet



80 Created Fracs – 125' between fracs – $L_f = 250$ feet



160 Created Fracs – 62.5' between fracs – $L_f = 250$ feet



320 Created Fracs – 31.25' between fracs – $L_f = 250$ feet



Producing History



- Wells producing from completions shaped like the previous slide will:
 - Have very similar decline characteristics
 - Their production histories can be used to determine:
 - Formation Permeability
 - The average effective fracture half-length of the producing fractures
 - The number of the producing fractures
 - Thus, the spacing of the producing fractures



Rate Normalization

- Normalized rate:

- $Q_n = \frac{Q}{(P_i - P_{wf})} * (P_i - P_n)$ for Oil

- $Q_n = \frac{Q}{(P_i^2 - P_{wf}^2)} * (P_i^2 - P_n^2)$ for Gas

- Where:

- Q_n = Normalized Rate
 - Q = Actual Rate
 - P_i = Initial Pressure
 - P_{wf} = Flowing pressure
 - P_n = Normalized flowing pressure (the flowing pressure the model will be produced at)

Time Normalization



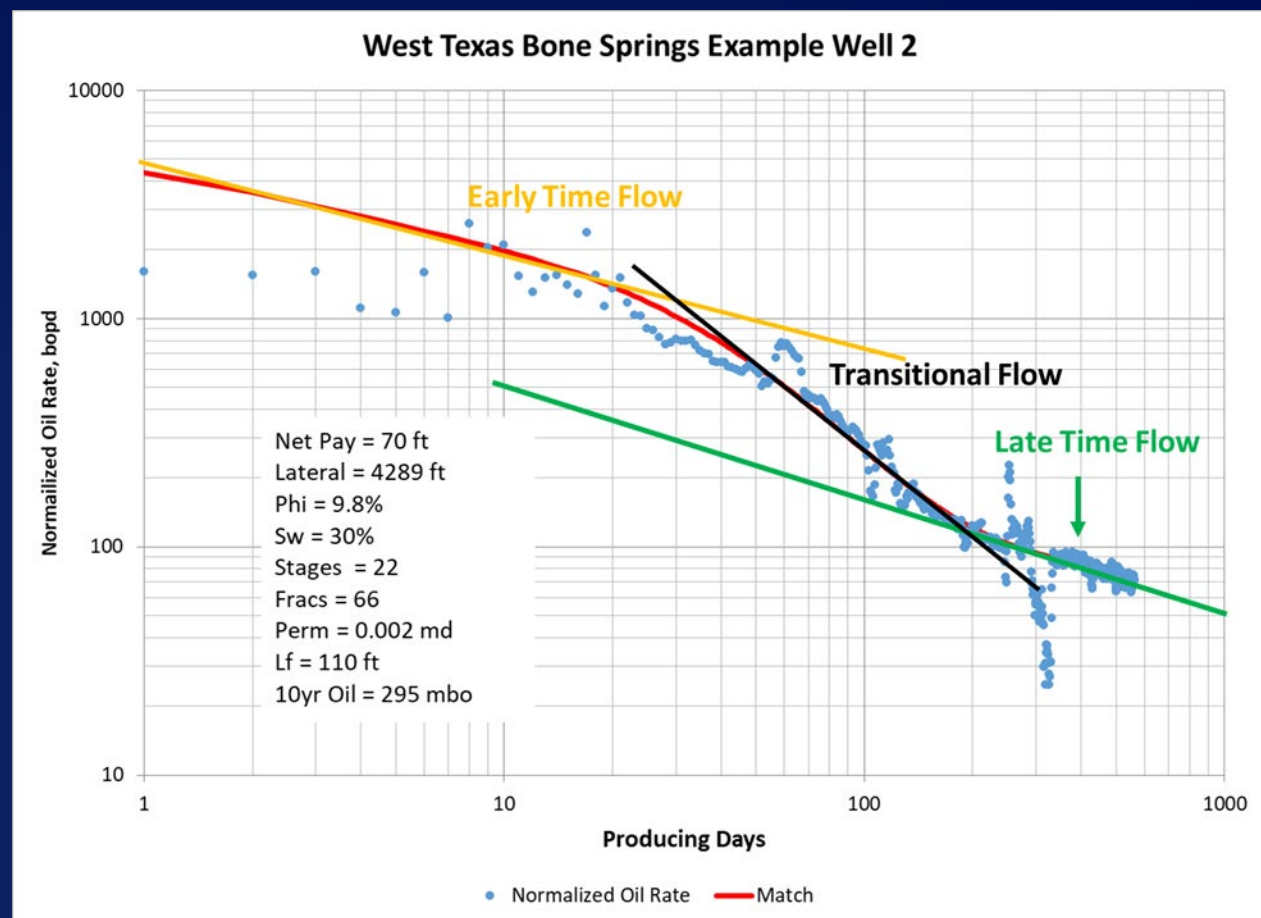
- Normalized time:
 - $\Delta tn = \frac{Q}{Qn}$
 - Where:
 - Δtn = Normalized incremental time
 - Q = Actual Rate
 - Qn = Normalized rate



- Early time flow
 - $f(k^{1/2}$ and effective frac surface area)
- Transitional flow
 - $f(k$ and distance between fracs)
- Late time flow
 - $f(k^{1/2}$ & Lateral Length)

Calculating Time to the End of Linear Flow		
k	2000	nD
Porosity	9.8%	
Viscosity	0.21	cps
Co	2.5E-05	psi-1
Cf	4.0E-06	psi-1
Sw	30%	
# of Fracs/Stage	3	
Ct	2.26E-05	psi-1
Stage Length	195	ft
Time End LF	12.3	days

Production Characteristics of Horizontal Multi-Stage Fractured Wells

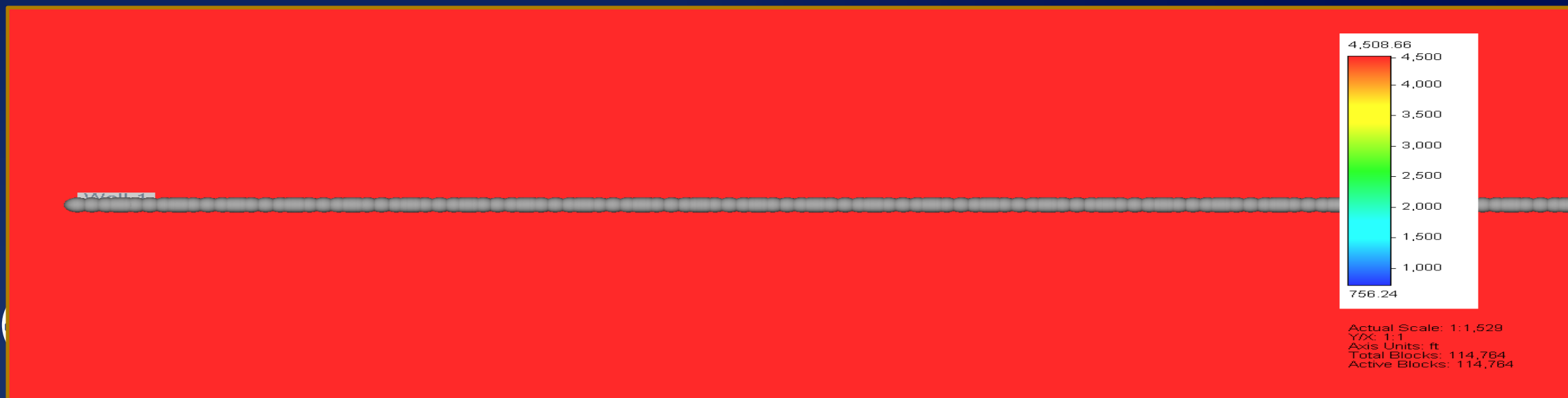


Month 0

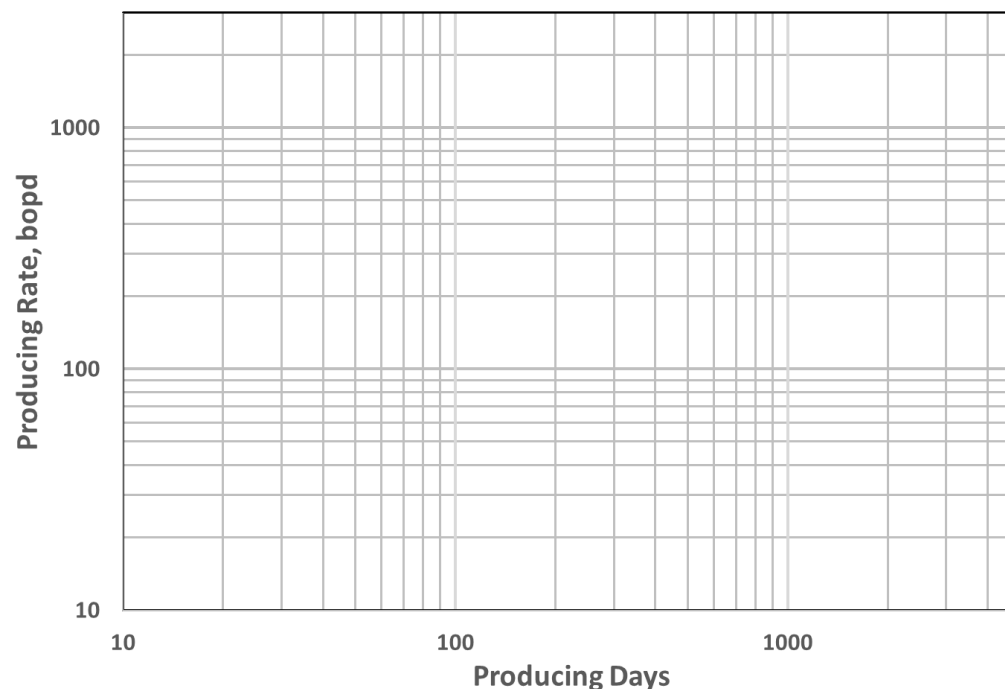
Calculating Time to the End of Linear Flow

k	250	nD
Porosity	5.3%	
Viscosity	0.18	cps
Co	2.5E-05	psi-1
Cf	4.0E-06	psi-1
Sw	30%	
# of Fracs/Stage	2	
Ct	2.26E-05	psi-1
Stage Length	200	ft
Time End LF	108.3	days

Reservoir Pressure Map



Production History - Example Well



Net Pay = 78 feet

Porosity = 5.3%

Permeability = 250 nD

Sw = 15%

Bo = 2.1

Oil Visc. = 0.18 cps

Pi = 4500 psi

Pwf = 750 psi

Lateral Length = 10,800 feet

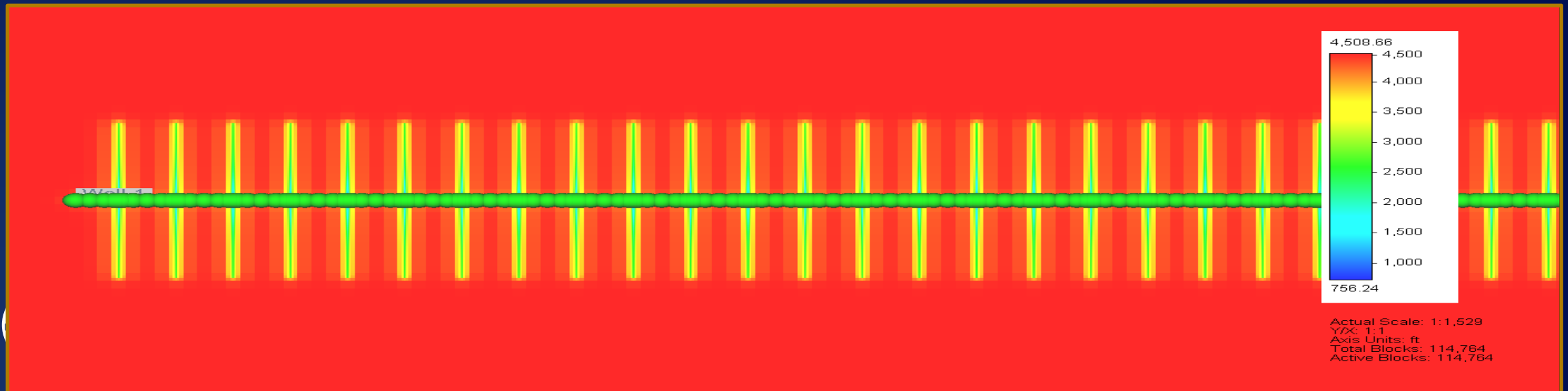
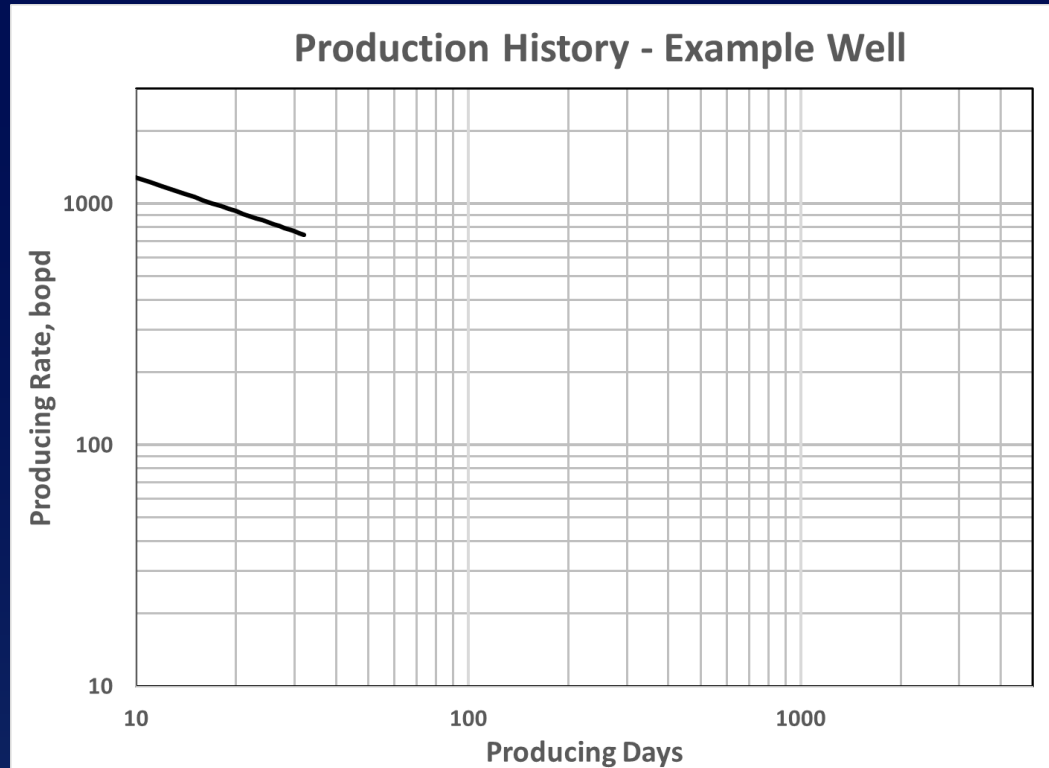
Fracture Spacing = 100 feet

