Simple and Efficient Representation of Faults and Fault Transmissibility in a Reservoir Simulator— Case Study from the Mad Dog Field, Gulf of Mexico

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ABSTRACT

The Mad Dog Field is one of BP's largest assets in the Gulf of Mexico, with over 4 billion barrels of oil in place. It was discovered in 1998 and came online in 2005. Further appraisal success has necessitated the Mad Dog 2 (MD2) development; a second tranche of producers and water injectors tied back to a second floating facility. To create the predicted production profiles that underpin the economics of the MD2 development, the Reservoir Management team uses a full field Nexus reservoir simulation model. The Nexus model is upscaled from the RMS geomodel and reflects a snapshot of our Integrated Subsurface Description at a point in time, with structure derived from seismic data and geologic and petrophysical properties derived from well results. The long cycle time of seismic processing, seismic interpretation, geomodel building, reservoir model building and finally history matching presents three challenges to the representation of faults in the dynamic simulator: Location, Transmissibility, and Presence. This article discusses how we have met these challenges in Mad Dog.

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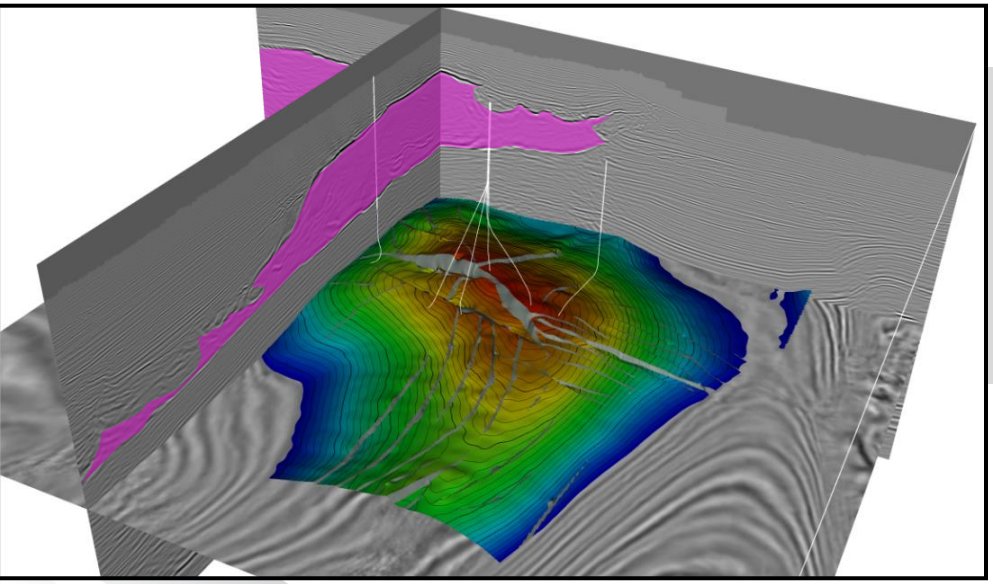
Reservoir Management

progressing resources, delivering production



Using Fault Transmissibility to Assess Compartmentalization and Forecast Reservoir Performance in the Mad Dog Field, Gulf of Mexico, USA

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GCAGS Corpus Christi

20th September 2016

Presentation Overview

1) Introduction
   Regional setting of the Mad Dog field

2) Location
   Hard-code grid offset vs transmissibility multiplier

3) Transmissibility
   Test sensitivities, best estimate for Mad Dog

4) Presence
   Incorporation of subseismic faults

5) Implementation in model
   Reference case, Upside and Downside cases

Mad Dog Introduction

A giant, sub-salt oil field in the southern Green Canyon protraction area, GOM

1998 Discovered by Amoco
2001 Sanction MD1 on 335 Mbbls
2005 First Oil
2007 West Appraisal
2009 South Appraisal
2011 North Appraisal
2016 Sanction MD2

Working Interest:

BP	60.5%
BHP Billiton Petroleum	23.9%
Chevron	15.6%

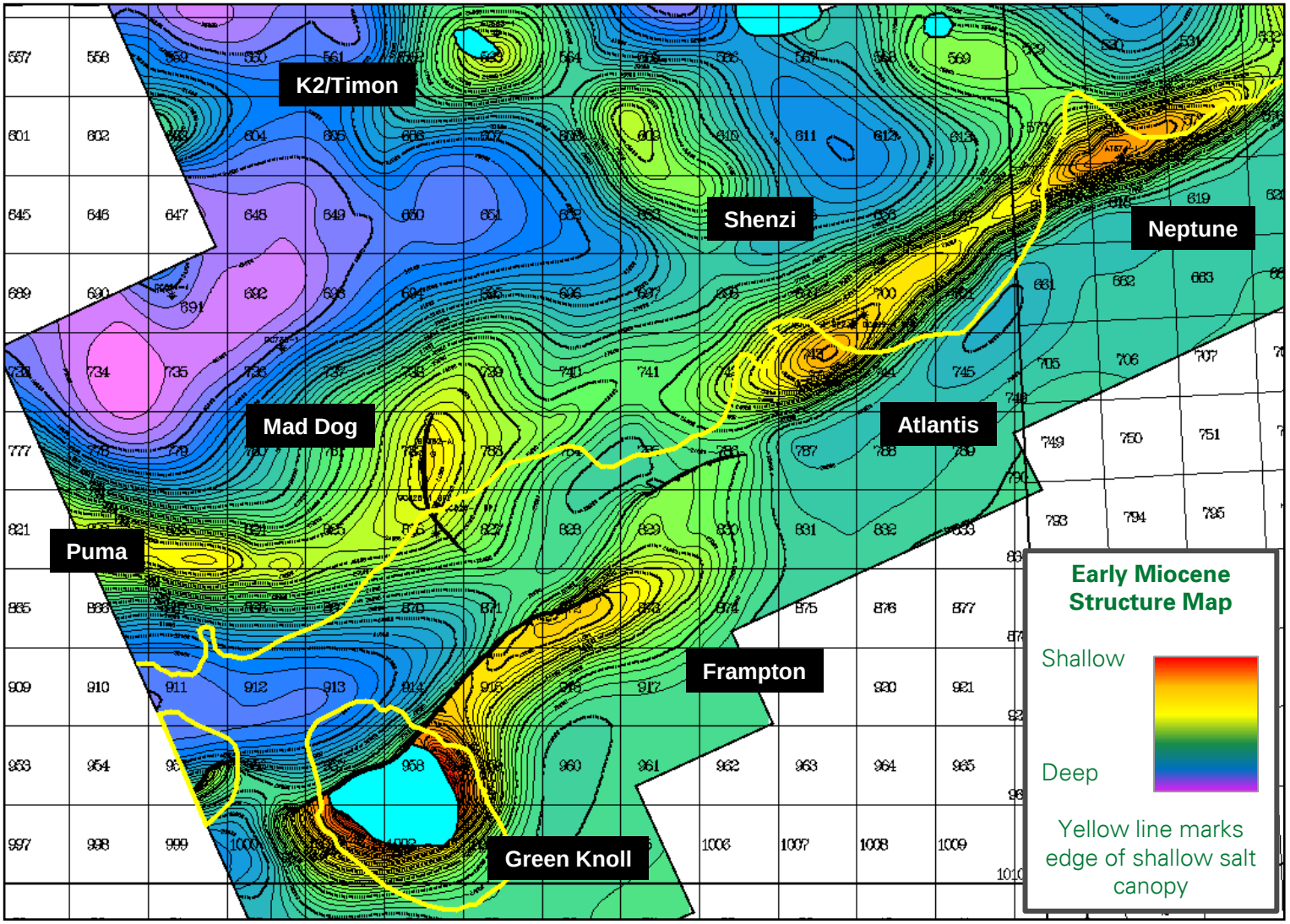
Phase 1:

Production spar 140 miles south of Louisiana coast line

Design Life: 2040
Dry Tree Slots: 14
Drilling Radius: 10,000 ft
Plant Capacities:
Oil: 80 mbo/d
Gas: 60 mmscf/d
Water: 50 mbw/d

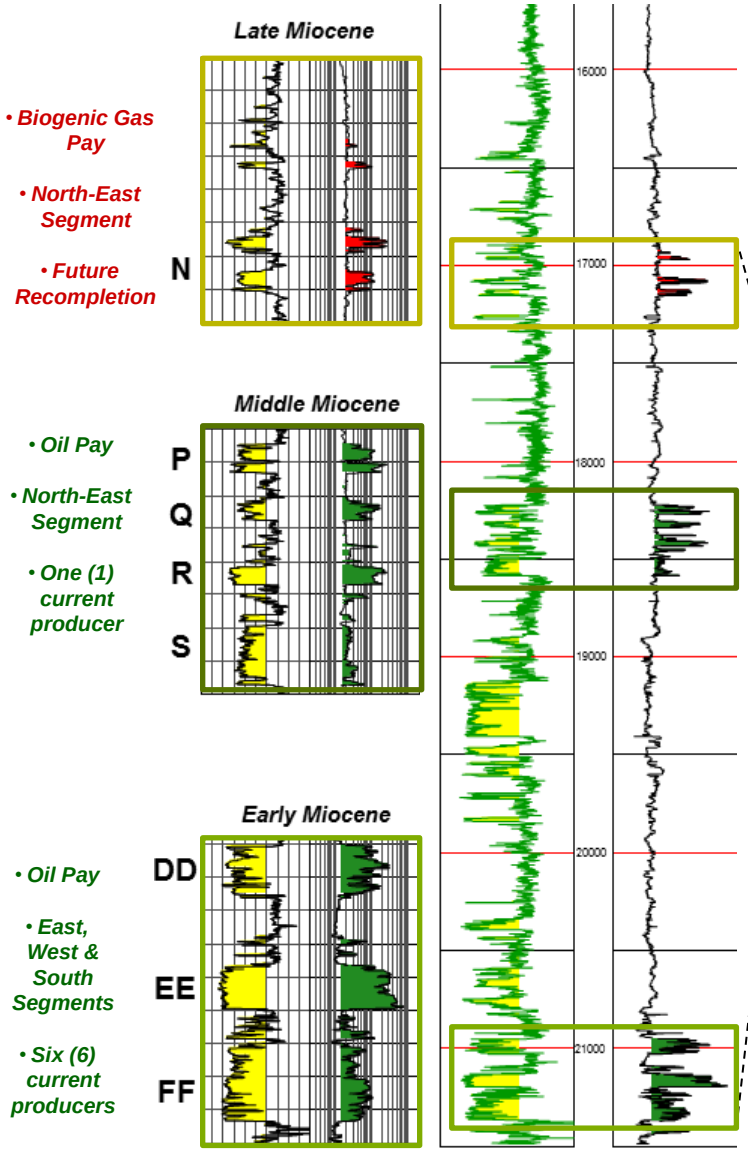
Mad Dog Introduction

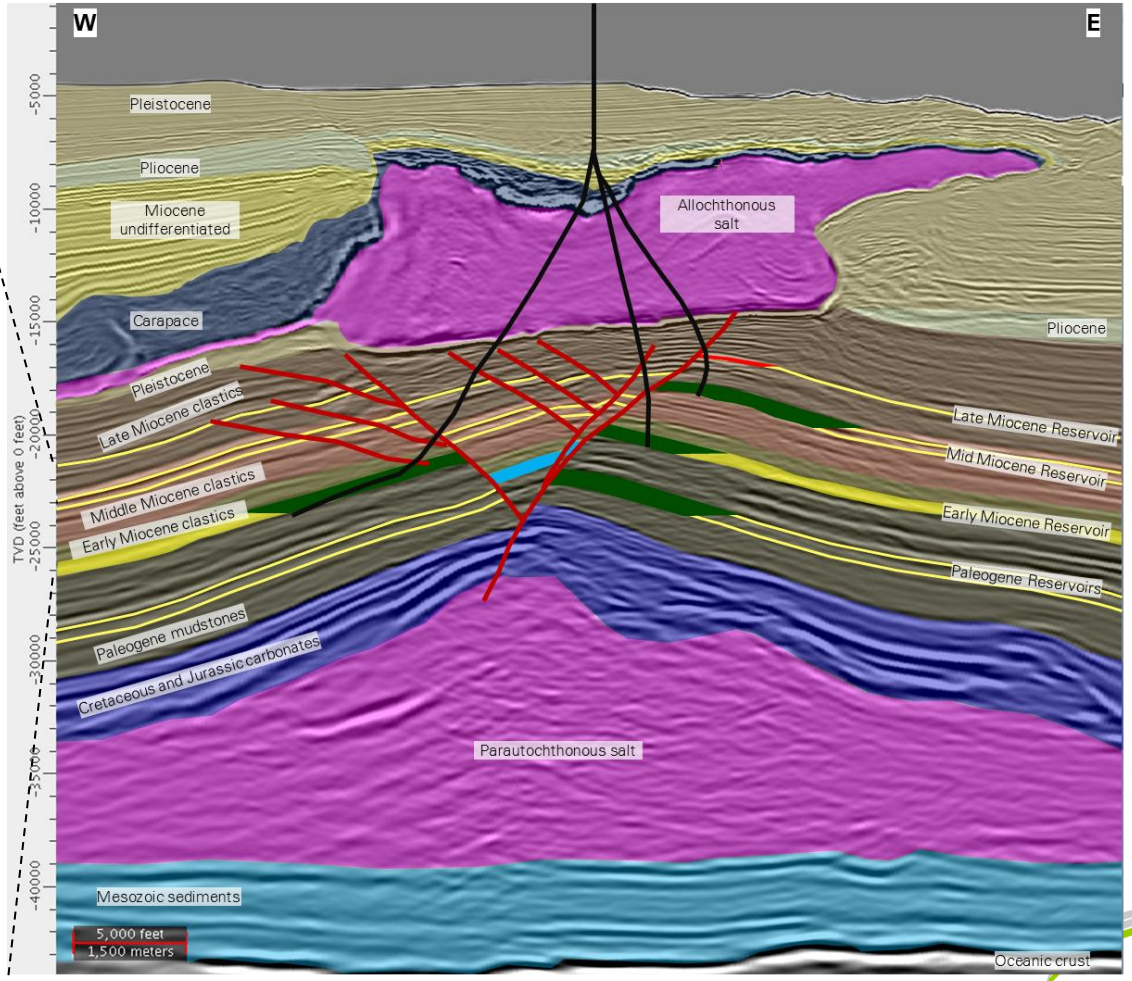
Atwater Valley fold belt, an established hydrocarbon province



