SPE-AAPG ATW on Naturally Fractured Reservoirs,
October 2010

Integration of Microseismic, Production Data and Numerical Simulation to Evaluate Uncertainties in Unconventional Reservoirs.
What is the Impact on Estimated Ultimate Recovery?

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Outline

Background

Objectives

Available Data

Interpretations & Assumptions

Uncertain Parameters of the Analysis

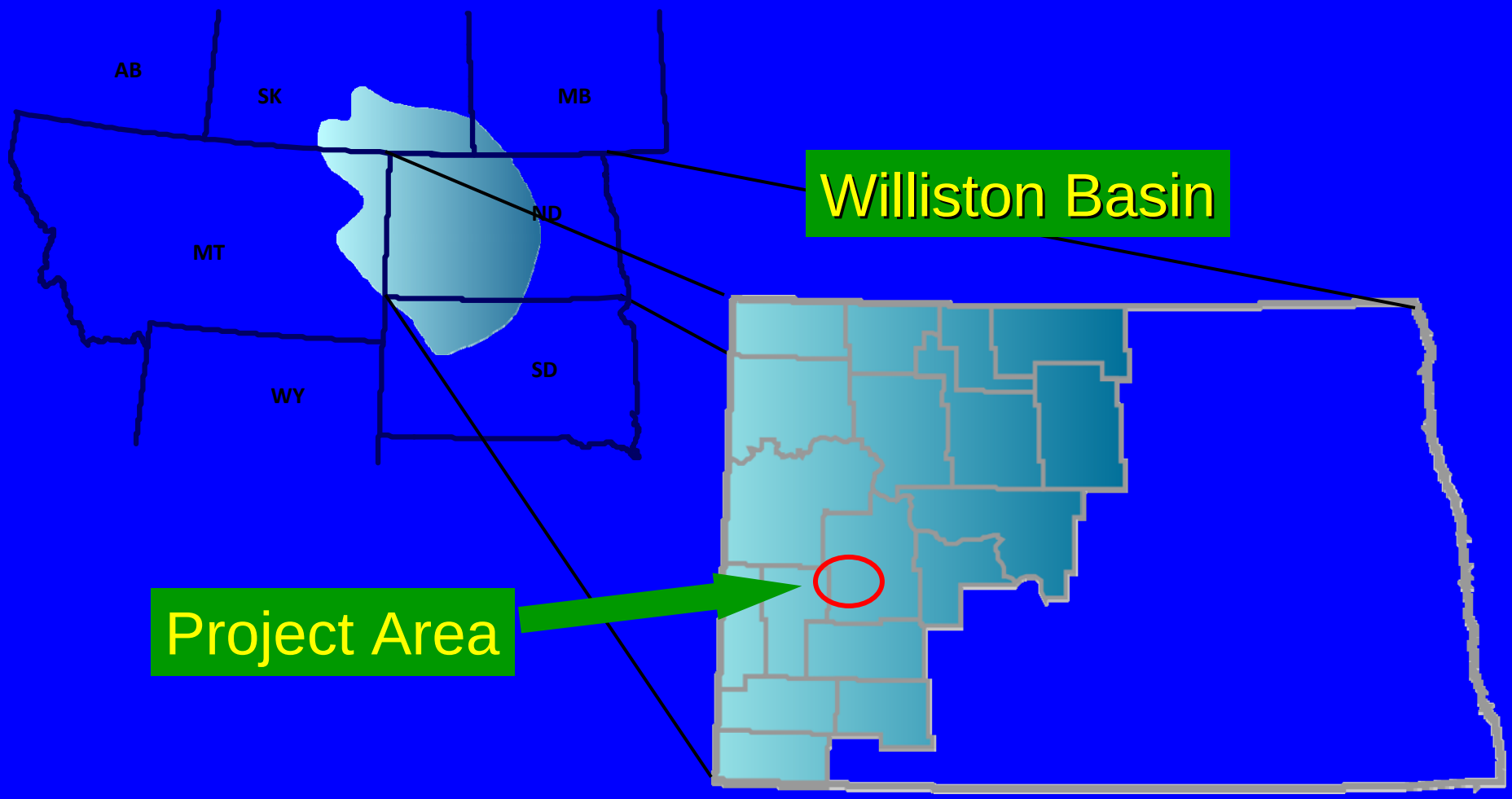
Dynamic Calibration Process and Results

Predictions and Sensitivity Analyses

Background

SPE-AAPG ATW on Naturally Fractured Reservoirs

Background



SPE-AAPG ATW on Naturally Fractured Reservoirs

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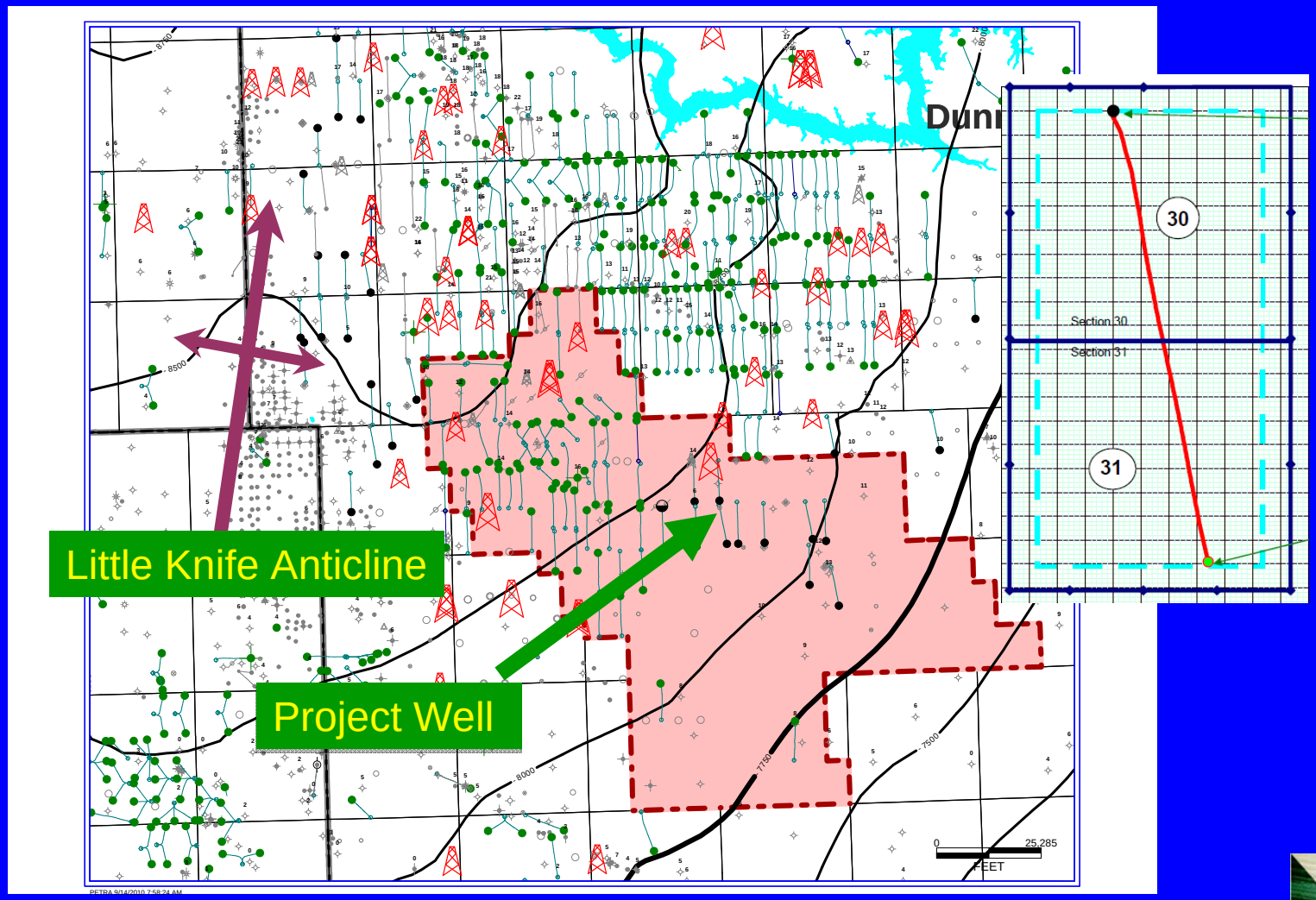

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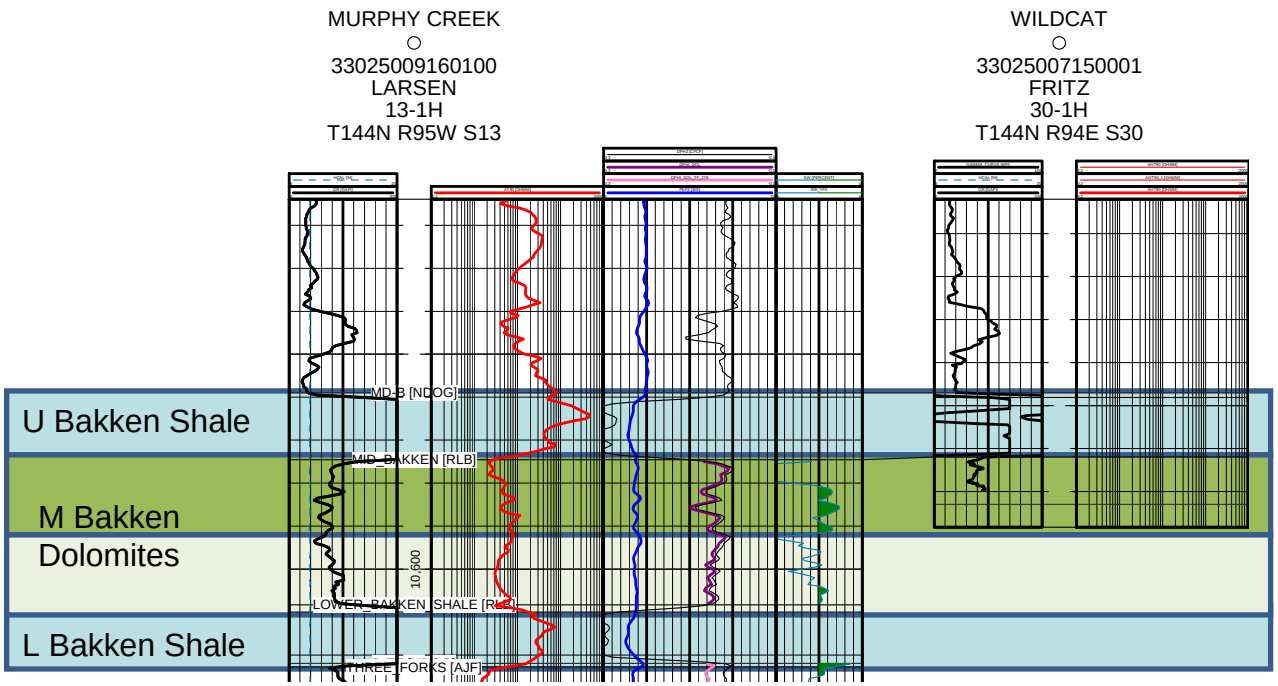

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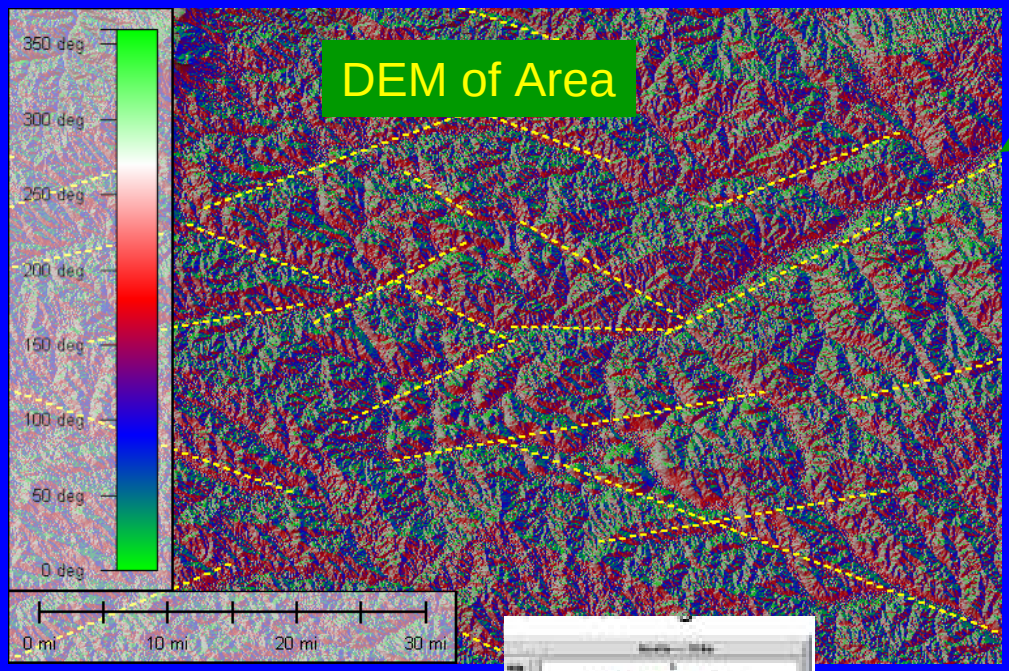
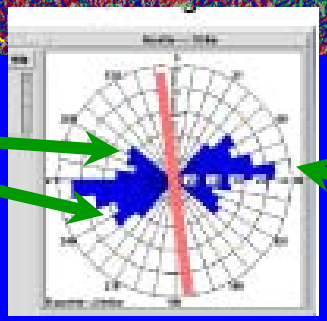


DEM of Area

2 Directions of Surface Lineaments inferred to be related to Basement Faulting

Surface and Subsurface Data Suggests a Diverse Natural Fracture Population Across the Location.