Effective Lf = 250 feet



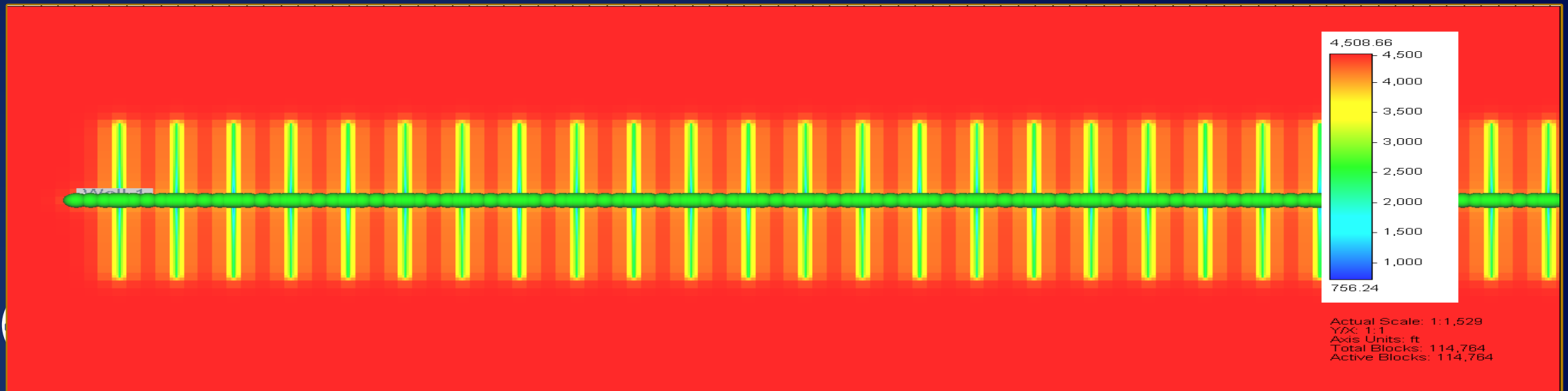
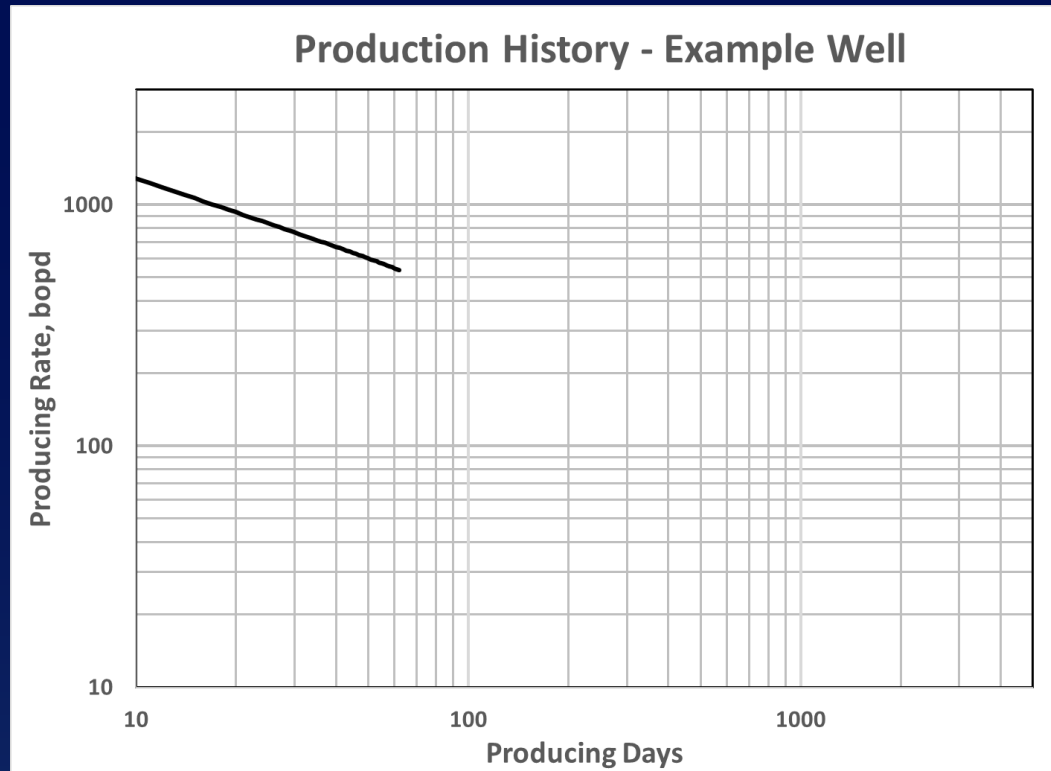
Month 1

Calculating Time to the End of Linear Flow		
k	250	nD
Porosity	5.3%	
Viscosity	0.18	cps
Co	2.5E-05	psi-1
Cf	4.0E-06	psi-1
Sw	30%	
# of Fracs/Stage	2	
Ct	2.26E-05	psi-1
Stage Length	200	ft
Time End LF	108.3	days



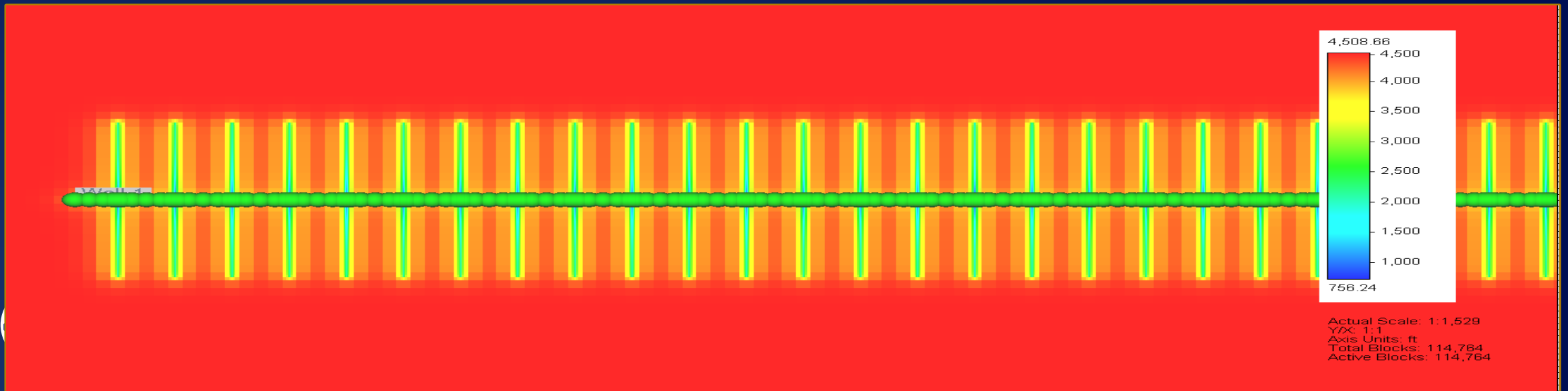
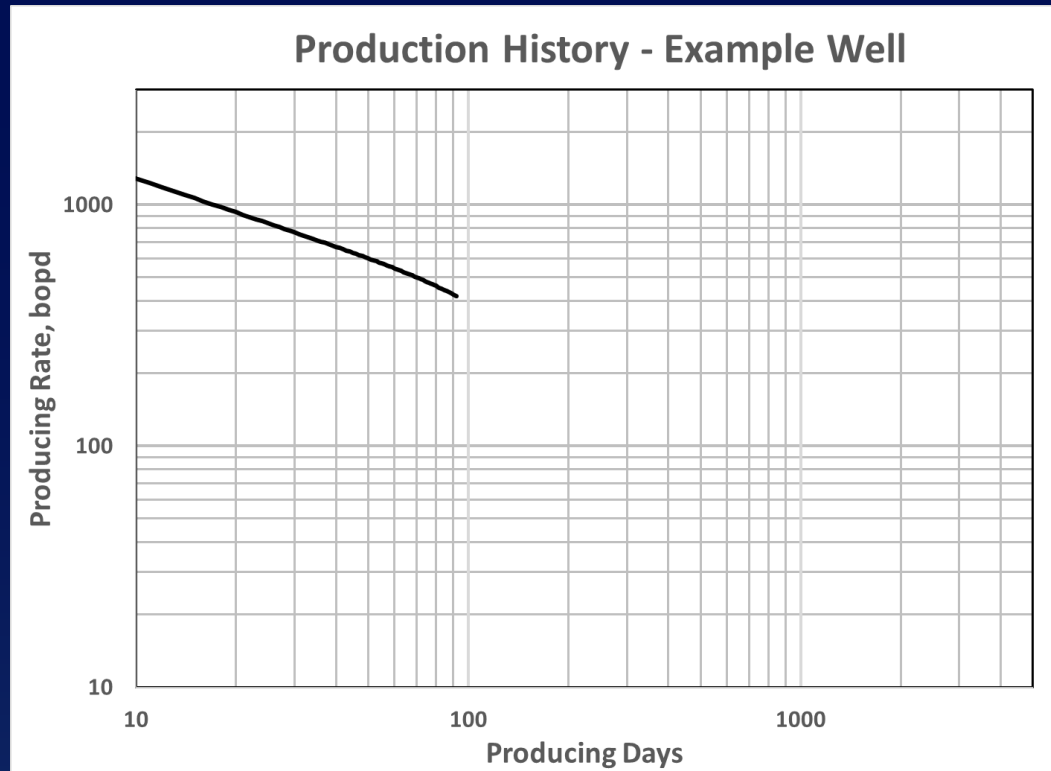
Month 2

Calculating Time to the End of Linear Flow		
k	250	nD
Porosity	5.3%	
Viscosity	0.18	cps
Co	2.5E-05	psi-1
Cf	4.0E-06	psi-1
Sw	30%	
# of Fracs/Stage	2	
Ct	2.26E-05	psi-1
Stage Length	200	ft
Time End LF	108.3	days



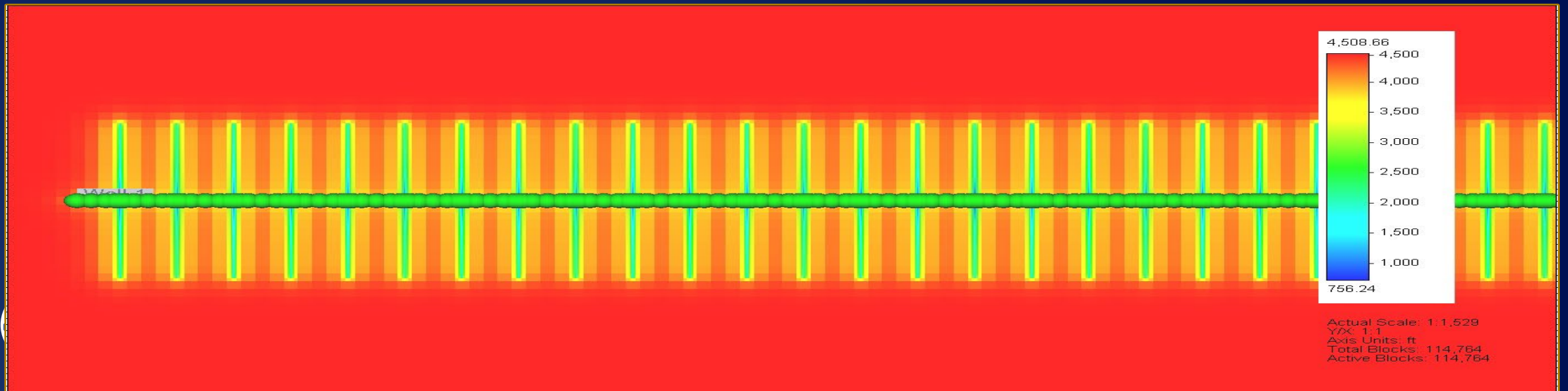
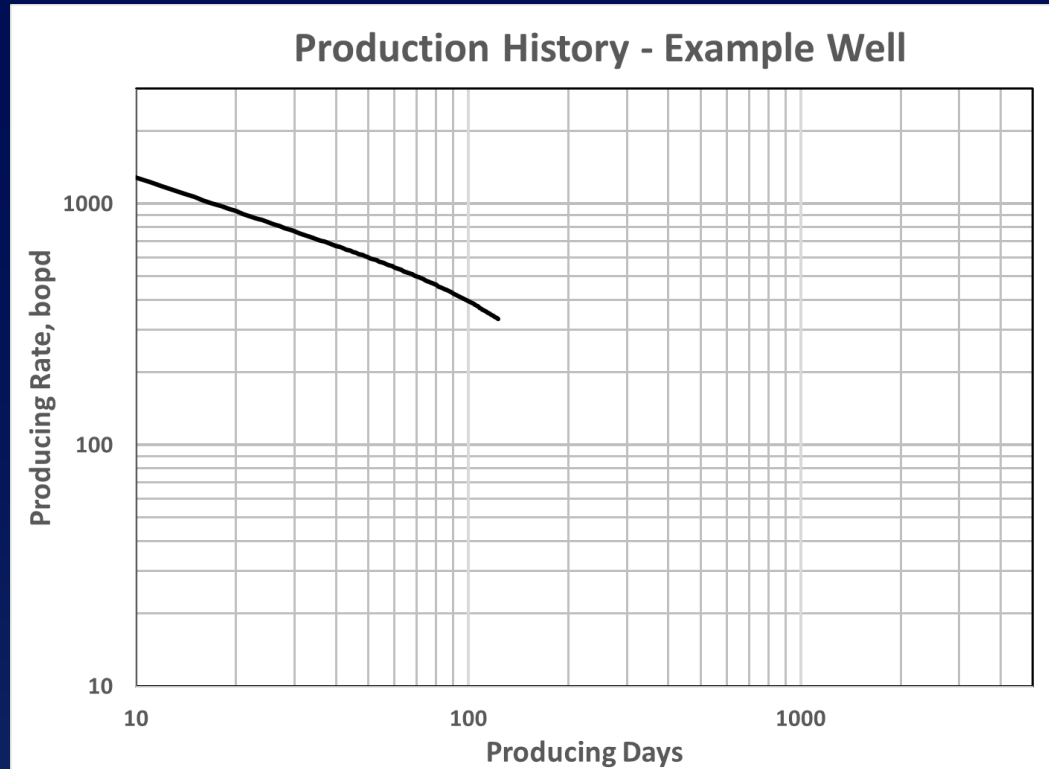
Month 3