Mad Dog Introduction

Multiple hydrocarbon bearing intervals; bulk of resources in the early Miocene

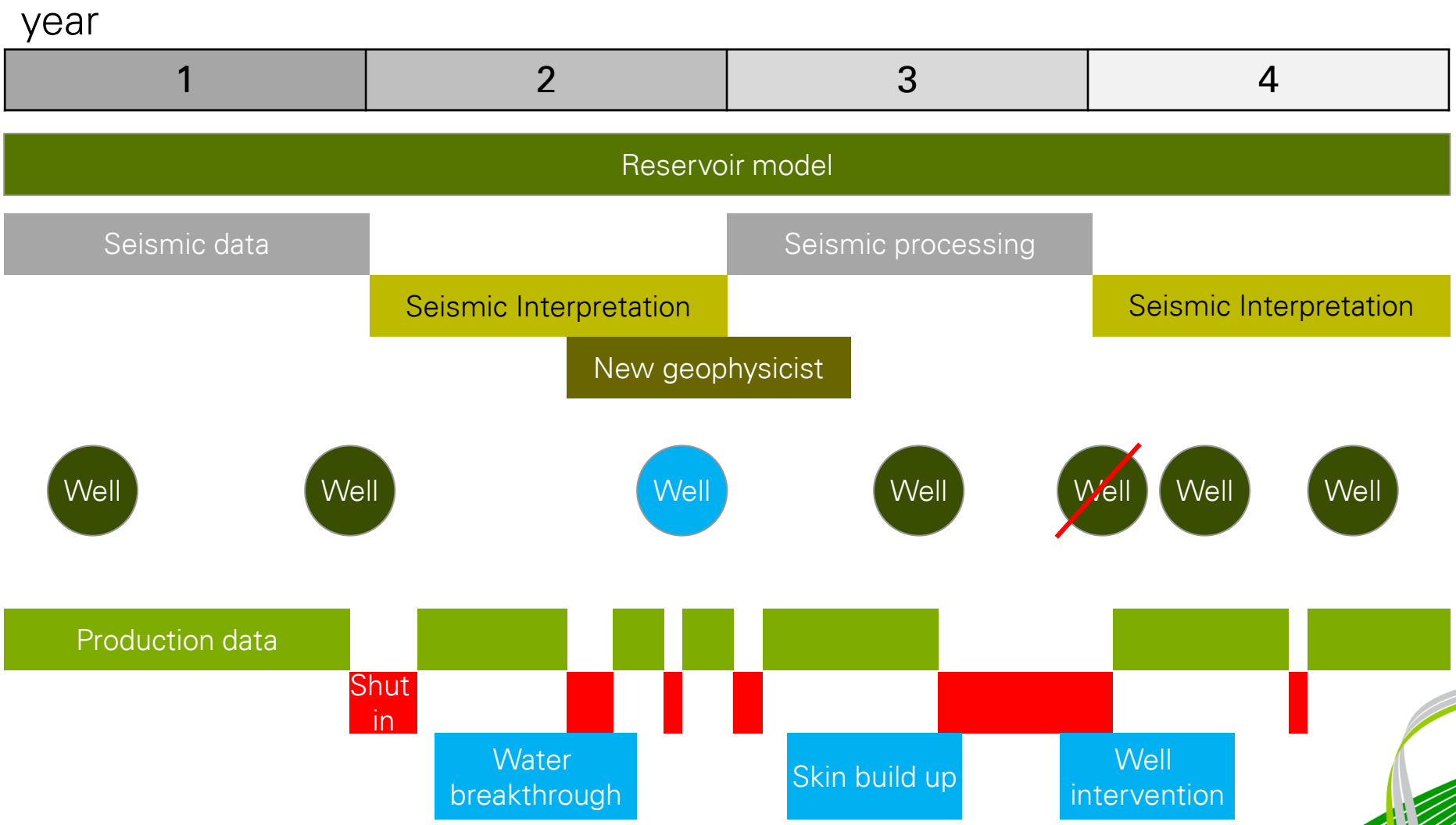




450 ft (137 m) thick
80-90% N:G
24% porosity
200-1000 mD perm
14 – 42% Sw

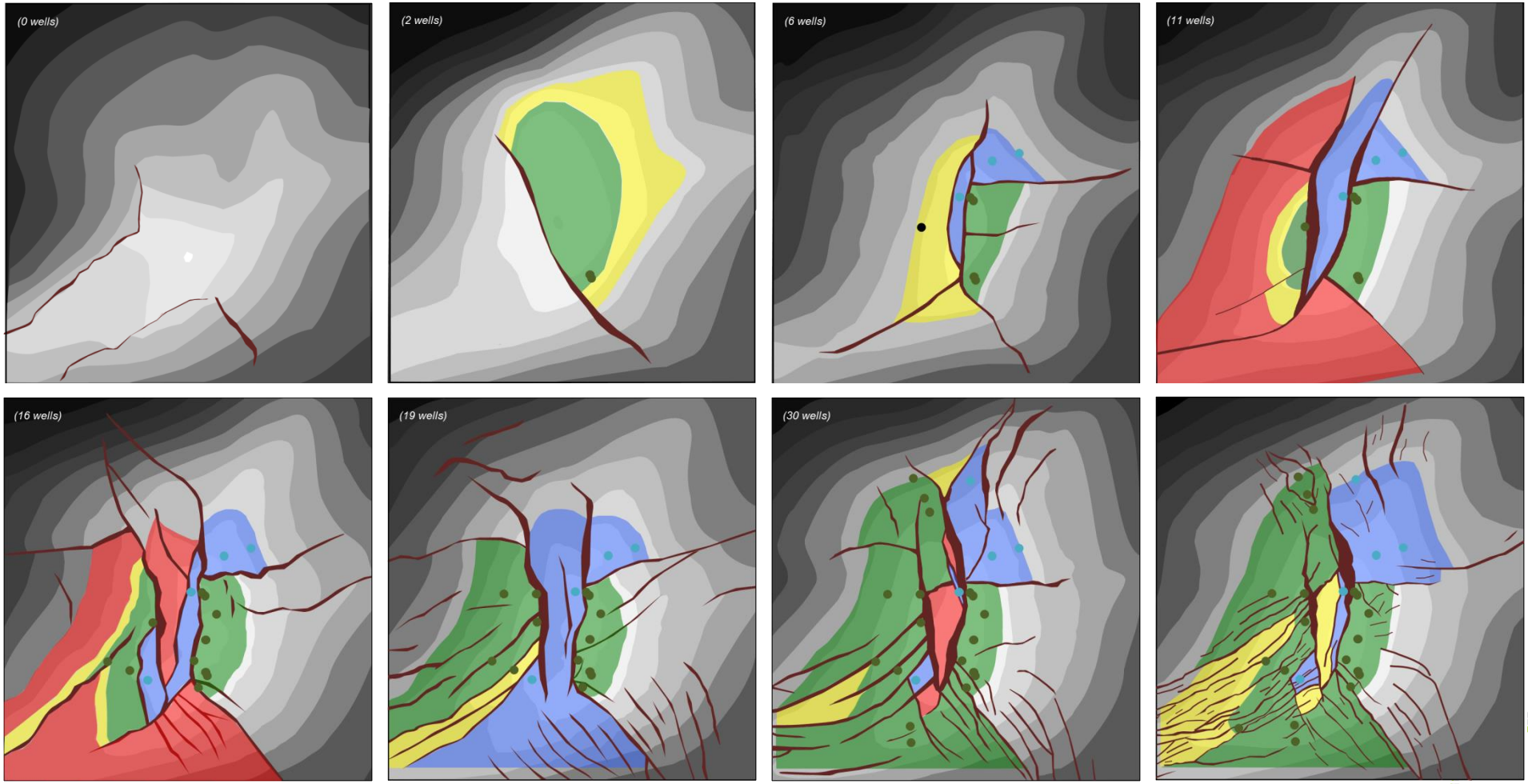
Need to build flexibility into model

New reservoir model every 3-4 years must cope with frequent changes



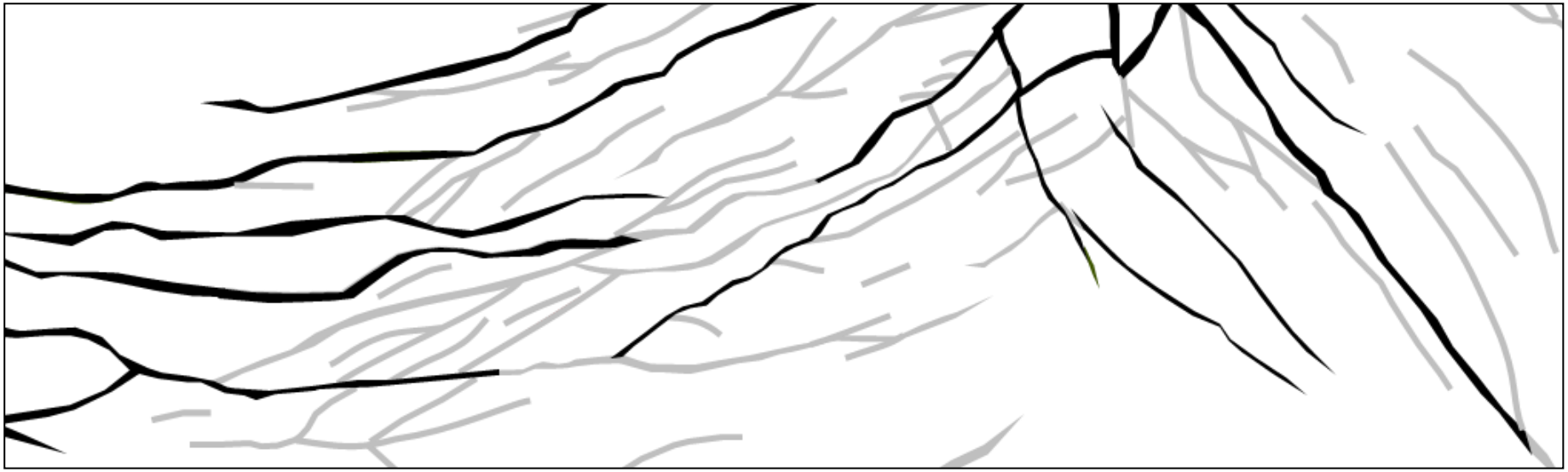
Need to build flexibility into model

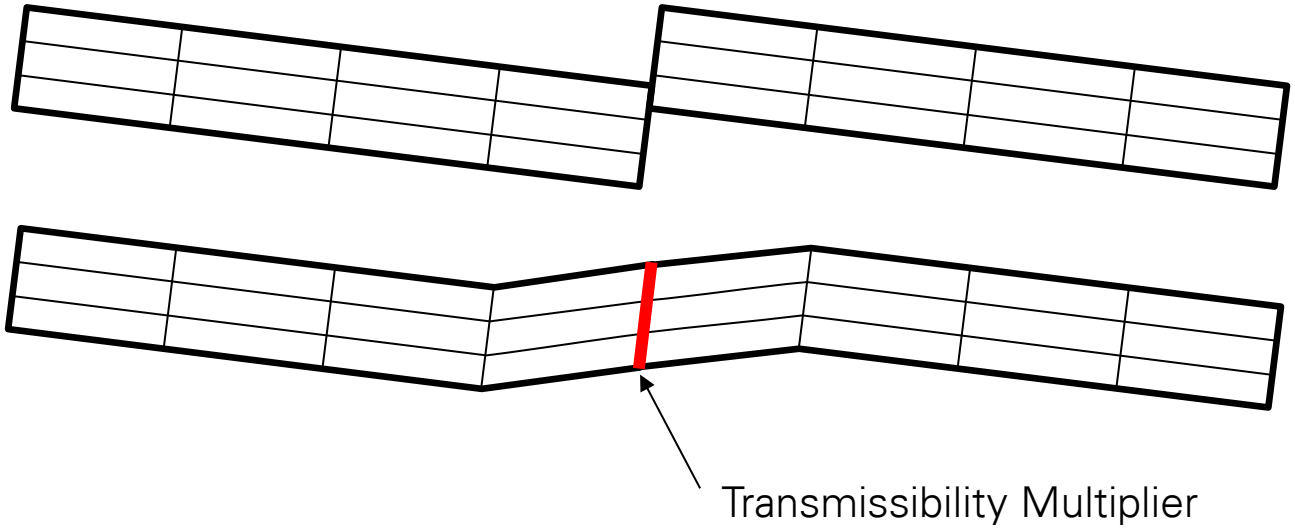
Review of Mad Dog maps through time shows frequent changes



Need to build flexibility into model

Large faults hard-coded with grid offset, small faults no grid offset



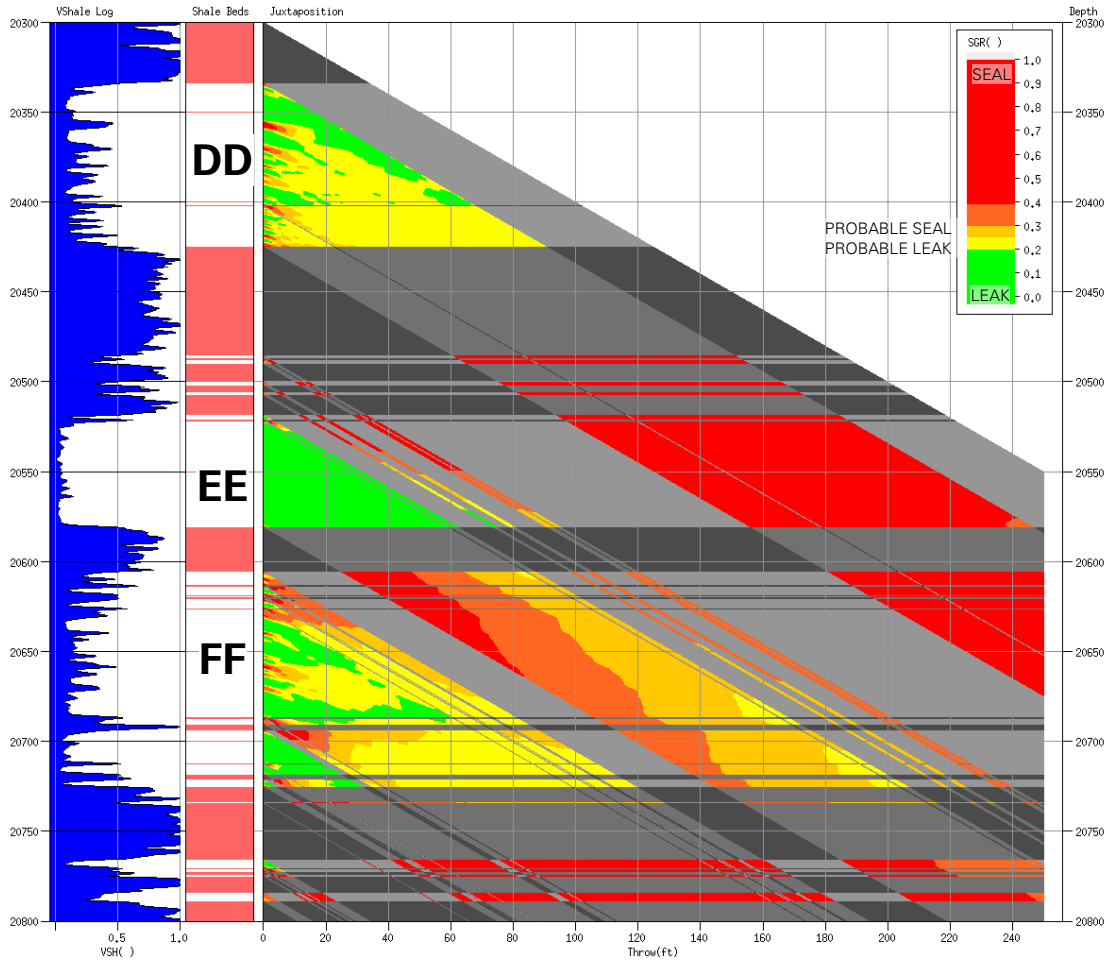


Hard-coded fault with offset

Fault without grid offset

How to incorporate transmissibility

Shale gouge ratio describes exploration seal risk, not applicable to production



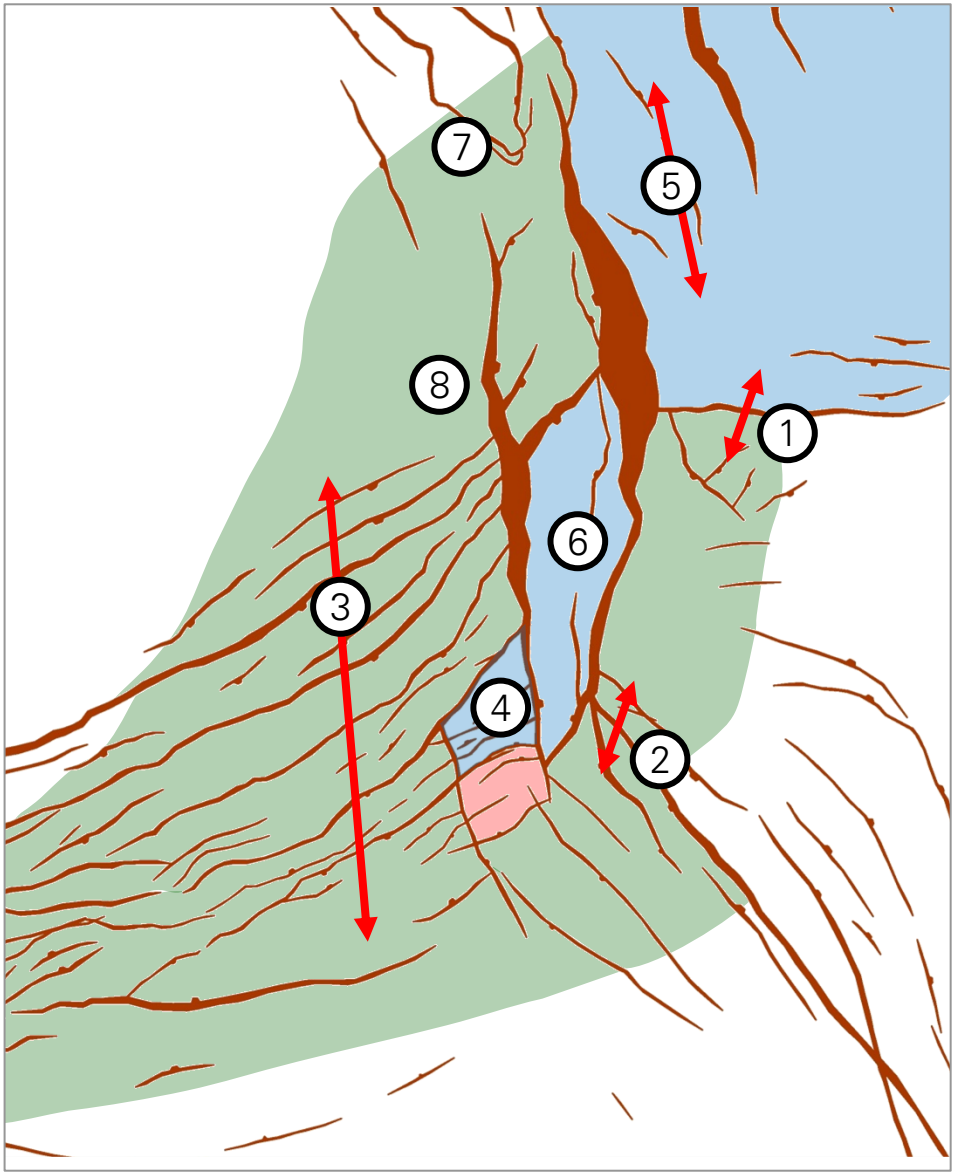
DD sand: high net-to-gross, no internal shales, therefore requires complete offset to seal reservoir section. Throw must be >90 feet

EE/FF sand: high net-to-gross, no internal shales, therefore requires complete offset to seal reservoir section. Throw must be >200 feet

Geological time

What do we **know** / infer?

1. **Oil in east, no oil in NE**
   Fault holds back oil column
2. **East OWC different from South LKO**
   Fault in between supports column height difference
3. **West, SW and South line up on same virgin pressure gradient**
   Intervening faults do not support pressure differences over geological time. West and south aquifers have different water gradients
4. **Crestal wet compartment**
   Surrounding faults prevented charge entry/ water exit
5. **Different water pressure gradients in NE wells**
   Pressure difference held back by sub-seismic fault
6. **Wet graben compartment**
   Isolated from oil charge by sealing faults
7. **Evidence for perched water in slump**
   Small fault is barrier to water movement over geological time
8. **Geochemical fingerprints are... complex**
   Barriers to compositional mixing over geological time
9. **Puma has separate OWC**
   Separated from Mad Dog by sealing faults



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50 wellbores in Mad Dog field

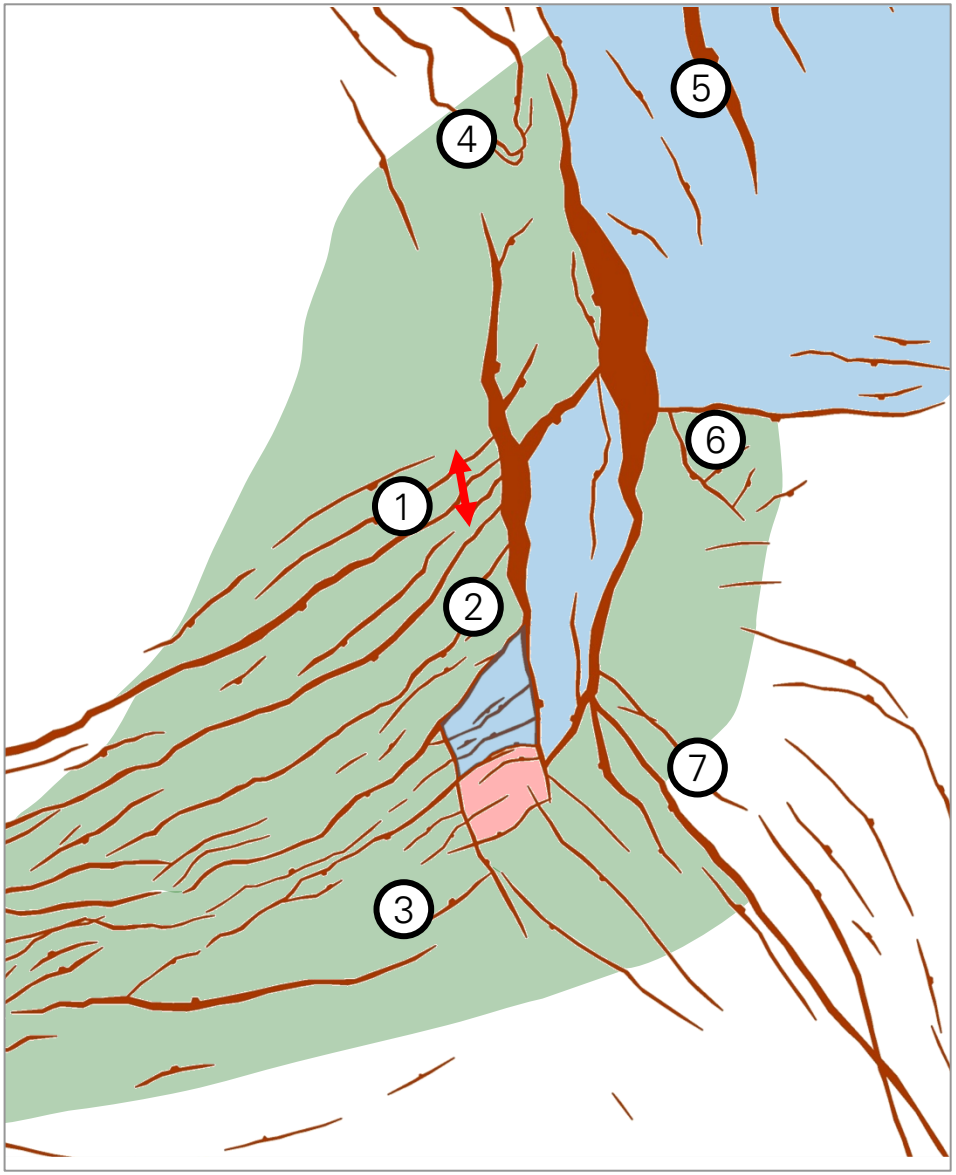
30 reservoir penetrations

- 25 oil bearing / 5 wet
- 11 are partially faulted out

Production time

What do we **know** / infer?