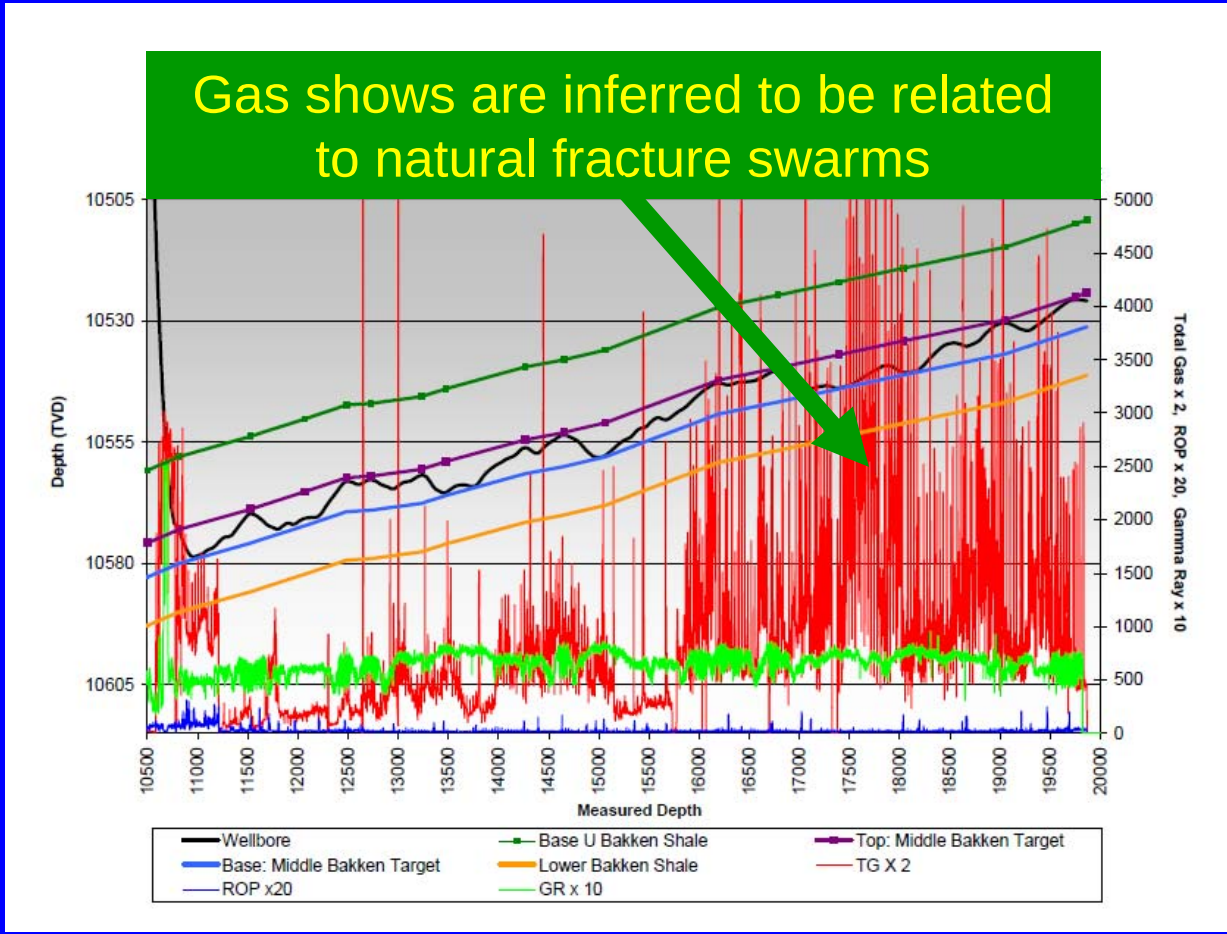
Lower Angle Shear Fractures related to Basement Faulting



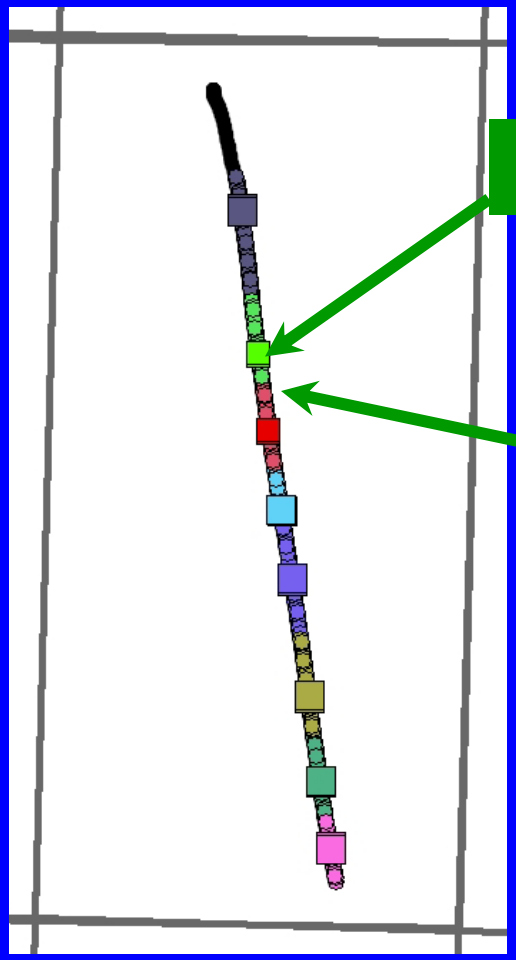
High Angle Type I Regional Extension Fractures (small aperture)

FMI Rose from TRD Thomas 4-1H (~15 mi NW)

Background


Gas shows are inferred to be related to natural fracture swarms
Depth (TVD)
10505
10530
10555
10580
10605
Total Gas x 2, ROP x 20, Gamma Ray x 10
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
10500
11000
11500
12000
12500
13000
13500
14000
14500
15000
15500
16000
16500
17000
17500
18000
18500
19000
19500
20000
Measured Depth
Wellbore
Base U Bakken Shale
Top: Middle Bakken Target
Base: Middle Bakken Target
Lower Bakken Shale
TG X 2
ROP x20
GR x 10

Background



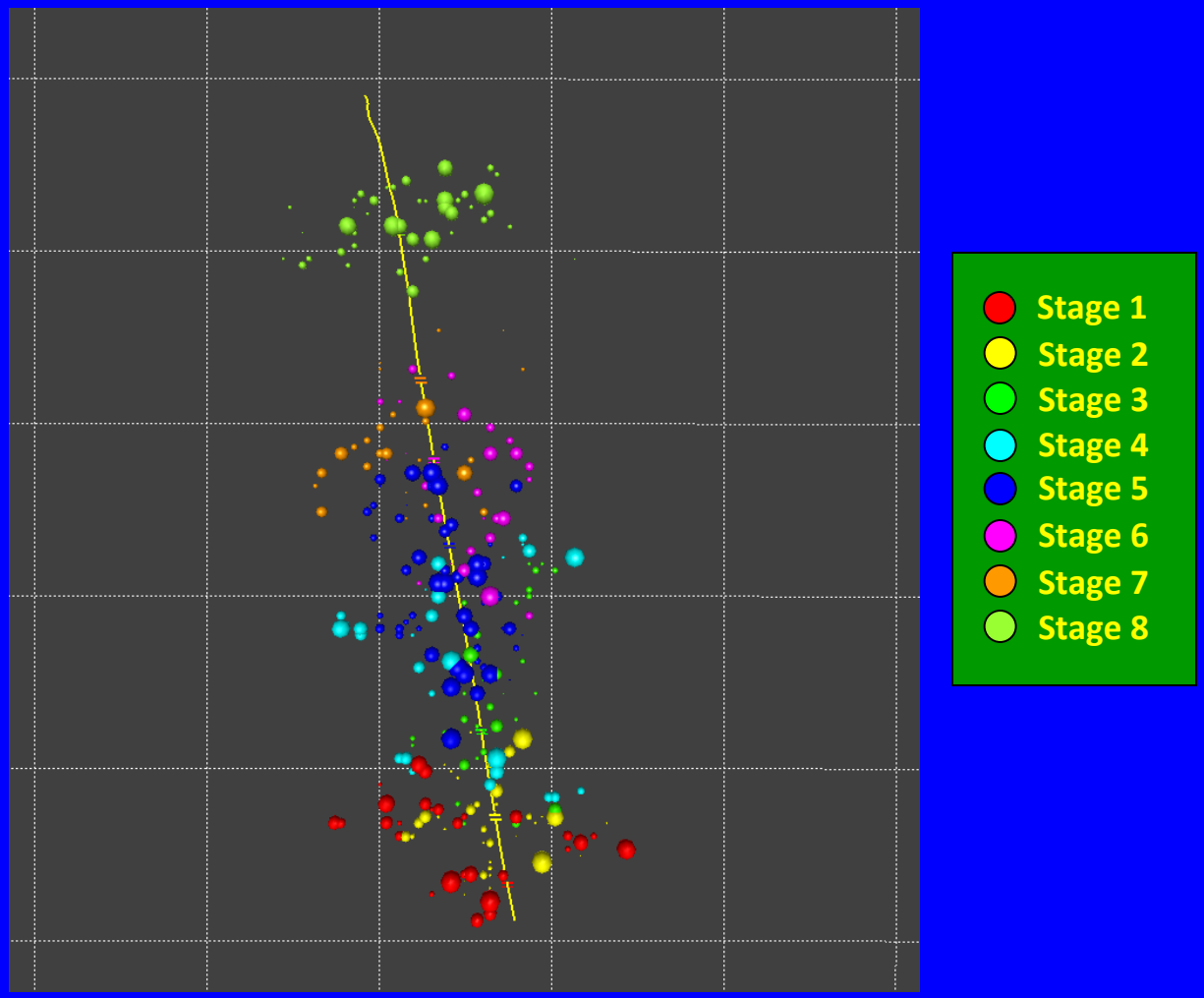
Frac treatment: 6/4/2008

Early multistage, Generation II, completion

Eight Ball/Sleeve Stages:

Job Type Slickwater
BORAjel-5
Sliding Sleeves: 11,400' – 19,861'
Max Slurry Rate: 56.1 bpm
Avg. Slurry Rate: 37.9 bpm
Max Pressure: 6,382 psi
Avg. Pressure: 5,919 psi
20/40 Ottawa: 351,000 lbs.
20/40 Super L/C: 94,800 lbs
Fluid: 17,688 bbls.

Background



Objectives

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To understand the impact of “seismic event window” on dynamic calibration and EUR predictions

To understand the impact of “assumptions in DFN generation” on dynamic calibration and EUR predictions

To understand the impact of additional wells on NPV and EUR

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To understand the impact of “seismic event window” on dynamic calibration and EUR predictions

To understand the impact of “assumptions in DFN generation” on dynamic calibration and EUR predictions

To understand impact of additional wells on NPV and EUR

This presentation focuses on the second objective

Available Data

Available Data

Drilling - vertical and horizontal wells

- Mud log, gas chromatography

Cores from nearby wells

- Porosity, permeability, capillary pressure

Electric logs from the vertical well

- Stratigraphy, NTG, porosity, ~water saturation

Hydraulic fracturing operation

- Injection pressure, injection volume, microseismic

Production operation

- Oil, gas and water volumes, flowing THP

Interpretations and Assumptions

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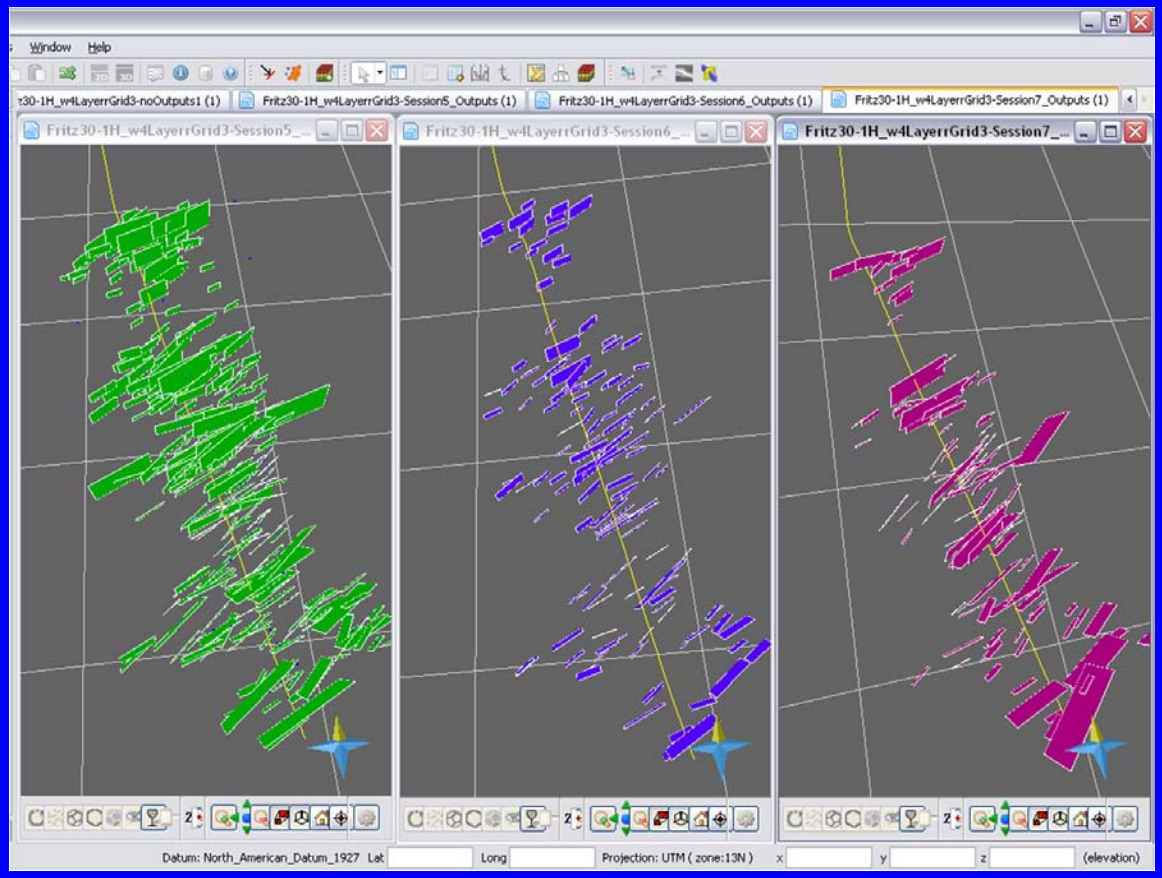
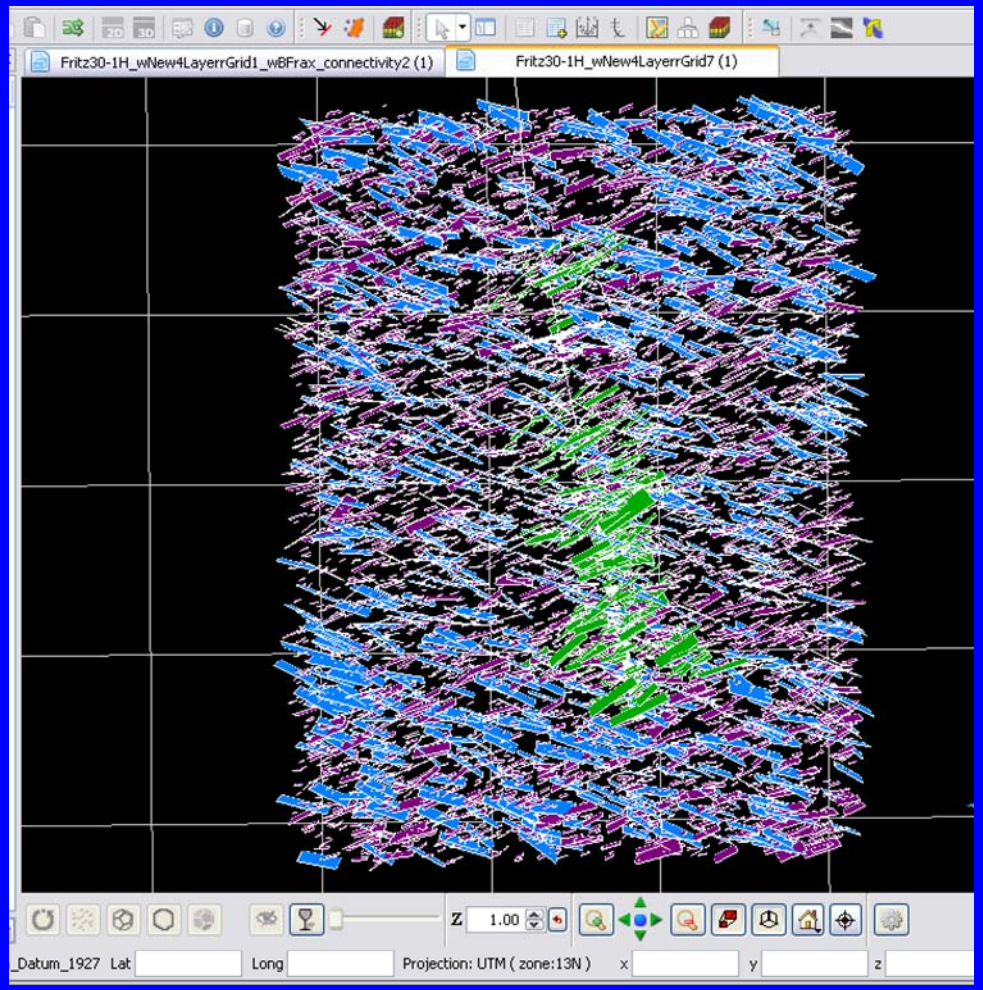


Microseismic Events Monitored during the Completion are used as seed loci for Stochastic DFN Generation

