The Importance of Recognizing Hydrodynamics for Understanding Reservoir Volumetrics, Field Development and Well Placement*

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Abstract

By recognizing and quantifying the regional distribution of overpressure a better understanding of hydrocarbon distribution can be built. Changes in aquifer overpressure represent fluid potential driving hydrodynamic flow. When hydrocarbons are trapped above a dynamic aquifer the hydrocarbon-water contact becomes tilted; the magnitude of the tilt is controlled by the differences in overpressure and the relative fluid densities. Structural closure may no longer be the key control on fluid distribution which is now being controlled by the hydrodynamic spill point. If the distribution of hydrocarbons is no longer controlled by structure then the placement of exploration or appraisal wells requires careful consideration. If a fluid contact can be shown to tilt down to the West then a well drilled on the East will encounter a shallower contact, or possibly water if the tilt is significant, and the decision may be made to abandon a prospect. However, a well drilled on the West may have a deeper than expected contact leading to an interpretation of a significant discovery. Furthermore, if the fluid contact is tilted then the volumetrics of the trapped hydrocarbons changes, either positively or negatively, but must be assessed. In all cases the impact for future exploration, development and appraisal are important.

The Miocene reservoir system has been shown to be laterally drained (Hauser et al., 2013), i.e. low overpressure reservoirs sandwiched between high overpressure shales in the K2 (Sanford et al., 2006) and Knotty Head (Williams et al., 2008) Fields. Systematic changes in reservoir overpressure have been identified in the location of the Mad Dog Field as well as a tilted hydrocarbon-water contact (Dias et al., 2010).

The work presented in this discusses in more detail the likely impact on hydrocarbon distribution for the Miocene reservoirs. Furthermore, the paper will extend the understanding of the geological-pressure controls on fluid distribution to the Lower Tertiary Wilcox play and comment on the likely impact for that system. The major implications of hydrodynamics are; a) Identification of regional overpressure gradients dictating natural aquifer flow and regional extent of sub-salt hydrodynamic reservoirs (natural pressure drive/support to a field), b) Identification of tilted

fluid contacts and the impact on hydrocarbon distributions and volumetrics, and c) Description of the impact for other reservoir systems in the Gulf of Mexico, e.g. the Wilcox.

Introduction

Aquifers can be classified as static (immobile) or hydrodynamic (mobile). The first descriptions of hydrodynamic systems as applied to petroleum basins (e.g. Hubbert, 1967) and many subsequent studies explore dynamic aquifers generated by a hydraulic head. Hydrodynamic aquifers are reported from various parts of the world, for example alluvial aquifers of Sparta in the Peloponnese (Antonakos and Lambrakis, 2000); Yucatan karstic aquifer, Cuba (Sánchez-Pinto et al., 2005); Upper and Lower Cretaceous aquifers of South-western Saskatchewan (Melnik and Rostron, 2011); Cretaceous-Jurassic aquifers of the Great Artesian Basin (Henning et al., 2006); Rubiales Field, Llanos Basin, Colombia (Person et al., 2012); Cooper Basin, Australia (Webster et al., 2000); Western Alberta Sedimentary Basin (Bachu et al., 1993), and deep aquifers of the Illinois Basin (Bond, 1972). Each of these case studies relates to hydrodynamic aquifers driven by a hydraulic head.

More recently hydrodynamic traps and evidence for hydrodynamic aquifers has emerged from basins where there is no demonstrable hydraulic head. Examples include the Central North Sea (Dennis et al., 2000; 2005), Ormen Langer Field, offshore Norway (O'Connor and Swarbrick, 2008), South Caspian Sea (Tozer and Borthwick, 2010), and the Atwater Fold Belt, Gulf of Mexico (Dias et al, 2010). These areas are characterized by reservoirs with lower overpressure in association with higher overpressure shales. In this paper we highlight the characteristics of typical hydrodynamic systems (with emphasis on unconventional aquifers) using worldwide analogues and review the evidence for these latter types in the deep-water Miocene and Lower Tertiary of the Gulf of Mexico. Finally we draw conclusions for the petroleum system of the presence of the reservoirs and how they offer the opportunity for new exploration models, influence appraisal drilling and field volumetrics.

Hydrodynamic aquifers driven by a hydraulic head are characterized by a highland "recharge" area and a lowland "discharge" area, allowing movement of the aquifer from highland towards the lowland, with rate of flow controlled by the permeability of the reservoir and associated flow paths (e.g. faults). One of the characteristics of these systems is that the reservoir pressure is higher than "normal" (termed Artesian Water by hydrogeologists) and also higher than the non-reservoir rocks (shales) above and below the reservoirs. These conditions of higher overpressure in the reservoir relative to the bounding strata are described in case studies from the North Sea (Dennis et al., 2000), Cooper Basin, Australia (Webster et al., 2000) and in Tertiary reservoirs of the Llanos Basin, Colombia (Person et al., 2012). Following Swarbrick (2009) we propose these basins are termed "conventional" hydrodynamic systems.