1. **West drilled, no depletion seen from 2 years of SW production**
   Fault(s) in between prevent pressure communication
2. **SW connected to >600 mmb of 'fluid'**
   Pressure buildup cannot be matched by mapped fault block
3. **South was virgin pressure**
   Separated from East and SW production by faults that can hold back production pressure response
4. **North is depleting, but not well connected to west**
   Something preventing full depletion from west
5. NE appears on W aquifer gradient but depleted
   Fault allowing some communication? Or around tip?
6. **East has water breakthrough**
   Faults slow but do not prevent water break-through
7. **Well did not see depletion after 6 months of east production**
   Small fault holds back depletion



50 wellbores in Mad Dog field

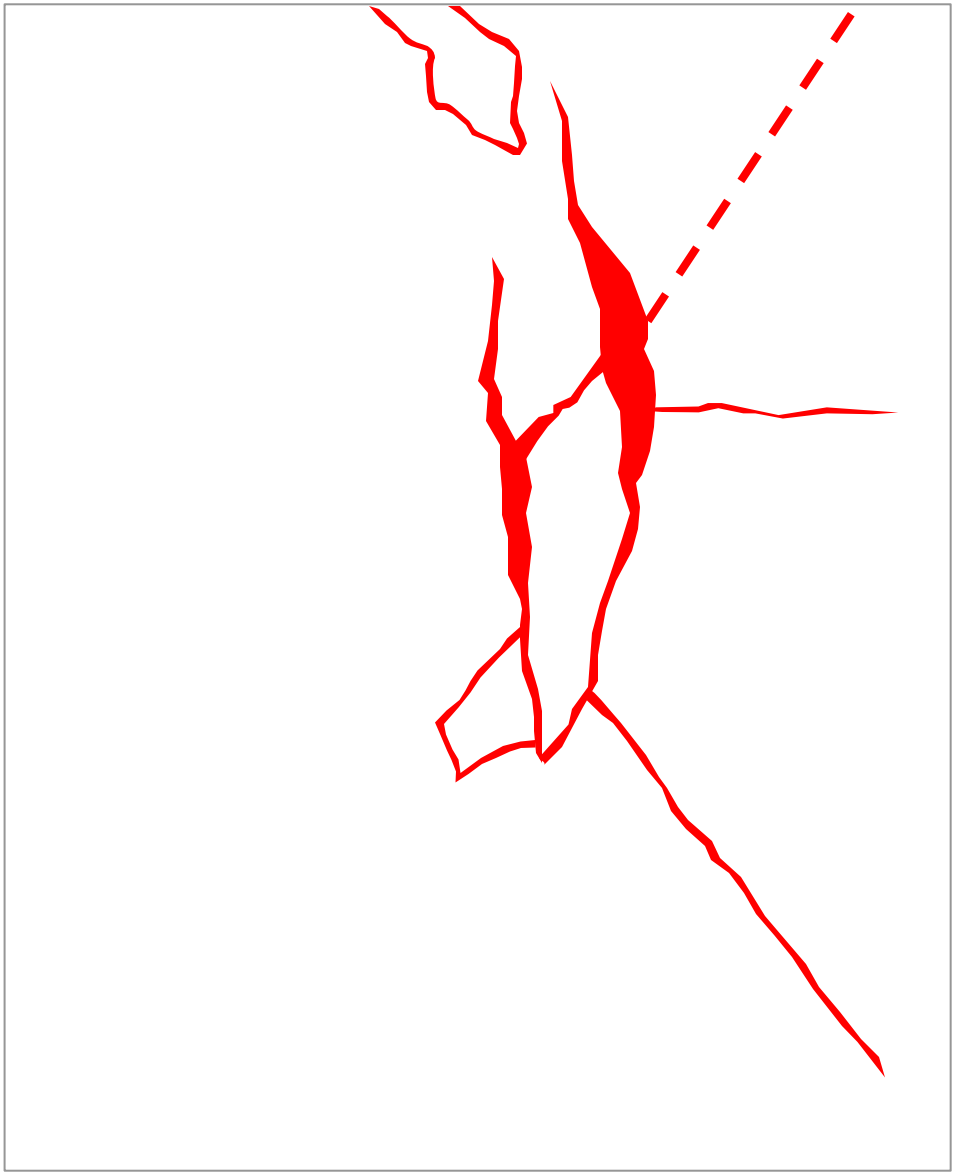
30 reservoir penetrations

- 25 oil bearing / 5 wet
- 11 are partially faulted out

Geological time

sealing / leaking faults

These are the faults that we conclude **must** hold back pressure over a geological timescale



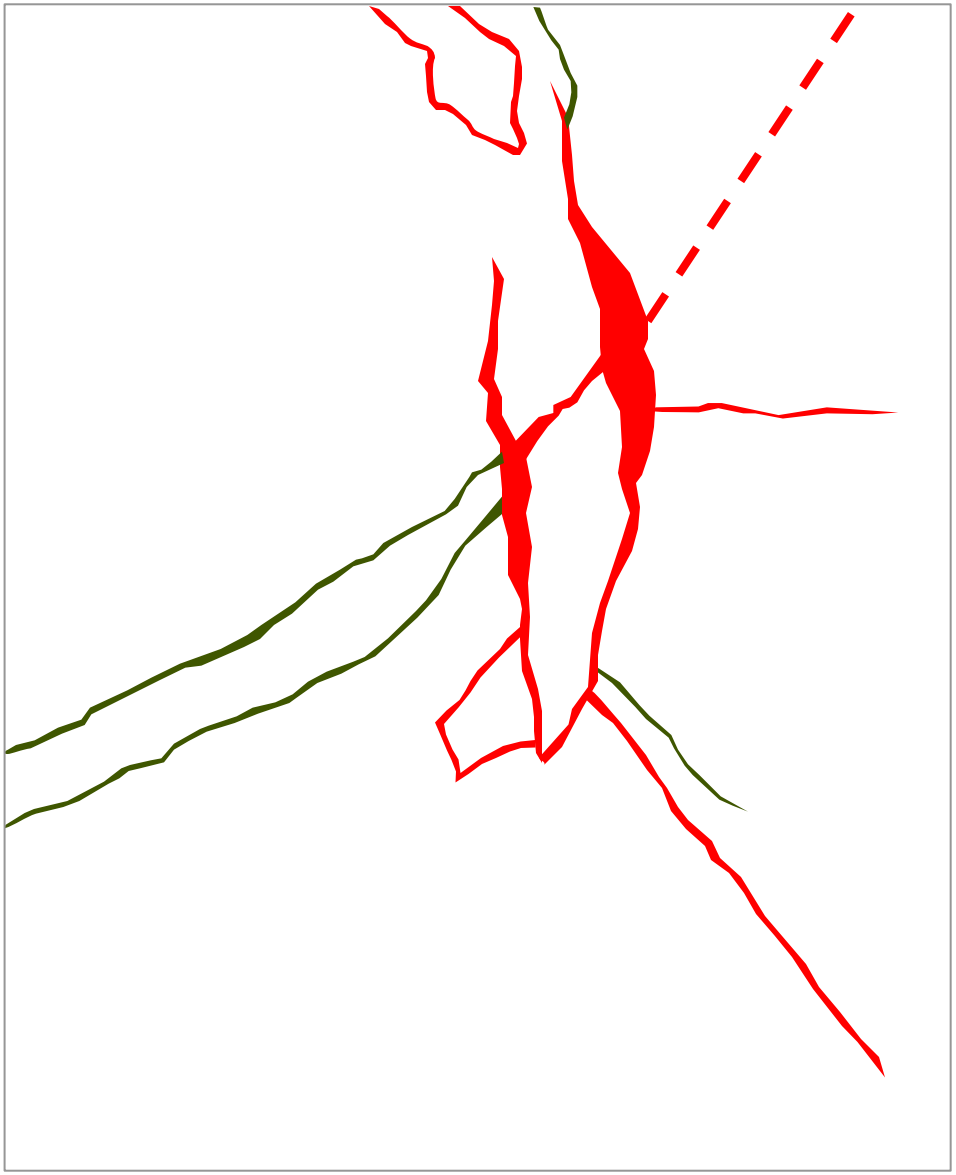
Geological time

sealing / leaking faults

These are the faults that we conclude **must** hold back pressure over a geological timescale

...and

The faults that we conclude **must not** hold back pressure over a geological timescale



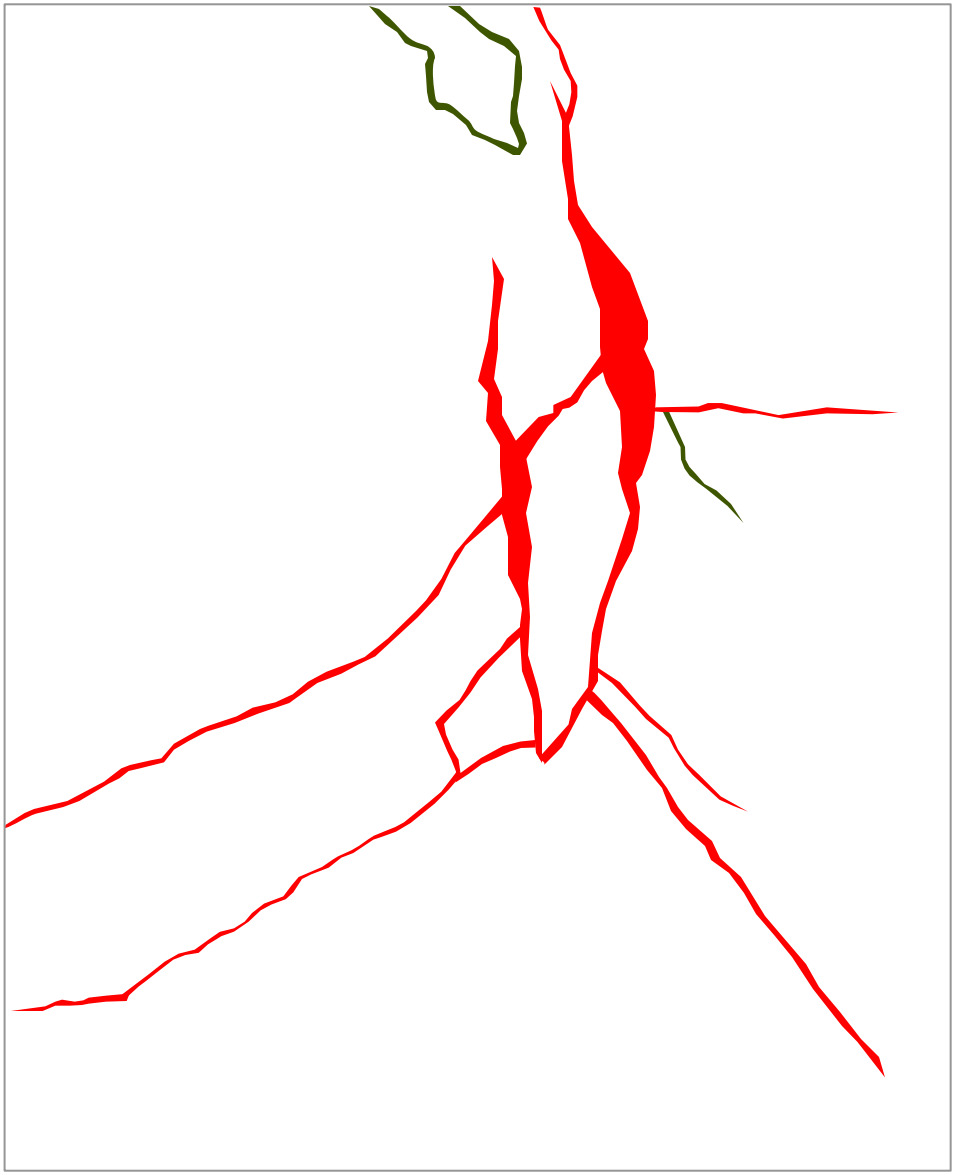
Production time

sealing / transmissive faults

These are the faults that we conclude **must** hold back pressure over a production timescale

...and

The faults that we conclude **must not** hold back pressure over a geological timescale



Transmissibility considerations

What impacts fault transmissibility?

Throw

Large faults will completely offset the reservoir, providing a juxtapositon seal. Medium sized faults are likely to have well developed fault gouge and therefore enhanced sealing capacity. Small faults are more likely to be transmissive

Length-to-throw ratio

Faults that are too long for the amount of throw interpreted on them are more likely to consist of individual fault segments with gaps or relay ramps in between that may represent more transmissive sections of the overall fault. Similarly, faults with length:throw ratios of 20-50 are more likely to be contiguous individual fault planes and less likely to have transmissive holes in them.

Fault timing

Based on our knowledge of structural and charge history, the Mad Dog faults formed pre-charge, and therefore were originally water-filled. To fill the fault with oil, the capillary entry pressure of the rock must be exceeded, by growing a hydrocarbon column or imparting a differential pressure across the fault from depletion

Column height

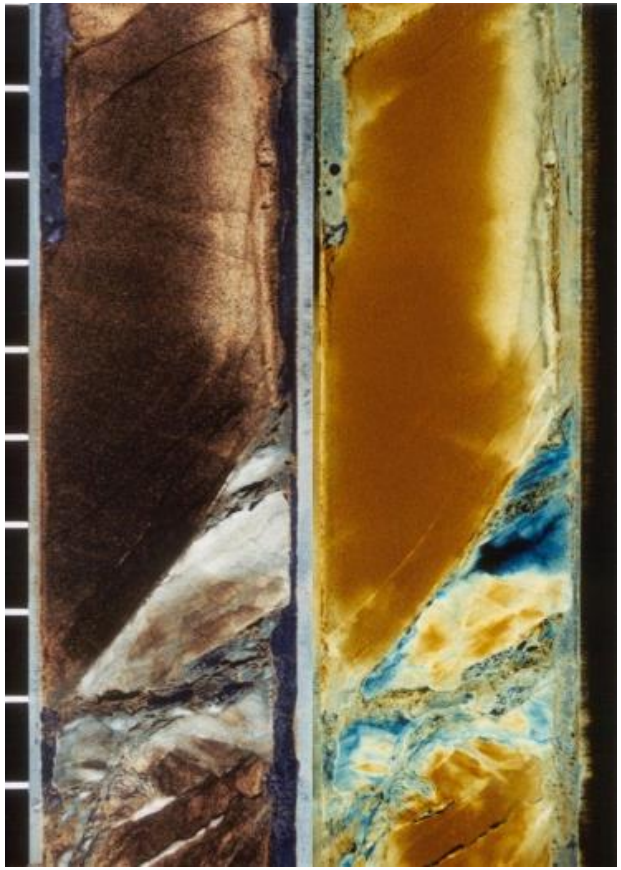
The increasing pressure above hydrostatic at the top of a large column is more likely to be able to overcome the capillary entry pressure of a fault zone. Therefore, faults are more likely to be non-transmissive to oil close to the OWC, and transmissive at the crest of the structure. Similarly, faults are likely to be transmissive to water in the water leg and non-transmissive to water at the crest of the structure

Orientation with respect to max horizontal stress

Faults parallel to Shmax are more likely to be held open and therefore more transmissive. Faults perpendicular to Shmax more likely to be pushed shut and therefore less transmissive

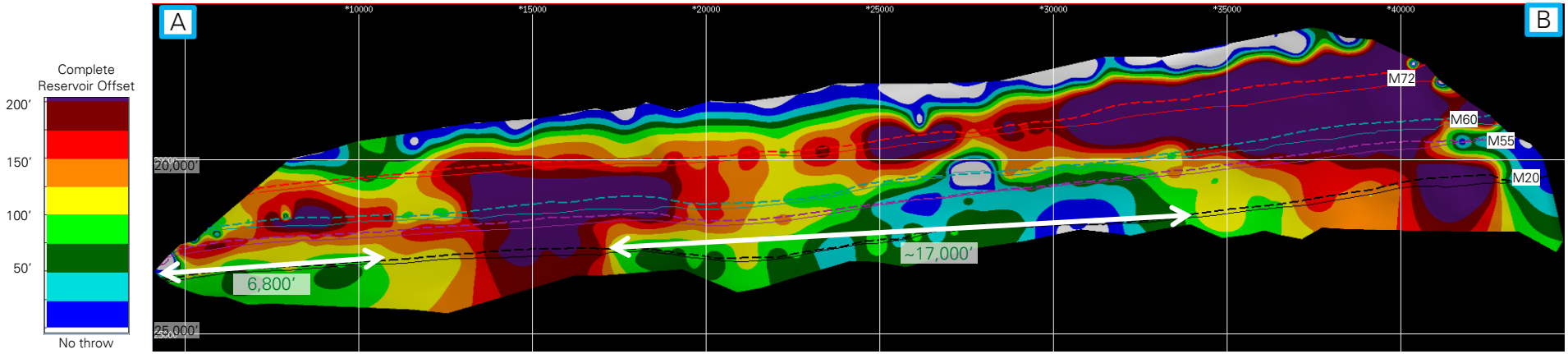
Permeability anisotropy

Deformation bands and small faults in the damage zone of a large fault are most likely to form sub-parallel to the master fault. Therefore permeability parallel to a fault is likely to be higher than the permeability perpendicular to a fault.