Aperture and Connectivity are linked to Event Amplitude and Distribution

Interpretations and Assumptions

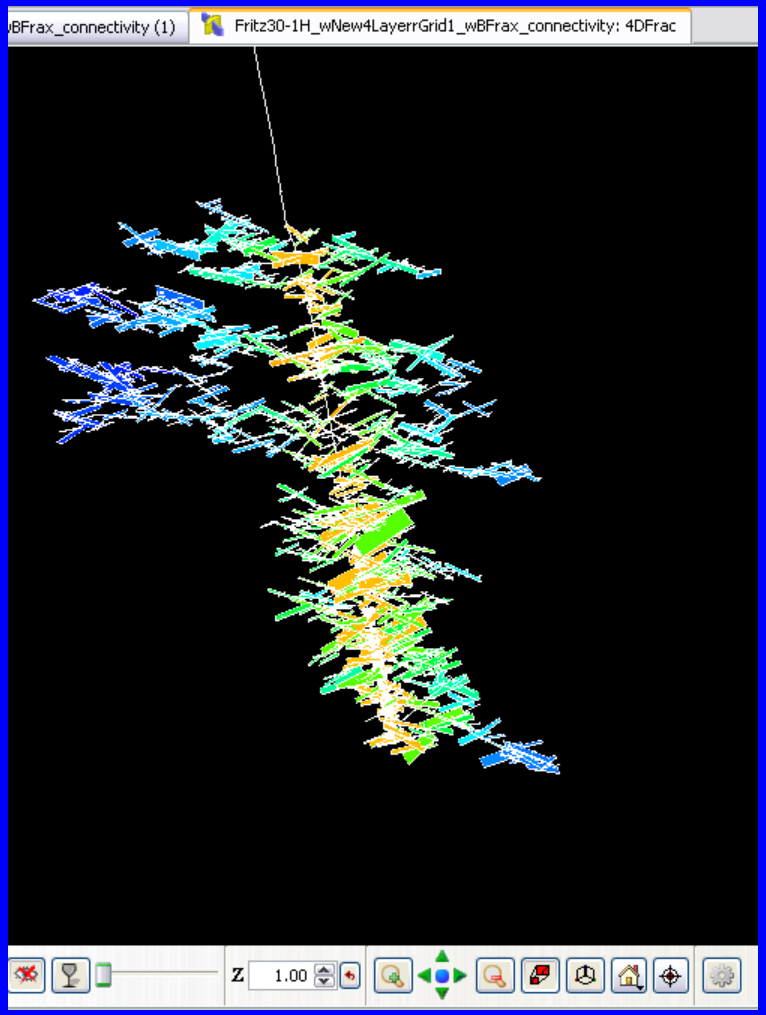


Wellbore Pseudo Fractures – White

FMI/Lineament Fractures – Purple/Blue

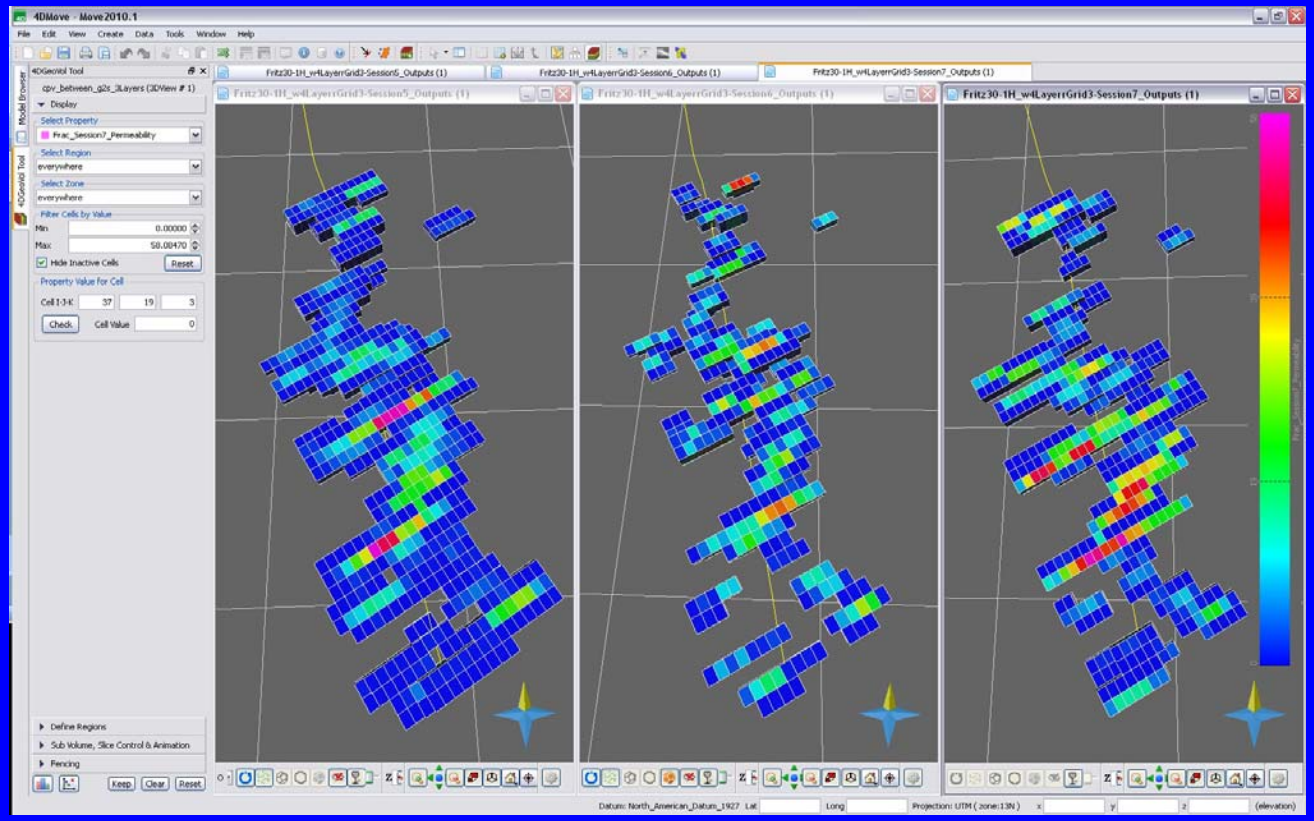
Hydraulic Fracture Network - Green

Interpretations and Assumptions



Only simulated fractures actually coincident with the wellbore or connected to the wellbore through adjacent fractures are shown.

Interpretations and Assumptions



Discrete Fracture Network is upscaled to delineate the Stimulated Rock Volume (SRV) distribution, connectivity and associated permeability.

Interpretations and Assumptions

In this presentation we compare 2 DFN Models

Model #1 has one fracture set, with strike parallel to the main axis and limited scatter in the strike orientation.

Model #2 has two intersecting fracture sets with one parallel to the main axis and other having strike of 80 degrees with significant amount of scatter.

Both models were upscaled for porosity, permeability and sigma array associated with the hydraulic fracture

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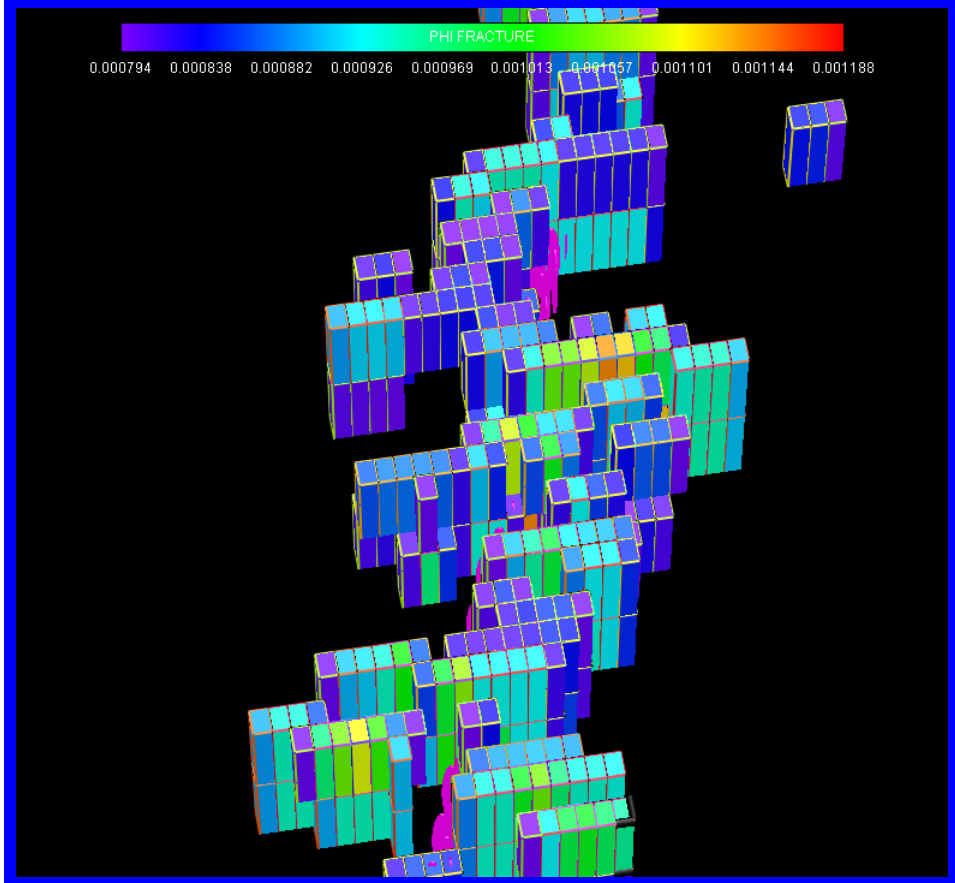
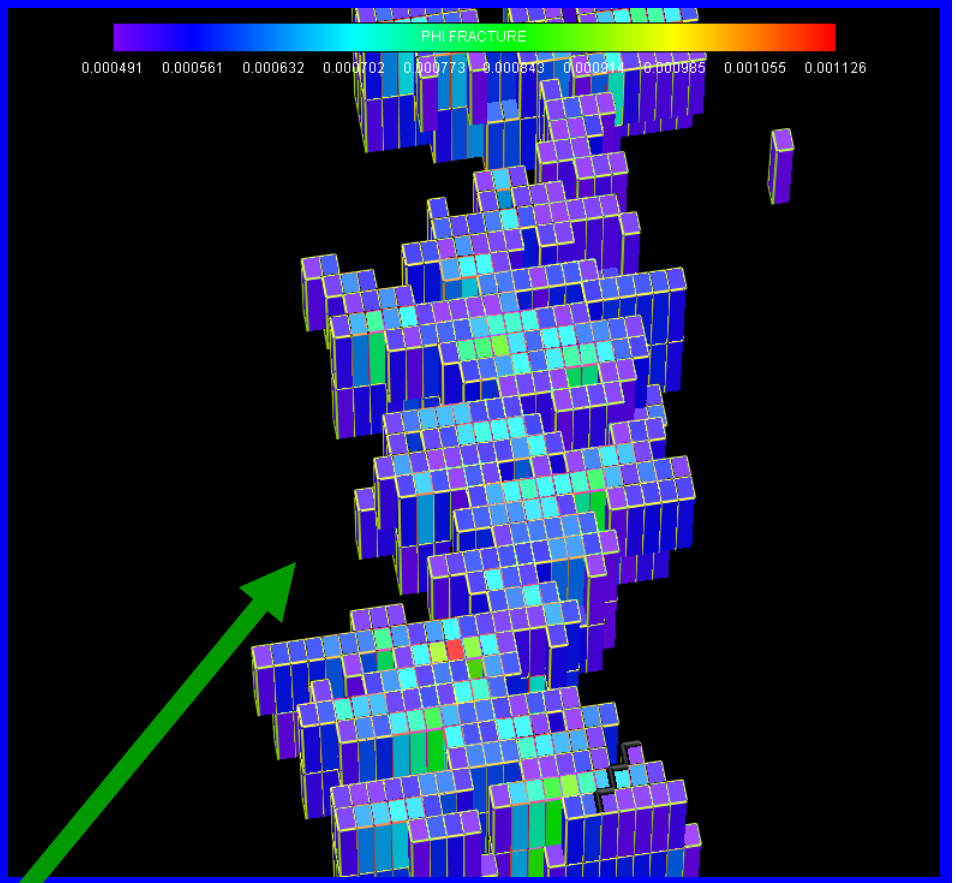
Interpretations and Assumptions





Larger Connected SRV estimated for Model #2

Interpretations and Assumptions

Effective porosity of bounding shales = 1%

Dolomite matrix porosity = 6.5%

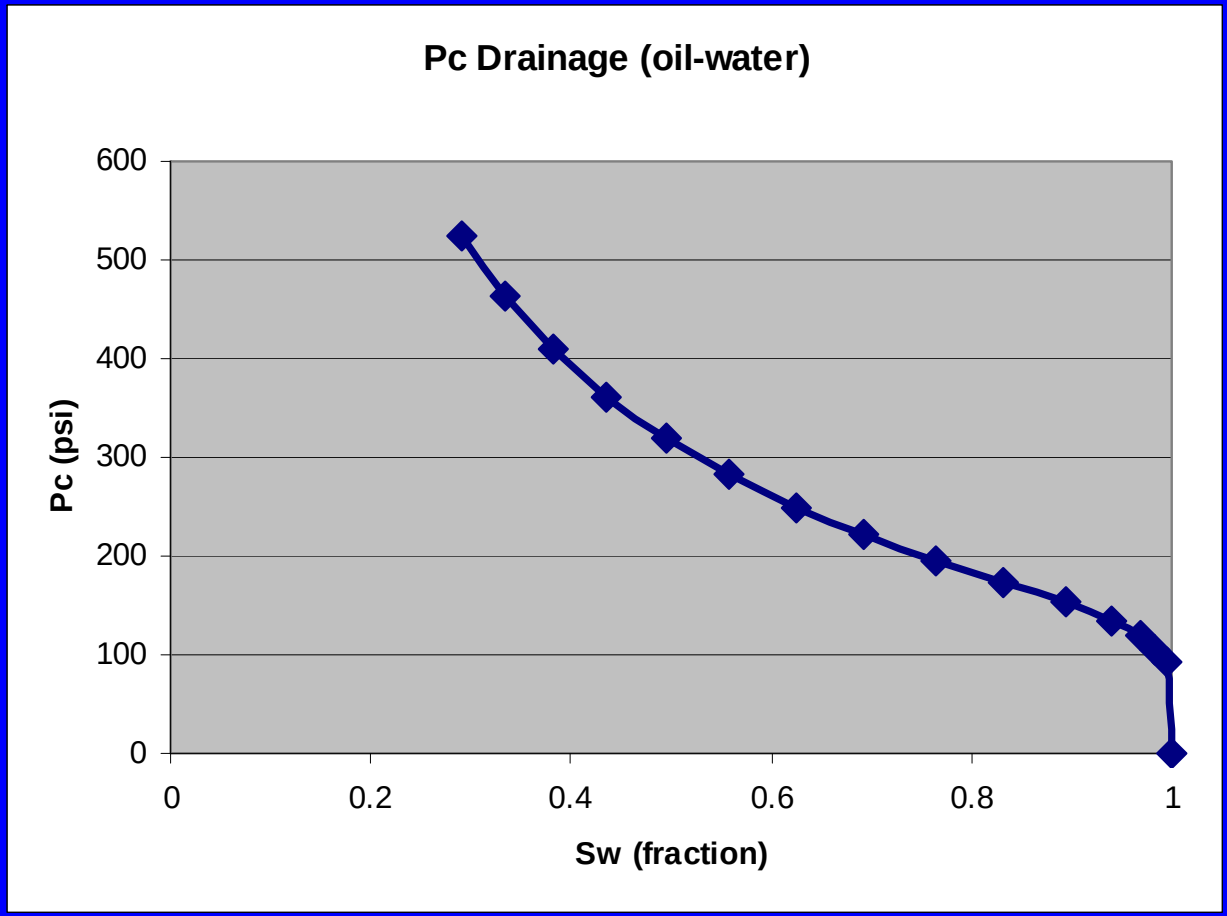
Dolomite matrix permeability = 0.010 mD

Single water-oil matrix drainage capillary pressure curve that corresponds to 6.5% porosity