Calculating Time to the End of Linear Flow		
k	250	nD
Porosity	5.3%	
Viscosity	0.18	cps
Co	2.5E-05	psi-1
Cf	4.0E-06	psi-1
Sw	30%	
# of Fracs/Stage	2	
Ct	2.26E-05	psi-1
Stage Length	200	ft
Time End LF	108.3	days



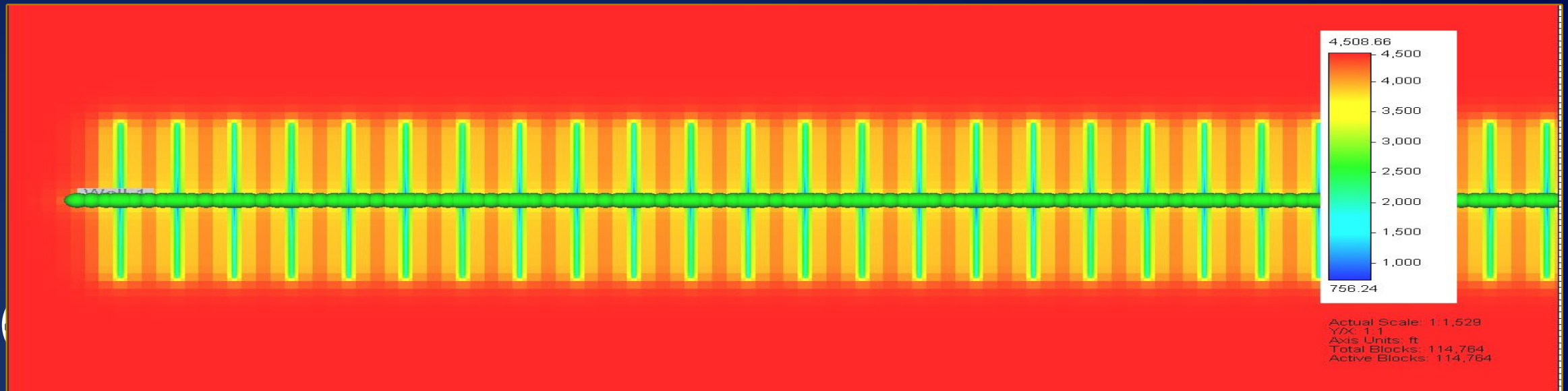
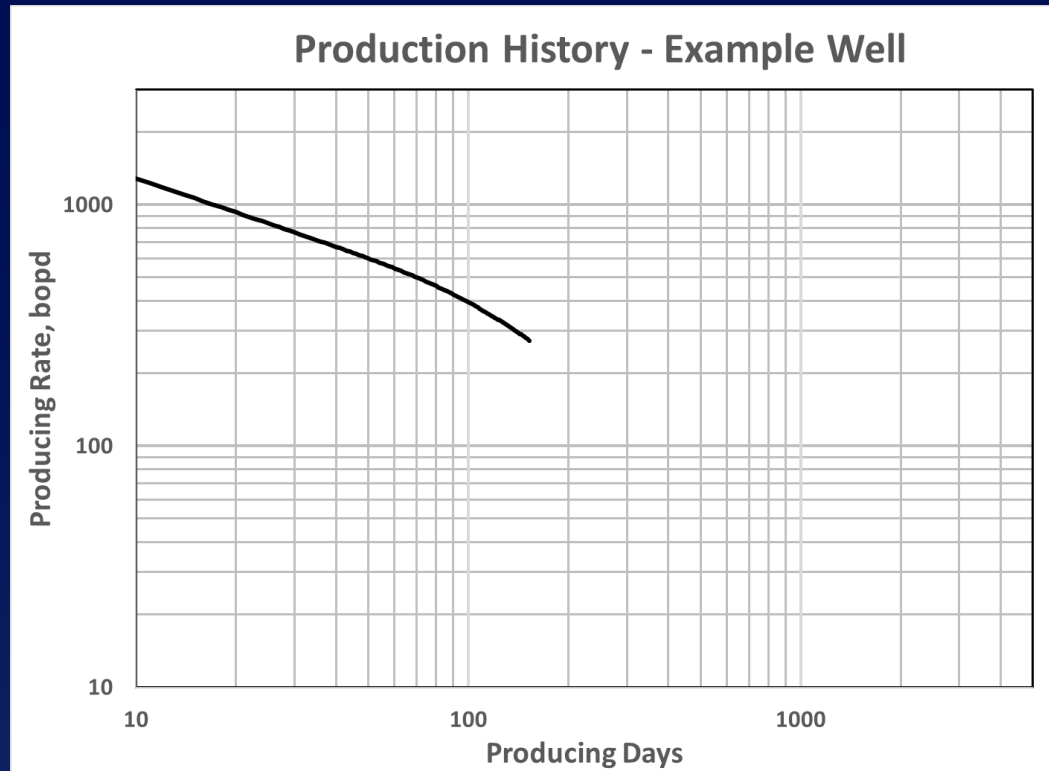
Month 4

Calculating Time to the End of Linear Flow		
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Porosity	5.3%	
Viscosity	0.18	cps
Co	2.5E-05	psi-1
Cf	4.0E-06	psi-1
Sw	30%	
# of Fracs/Stage	2	
Ct	2.26E-05	psi-1
Stage Length	200	ft
Time End LF	108.3	days

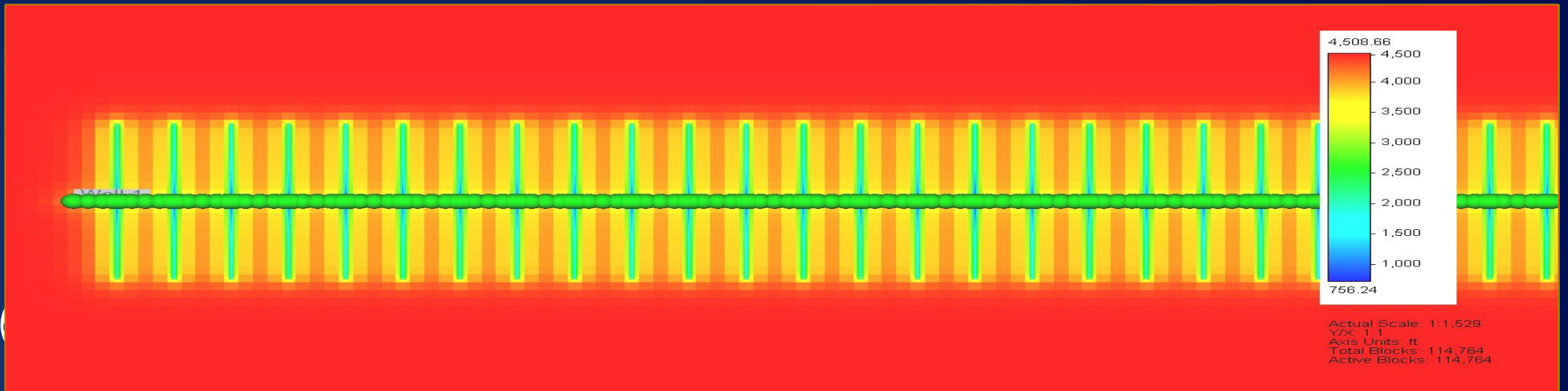
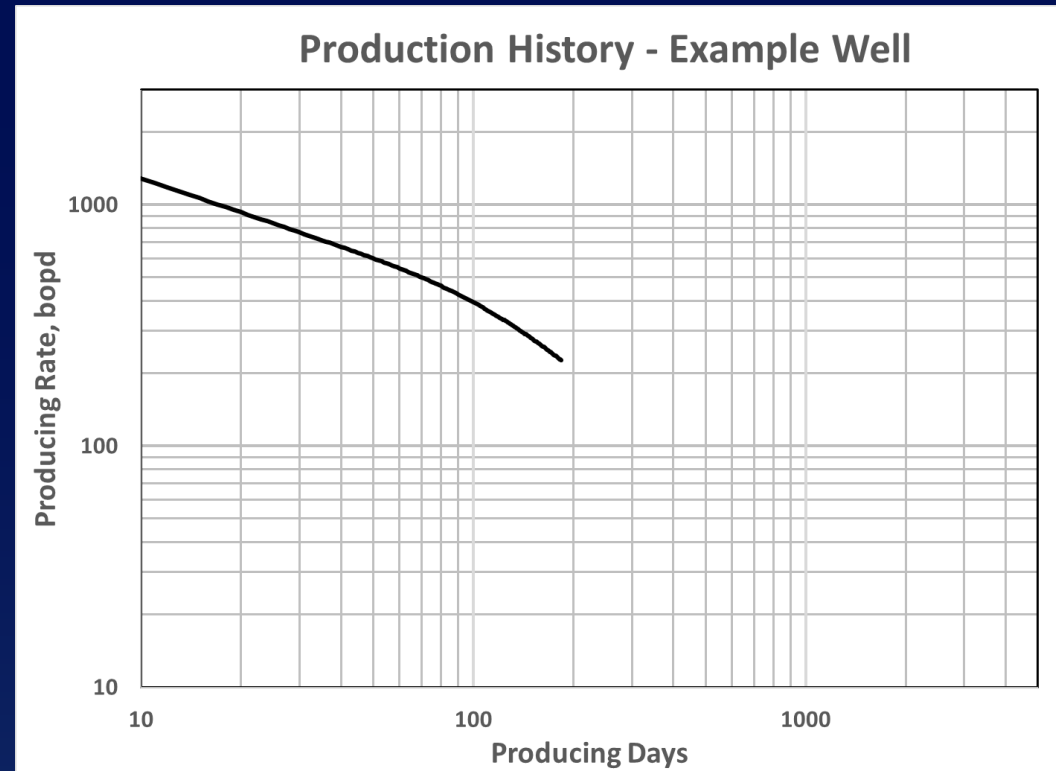


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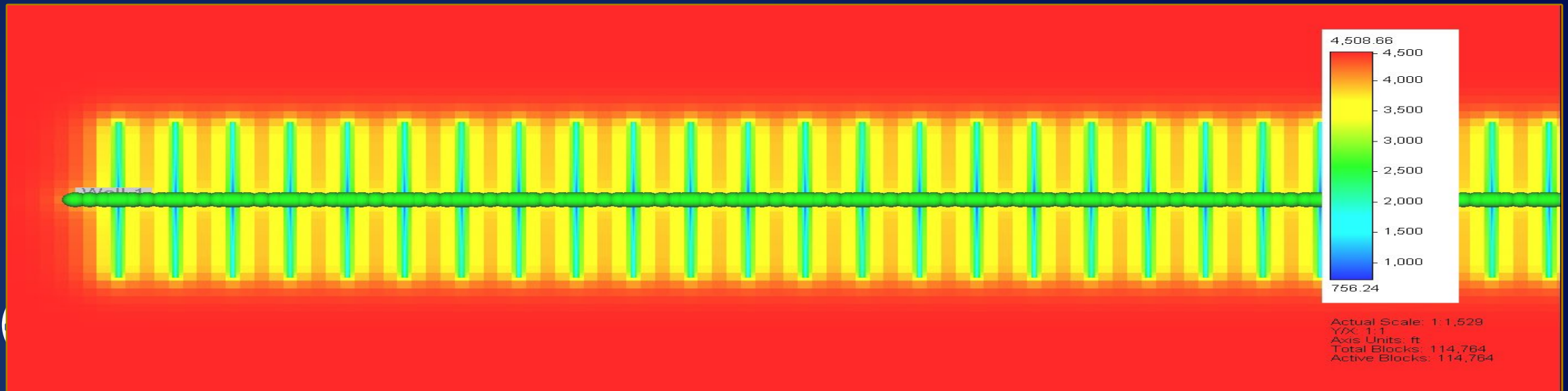
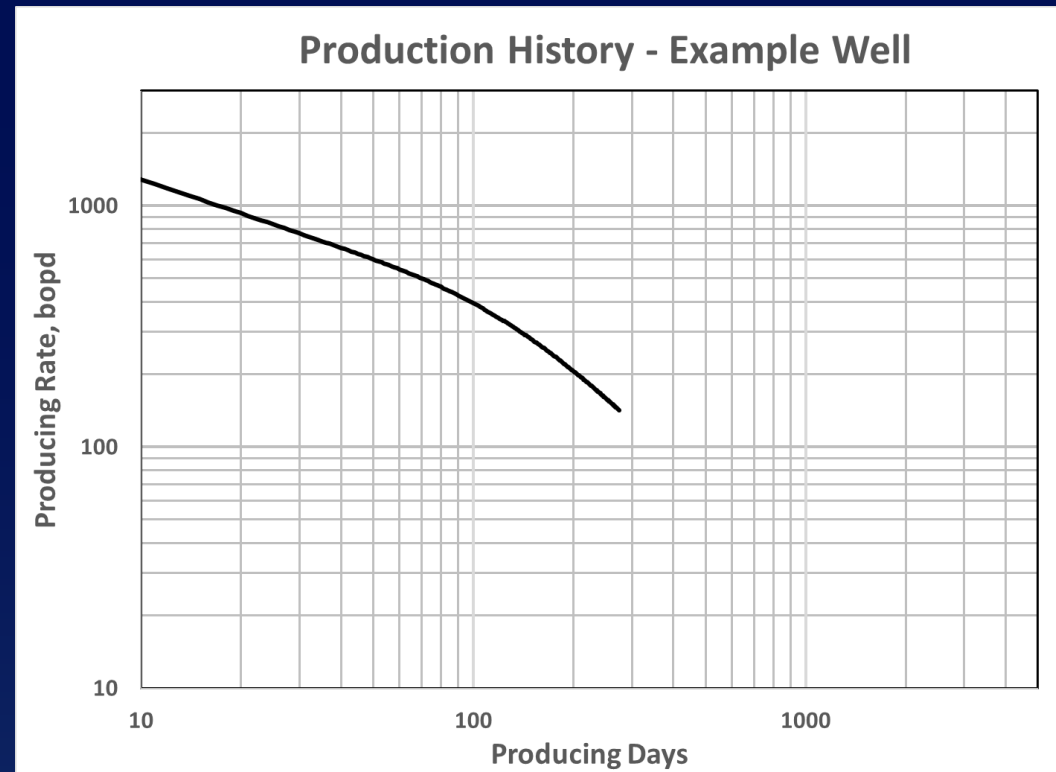
Calculating Time to the End of Linear Flow		
k	250	nD
Porosity	5.3%	
Viscosity	0.18	cps
Co	2.5E-05	psi-1
Cf	4.0E-06	psi-1
Sw	30%	
# of Fracs/Stage	2	
Ct	2.26E-05	psi-1
Stage Length	200	ft
Time End LF	108.3	days