Throw

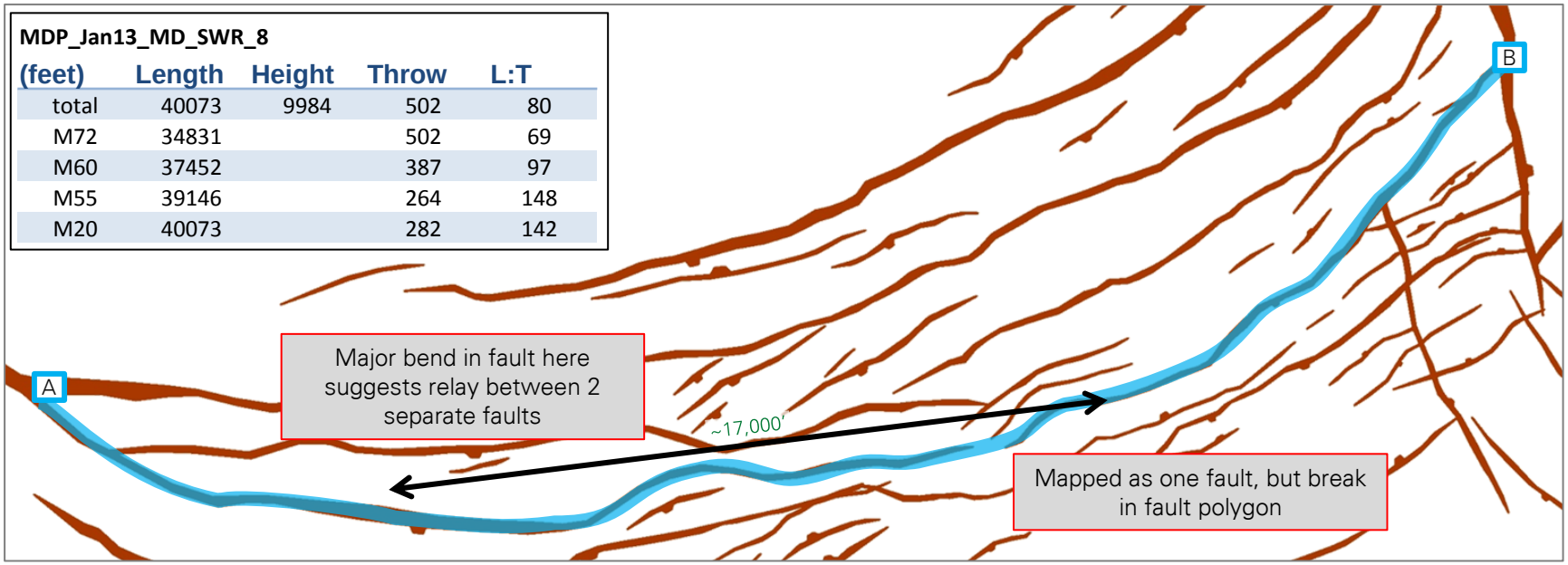
Derived from seismic data through TrapTester



Two large windows below 100' throw - questionable if it is a through-going fault...

MDP_Jan13_MD_SWR_8

(feet)	Length	Height	Throw	L:T
total	40073	9984	502	80
M72	34831		502	69
M60	37452		387	97
M55	39146		264	148
M20	40073		282	142

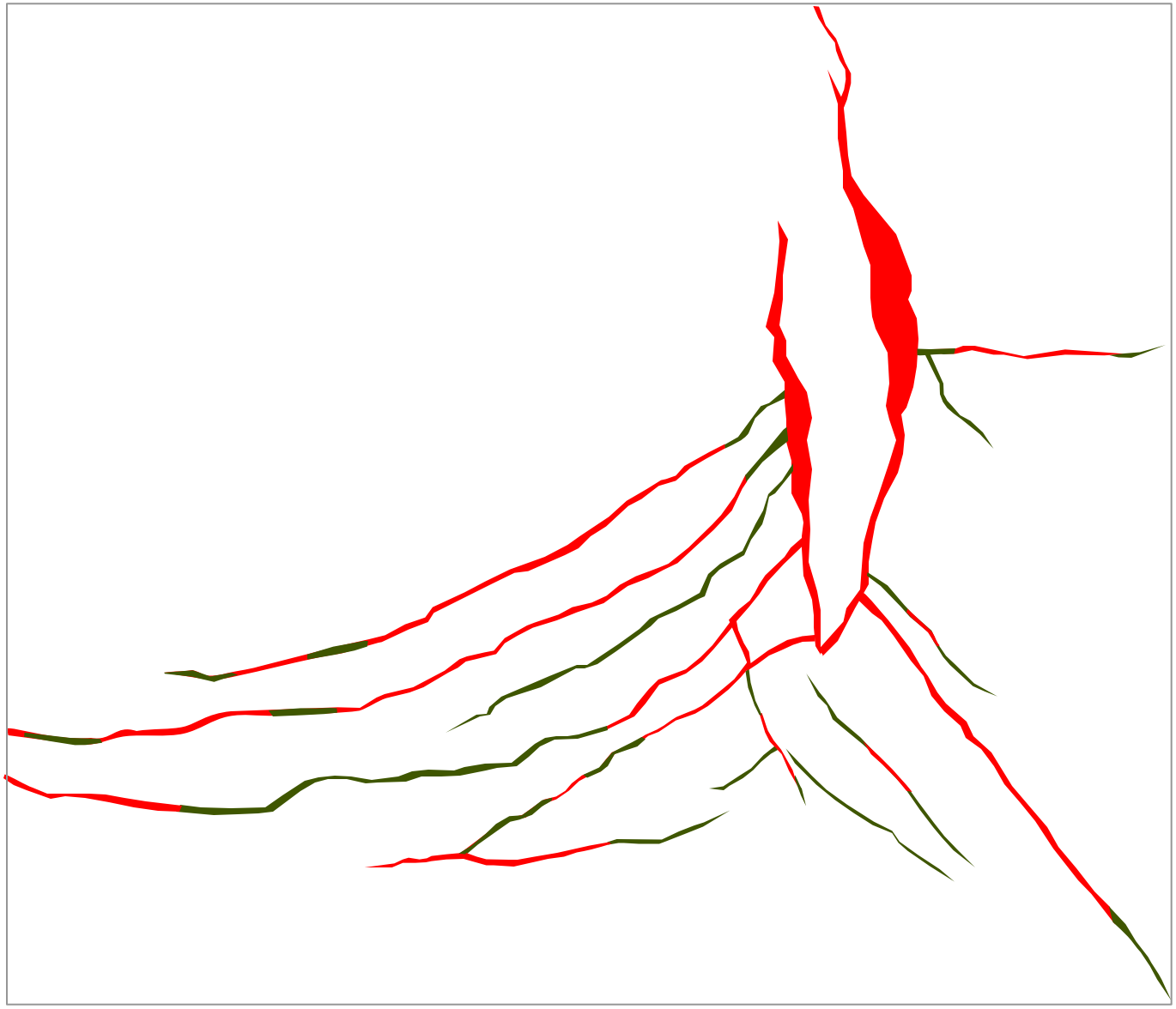


Estimates of fault throw

>100 / <100 faults

Faults > 100' throw should seal the DD and EE and severely reduce communication in the FF

Faults < 100' throw should reduce communication severely in the DD and EE and some in the FF

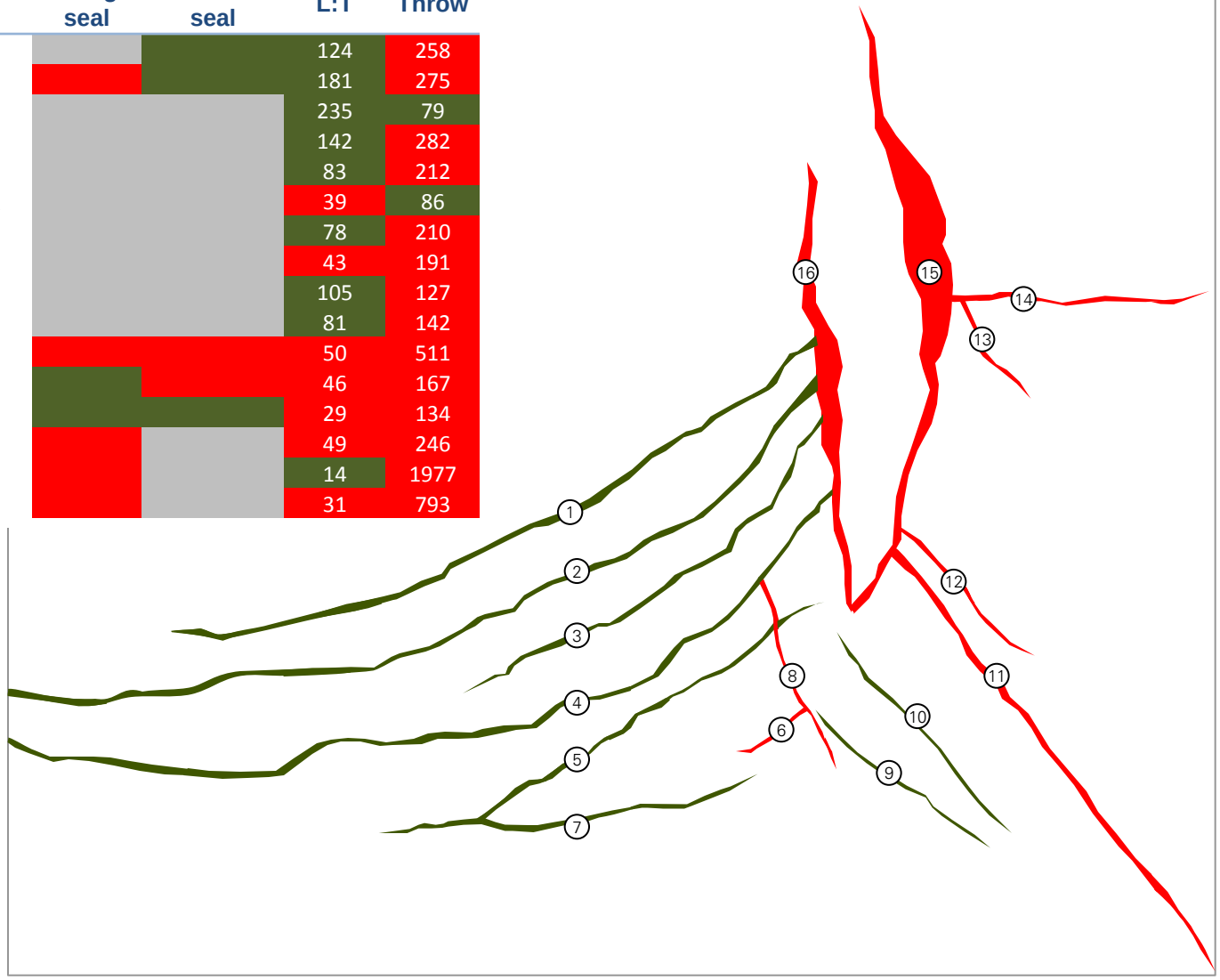


Length: Throw ratio

20-50 / not 20-50

Segment	#	Fault	Geologic seal	Production seal	L:T	Throw
W-SWR	1	MDP_Jan13_MD_SWR_11_DTSE			124	258
SWR	2	MDP_Jan13_MD_W_2_DTSE			181	275
SWR	3	MDP_Jan13_MD_W3_DTSE			235	79
SWR-FA	4	MDP_Jan13_MD_SWR_8			142	282
FA-S	5	MDP_Jan13_MD_SWR4			83	212
S	6	MDP_Jan13_MD_MDSouth_DTN1			39	86
S	7	MDP_Jan13_MD_MDS_2_DTN			78	210
S	8	MDP_Jan13_MDS_new_DTE_4			43	191
S	9	MDP_Jan13_MD_MDS_15			105	127
S	10	MDP_Jan13_MD_MDS_30			81	142
S-E	11	MDP_Jan13_MD_E_3_DTSW			50	511
E	12	MDP_Jan13_MDS_new_1			46	167
E	13	MDP_Jan13_MD_East4_DTSW			29	134
E-NE	14	MDP_Jan13_MD_NE_1A			49	246
Graben	15	FOR_GrabenDTW_test			14	1977
Graben	16	MDP_Jan13_MD_WGraben			31	793

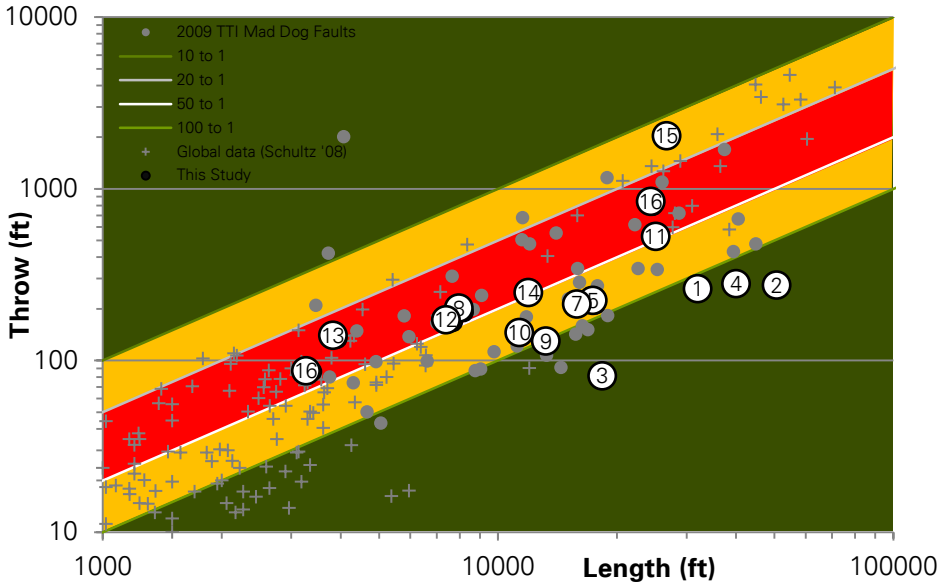
The "should seal, do seal" matrix

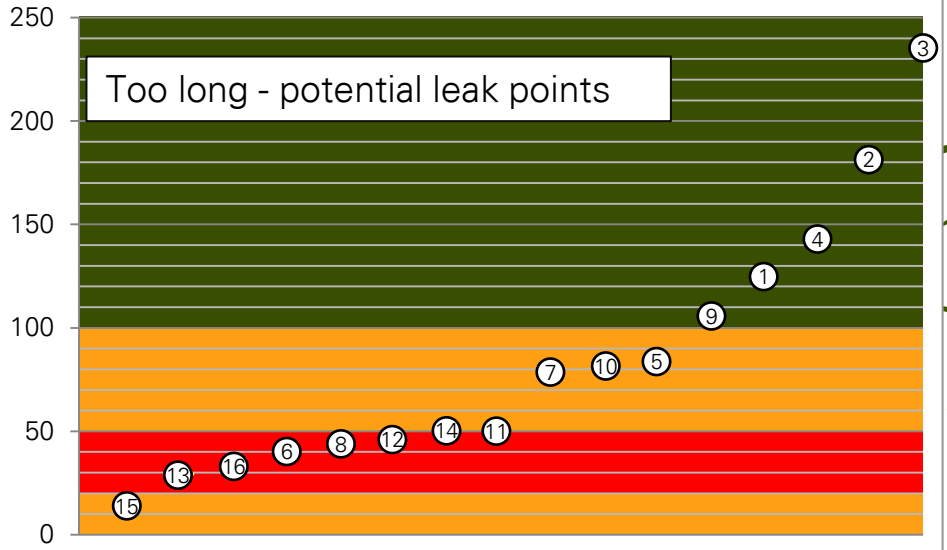


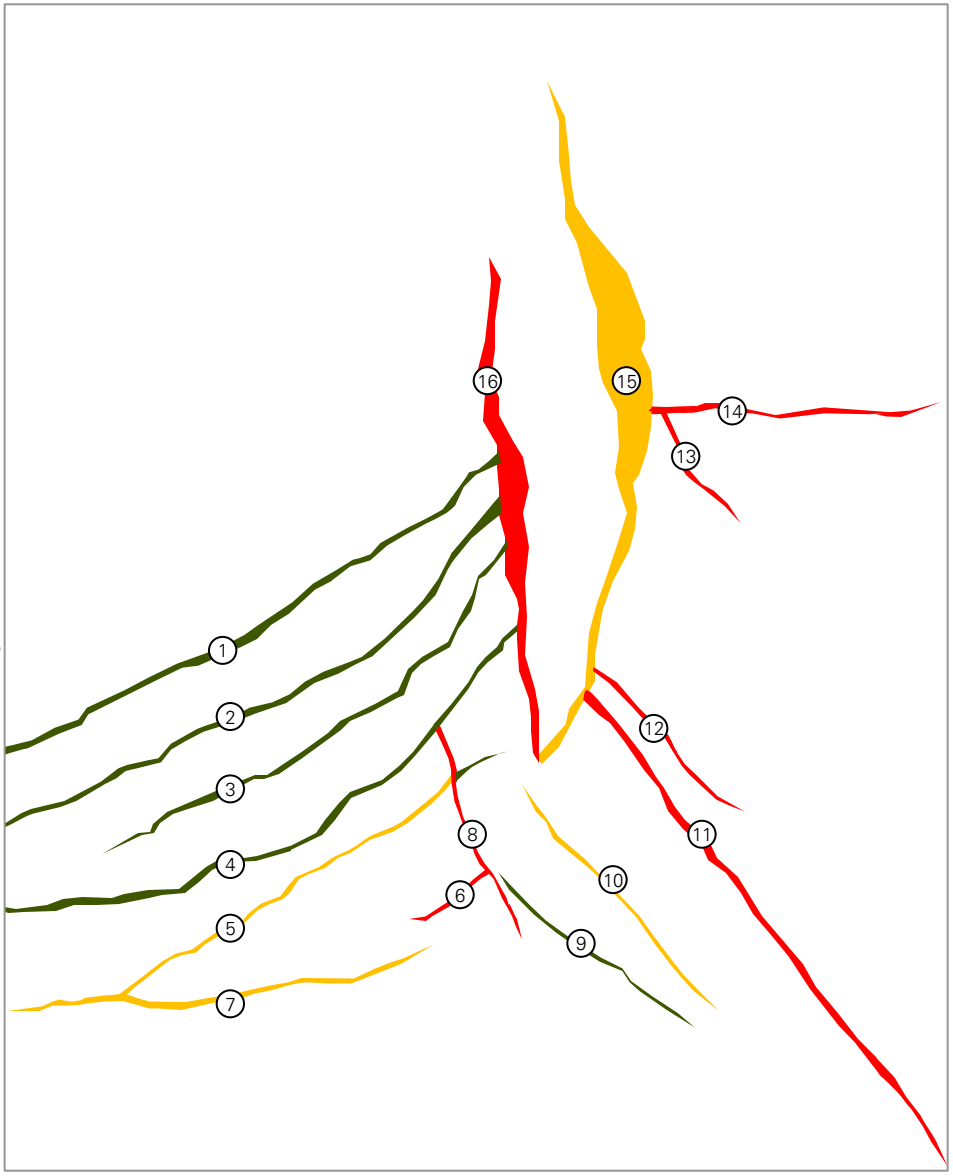
Faults outside a reasonable L:T ratio are likely to be linked faults with a higher potential for leak points