Zero capillary pressure in the fractures

Straight line water-oil matrix/fracture relative permeability curves

Interpretations and Assumptions



Uncertain Parameters of the Analysis

Uncertain Parameters of the Analysis

- Initial reservoir pressure
  - 72-hour buildup shows minimum of 5200 psia
- Initial matrix water saturation
  - set through depth of pseudo WOC
- Water-oil relative permeability scaling
  - Krw left constant and Kro is scaled

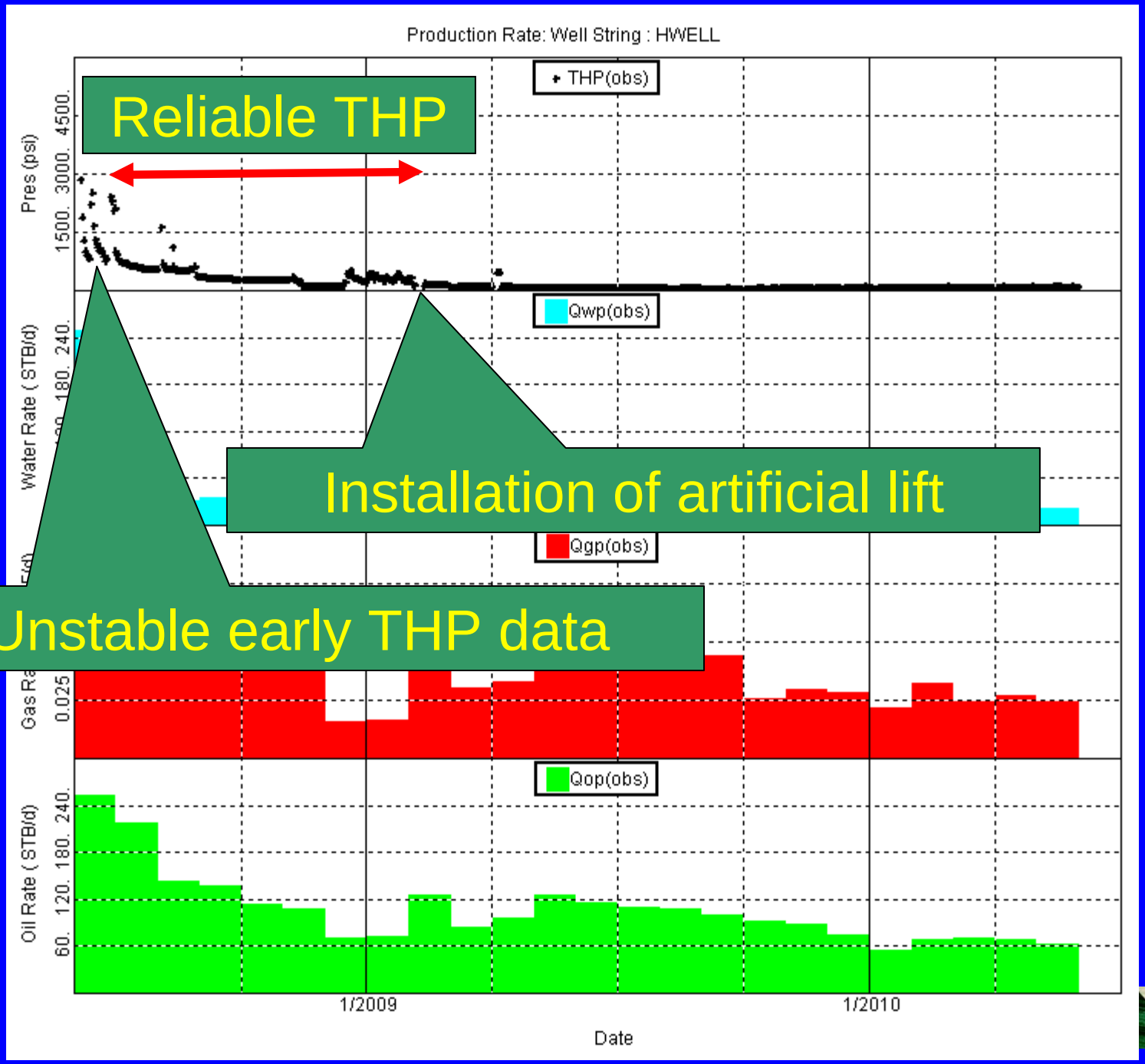
Uncertain Parameters of the Analysis

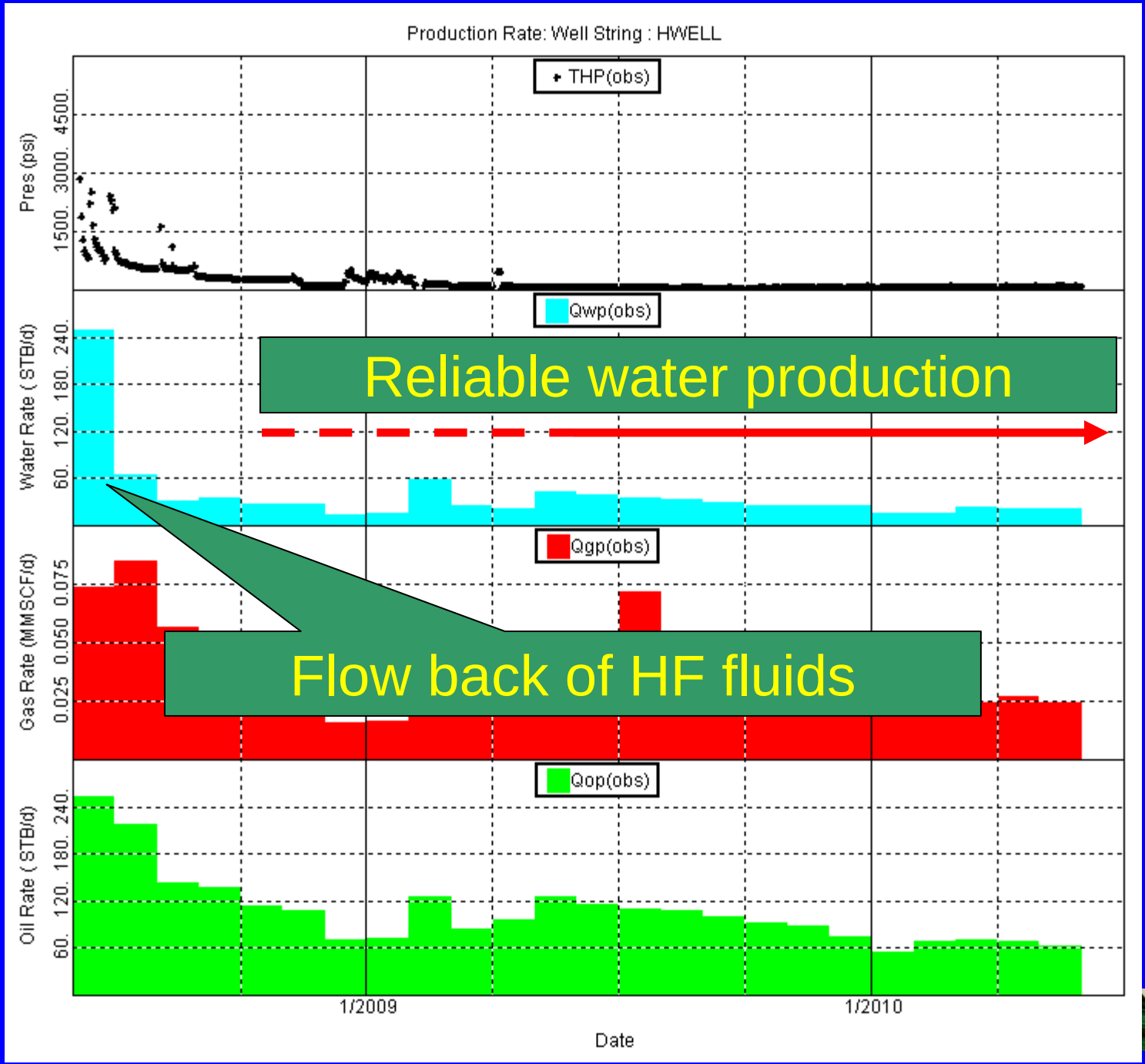
- Vertical communication among the layers
  - Intercalated shale streaks
- Permeability of the natural fractures
  - Assume uniform value
- Porosity of the natural fractures
  - Assume uniform value
- Sigma for the natural fractures/matrix
  - Assume uniform value

Uncertain Parameters of the Analysis

- Amplitude of HF permeability distribution
  - Use multiplier to upscaled DFN values
- Amplitude of HF porosity distribution
  - Use multiplier to upscaled DFN values
- Amplitude of HF based sigma distribution
  - Use multiplier to upscaled DFN values
- Connection % of HF to the wellbore
  - Use well PI (or WI) multiplier

Dynamic Calibration Process and Results


Production Rate: Well String : HWELL
THP(obs)
Pres (psi)
1500. 3000. 4500.
Reliable THP
Qwp(obs)
Water Rate (STB/d)
240.
180.
Installation of artificial lift
Qgp(obs)
Unstable early THP data
0.025
Qop(obs)
Oil Rate (STB/d)
60. 120. 180. 240.
1/2009
1/2010
Date


Production Rate: Well String : HWELL
THP(obs)
Pres (psi)
1500. 3000. 4500.
Qwp(obs)
Water Rate (STB/d)
60. 120. 180. 240.
Reliable water production
Qgp(obs)
Gas Rate (MMSCF/d)
0.025 0.050 0.075
Flow back of HF fluids
Qop(obs)
Oil Rate (STB/d)
60. 120. 180. 240.
1/2009
1/2010
Date

Dynamic Calibration Process and Results

DFN Model #1

In-house Assisted History Matching Software

11 history matching parameters

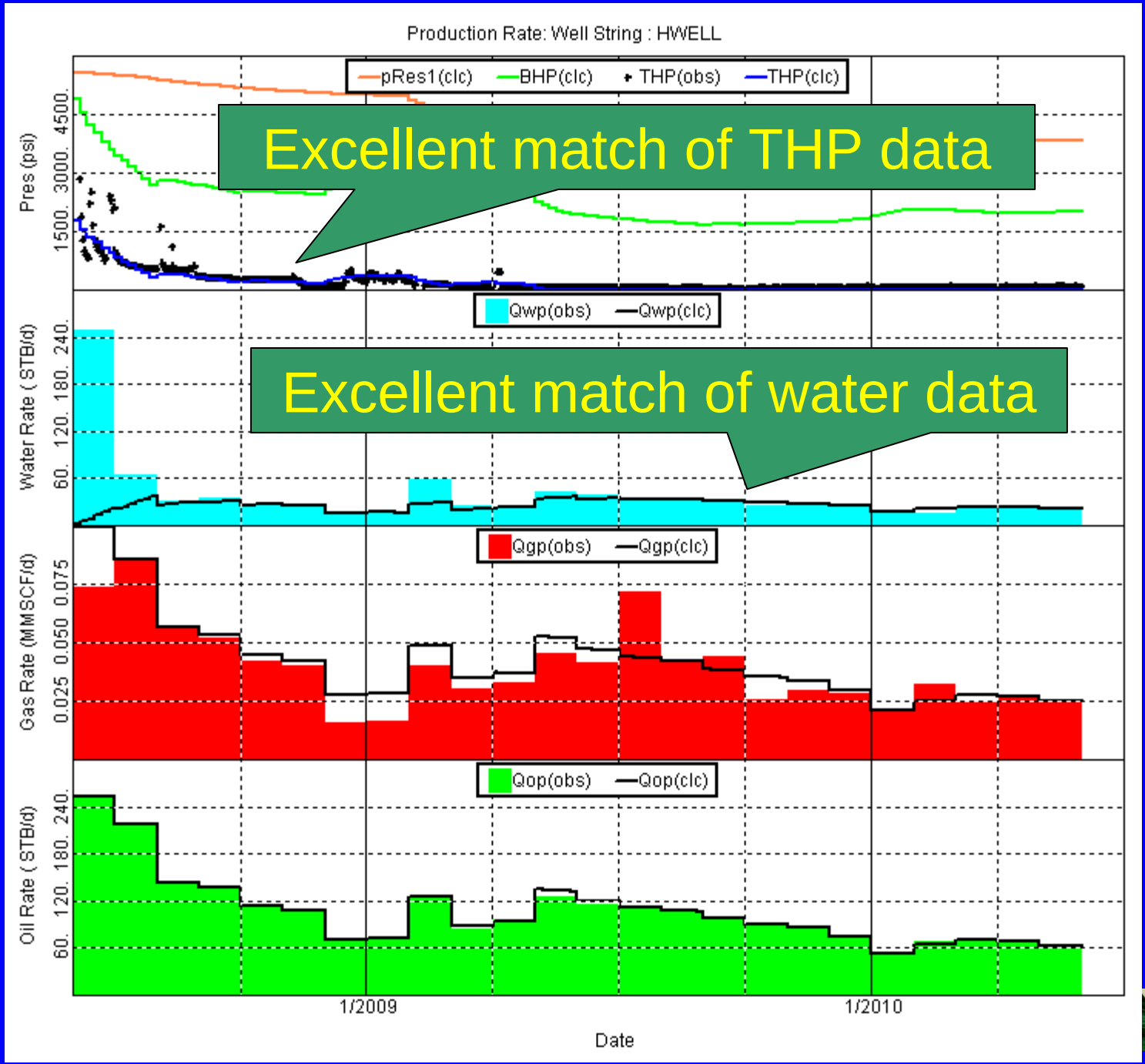
Experimental design for coverage of range

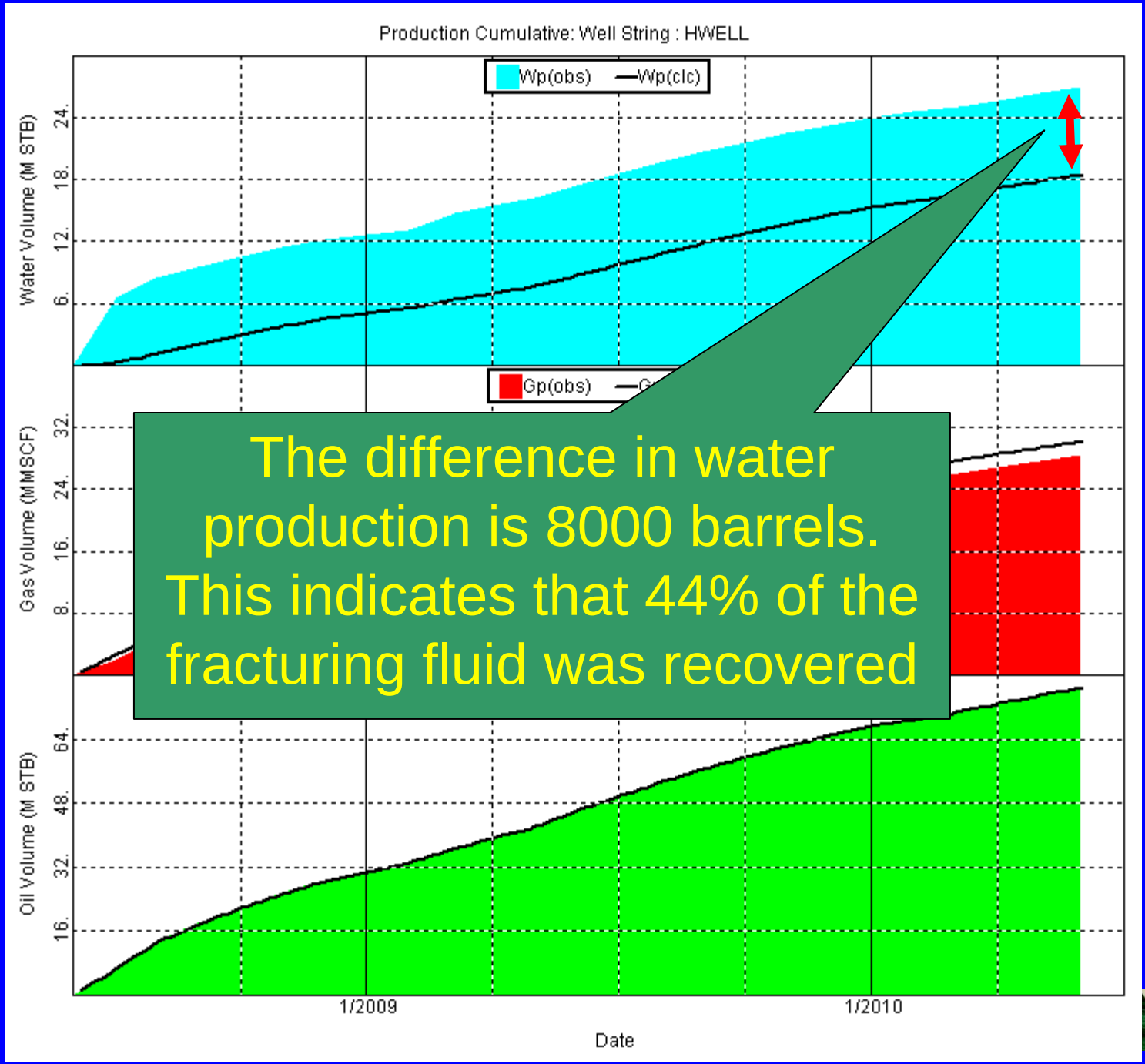
ANN and Genetic Algorithm for global search