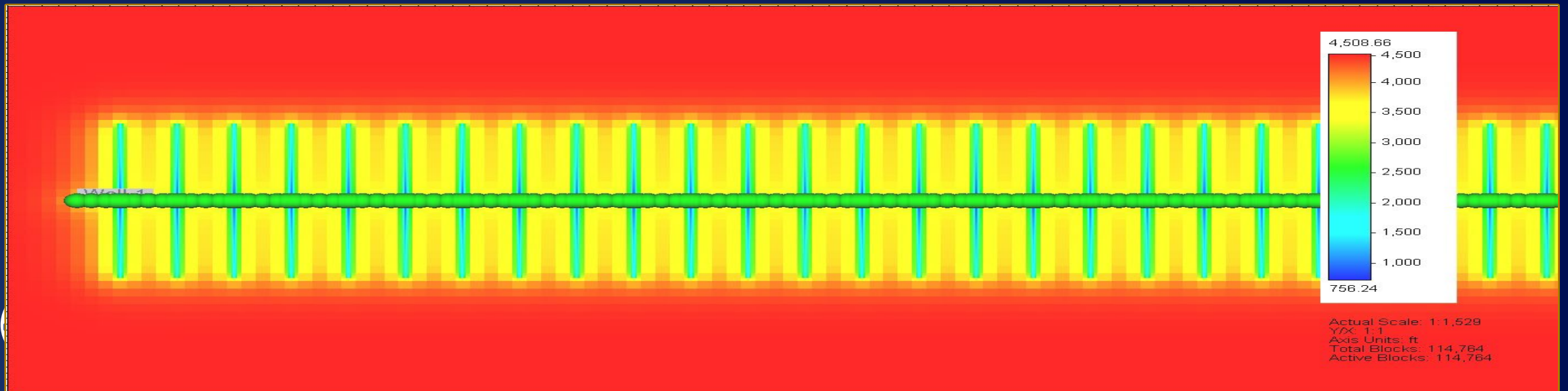
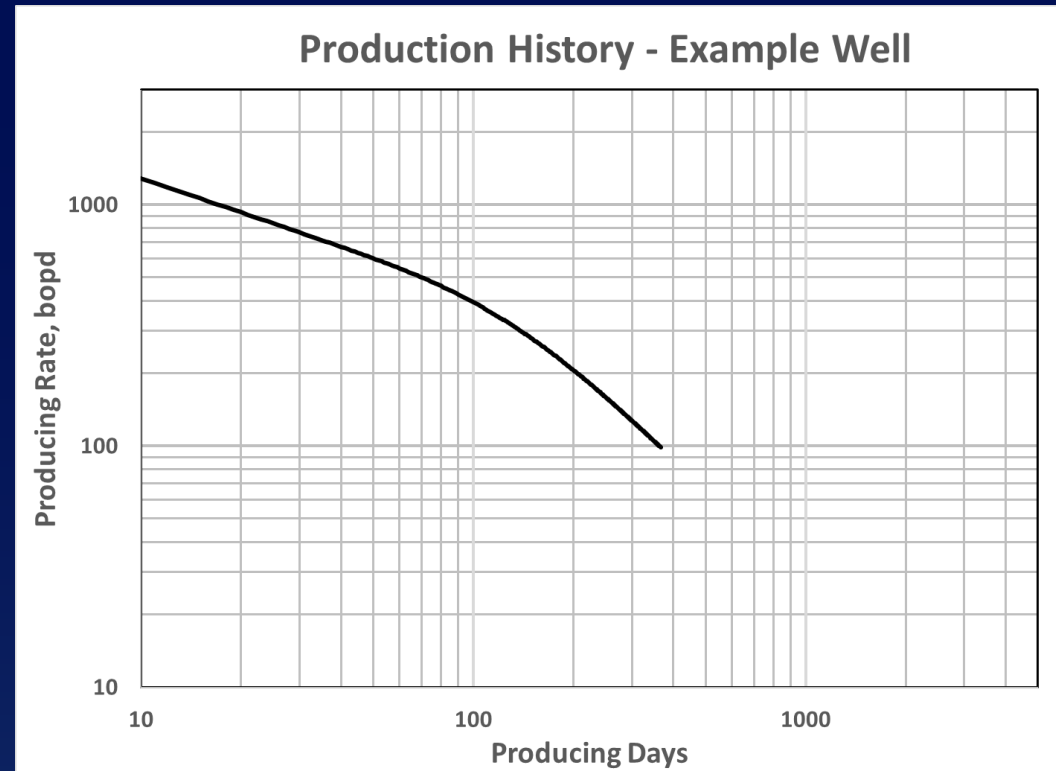
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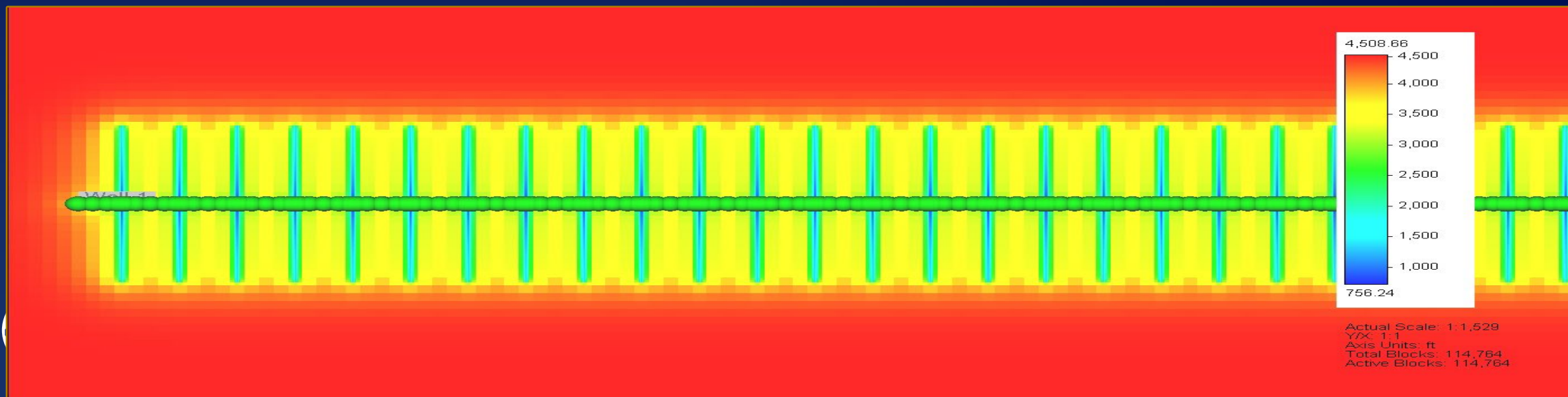
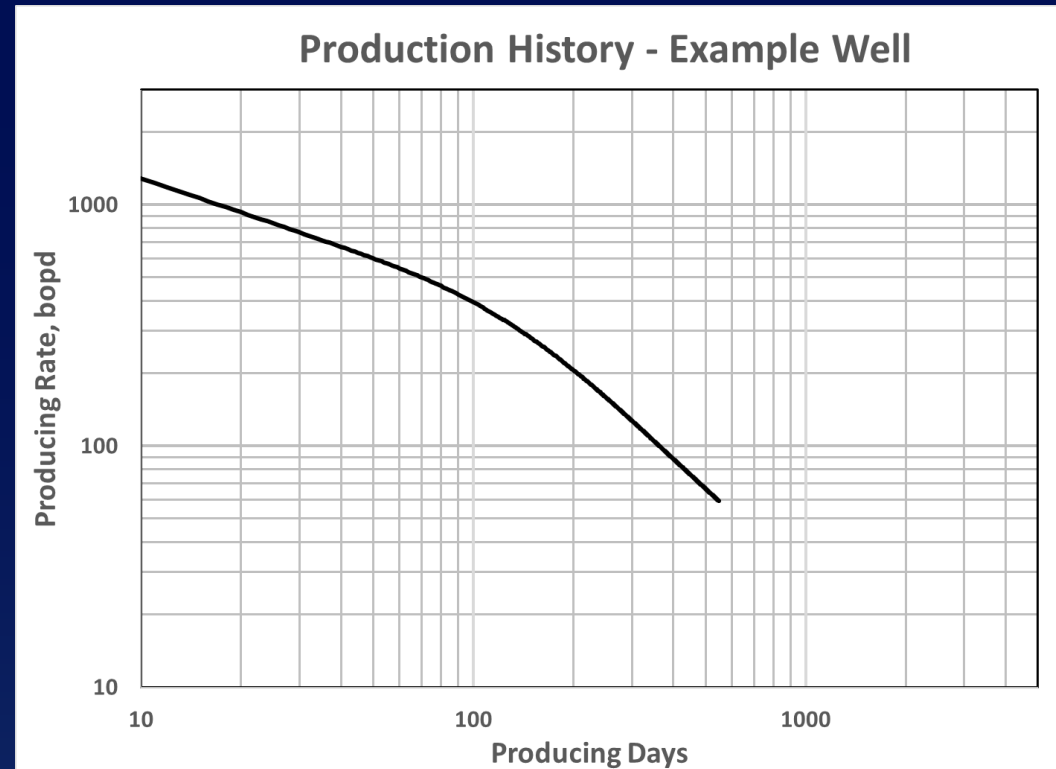
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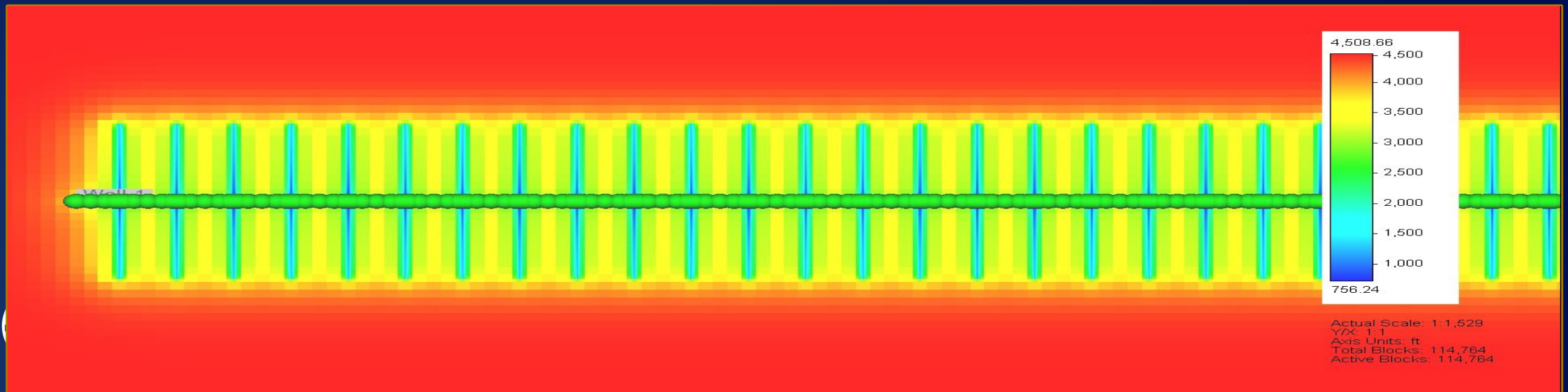
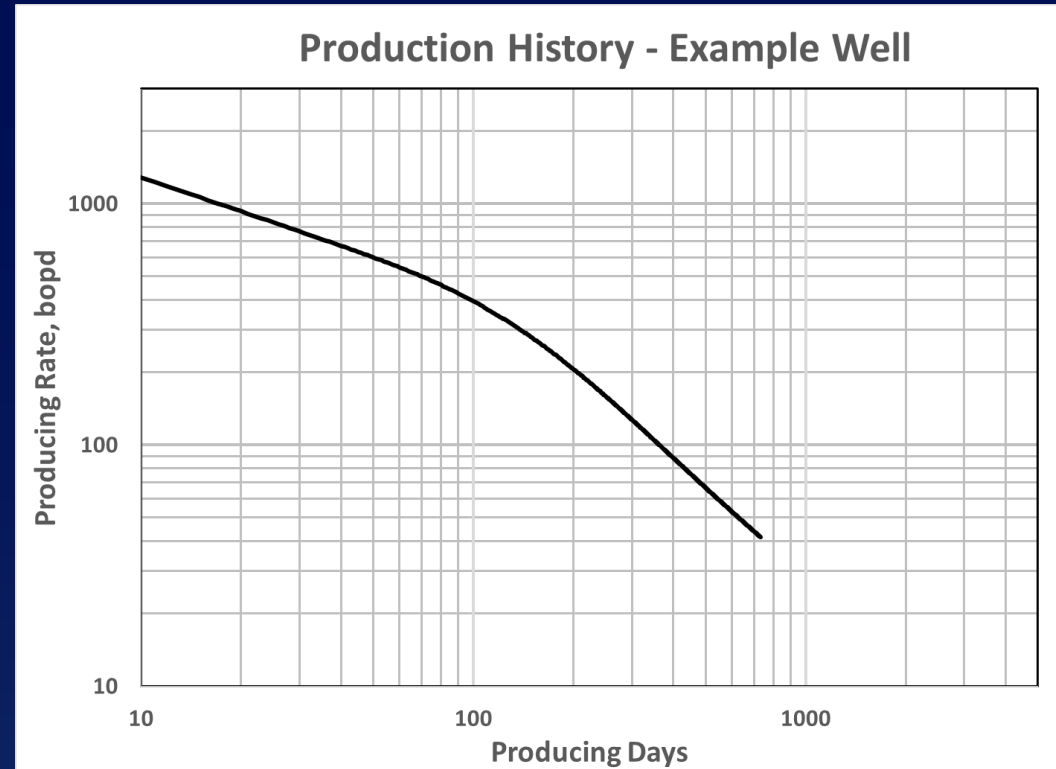
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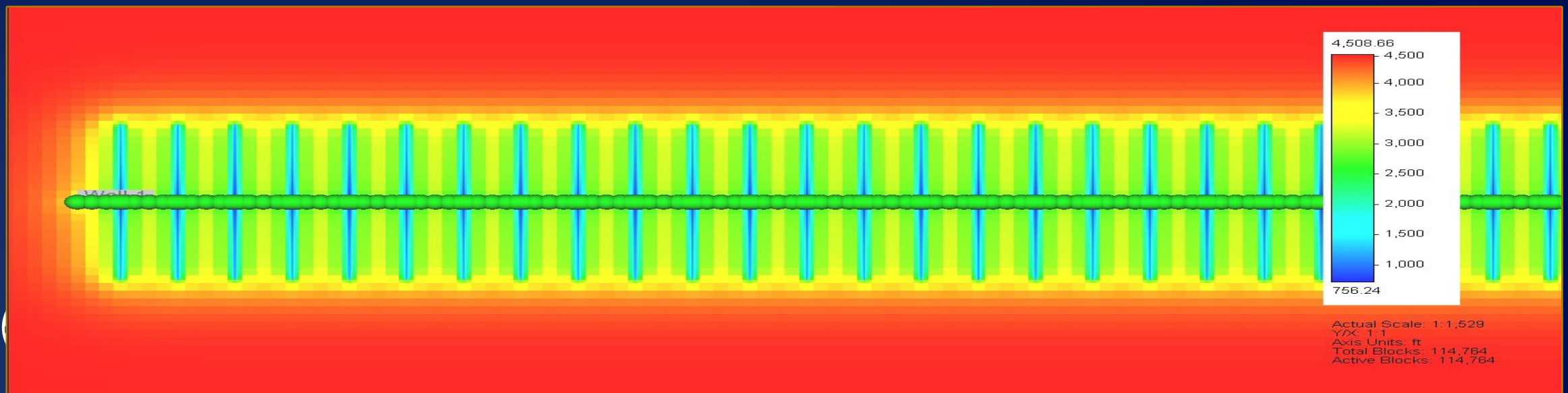
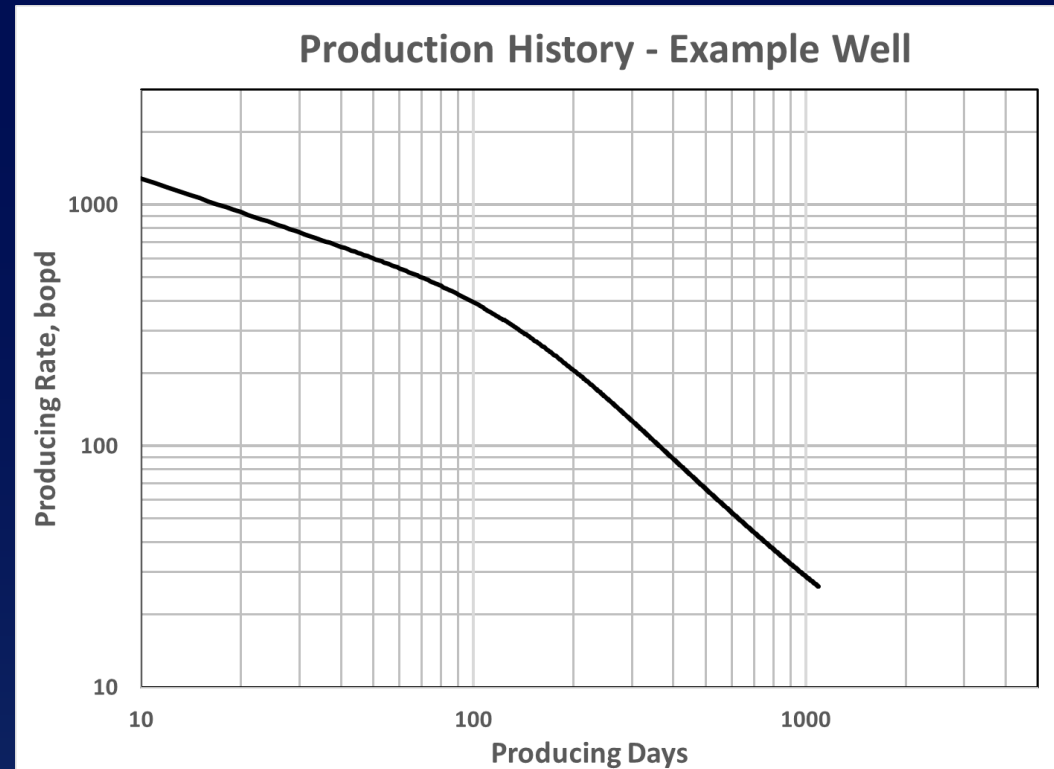