Length: Throw ratio

20-50 / not 20-50





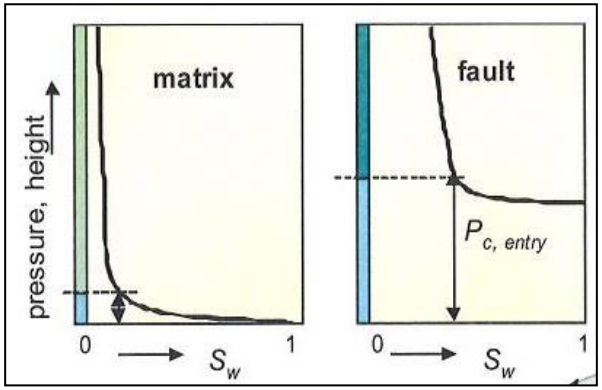


Sealing capability of faults

Faults act as a "wall of water"

Faults behave like a zone of poor quality rock, therefore will have a transition zone further above the FWL than good quality reservoir rock

- Faults are more likely to be non-transmissive to oil close to the OWC, and transmissive at the crest of the structure
- Faults are likely to be transmissive to water in the water leg and non-transmissive to water at the crest of the structure
- Calculation using Mad Dog rocks suggest OWC in faults likely to be >1000' higher than FWL in reservoir rock



from Fisher and Jolley (2007): Treatment of Faults in Production Simulation Models, Geological Society of London, Special Publications 2007, v.292; p. 219-233. doi: 10.1144/SP292.13

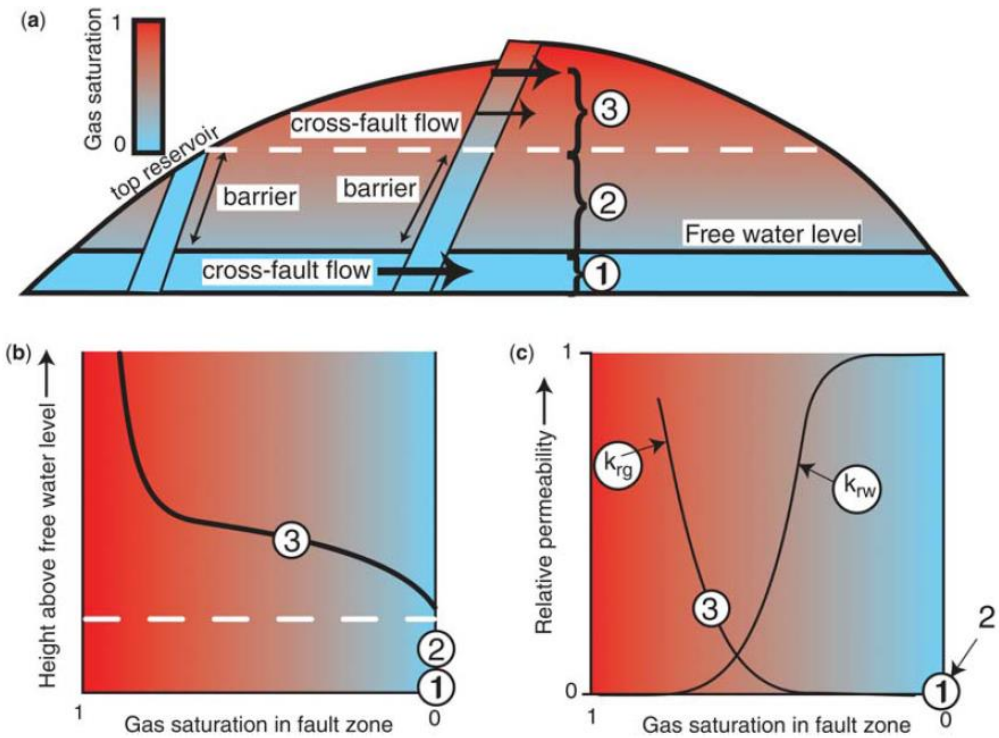
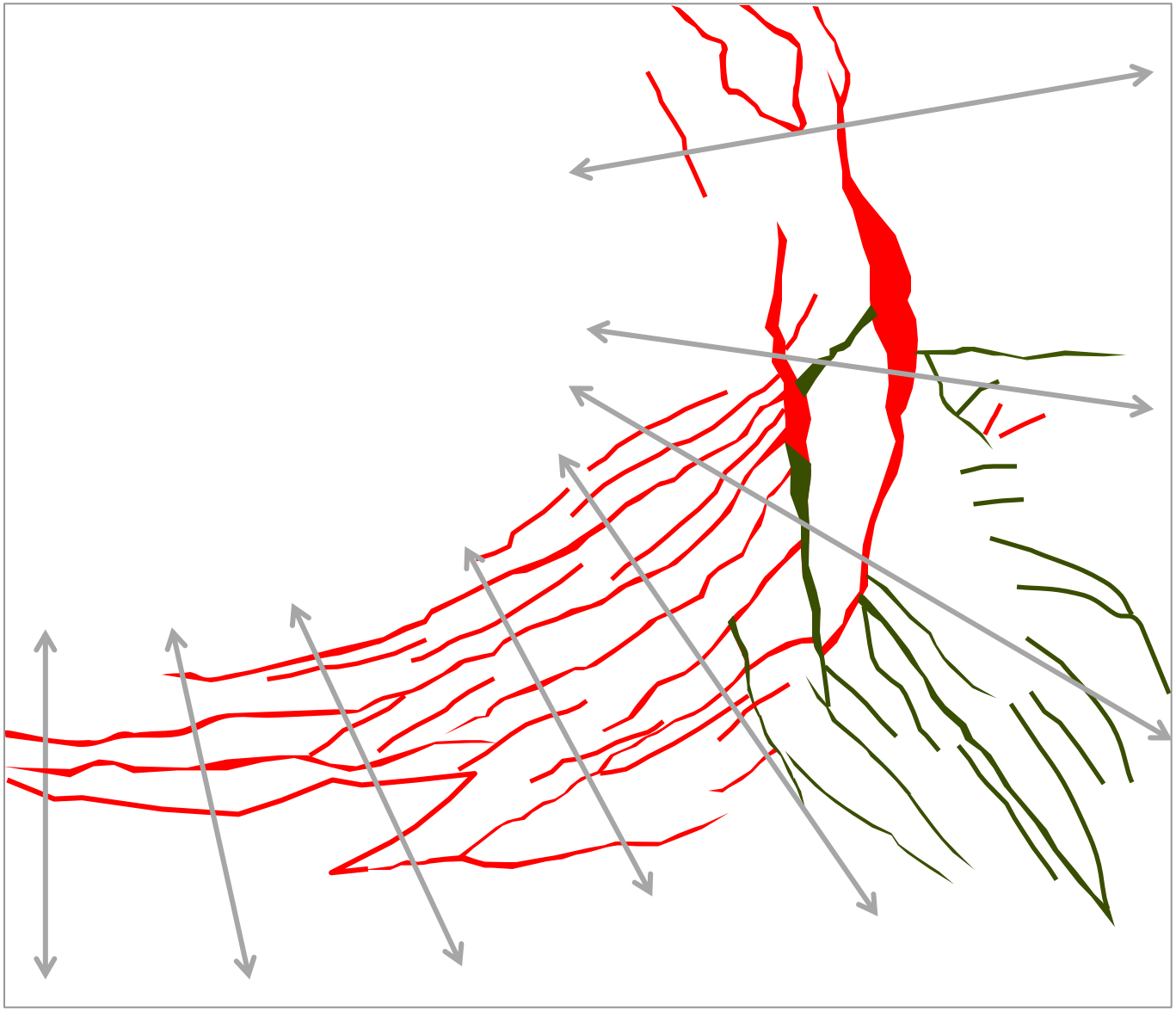


Fig. 4. Conceptual model for multi-phase flow across a fault in a petroleum reservoir. (**a**) The fluid saturations within the reservoir and fault, red for gas, blue for water. (**b**) The capillary pressure and (**c**) The relative permeability curves for the fault rock. It is assumed that the fault rock is homogenous throughout the model and that any differences in flow behaviour are due to the balance between capillary and buoyancy forces. The fault has a higher capillary entry pressure than the reservoir. Below the FWL (Zone 1), only brine is present in the undeformed reservoir and the fault rock and therefore TM values can be calculated from the single-phase fault rock permeability values. Close to the FWL (Zone 2), the buoyancy force in the hydrocarbon column is not sufficient to overcome the threshold pressure of the fault. Hence, it has zero relative permeability to hydrocarbon. If the column height is sufficiently high to overcome the capillary entry pressure of the fault (Zone 3) the fault will have a finite relative permeability to gas. The red line marks the height at which the buoyancy force in the gas column is sufficiently high to overcome the capillary entry pressure of the fault rock. It can be seen that faults at the flank of the reservoir are more likely to act as barriers to gas flow because the buoyancy force at the edge of the reservoir is not as high as can be generated in the centre of the reservoir. So the capillary entry pressure of faults in the centre of the field are more likely to be overcome than faults at the flank (adapted from Fisher *et al.* 2001).

Sealing changes relative to possible stress

Enhanced sealing / enhanced transmission

- Faults parallel (45-90°) to SHmax sealing-capacity enhanced
- Faults perpendicular (0-45°) to SHmax sealing-capacity degraded
- Actual direction of SHmax is unknown



Calculation of transmissibility multipliers

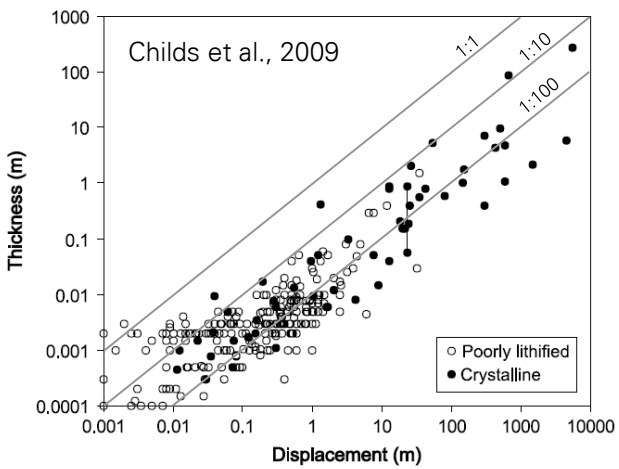
1) Plug and Chug

$$TM = k_{unfaulted} / k_{faulted}$$

$$k_{faulted} = L / \{[(L - L_f)/k] + [L_f/k_f]\}$$

where
L = cell length
k = host rock perm
L_f = fault rock thickness
k_f = fault rock permeability

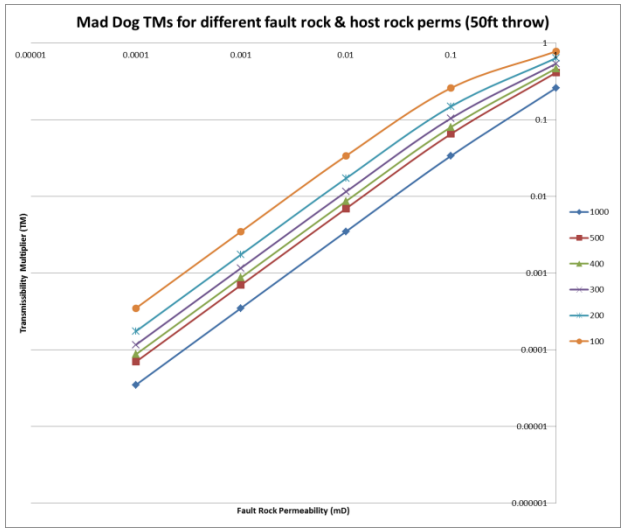
Fault Core Thickness (T) vs. Fault Slip (D)

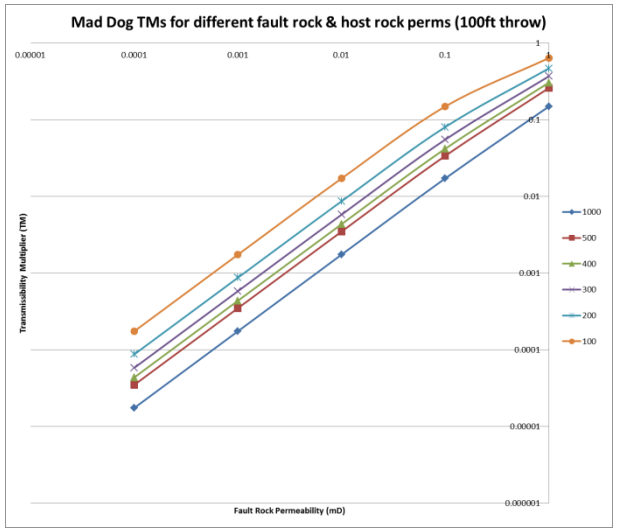


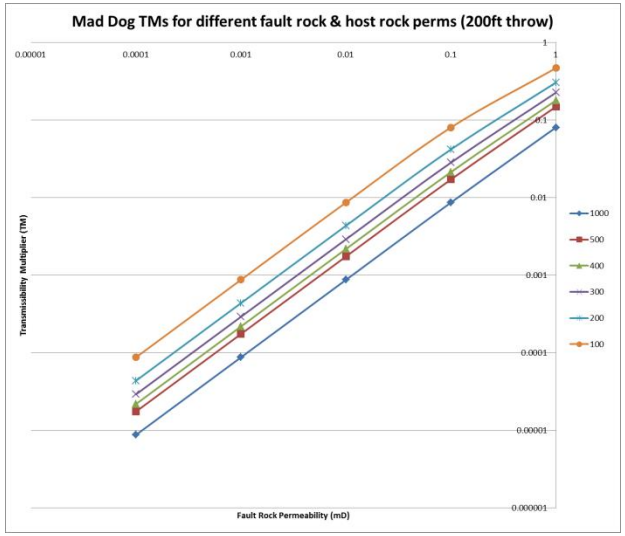
Average Scaling Factors

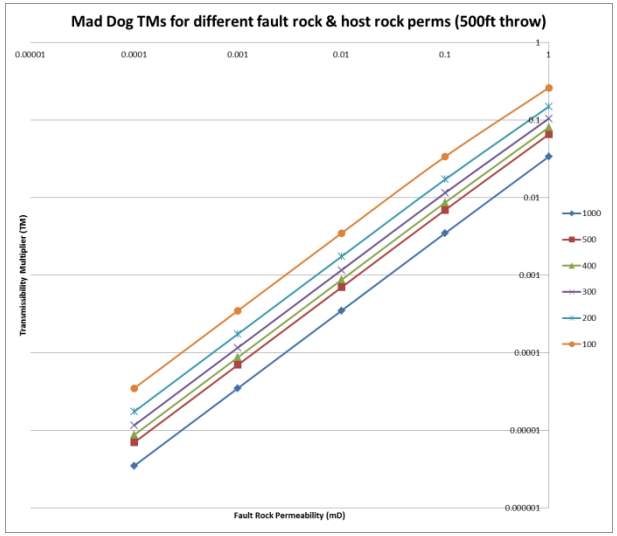
D = 70 x T; T = 0.0143 x D

Testing throw (therefore fault rock thickness)









Calculation of transmissibility multipliers

2) Test Sensitivities

$$TM = k_{unfaulted} / k_{faulted}$$

$$k_{faulted} = L / \{[(L - L_f)/k] + [L_f/k_f]\}$$

where
L = cell length
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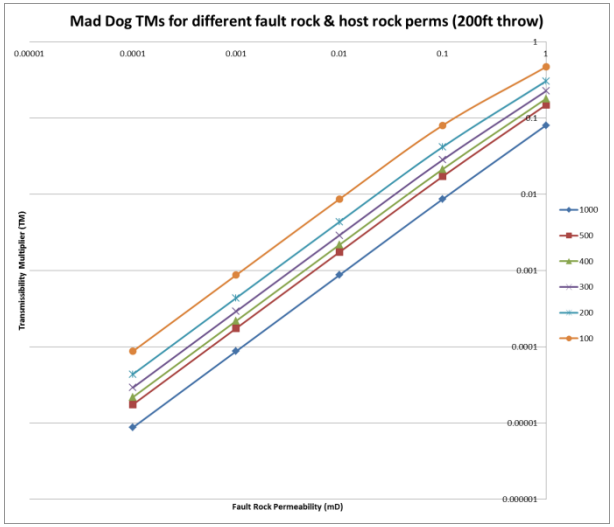
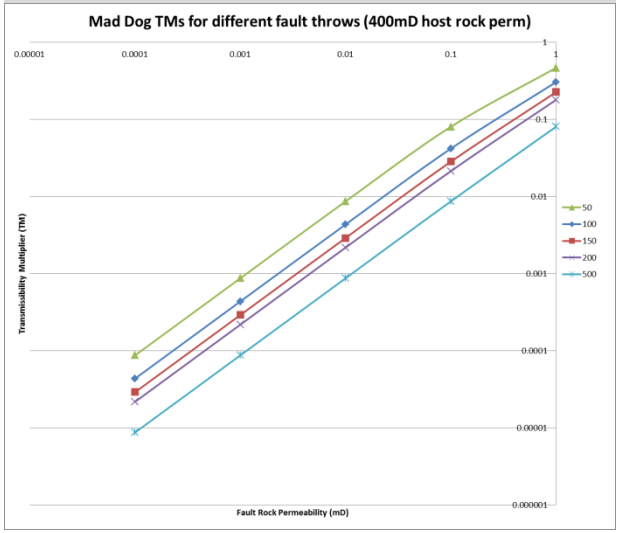
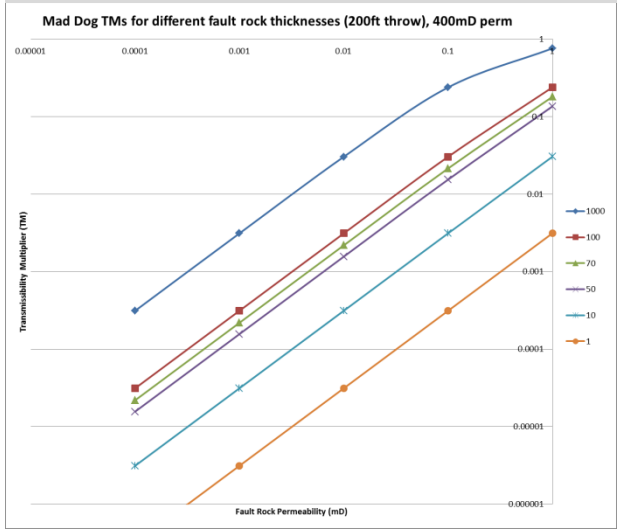


Testing throw (constant host rock perm)