Response Surface and GA for optimization

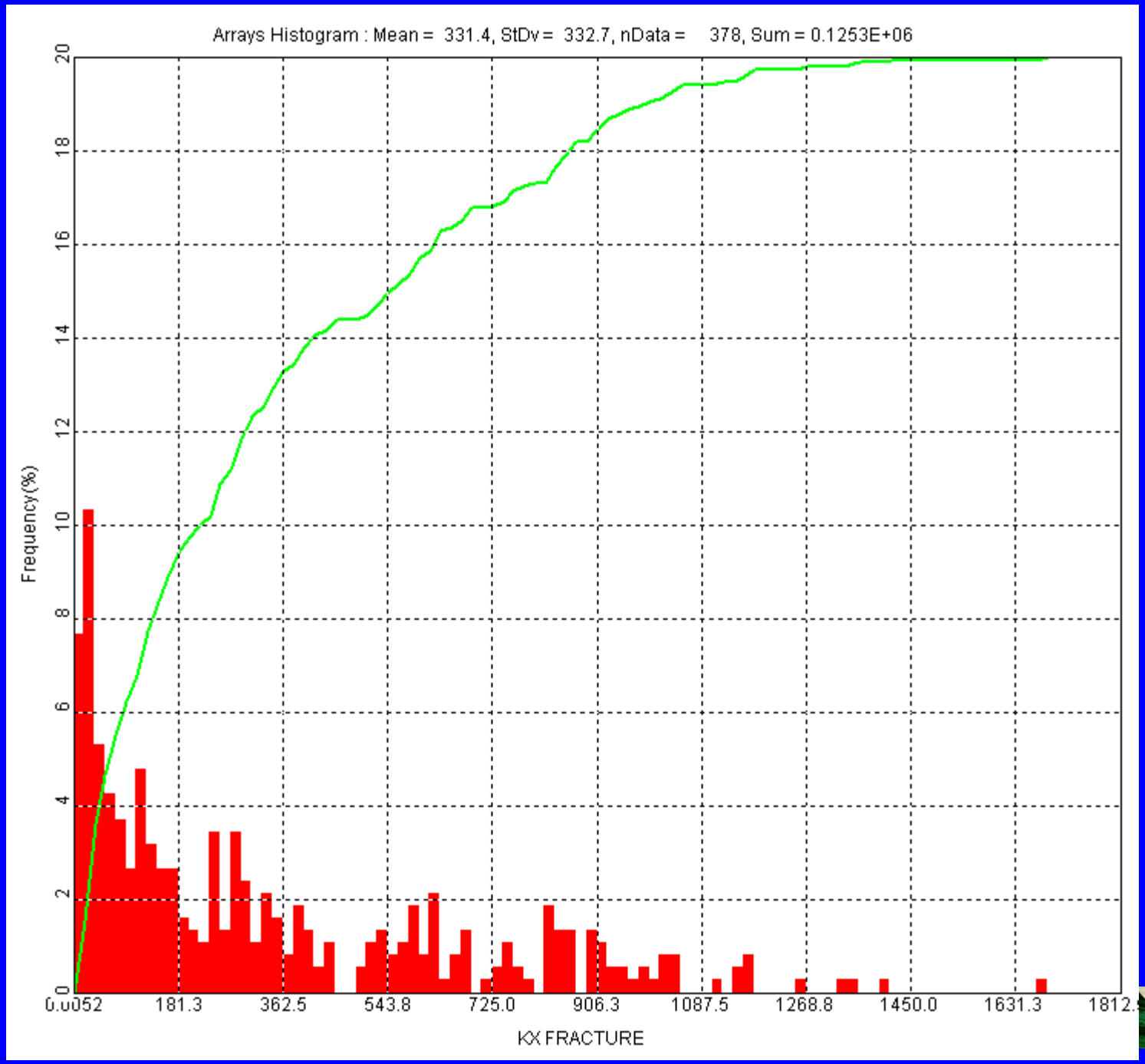
Runs ~15 minutes - maximum 5-day time steps

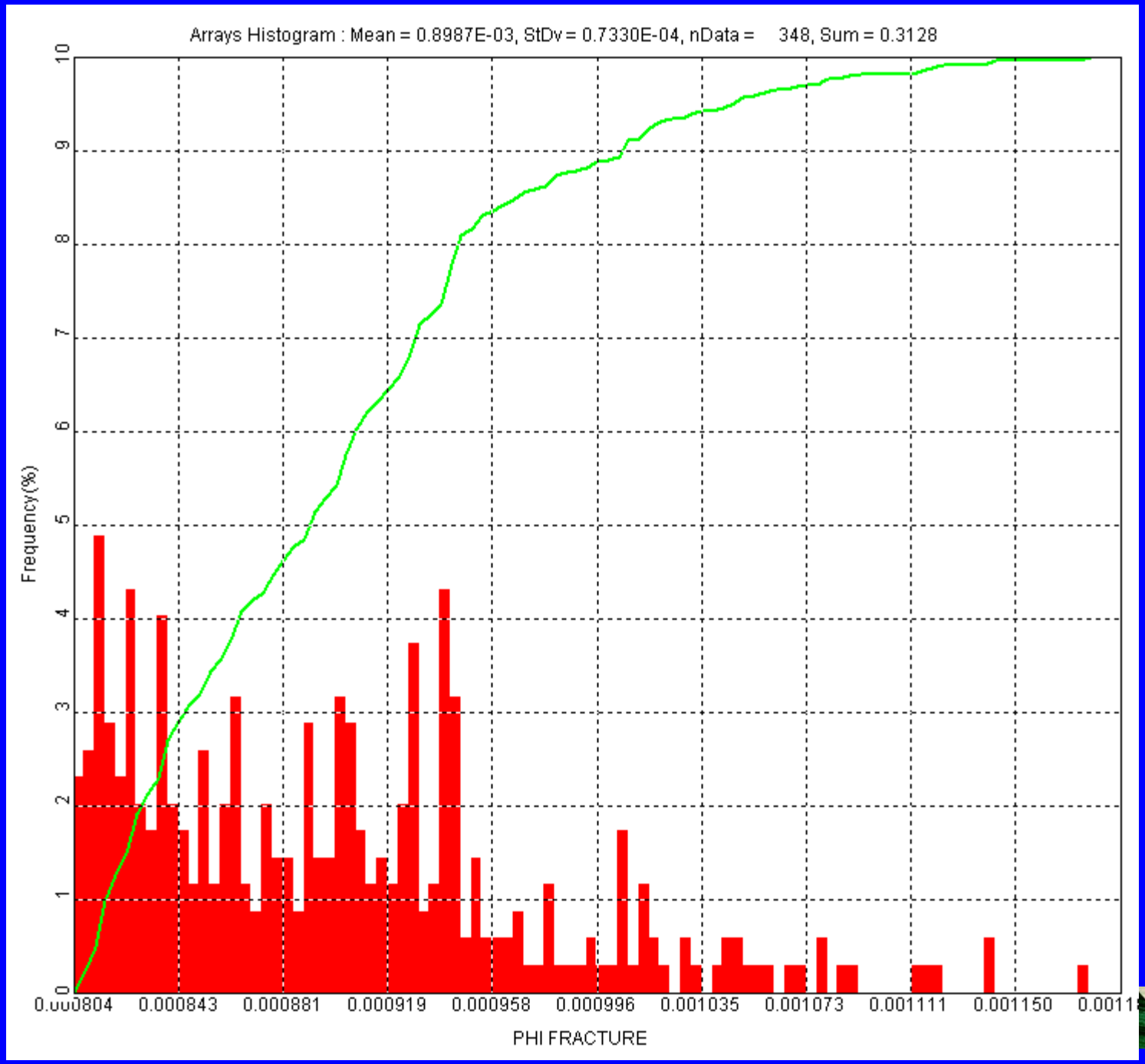
Approximately 170 simulation runs


Production Rate: Well String : HWELL
pRes1(clc)
BHP(clc)
THP(obs)
THP(clc)
Pres (psi)
1500. 3000. 4500.
Excellent match of THP data
Qwp(obs)
Qwp(clc)
Water Rate (STB/d)
60. 120. 180. 240.
Excellent match of water data
Qgp(obs)
Qgp(clc)
Gas Rate (MMSCF/d)
0.025 0.050 0.075
Qop(obs)
Qop(clc)
Oil Rate (STB/d)
60. 120. 180. 240.
1/2009
1/2010
Date



The difference in water production is 8000 barrels. This indicates that 44% of the fracturing fluid was recovered


Arrays Histogram : Mean = 331.4, StDv = 332.7, nData = 378, Sum = 0.1253E+06
Frequency(%)
0
2
4
6
8
10
12
14
16
18
20
0.0052
181.3
362.5
543.8
725.0
906.3
1087.5
1268.8
1450.0
1631.3
KX FRACTURE


Arrays Histogram : Mean = 0.8987E-03, StDv = 0.7330E-04, nData = 348, Sum = 0.3128
Frequency(%)
0
1
2
3
4
5
6
7
8
9
10
0.000804
0.000843
0.000881
0.000919
0.000958
0.000996
0.001035
0.001073
0.001111
0.001150
PHI FRACTURE

Dynamic Calibration Process and Results

DFN Model #2

In-house Assisted History Matching Software

11 history matching parameters

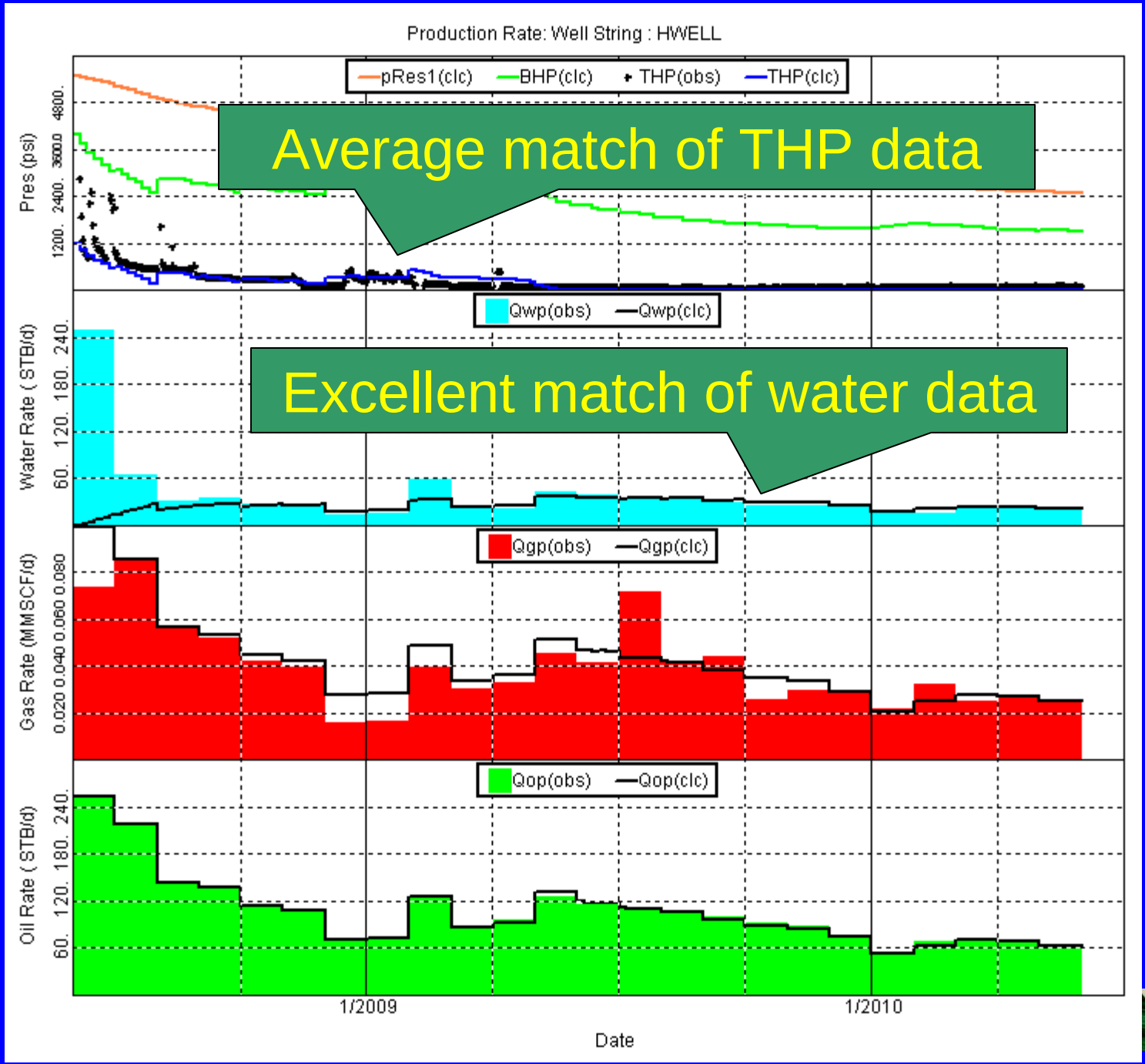
Experimental design for coverage of range