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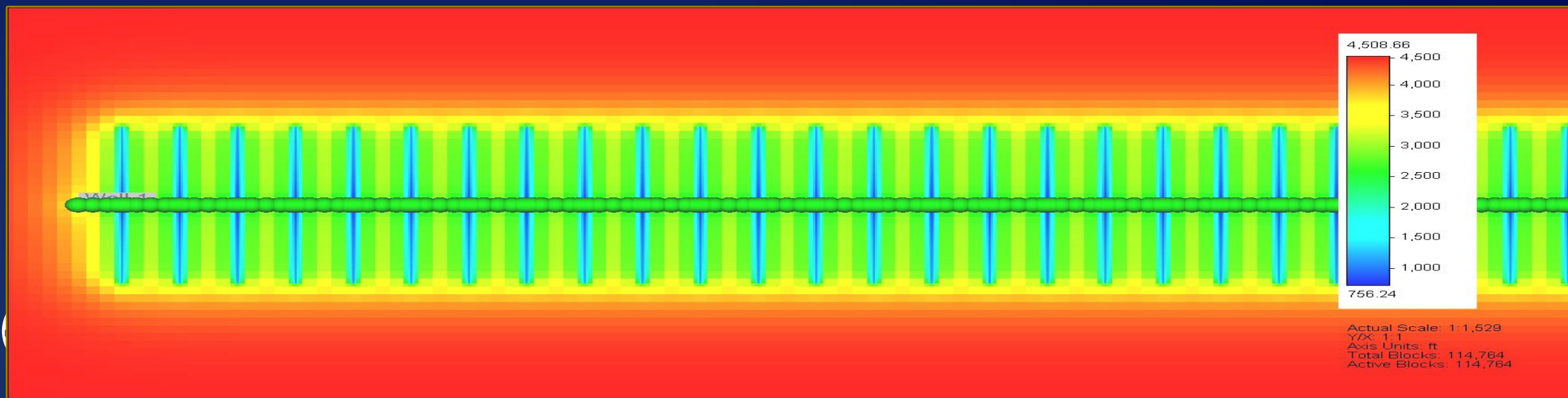
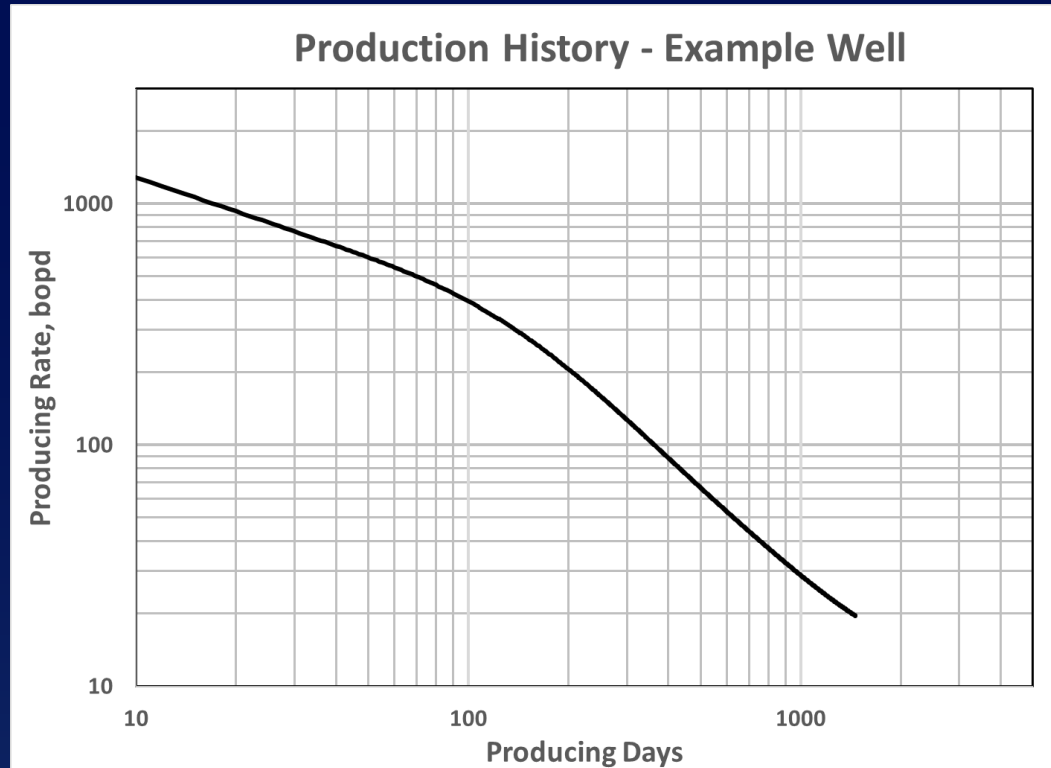
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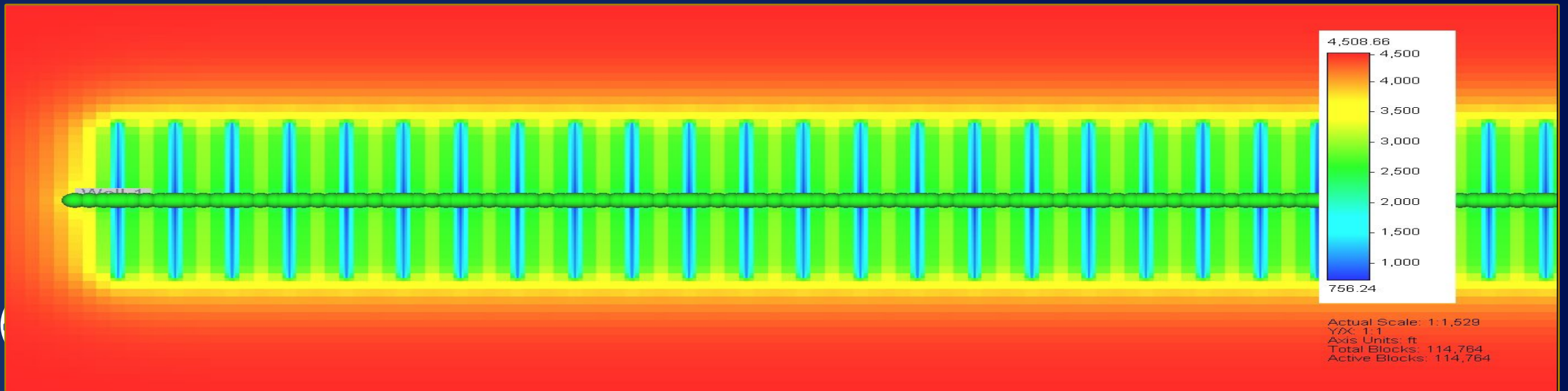
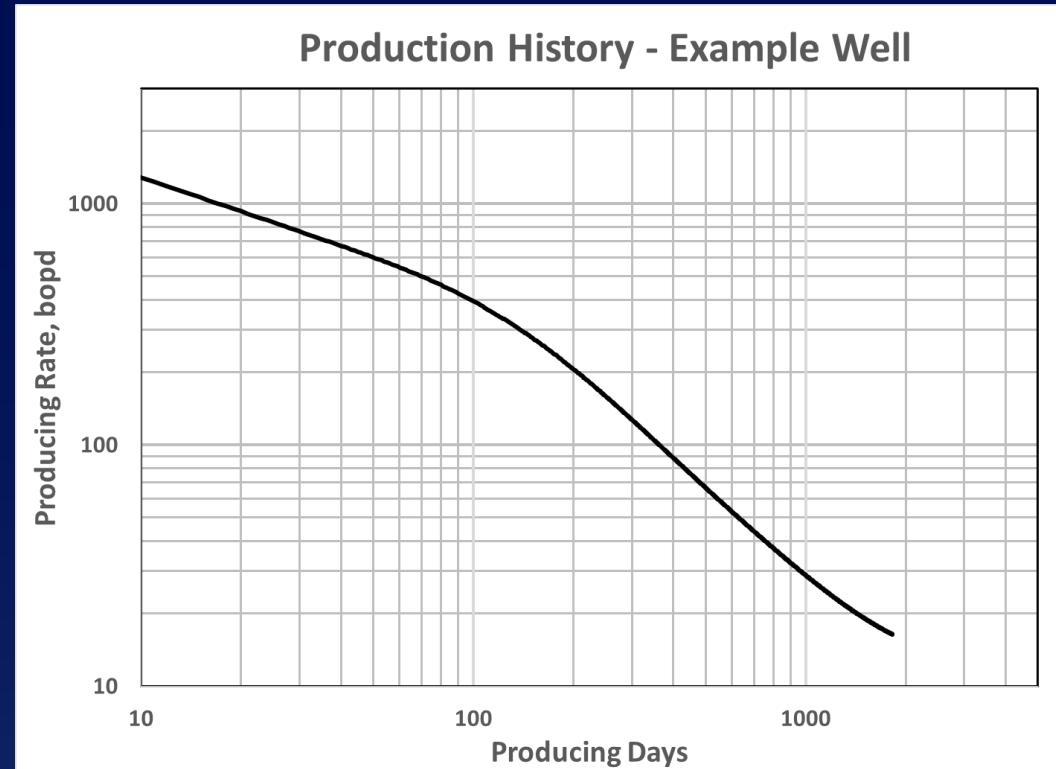
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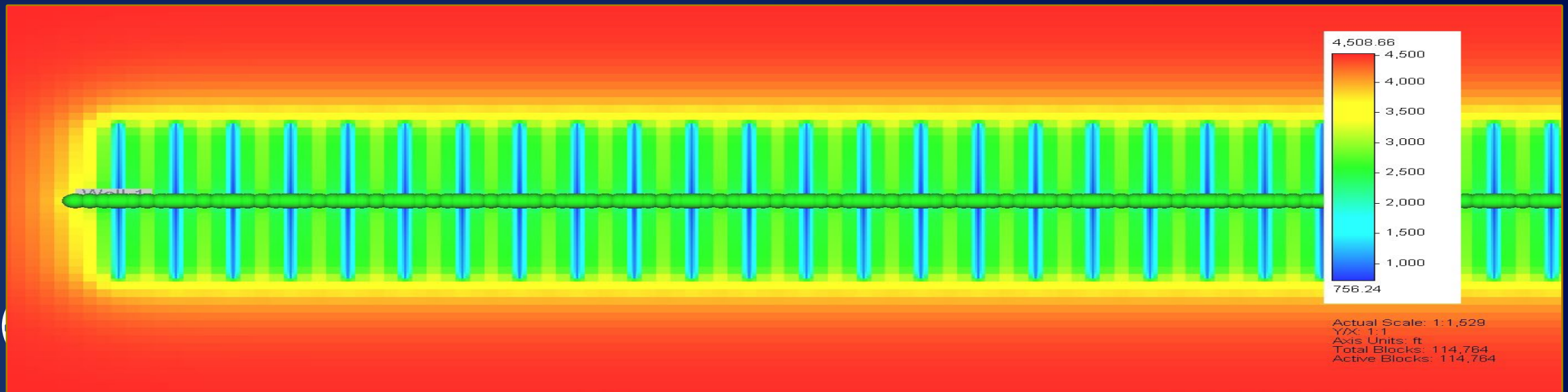
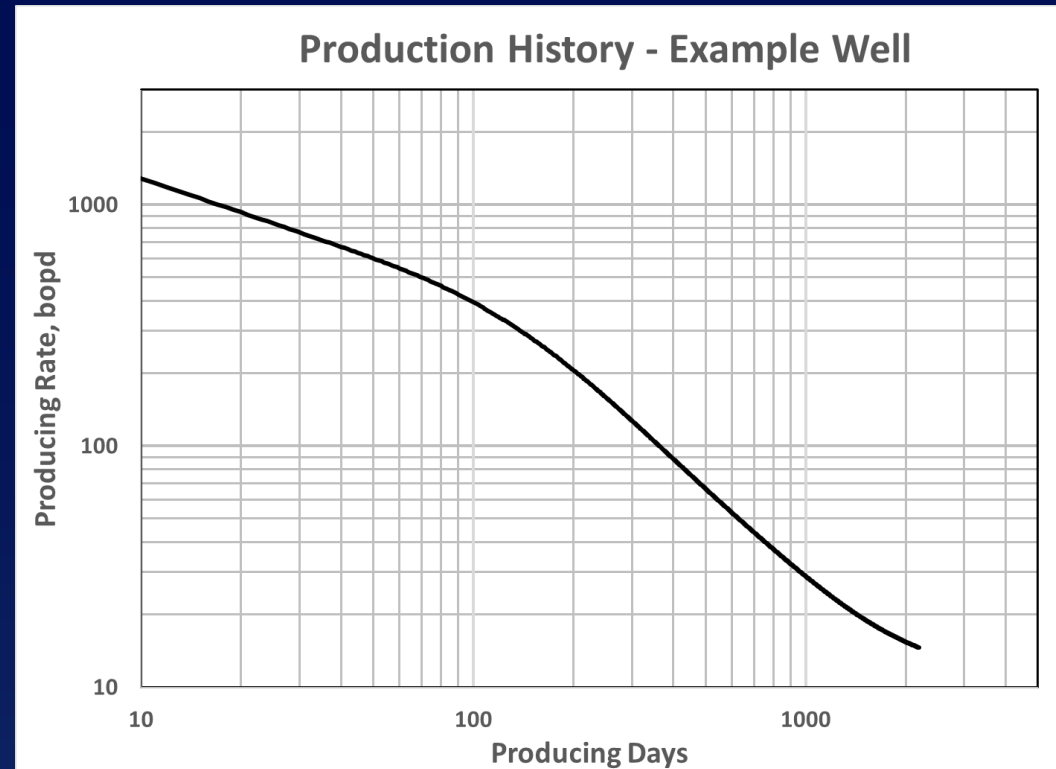
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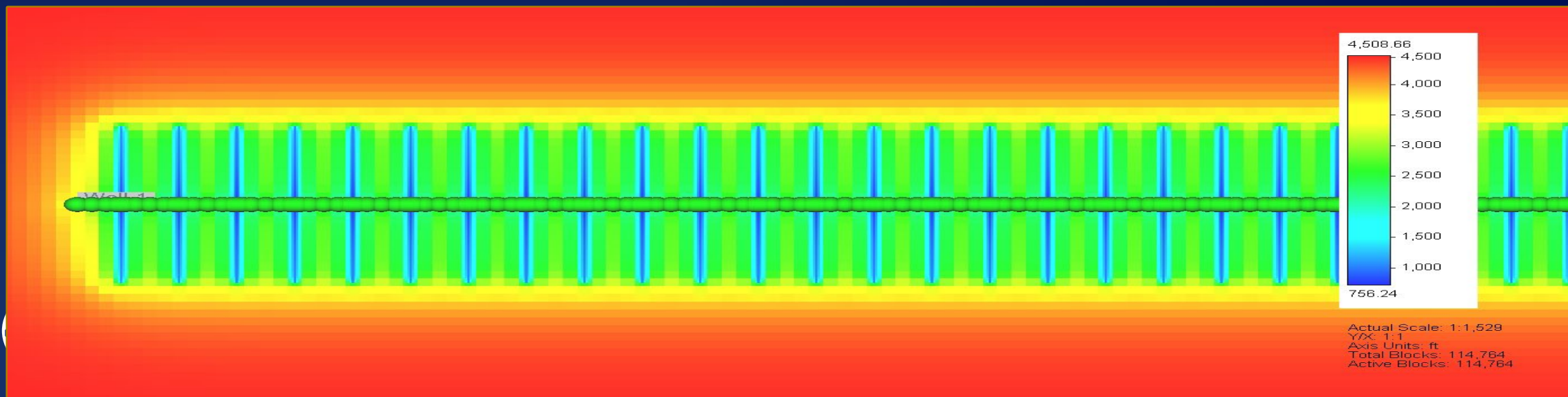