Testing fault rock thickness



Testing grid cell length

Calculation of transmissibility multipliers

3) Define best estimate for Mad Dog

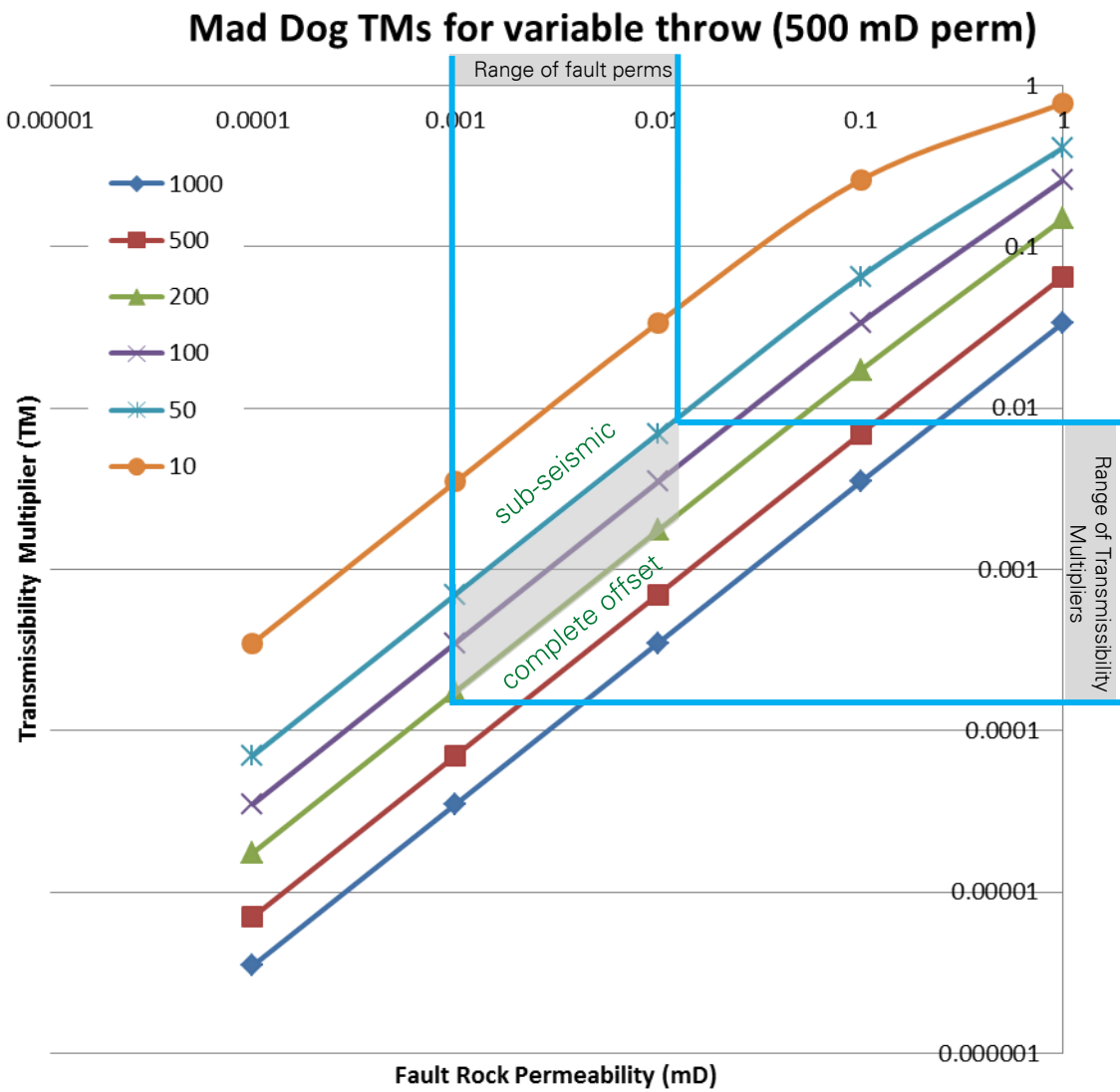
$$TM = k_{unfaulted} / k_{faulted}$$

$$k_{faulted} = L / \{[(L - L_f)/k] + [L_f/k_f]\}$$

where
L = cell length
k = host rock perm
L_f = fault rock thickness
k_f = fault rock permeability

Measured values from Mad Dog core

Sample ID	Clay (%)	Porosity (%)		Permeability (mD)		Hg-air thresh-old pressure (psi)		Deformation Features
		Host	Fault	Host	Fault	Host	Fault	
MD1	9	30	11	1137	0.04	5	140-650	Cataclastic fault
MD2	8	26	8	657	1.3	12	100	Cataclastic fault
MD3	11	25	8	259.3	0.01-0.003	15	100-185	Cataclastic fault
MD4	17	22	7	53	0.5	15	70	Phyllosilicate-framework fault
MD5	12	25	8	498.2	1.30	12	75	Cataclastic fault
MD6	11	26	5	503.5	0.03	12	400	Cataclastic fault
MD7	8	25	5	621.1	0.03	5	130	Cataclastic fault rock with clay smears
MD8	12	24	6	415.1	0.01-0.07	10	150	Cataclastic fault
MD9	N/A	N/A	7	N/A	<0.001	N/A	>2000	Clay smears



Presence of subseismic faults

How to represent complexity we can't see

Based on Mad Dog history, we can interpret around 3 times as many faults on dipmeter data as we can see on seismic data ...

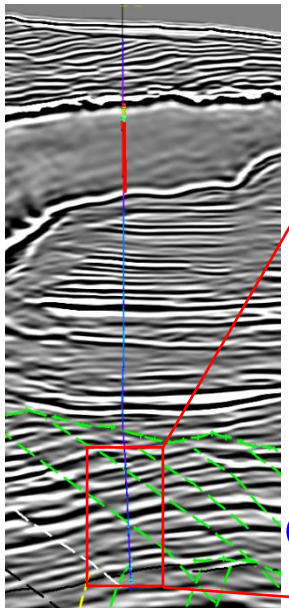
Well	Seismic faults	Well Pick faults	Dipmeter faults
A	1	1	2
B	1	4	3
C	1	1	1
D	1	1	0
E	0	1	3
F	2	2	4
G	0	0	2
H	0	1	0
I	2	2	8
Total	**8**	**13**	**23**

Added small faults to increase density using history match information from East as an analog

Faults added:

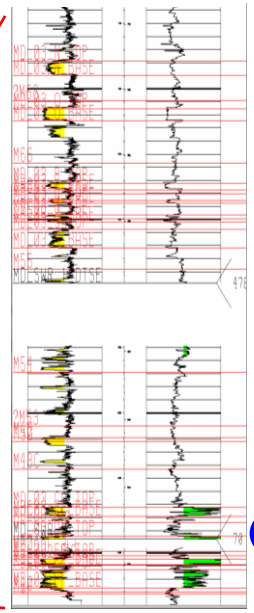
- Parallel/ sub-parallel to existing faults
- Generally shorter than shortest mapped faults
- At vestigial tips where faults bend
- Linking faults that come close but do not touch
- Fewer outboard of salt, more beneath salt

Seismic faults



2

Well picks



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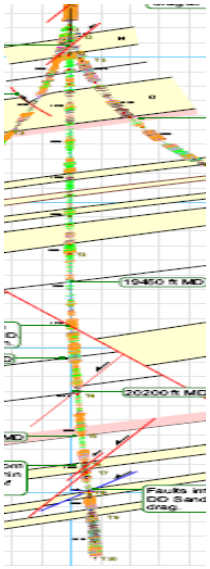
Dipmeter picks



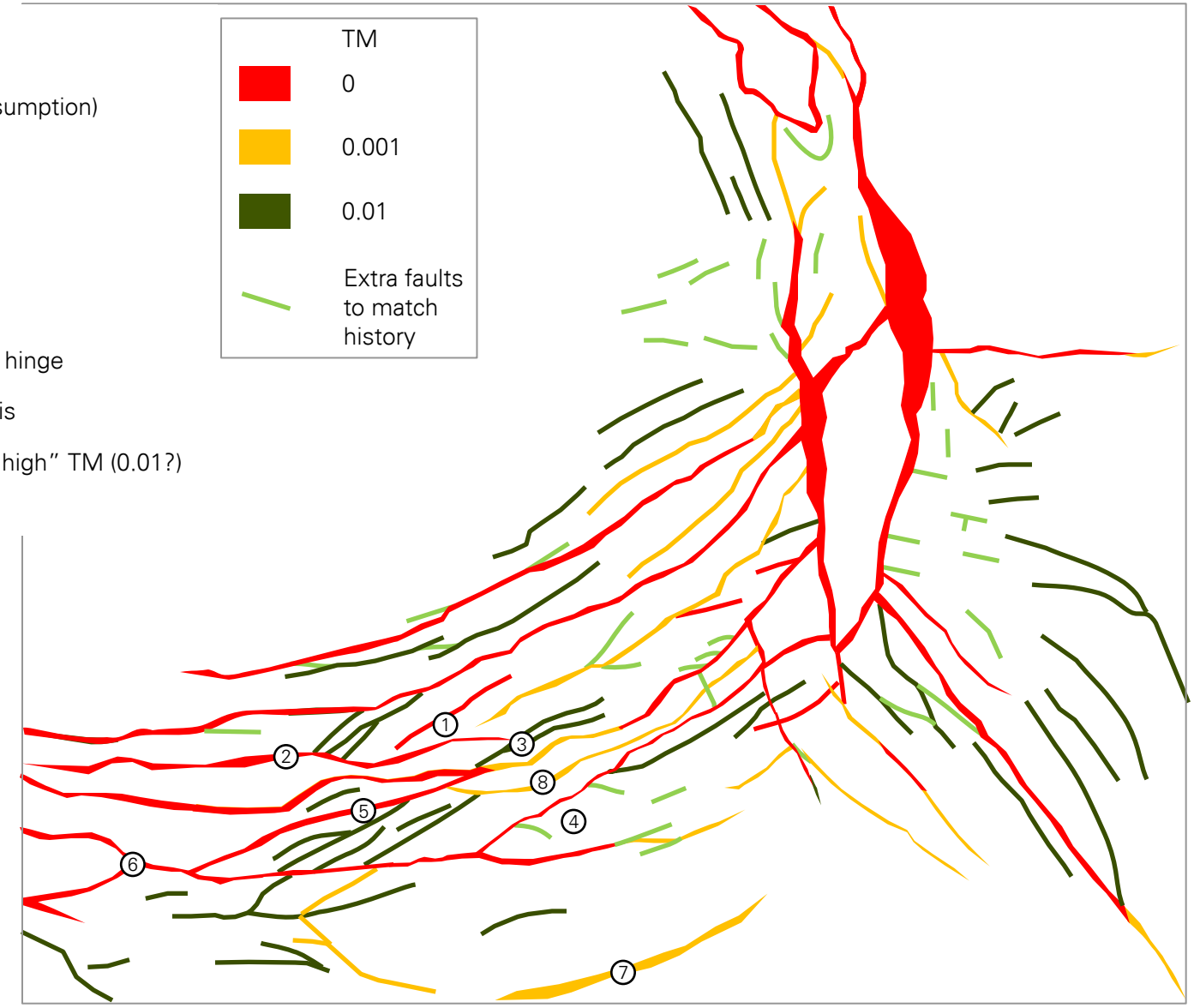
8

Implementation into reservoir model

Non transmissive / transmissive faults

1. Extended fault to close
2. Sealed fault (most conservative assumption)
3. Extended fault to close
4. Extended fault to close
5. Extended fault to close
6. Extended fault to close
7. Added to represent damage at fold hinge
8. Added to compartmentalize fold axis

... Consider all other faults to have a "high" TM (0.01?)



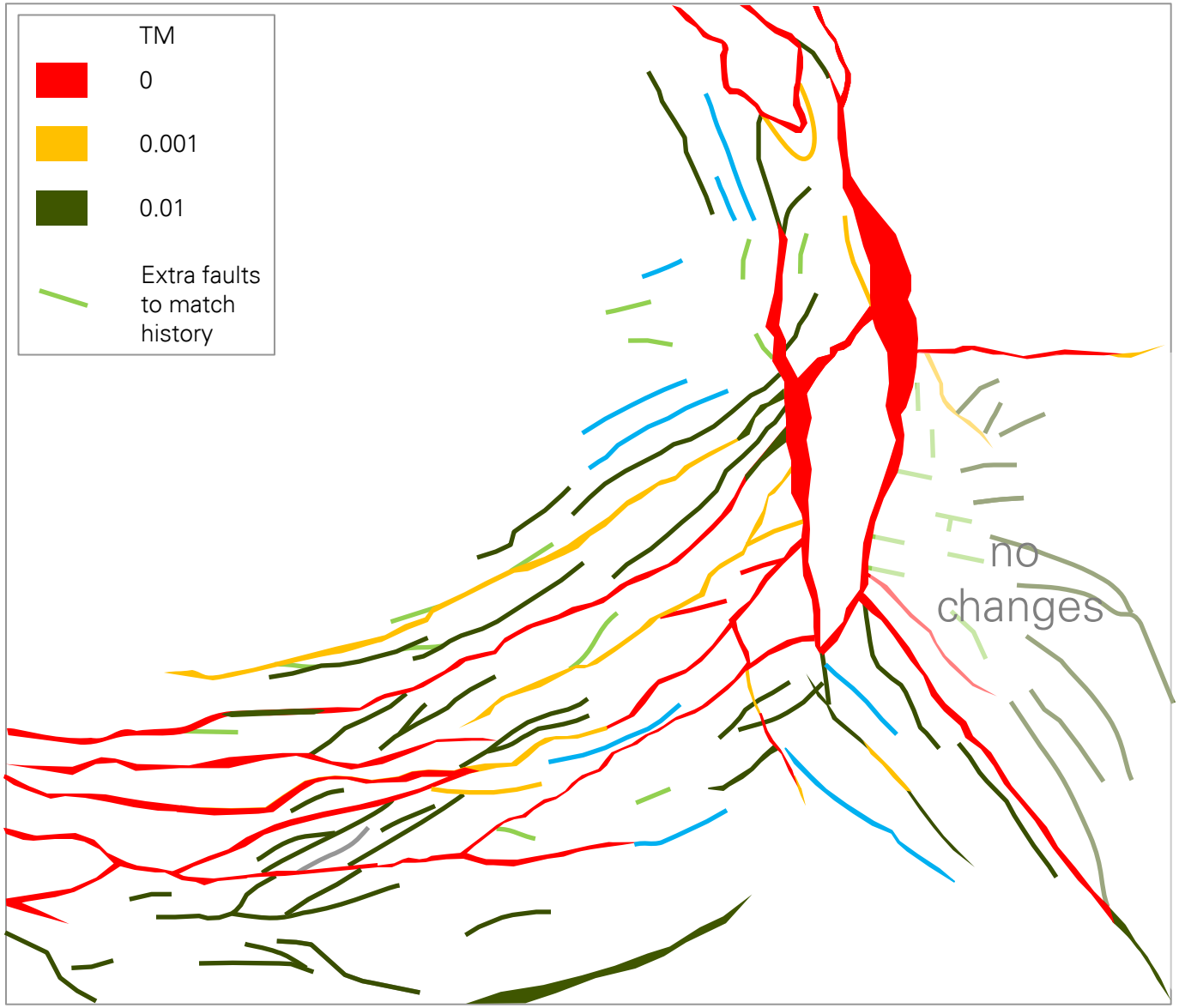
Other considerations:

- Faults are more likely to be non-transmissive to oil close to the OWC, and transmissive at the crest of the structure
- Faults are likely to be transmissive to water in the water leg and non-transmissive to water at the crest of the structure
- Mad Dog faults formed pre-charge, therefore were originally water-filled
- Faults parallel to Shmax more likely to be transmissive
- Faults perpendicular to Shmax more likely to be non-transmissive
- Perm anisotropy parallel/ perpendicular to faults

Implementation into reservoir model

Upside Case

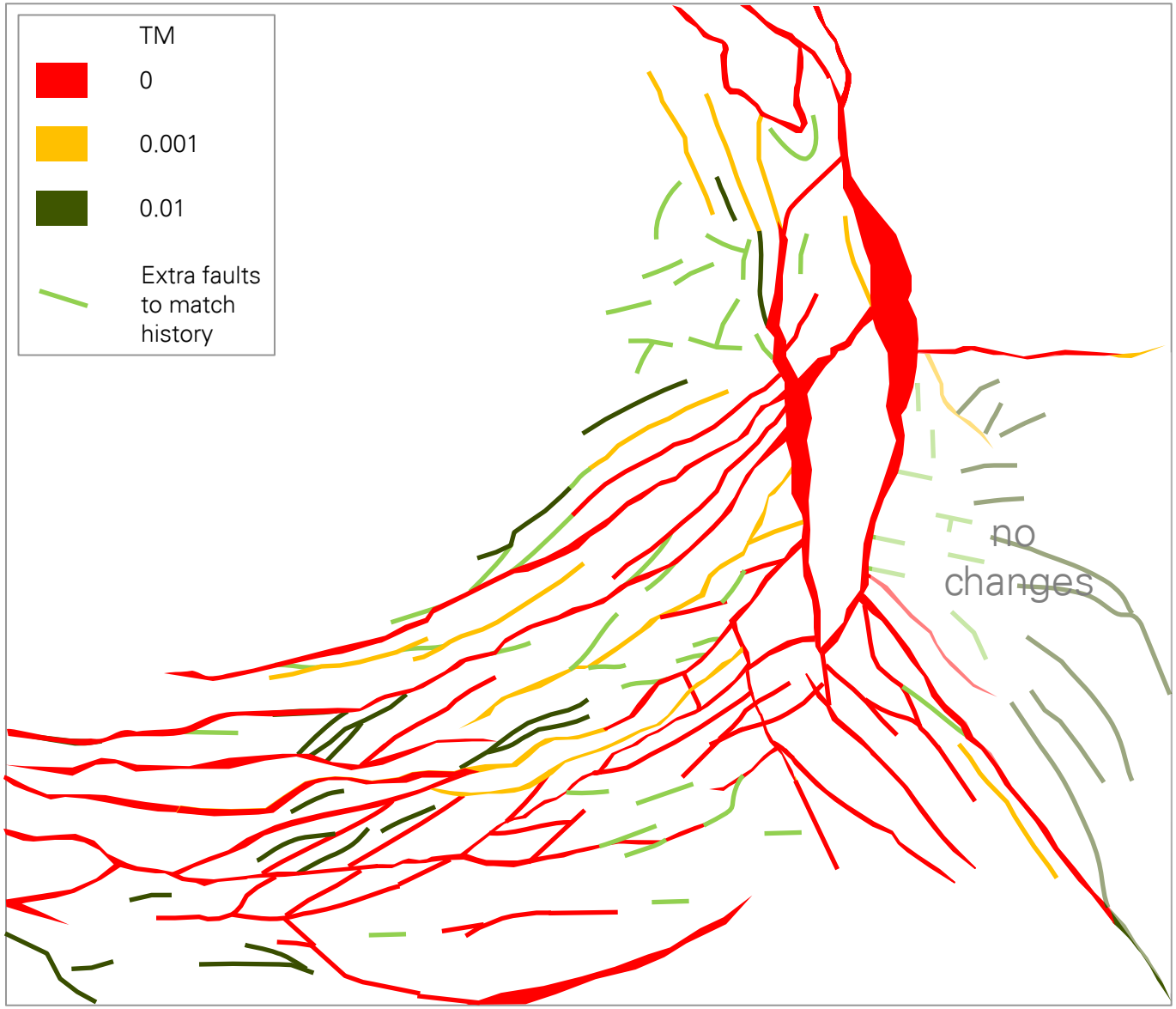
Upside reservoir model still has to match production history, therefore few changes possible near producing wells, more changes can be made further away



Implementation into reservoir model

Downside Case

Downside reservoir model still has to match production history, therefore few changes possible near producing wells, more changes can be made further away



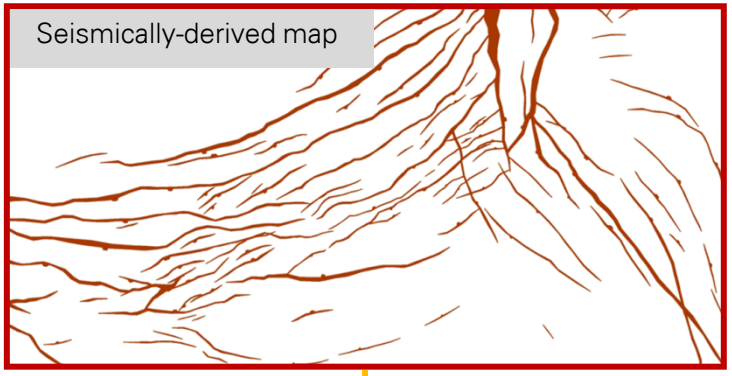
Building a better reservoir model

Start with seismic map and add geology

Major concerns

- Location
- Transmissibility
- Presence

Seismically-derived map



- Begin with the seismically defined top reservoir structure map
- Amend to match static and dynamic pressure data
- Decision must be made about the transmissive properties of each fault.