ANN and Genetic Algorithm for global search

Response Surface and GA for optimization

Runs ~15 minutes - maximum 5-day time steps

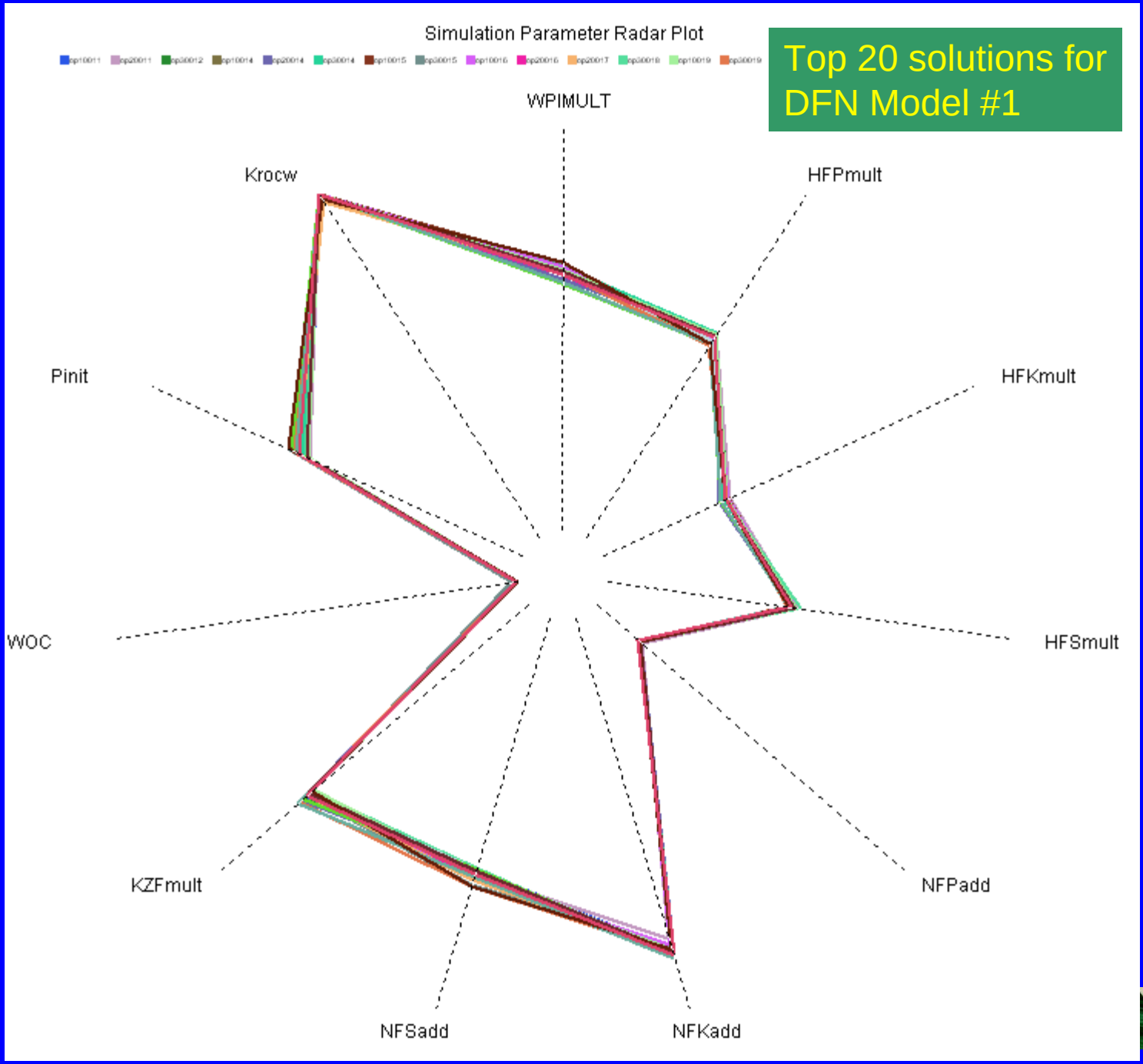
Approximately 240 simulation runs

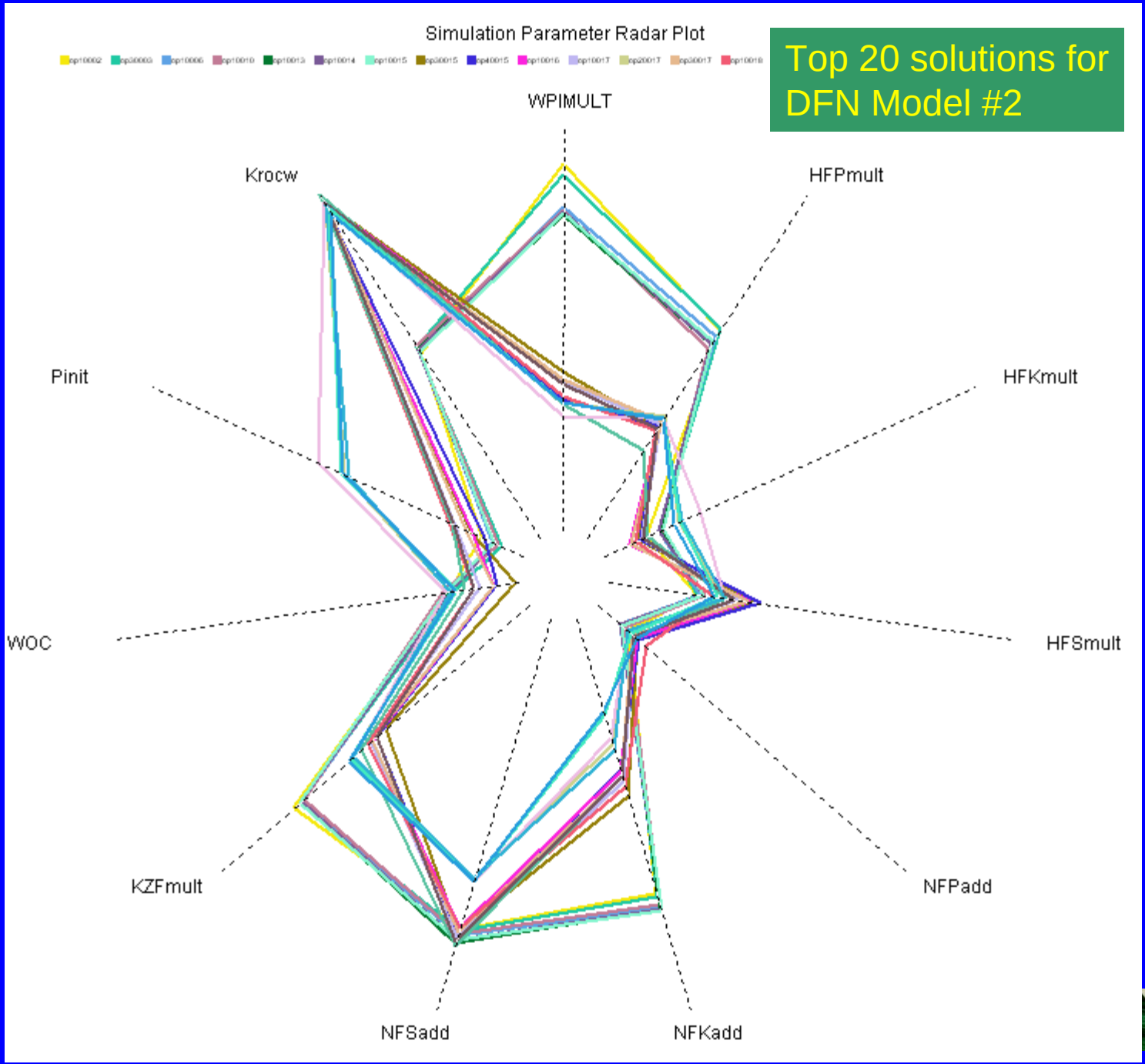

Production Rate: Well String : HWELL
pRes1(clc)
BHP(clc)
THP(obs)
THP(clc)
Pres (psi)
Average match of THP data
Qwp(obs)
Qwp(clc)
Water Rate (STB/d)
Excellent match of water data
Qgp(obs)
Qgp(clc)
Gas Rate (MMSCF/d)
Qop(obs)
Qop(clc)
Oil Rate (STB/d)
1/2009
1/2010
Date