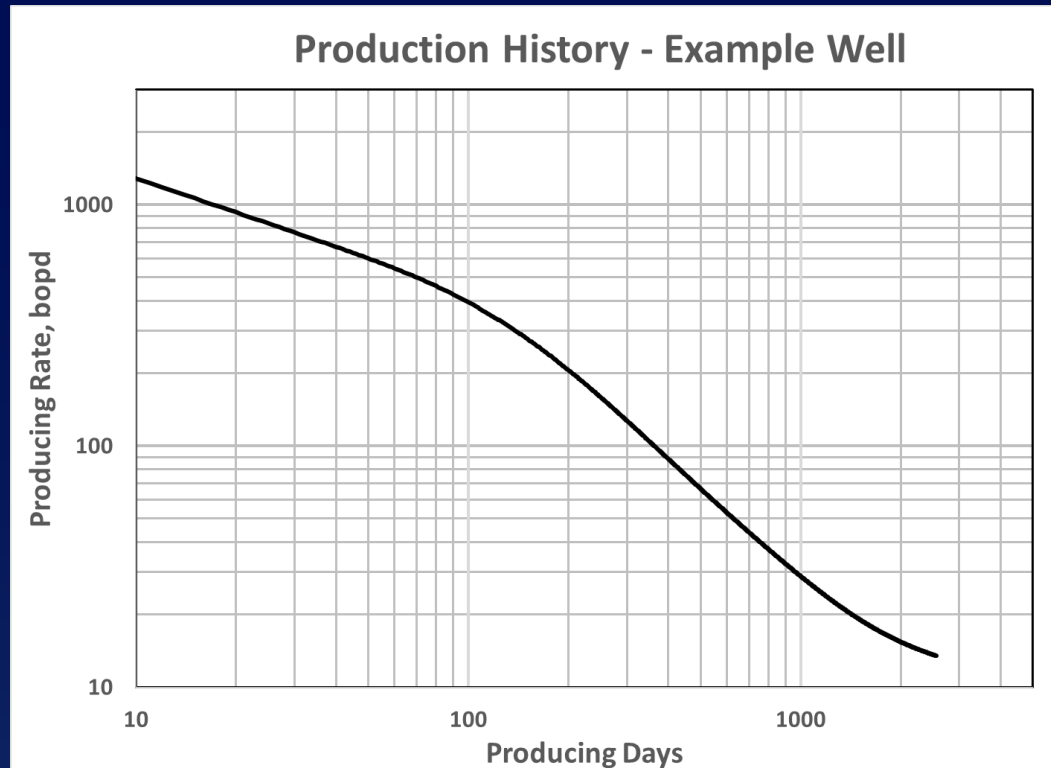
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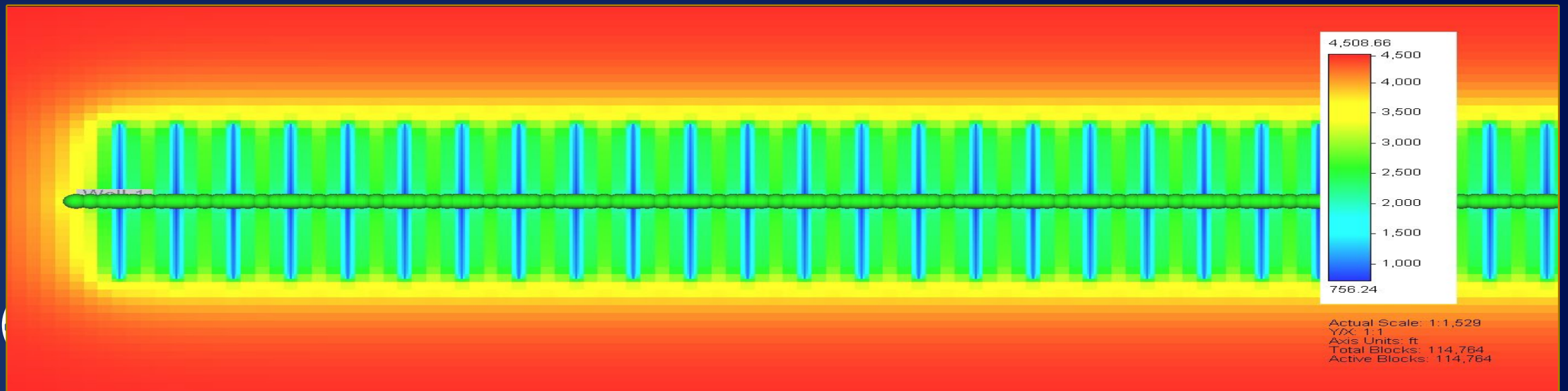
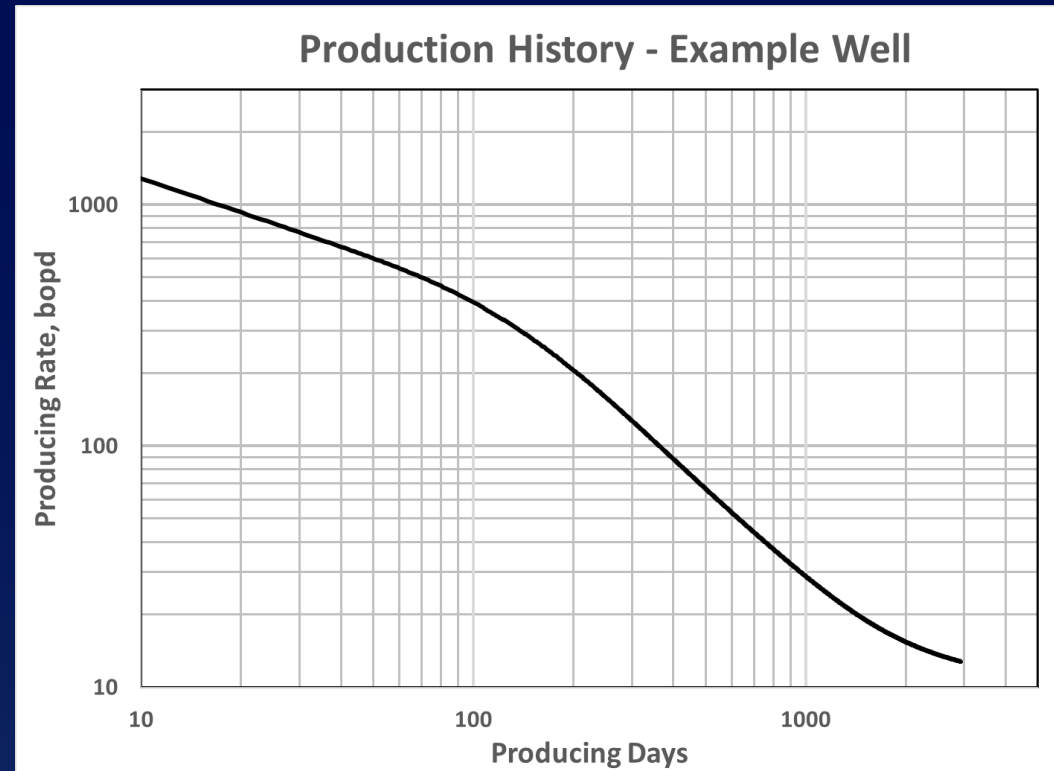
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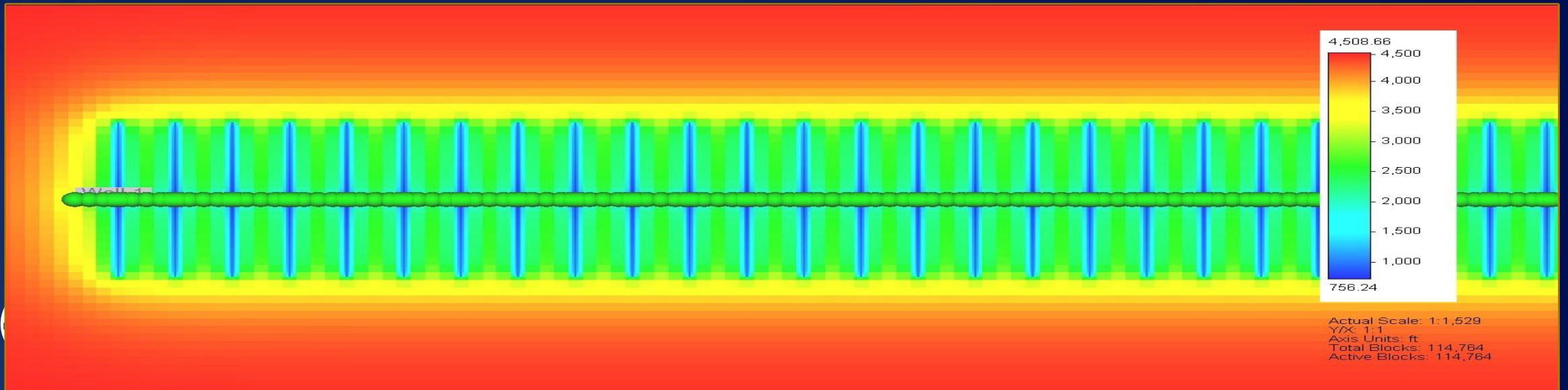
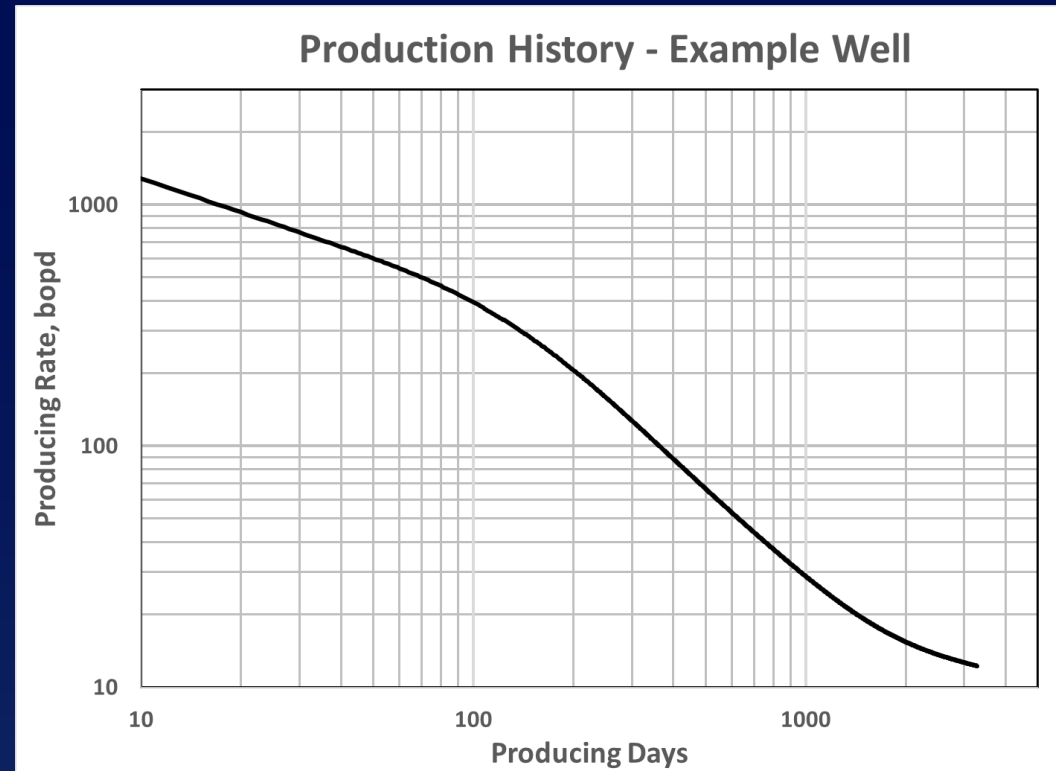
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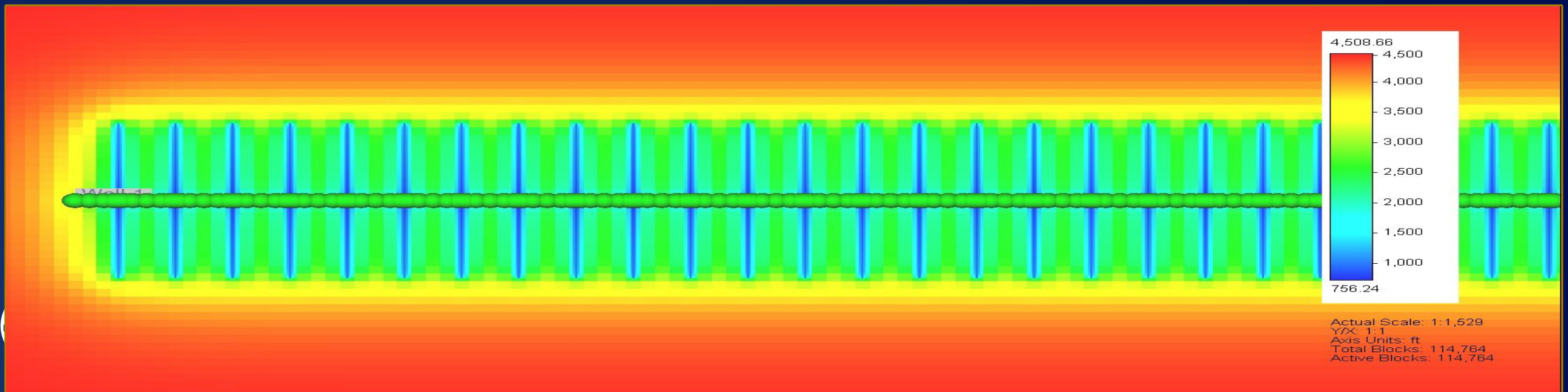
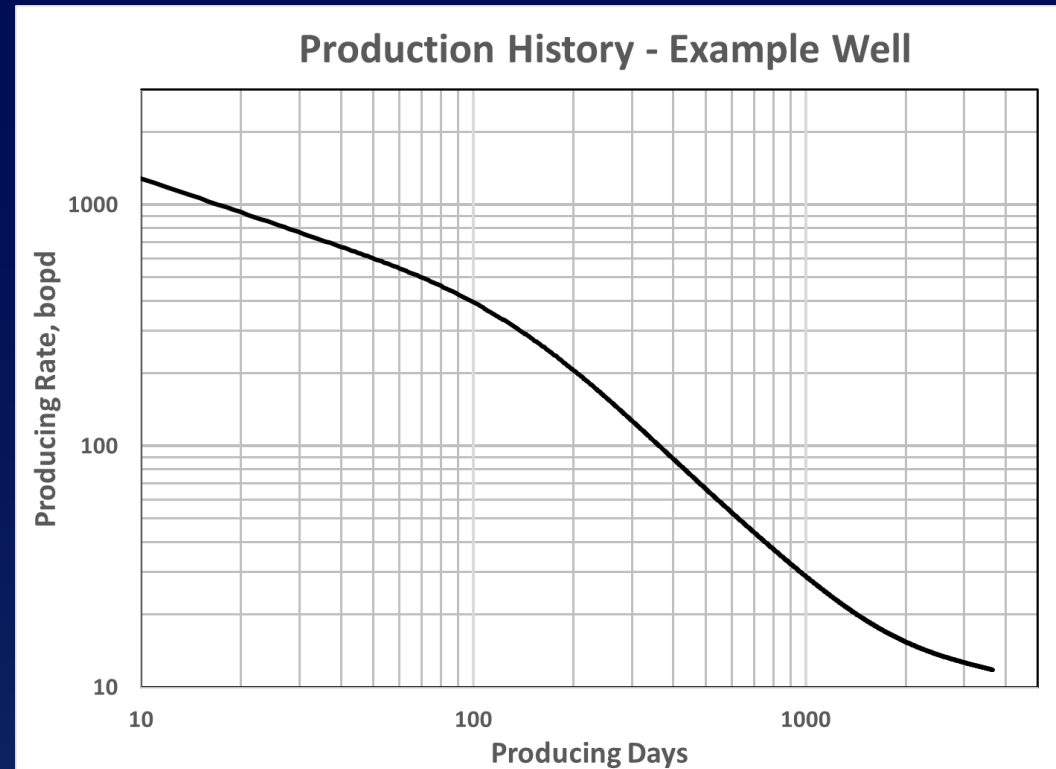
Month 96