Reference realization

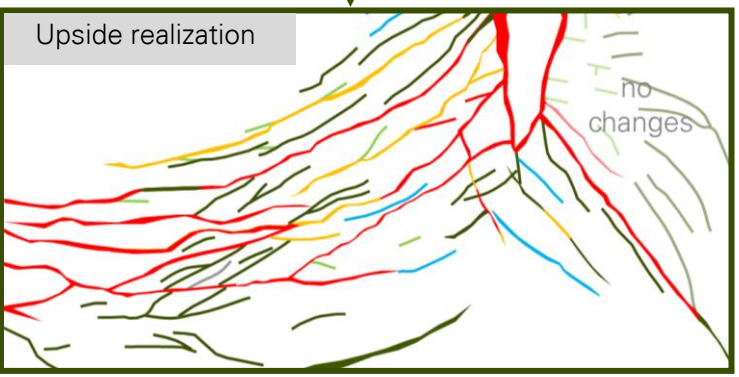
Upside changes

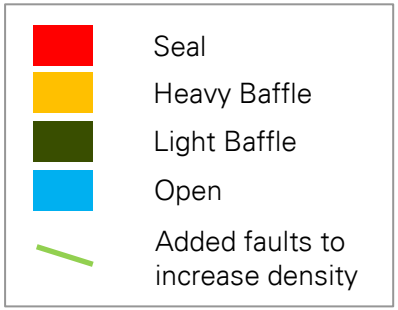
- Fault transmissivity increased
- No isolated compartments
- High L:T mapped faults segmented
- Fewer sub-seismic faults

Downside changes

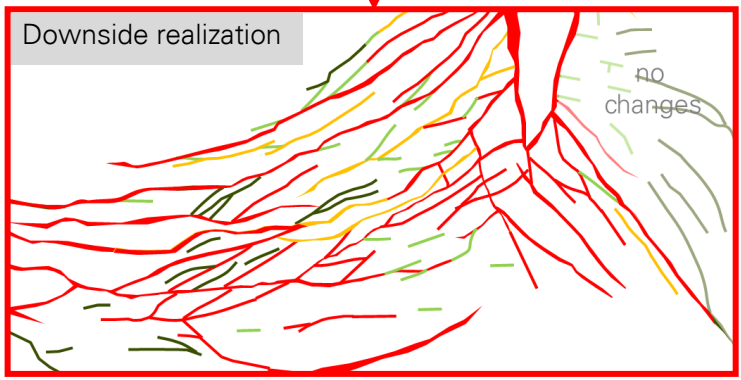
- Fault transmissivity decreased
- More isolated compartments
- Mapped faults lengthened
- More sub-seismic faults

Upside realization





Downside realization



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Walker, C. D., G. A. Anderson, P. G. Belvedere, A. T. Henning, F. O. Rollins, E. Soza, and S. Warrior, 2015, Compartmentalization between the GC0738_1 Mad Dog North wellbores - Evidence for post-depositional slumping in the Lower Miocene reservoirs of the deepwater southern Green Canyon, Gulf of Mexico: Gulf Coast Association of Geological Societies Transactions, v. 65, p. 389–402.

Simple and Efficient Representation of Faults and Fault Transmissibility in a Reservoir Simulator: Case Study from the Mad Dog Field, Gulf of Mexico

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BP America, 501 Westlake Park Blvd., Houston, Texas 77079

ABSTRACT

The Mad Dog Field is one of BP's largest assets in the Gulf of Mexico, with over 4 billion barrels of oil in place. It was discovered in 1998 and came online in 2005. Further appraisal success has necessitated the Mad Dog 2 (MD2) development; a second tranche of producers and water injectors tied back to a second floating facility. To create the predicted production profiles that underpin the economics of the MD2 development, the Reservoir Management team uses a full field Nexus reservoir simulation model. The Nexus model is upscaled from the RMS geomodel and reflects a snapshot of our Integrated Subsurface Description at a point in time, with structure derived from seismic data and geologic and petrophysical properties derived from well results. The long cycle time of seismic processing, seismic interpretation, geomodel building, reservoir model building and finally history matching presents three challenges to the representation of faults in the dynamic simulator: Location, Transmissibility, and Presence. This article discusses how we have met these challenges in Mad Dog.

INTRODUCTION

Mad Dog Field, located in the Gulf of Mexico, is a major BP asset, with over 4 billion barrels of oil (Brenner, 2011). Generally we rebuild our full field reservoir model once every three or four years. However, new production information arrives daily, and new subsurface data arrives frequently—every year there may be new seismic acquisition and/or processing results, new seismic interpreters, and well results that result in significant changes to the mapping of the reservoir (Walker et al., 2015). The challenge for the team is how to ensure that the reservoir simulator remains "evergreen" and represents the most up-to-date subsurface interpretation of the field (Fig. 1). The method the Mad Dog team uses is to treat the largest seismically interpreted faults differently from the smaller ones. Experience in the Mad Dog Field shows that the interpretation of the faults in the field changes with each new iteration of seismic information and mapping (Fig. 2). However, the largest faults are the least likely to move significantly with each interpretation refresh, and therefore they can be "hard-coded" into the reservoir model grid with discrete offset (Fig. 3). Conversely, the faults with less offset are more likely to move around or substantially change with each interpretation refresh. These are smoothed out of the geogrid and instead represented in the reservoir model as a line of transmissibility multipliers along cell faces. The Mad Dog reservoir is well suited to this kind of approach as it consists of three sands that are in communication over geological time, but act as separate flow units during production (Fig. 4). Therefore the details of cross-fault juxtaposition and crossflow have not been seen to impact performance to this point in field life.

This configuration has allowed the reservoir engineers to quickly update the faults in the reservoir model whenever the seismic interpretation is refreshed or to perform compartmentalization uncertainty studies on a reference case realization. This has ensured that the interpretation and dynamic model are always "in sync" with each other, extending the life of the property model without requiring time-consuming rebuilds.

Walker, C. D., and G. A. Anderson, 2016, Simple and efficient representation of faults and fault transmissibility in a reservoir simulator: Case study from the Mad Dog Field, Gulf of Mexico: Gulf Coast Association of Geological Societies Transactions, v. 66, p. 1109–1116.

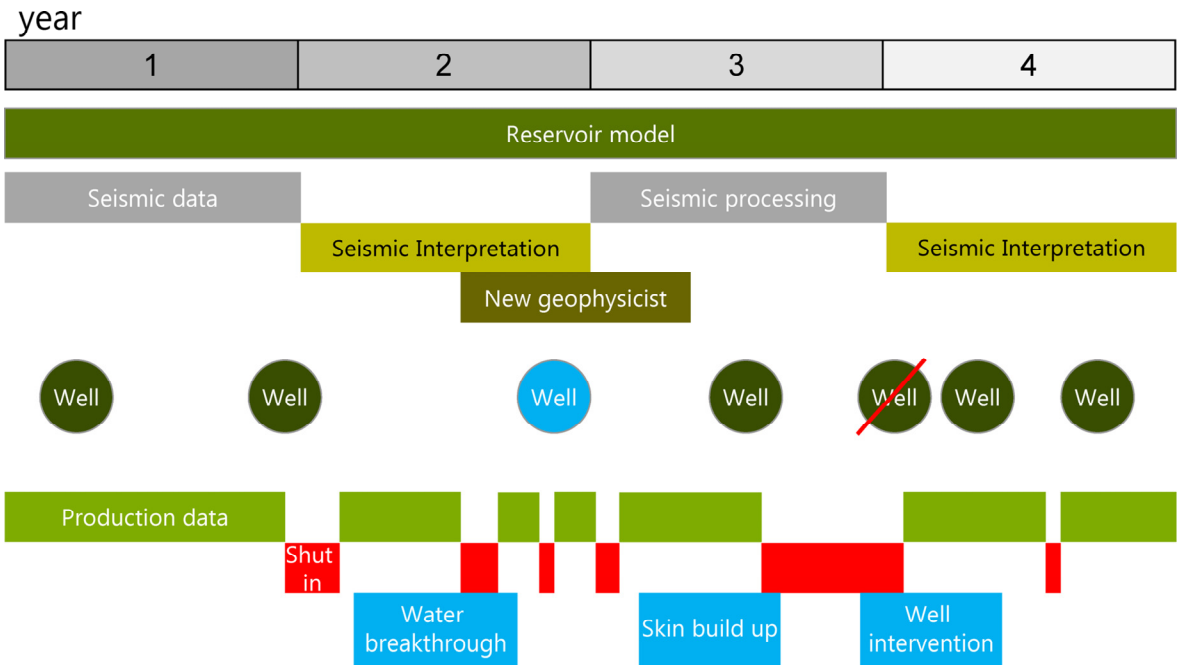

Figure 1. Frequency of events that impact the understanding of reservoir performance during field development.

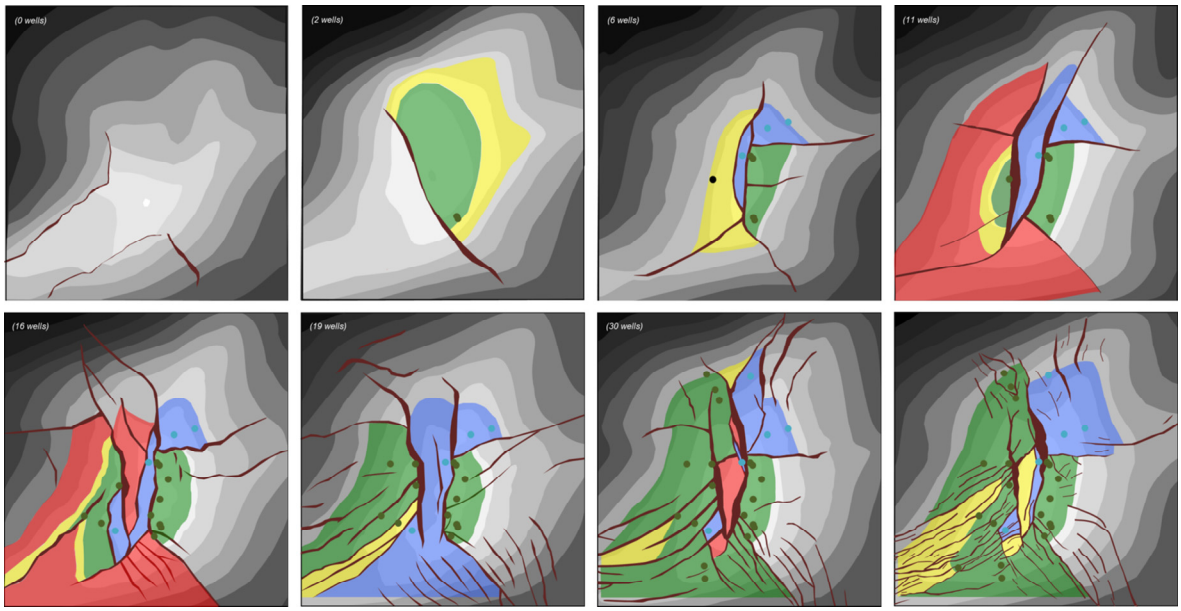

Figure 2. The Mad Dog top reservoir map has undergone significant changes from before field discovery (top left) through 15 years of seismic acquisition and well results (bottom right). In these maps, green represents known oil; blue is known water; yellow is probably oil; and red is probably water. Circles are well penetrations and brown polygons represent fault heave gaps. Structure is shaded from light (shallow) to dark (deep).

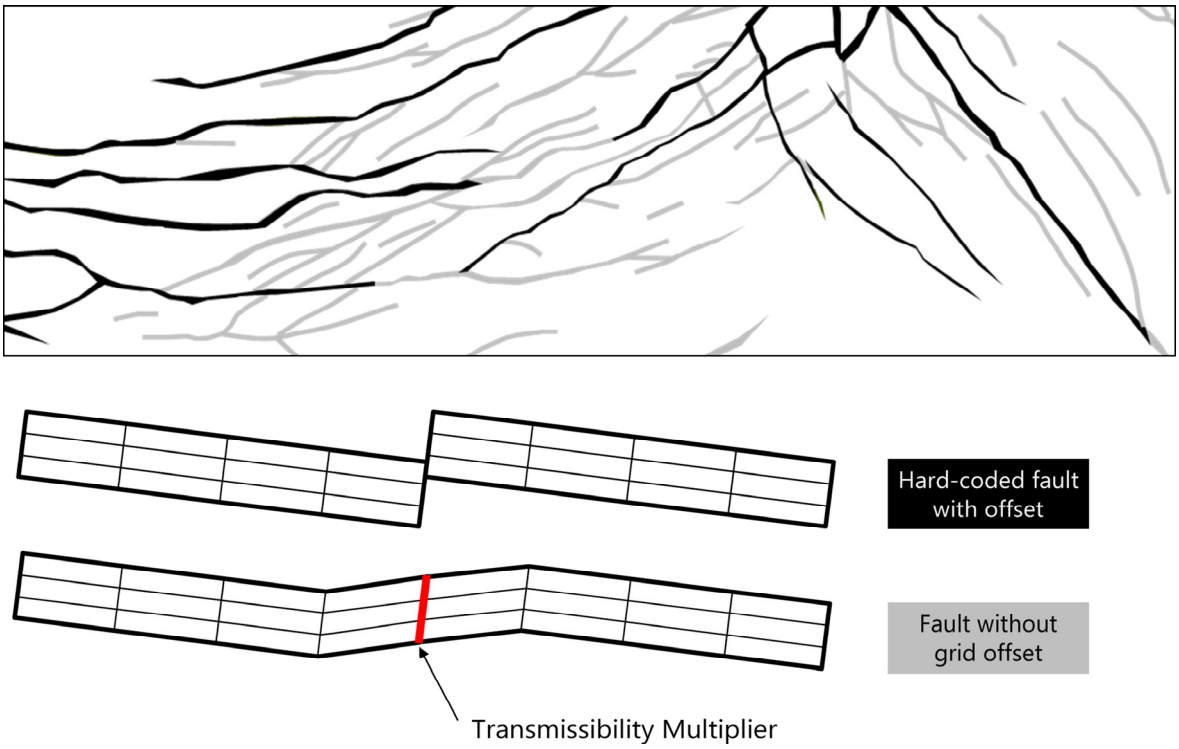

Figure 3. Map view and cross-section illustration of the different representation of large faults (black) and smaller faults (grey) in the Mad Dog reservoir grid.

TRANSMISSIBILITY

The increased number of faults represented as vertical planes in the reservoir model has placed extra significance on the transmissibility modeled on each of the faults. Fault transmissibilities can be calculated in RMS, using fault throw and shale gouge ratio to create a different value at each faulted cell-to-cell contact. However, while these values will be exceedingly precise, they will be precisely wrong, because of the uncertainty inherent in both the seismic interpretation and the population of lithological variations away from well control. Additionally, the complex, varying matrix of values will be difficult for a reservoir engineer to change in order to obtain a better match of production history.

Instead we have chosen a simpler approach. We identified 3 categories of faults: Seal, Heavy Baffle, and Light Baffle. Each fault in the field was then assigned to one of these categories based on several criteria. These criteria include throw (larger faults more likely to seal; e.g., Bretan et al., 2003), length-to-throw ratio (faults that are too long for the amount of throw mapped on them are more likely to be composed of several linked faults, and therefore have leak points along them), column height (faults close to the oil-water contact [OWC] are more likely to seal; e.g., Fisher and Jolley, 2007), and orientation relative to the maximum horizontal stress (faults perpendicular to max horizontal stress more likely to seal). We used pressure and compartmentalization information from virgin wells, depleted wells and production interference to determine which faults must seal over geological and production timescales, and assigned those a transmissibility multiplier (TM) of 0 (red on Figure 5). Then we used information from studies of faults cored in the field to determine a range of transmissibilities for the remaining faults (Fig. 6). From this we determined that our "Heavy Baffle" faults should have a TM of ~0.001 (orange on Figure 5), whereas our "Light Baffle" fault TMs would be ~0.01 (green on Figure 5).