Dynamic Calibration Process and Results

Pinit	WOC
Krocw	KzfMult
WPImult	
NFKadd	HFKmult
NFPadd	HFPmult
NFSadd	HFSmult

Top 20 solutions for DFN Model #1

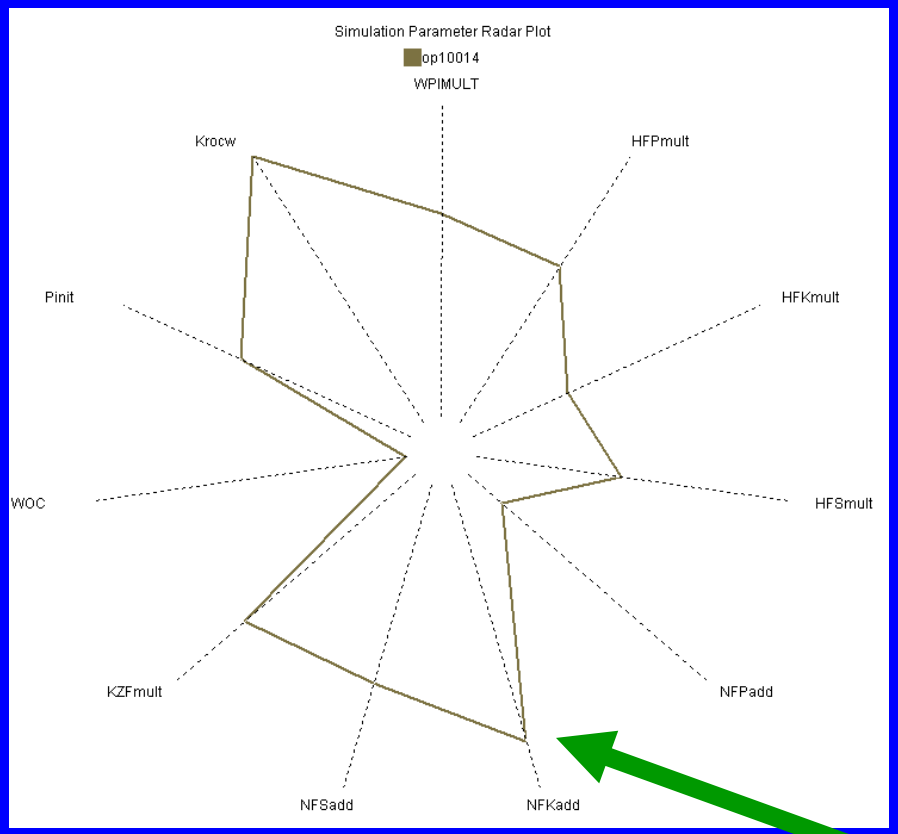


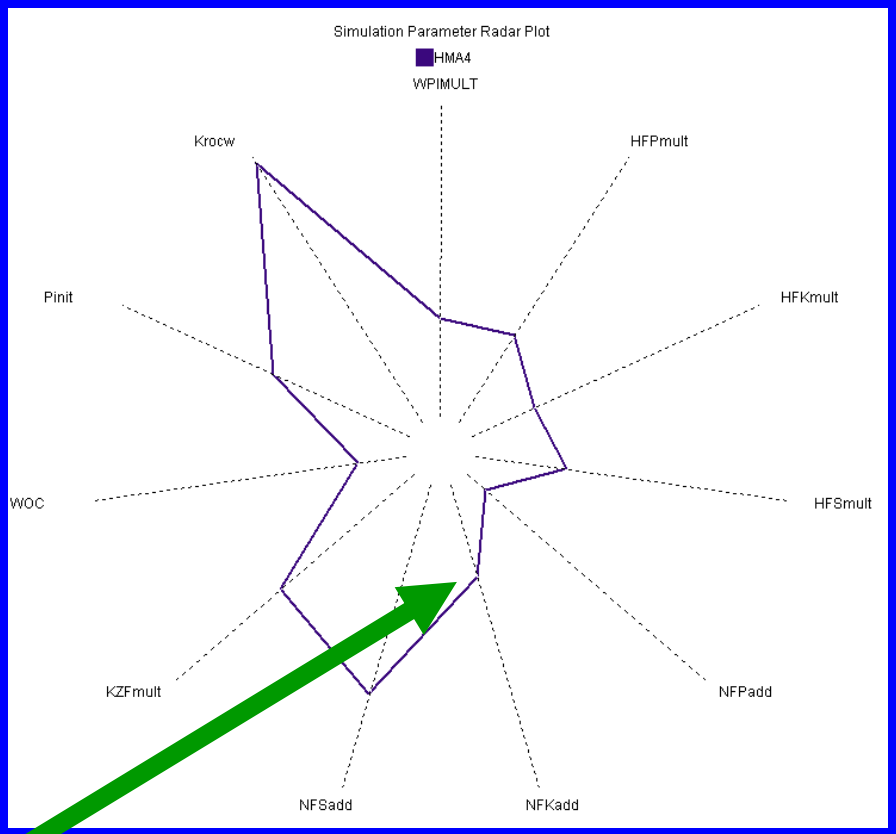


Top 20 solutions for DFN Model #2

Dynamic Calibration Process and Results

Uncertain parameters for best solutions

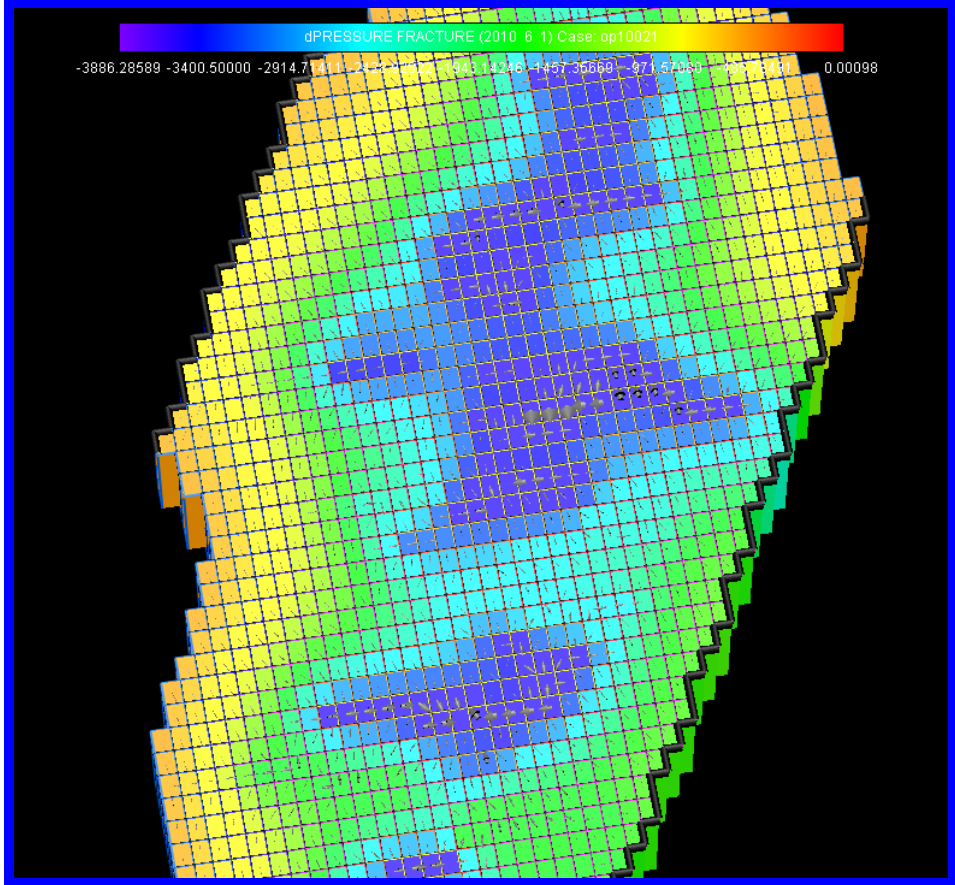


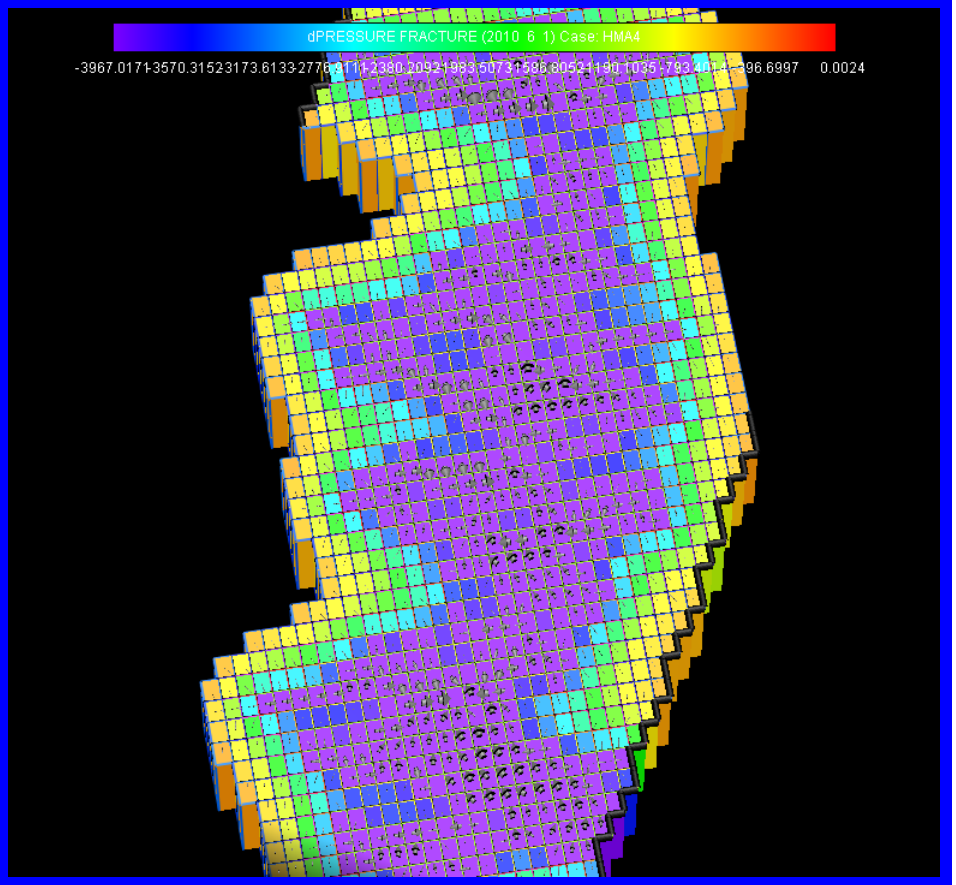


Best solutions are especially different in NF Permeability values

Dynamic Calibration Process and Results

Fracture delta P at 6/2010 for both DFN Models

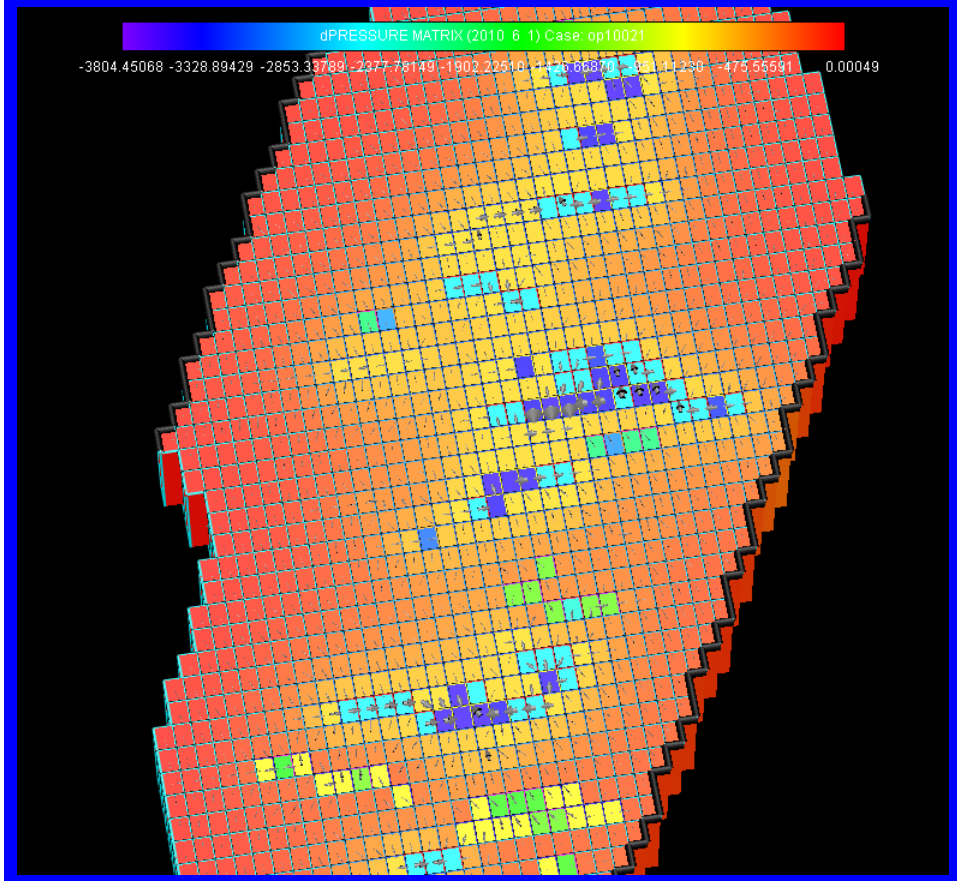


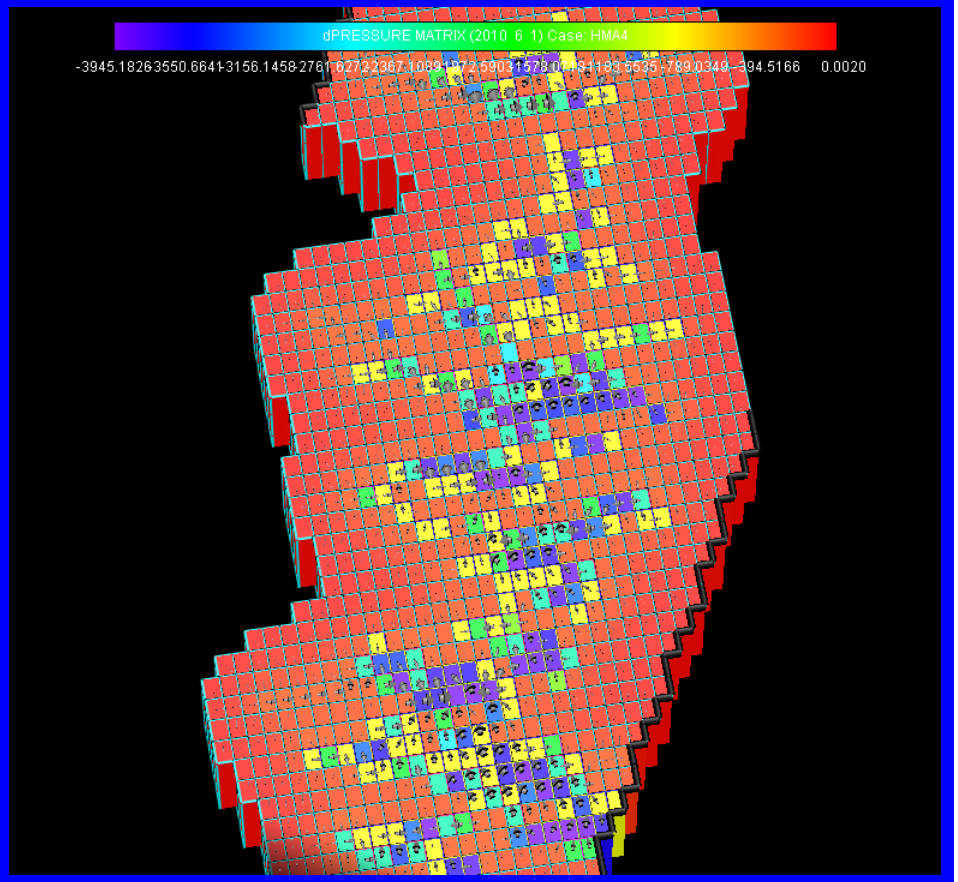


Filtered at minimum fracture delta P of -500 psi

Dynamic Calibration Process and Results

Matrix delta P at 6/2010 for both DFN Models

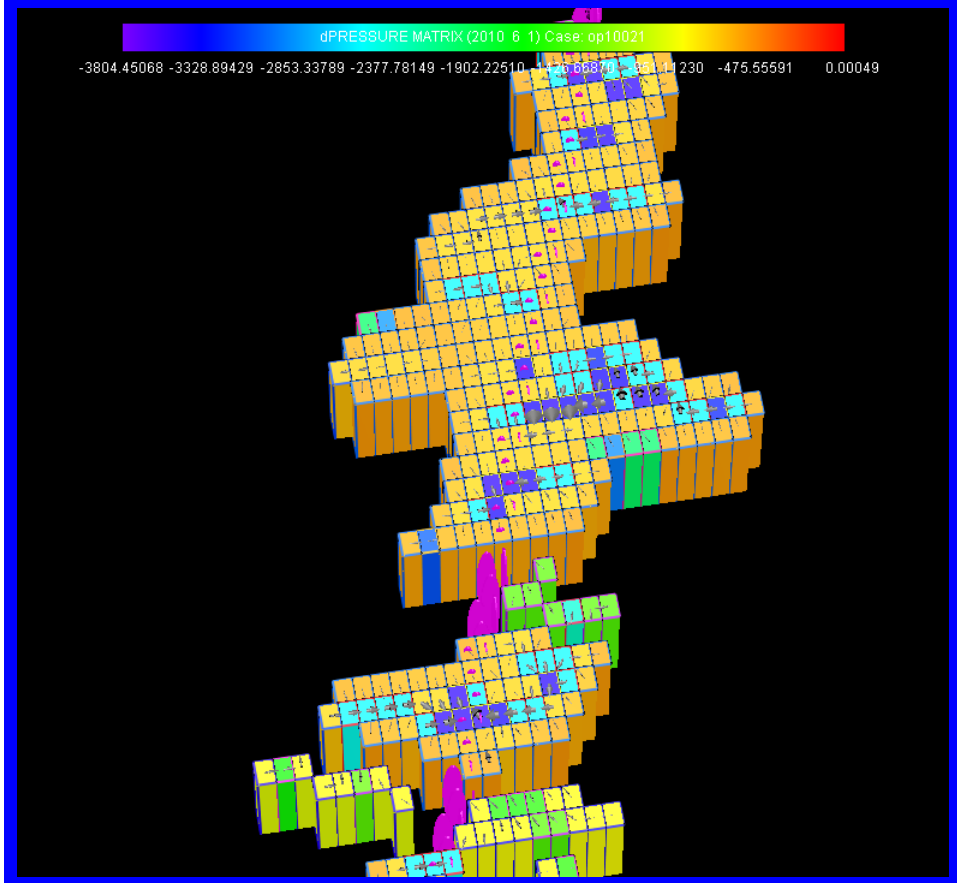


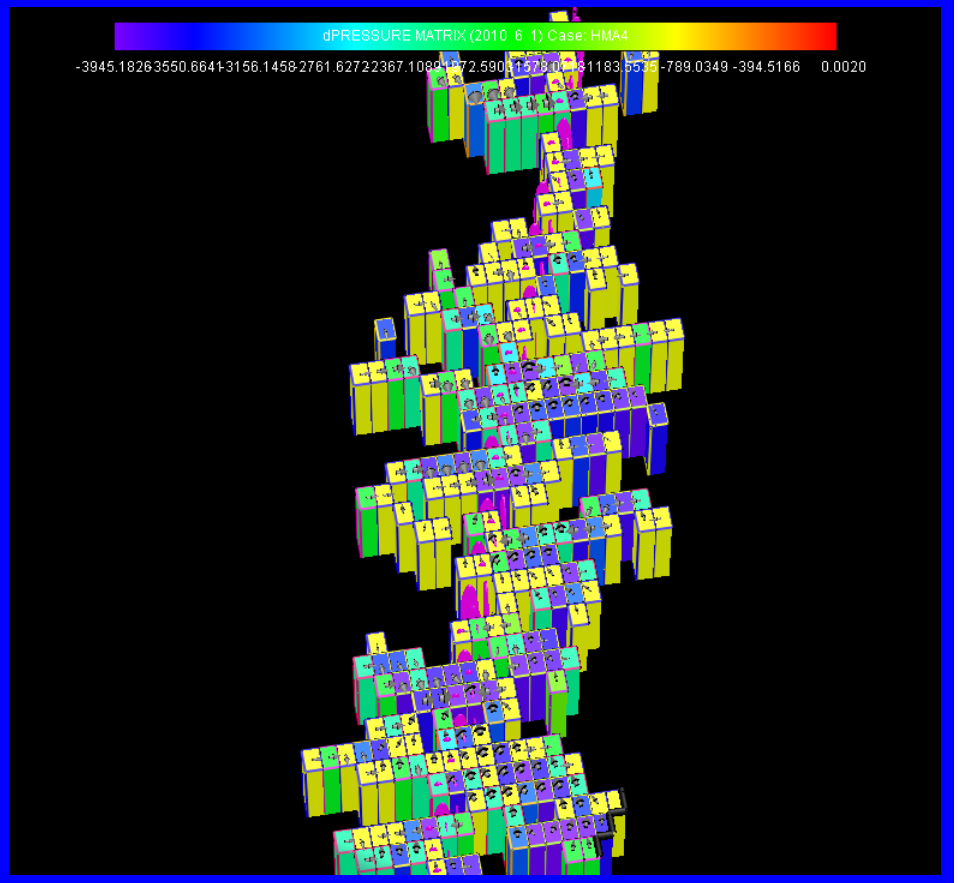


Filtered at minimum fracture delta P of -500 psi

Dynamic Calibration Process and Results

Matrix delta P at 6/2010 for both DFN Models





Filtered at minimum matrix delta P of -500 psi

Predictions and Sensitivity Analyses

Predictions and Sensitivity Analyses

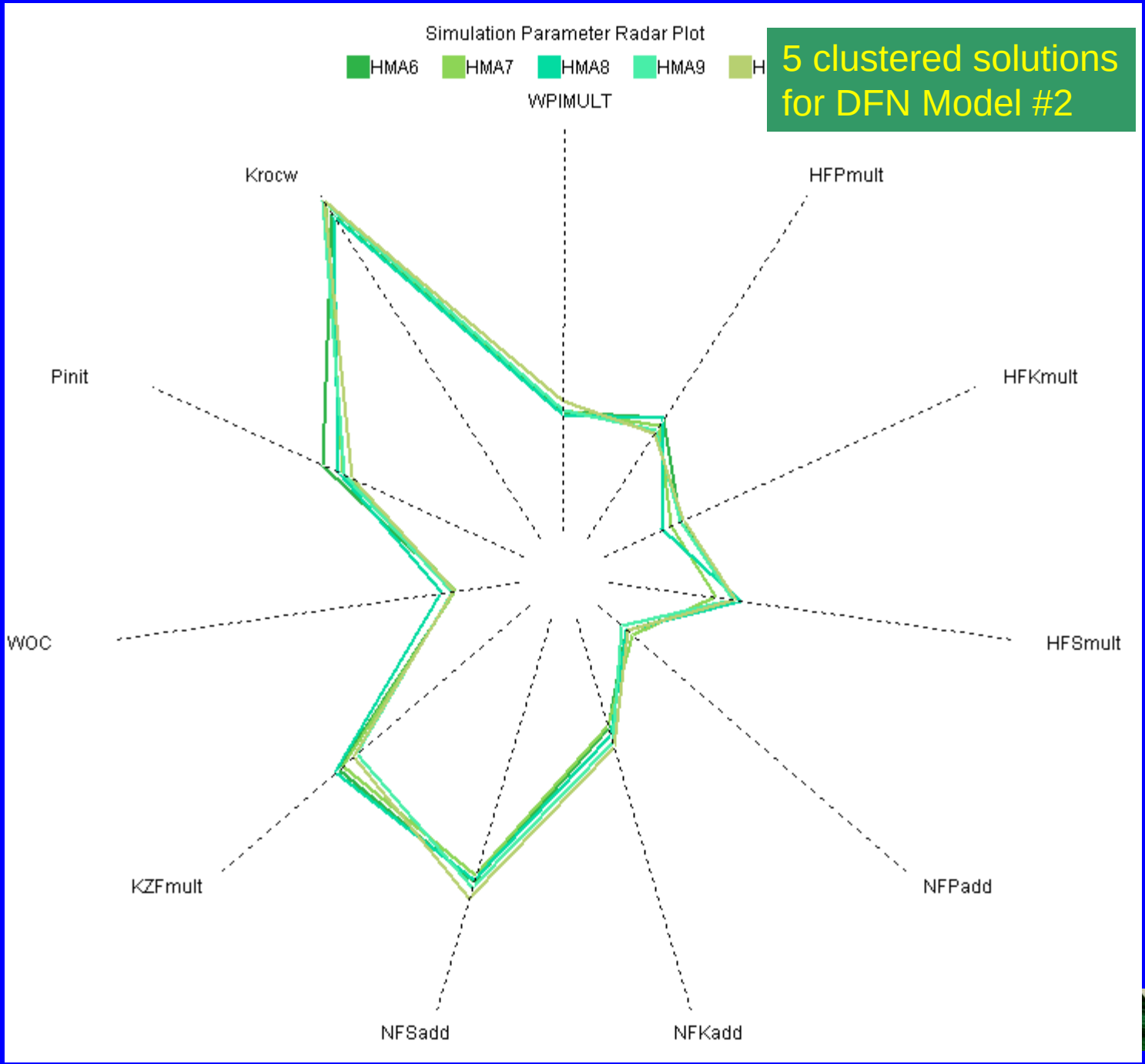
Response surface + Monte Carlo: 100 solutions