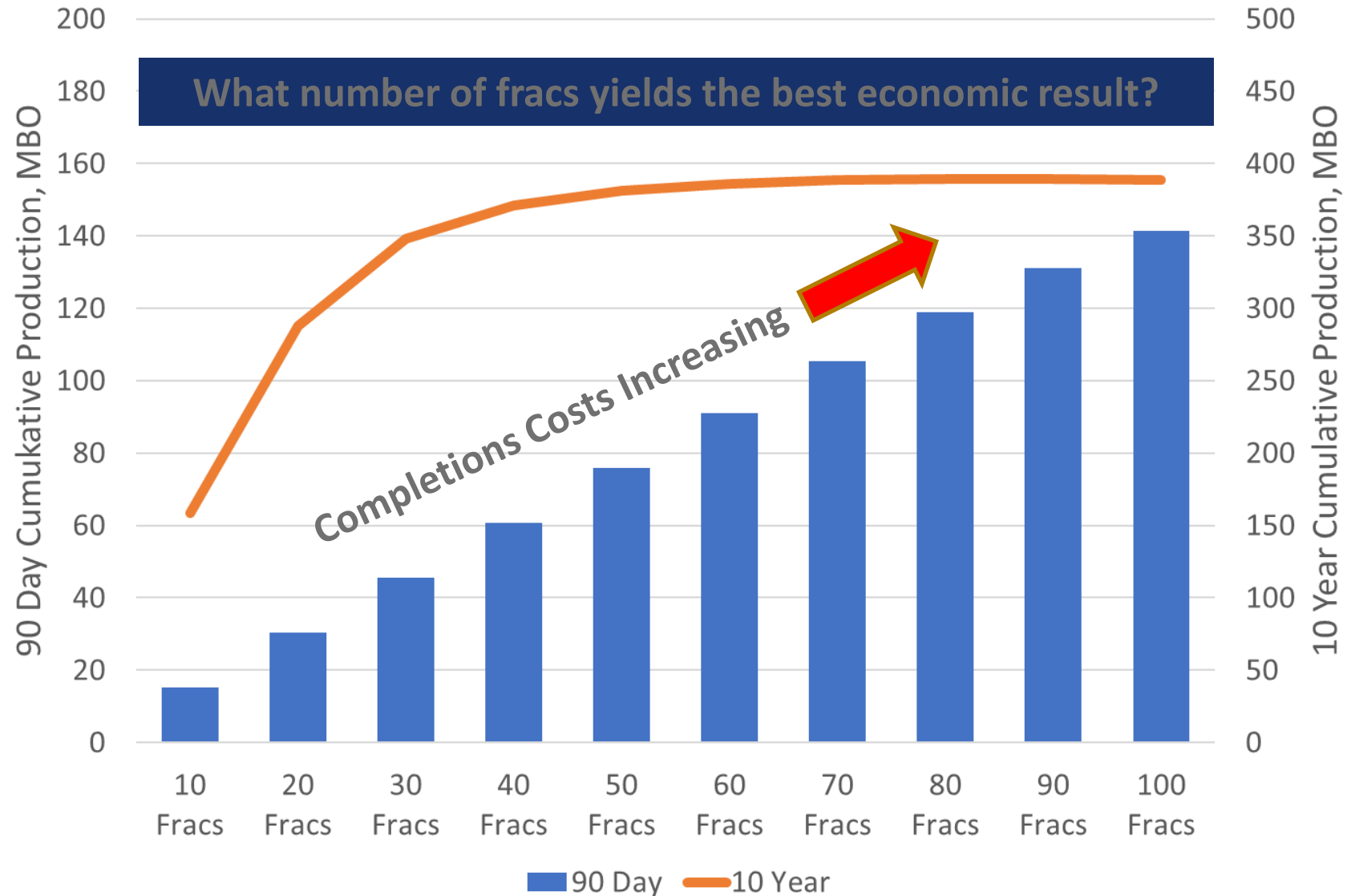
Month 108



Month 120



Early Time and Late Time Cumulative Production



Field Perm Distribution

- Tight Gas Sand Example from SPE 28610 – Moxa Arch Frontier Formation
- 3 orders of magnitude variation in permeability from well to well
- Over 80 wells evaluated