Finally, we know from field observations that faults are surrounded by haloes of deformed rock that generally reduce permeability (e.g. Childs et al., 2009). This is also seen around the 3 faults we have cored in Mad Dog. The distance that these fault damage zones penetrate out into the host rock scales ~1:1 with fault slip, which is

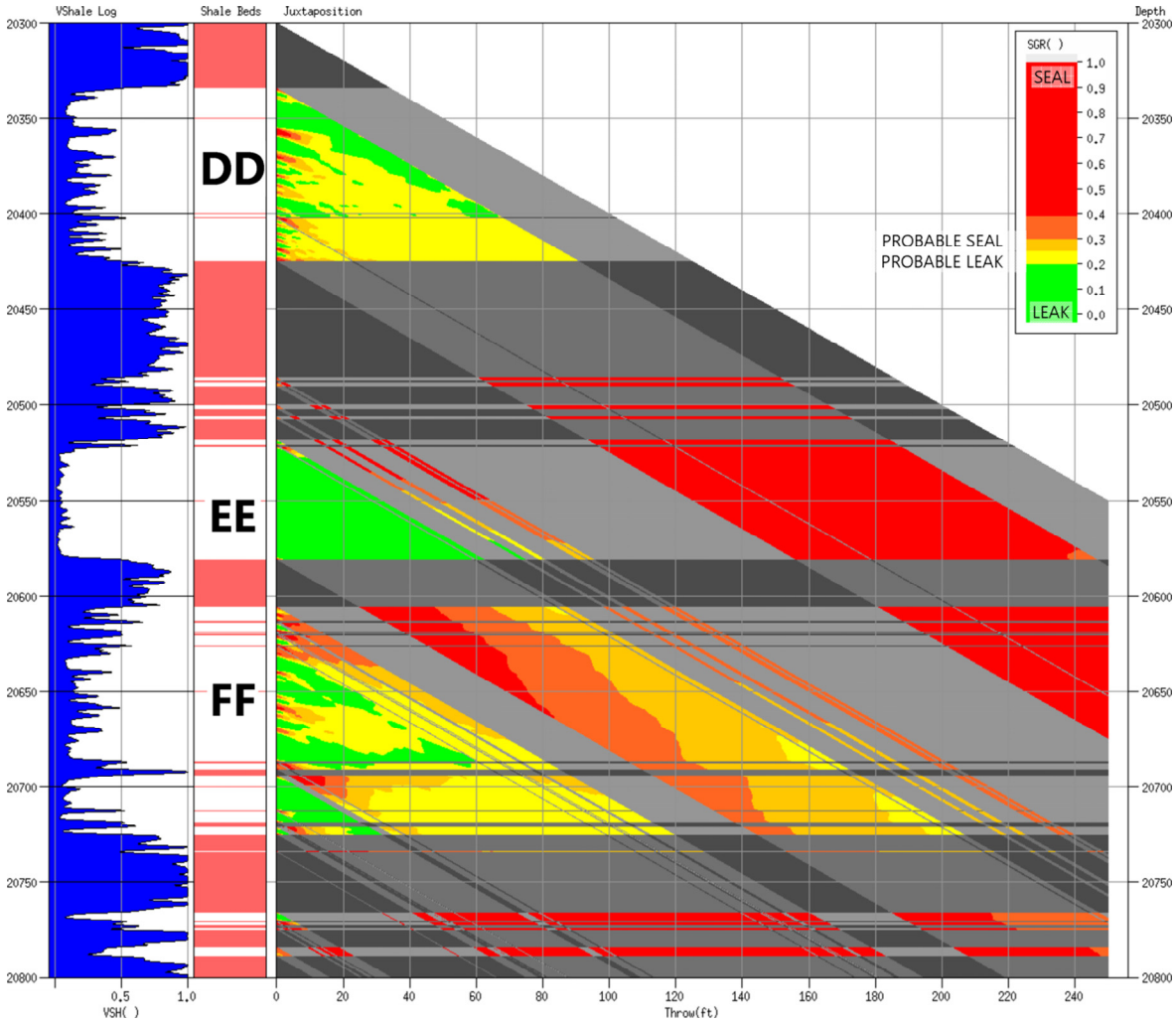

Figure 4. Triangle diagram from a representative Mad Dog well log colored by shale gouge ratio, illustrating that small faults will not allow the DD sand to communicate with the EE/FF sands, and that the EE and FF will likely have poor connectivity across small faults.

difficult to fully implement in a geocellular model with 250 ft long grid cells. Therefore, in addition to the TMs embedded along the fault plane in the model, we reduced the transmissibility of the neighboring grid blocks too, with 0.25 TM in the reference case, and 0.5 and 0.15 in the downside and upside cases respectively.

PRESENCE

One of the fundamental, long-standing observations about mapping Mad Dog is that the geophysical map of the structure does not explain the well pressure and performance data (Walker et al., 2012). We know that there are more features out there than we can see. As our sedimentological evidence and depositional model suggests the reservoirs are somewhat akin to stacked pancakes, the traditional explanation has been that sub-seismic faults are responsible for compartmentalizing the reservoir beyond what we can see. As our image has improved through the years, we've been able to identify more faults, and shrink the limits of what is unresolvable. Howev-

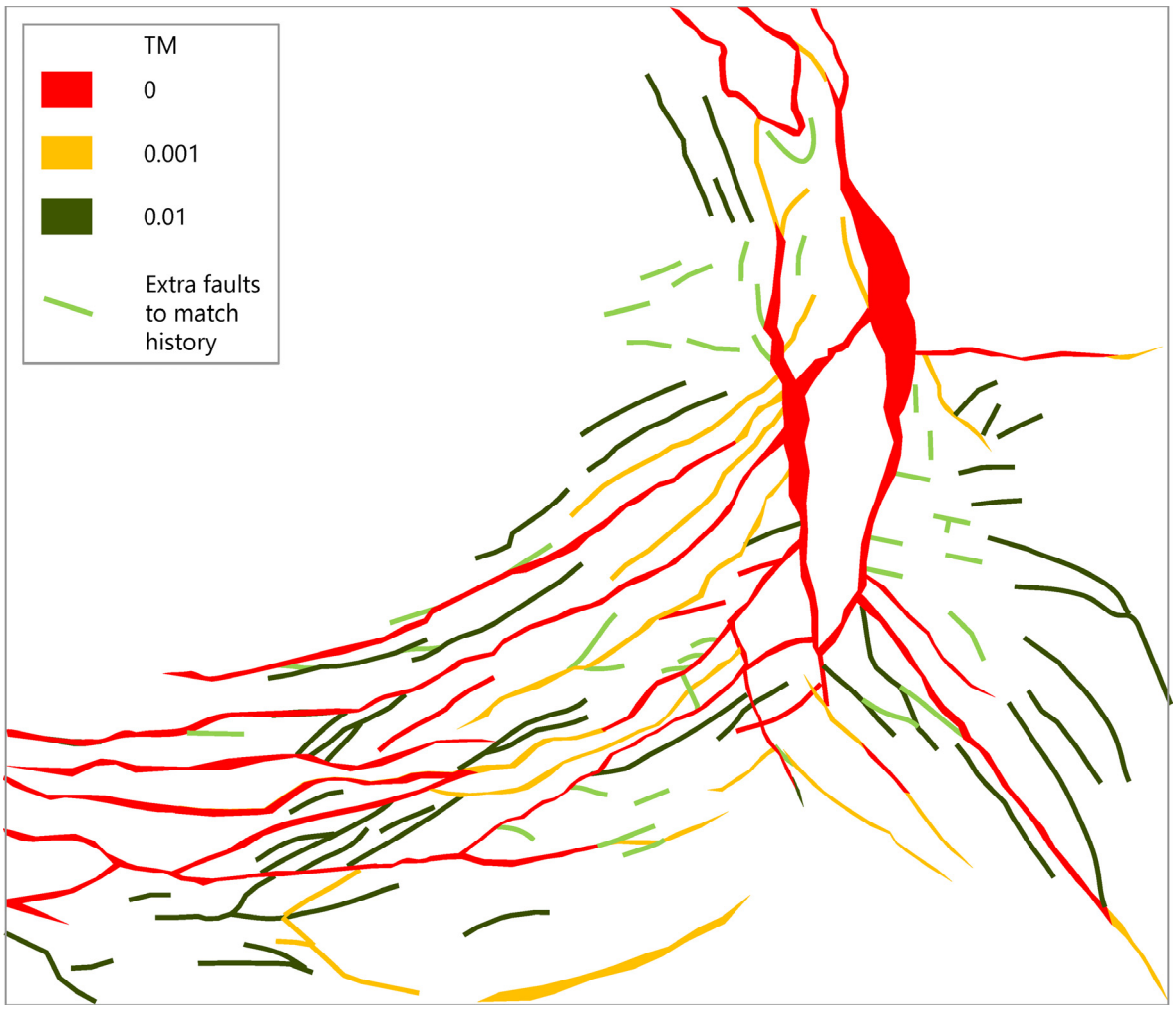

Figure 5. Transmissibility multipliers used for Mad Dog reservoir modeling reference case.

er, we cannot accurately resolve faults with less than ~50 ft of throw in the best-imaged areas of the field—and most of the field lies beneath a complex salt body (Walker et al., 2012). From our 30 reservoir penetrations across the field we can estimate that for every fault we can see on seismic, there are at least another 2 faults we cannot see (Fig. 7). Furthermore, our 5 whole cores in the field have unintentionally encountered 3 faults.

We increase our fault density based on these observations, and distribute sub-seismic faults throughout the reservoir model following several principles - small faults should be clustered near big faults, with the roughly the same strike; they may be added where a large fault kinks as a vestigial fault tip (e.g., Fig. 8); added faults should be shorter than the shortest mapped fault; they can link faults that come close but do not otherwise touch; and we will add more faults sub-salt than outboard of salt to honor imaging quality. These added faults are generally modeled as "Light Baffles" using the TM values identified above.

RESULTS

Using this method we have been able to create a reference case Mad Dog reservoir model that is robust yet flexible. After the reference case model was history matched, we created upside and downside realizations using

$$TM = k_{unfaulted} / k_{faulted}$$

$$k_{faulted} = L / \{[(L - L_f)/k] + [L_f/k_f]\}$$

where
L = cell length
k = host rock perm
L_f = fault rock thickness
k_f = fault rock permeability

Measured values from Mad Dog core

Sample ID	Clay (%)	Porosity (%)		Permeability (mD)		Hg-air thresh-old pressure (psi)		Deformation Features
		Host	Fault	Host	Fault	Host	Fault	
MD1	9	30	11	1137	0.04	5	140-650	Cataclastic fault
MD2	8	26	8	657	1.3	12	100	Cataclastic fault
MD3	11	25	8	259.3	0.01-0.003	15	100-185	Cataclastic fault
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MD9	N/A	N/A	7	N/A	<0.001	N/A	>2000	Clay smears

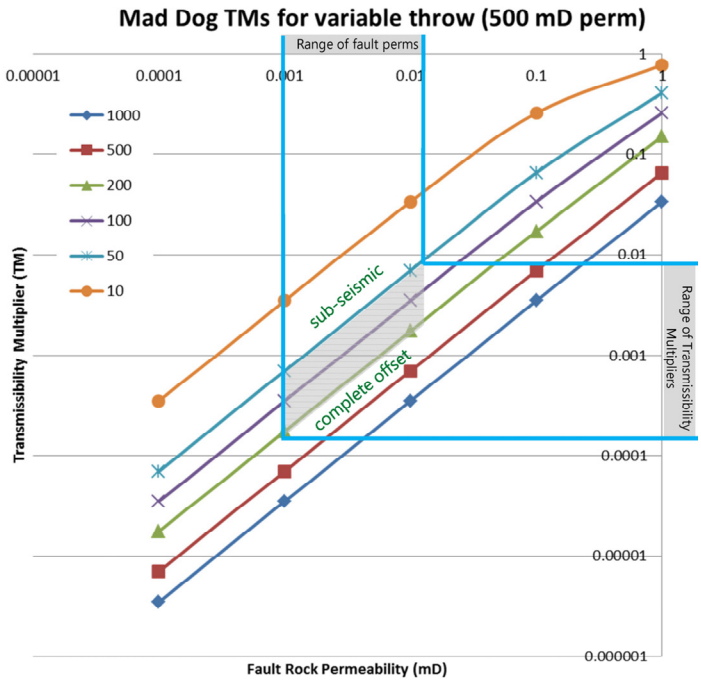

Figure 6. Range of transmissibility multipliers for a sand of 500 mD across faults of increasing throw determined from a range of fault permeabilities measured on Mad Dog core samples.

the same principles, making faults more transmissible in an upside case and less transmissible in a downside case (Fig. 9). These models were also history matched and used to forecast future production, run economics and allow the identification of key risks and uncertainties, along with our mitigations and contingency plans.

The flexibility of the model was recently demonstrated after the results of the first MD2 predrill producer came in with a different amount of depletion than forecast. Using the model we were able to quickly alter the transmissibility of a few distant faults to improve the pressure prediction and update pressure predictions for the next well in the drill sequence to ensure the casing program was still robust, as well as rapidly generate several alternative models to explore other subsurface scenarios. This rapid turnaround would not have been possible with our previous model, demonstrating the value to be found in simple yet efficient models.

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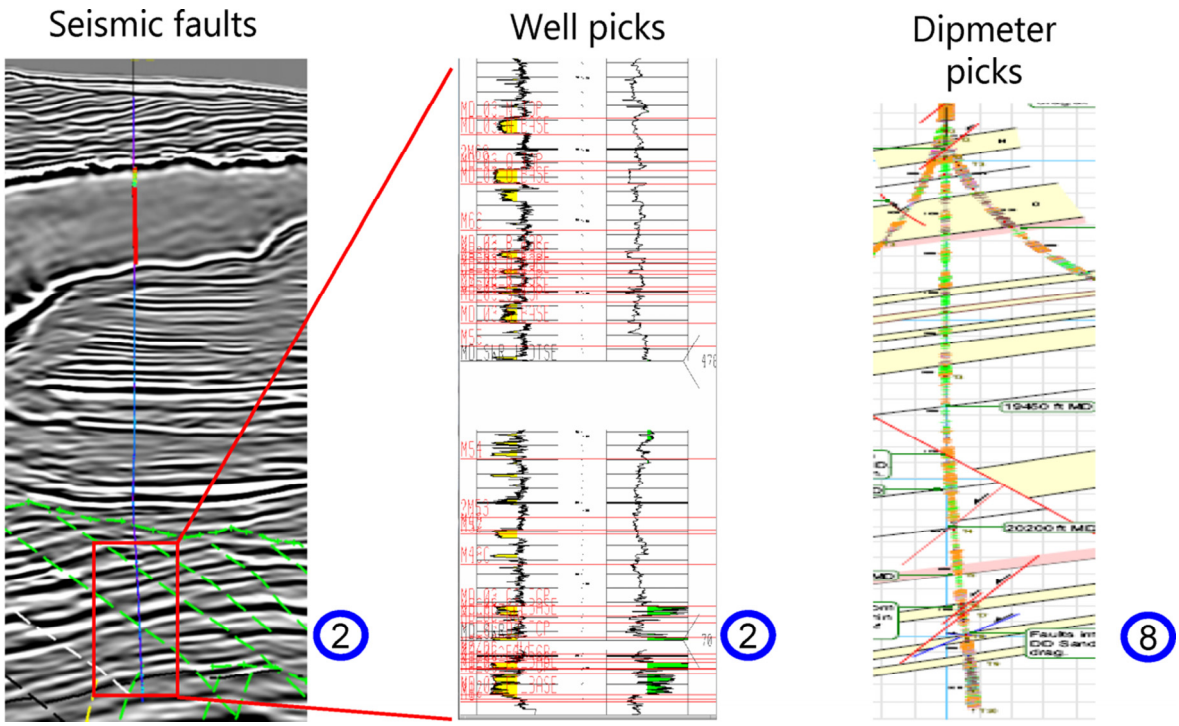

Figure 7. Example of sub-seismic faulting. A wellbore drilled in the field encounters two seismic faults, both of which can be picked as missing section in the logs. However, detailed dipmeter interpretation reveals an additional 6 faults.

Figure 8. Perspective aerial photograph of a linked fault system from the Volcanic Tablelands, California. Vestigial tips, through-going fault, and clustering of small faults near large faults can be seen. Maximum throw on largest fault is ~100 ft. Image is ~3 mi across, with 3x vertical exaggeration. Image courtesy of Google Earth.

margins of the world: Proceedings of the 32nd Annual Gulf Coast Section of the Society of Economic Paleontologists and Mineralogists Foundation Bob F. Perkins Research Conference, v. 32, p. 25–64.

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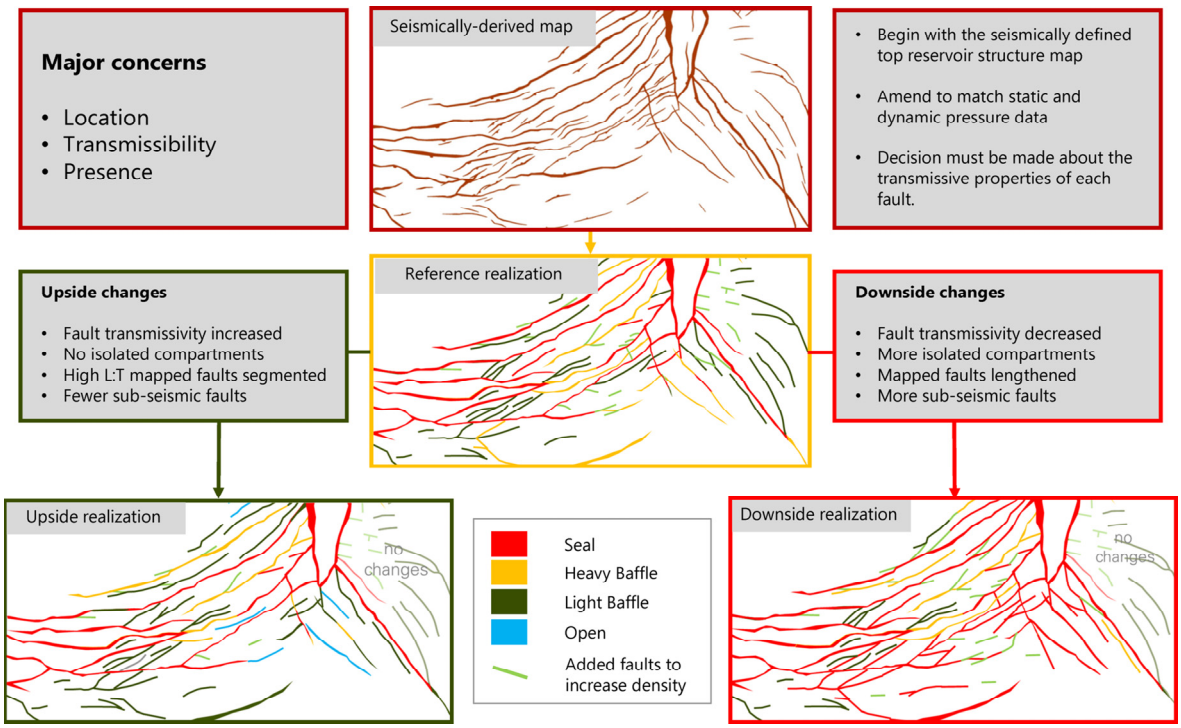

Figure 9. Summary of steps for creating reference case, and upside and downside reservoir models from the seismically-derived map using structural principles.