Classified 100 solutions into 5 clusters

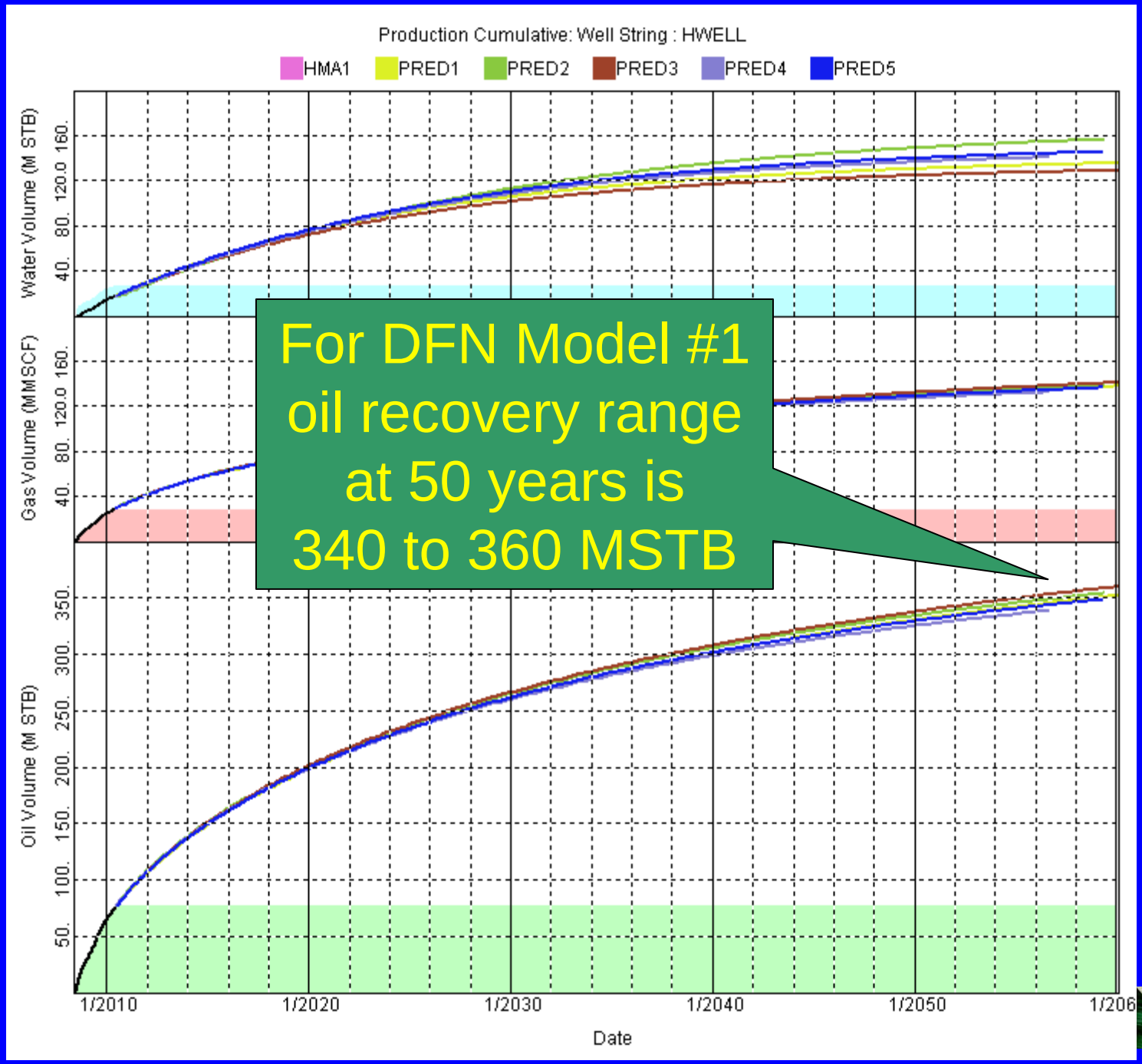
For each DFN model:

- Repeated five history match runs
- Performed five predictions into the future
- Each prediction has different probability

Kept the flowing BHP at 6/2010 values



5 clustered solutions for DFN Model #2



For DFN Model #1 oil recovery range at 50 years is 340 to 360 MSTB

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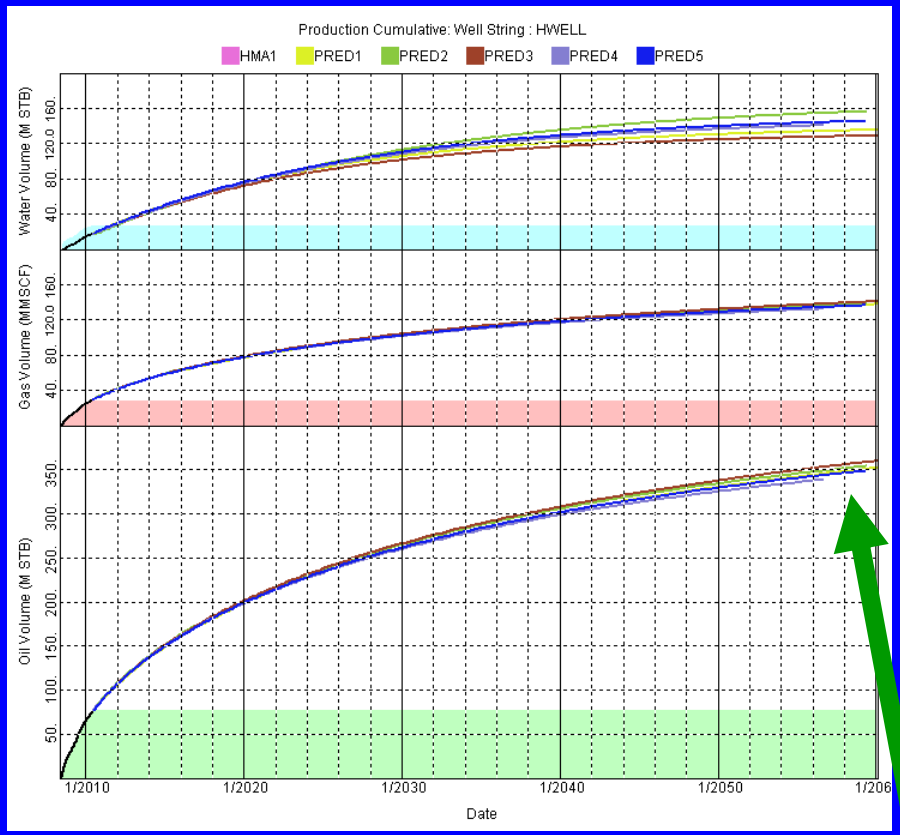
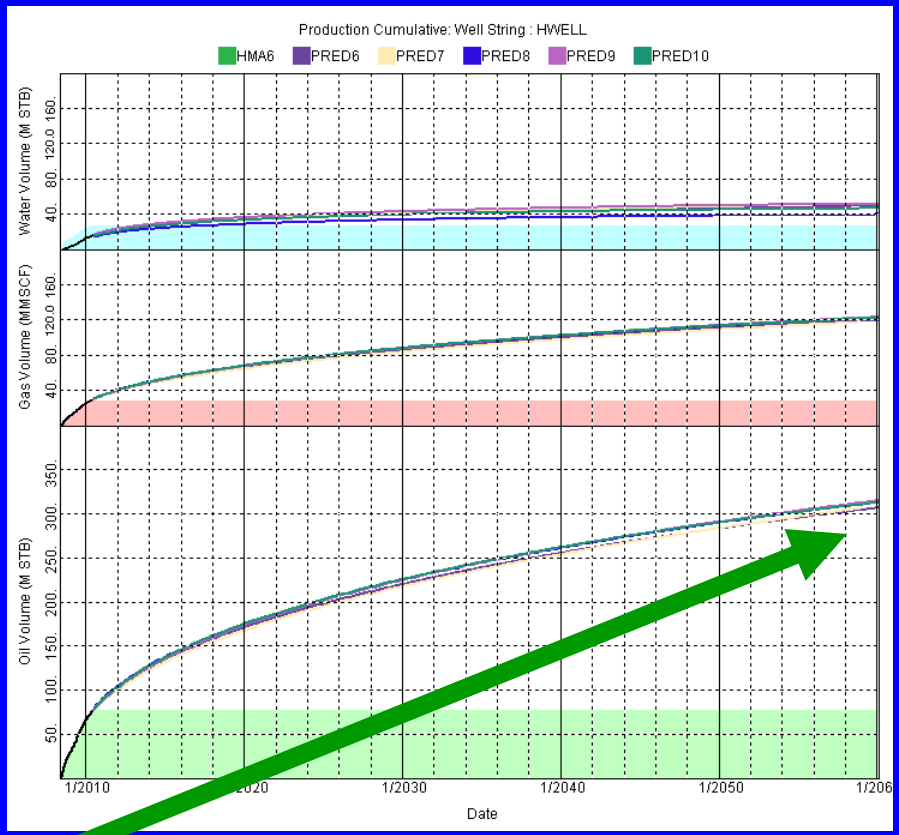
Predictions and Sensitivity Analyses

Performance of DFN Models #1 and #2

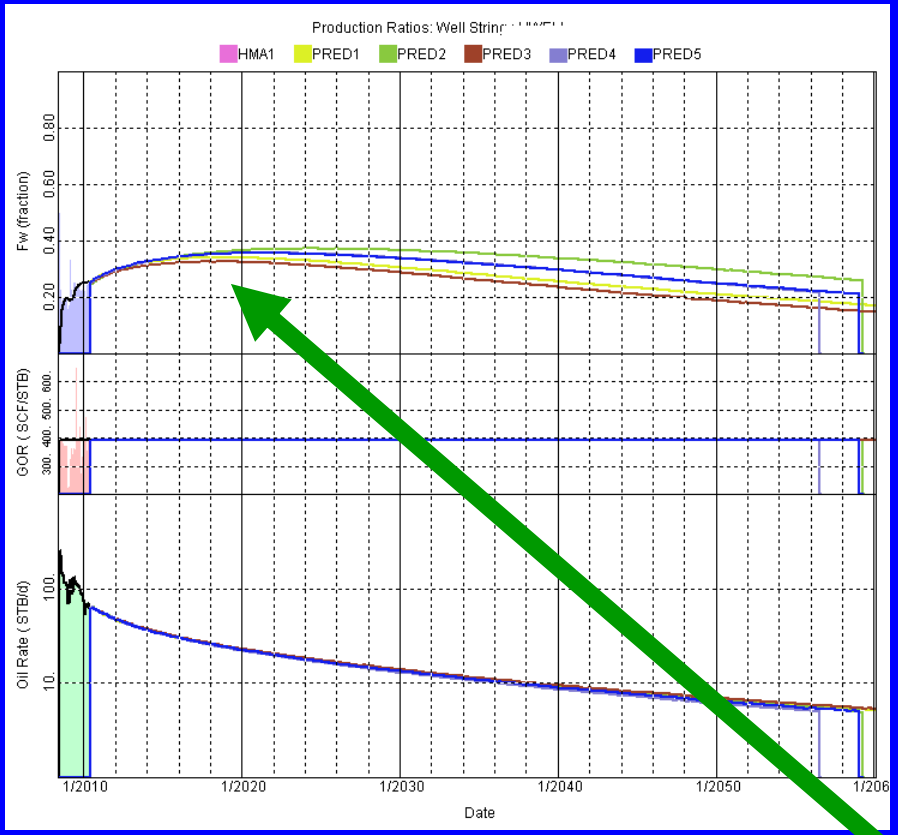


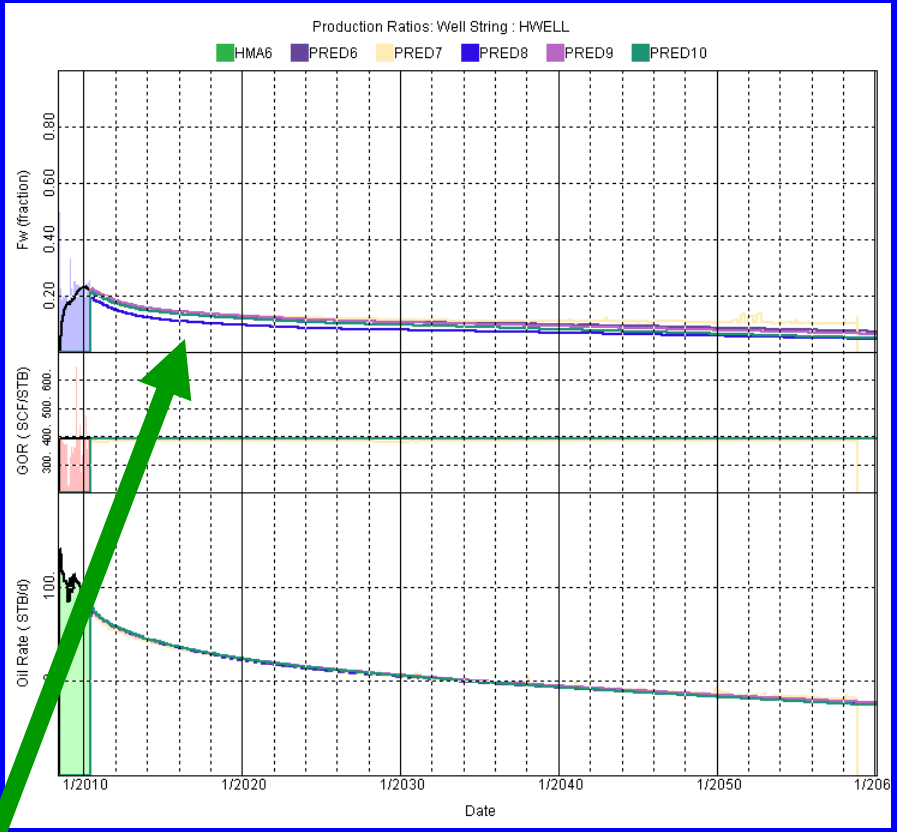


16% Difference in 50-year Oil Recovery Estimates

Predictions and Sensitivity Analyses

Importance of measuring water production





Significant Difference in Predicted Water Cut Profile

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The End

Integration of Microseismic, Production Data and Numerical Simulation to Evaluate Uncertainties in Unconventional Reservoirs.
What is the Impact on Estimated Ultimate Recovery?

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