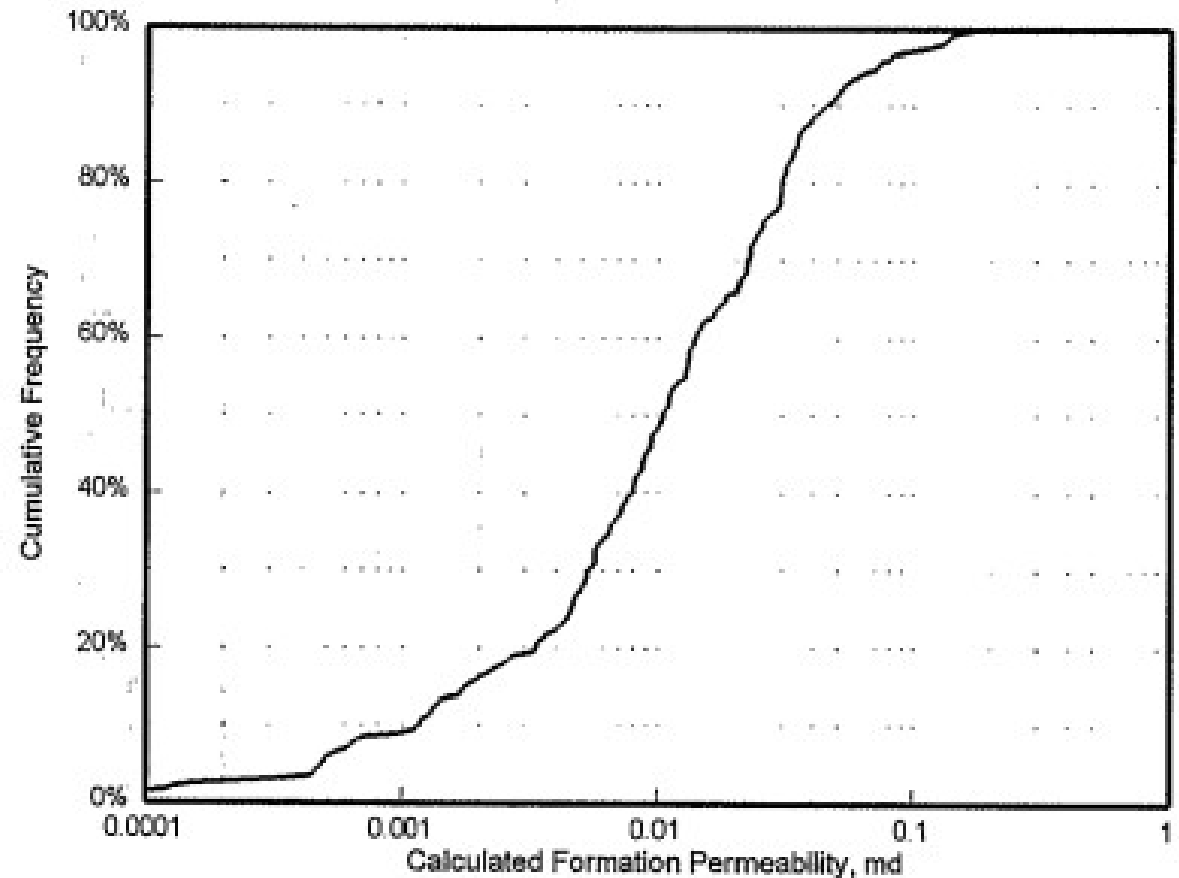
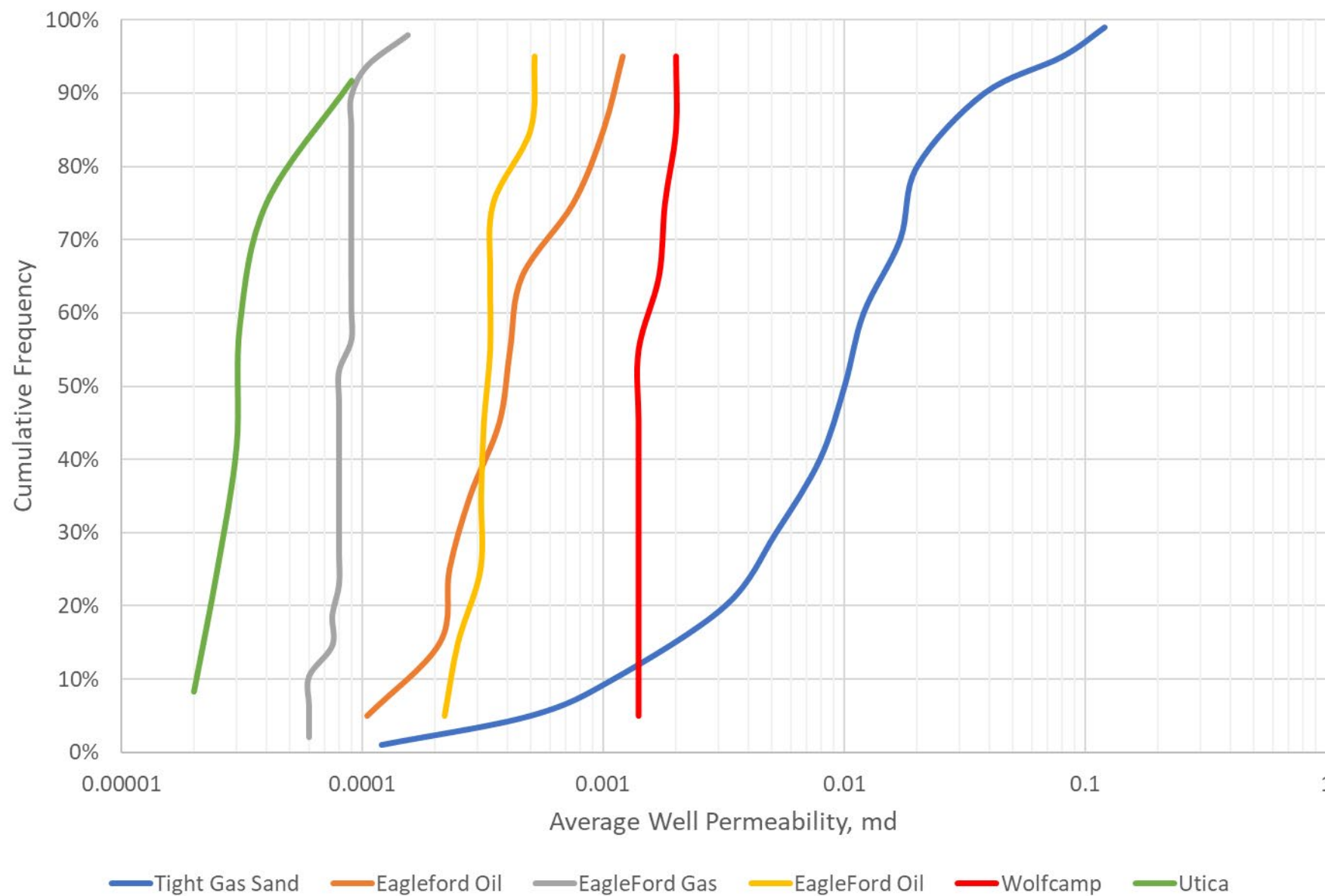


Figure 17. Calculated Formation Permeability Distribution

Distribution of Average Well Permeability



Reservoir Characterization leads to Optimization



- Using production evaluation & production history matching
 - Formation permeability can be estimated
 - Effective lengths of created fractures can be determined
 - The number of producing fractures for a given completion design can be determined
- Using the same models we used to evaluate the production
 - Estimate the production from different future completion designs
 - Perform economics to determine the optimum design



- Knowing the well cost for all possible completion scenarios we can run the reservoir simulator for all possible completion configurations and determine revenue generated for each scenario
- We do this for over 1000 completion design scenarios and determine the NPV for each case
- This let's us know where the current completion design economics are and which direction we need to go to improve

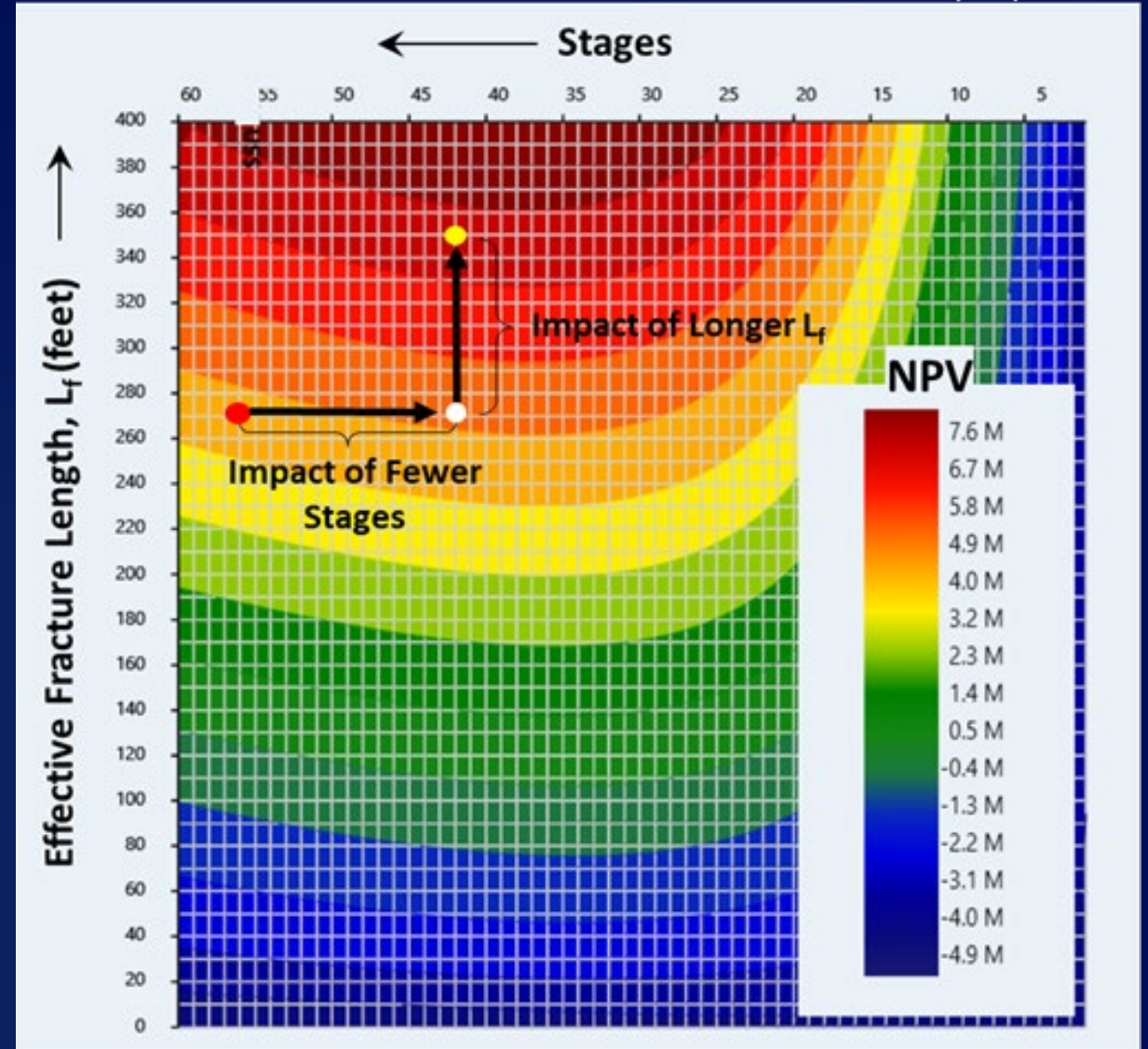


Figure 5 - NPV Road Map @ 400 nD

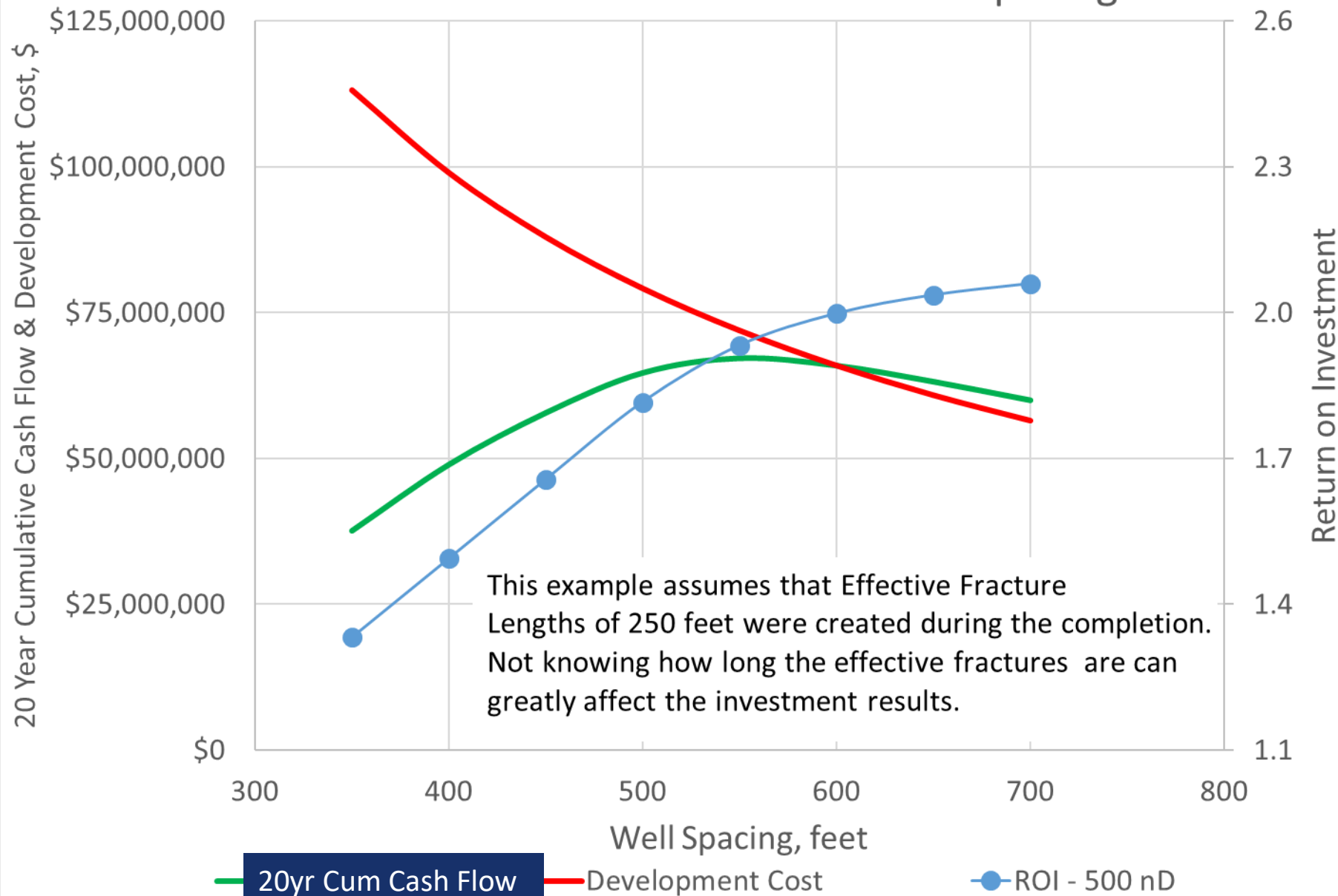
Optimizing Well Spacing



- Reservoir simulation models can be used to Optimize Well Spacing using Optimized Completion Design
 - Determine the effect of well spacing on ultimate recovery
 - Perform field development economics on acreage to be developed



20 Year Cumulative Cash Flow vs. Well Spacing



Environmental Impact of Optimized Design – Stage & Well Spacing



*assuming the development of 50,000 acres

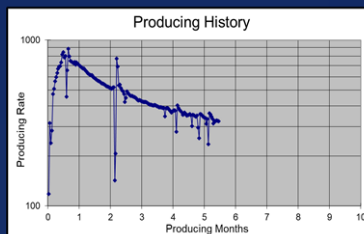
- Reduced number of wells to develop acreage – **234 vs. 335**
- Reduced frac water volume needed by **80 million barrels**
- Reduced frac sand needed by **3.2 billion pounds**
- Reduced diesel fuel needed by **15 million gallons**
- Reduced CO₂ emissions from diesel fuel by **195 thousand tons**
- Reduced capital needed to develop acreage - **\$932 million**



Summary



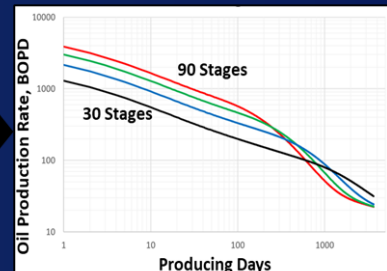
- Optimizing economics on horizontal multi-stage completions can be a complex process
- Production history matching can determine the primary reservoir/completion properties we need to know:
 - Formation permeability
 - Effective fracture half-length achieved
 - Number of dominant producing fractures
- Millions of dollars of capital costs can be Reduced and Profit added
- A major **positive Environmental Impact** can be achieved



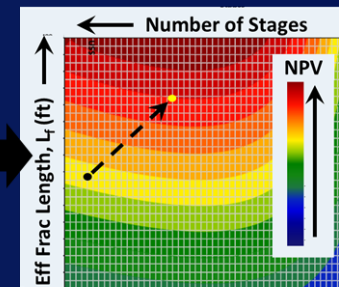
Cost Free Data

Perm
Eff Frac Length
Number of Fracs

Evaluate



Predict



Economics

Capital Cost ↓
NPV & ROI ↑

Results