Hydrodynamic aquifers in basins without a hydraulic head and with high overpressure sediments (most commonly shales) are characterized by lower overpressure in the reservoir than the surrounding sediments. To achieve flow along the aquifer there is a requirement for fluid expulsion, usually through lateral drainage to the surface. So, for example, a laterally continuous reservoir from deep burial (and at depths at which the sediments are typically overpressured) towards the surface (where fluid escapes and pressures are normal) will act as a drain to the high overpressure sediments. Following Swarbrick (2009) we propose that these basins are termed "unconventional" hydrodynamic systems.

A cartoon to illustrate a "conventional" hydrodynamic system (Figure 1) features an elevated "highland" area, a situation where meteoric water from an uplifted reservoir creates a hydraulic head relative to the adjacent "lowland" area in which there is fluid discharge, allowing flow into and out of the basin along the aquifer. By contrast the "unconventional" hydrodynamic system (Figure 1) features deep overpressured sediments with the potential for fluid escape out of the basin, in this example to the sea-bed. The fluid potential relates to the higher overpressure in the surrounding shales relative to the laterally draining reservoir.

Recognizing Hydrodynamic Aquifers

All hydrodynamic reservoirs have the following characteristics:

- overpressures systematically reduce in the direction of flow;
- trapped hydrocarbons exhibit tilt of the hydrocarbon-water contact in the direction of flow; and
- reservoir overpressures rarely match the non-reservoir overpressures

Methods to describe and quantify these characteristics include geological maps of overpressure, observations of variable hydrocarbon-water contacts, diagnostic relationships between hydrocarbon, and water gradients revealed in pressure-depth plots and inferences of overpressure differences between reservoir and non-reservoir. In the case of unconventional hydrodynamic systems, the demonstration of laterally draining reservoirs can be a key identifier.

Geological Maps

Hydrodynamic aquifers can be recognized using overpressure values posted on a map. Overpressure values are taken from measured reservoir pressures at depth where they exceed the hydrostatic pressure gradient. Care must be taken that overpressure values are from the same aquifer, with an explanation of data distribution from static barriers to flow eliminated. Any systematic change in overpressure then signifies hydrodynamics and indicates the direction of fluid flow (Figure 2) redrawn from O'Connor and Swarbrick, 2008). Dias et al. (2010) show an example of a hydrodynamic system in the deep Lower Miocene sands of the Gulf of Mexico; the system shows systematic change (decrease) in aquifer overpressure from the Puma well (south-east Green Canyon) which has 3023 psi overpressure and the overpressure decreases systematically north-east into Atwater Valley in the direction of Everest (2616 psi) which is the lowest value shown.

Variation in Fluid Contacts

There are several reasons for hydrocarbon/water contacts to be at different levels in the same reservoir such as lithological barriers, sealing faults, perched water or production effects; hydrodynamic tilting is another mechanism. When dealing with tilt defined by pressure data, the data refer to the Free-Water Level (FWL) rather than the physical contact between hydrocarbon and water (Figure 3). The FWL will be tilted in the direction of lower overpressure. Tilt is a function of the equilibrium between aquifer overpressure (changing beneath the hydrocarbon accumulation) and the statically trapped hydrocarbons (see Hubbert, 1953; Dennis et al., 2005). High overpressure differences lead to strong tilt.

One of the building blocks of hydrodynamic study is a detailed investigation of every well involved in terms of Pressure-Depth (P-D) plots. P-D plots reveal relationships between hydrocarbon and water gradients, from which overpressures and FWLs of the wells concerned can be extracted. In Figure 4a, a static reservoir is shown in cross-section on the left-hand side and a dynamic reservoir is shown on the right-hand side. One of the principal characteristic features of a hydrodynamic system is a common hydrocarbon column defined by data from several wells in which their water gradients have variable overpressure (Figure 4b). The relationship is only revealed when the wells are orientated along the strike of the flow direction (Figure 4c) which also shows how the hydrocarbons no longer conform directly to the structure contours).

Reservoir versus Shale Overpressure

Lateral drainage is the process by which fluids can escape from a reservoir generating the conditions conducive for "unconventional" hydrodynamics (Swarbrick, 2009). Laterally draining reservoirs are those in which the aquifer is laterally connected and with good fluid-flow pathways. It should be realized that due to permeability differences, shales and sands drain differentially and such can create a pressure regression; a situation where sands with drained pressure are associated with highly-pressured shales (e.g. Figure 1 and Figure 6). The ability to recognize lateral drainage can be key to identifying an unconventional hydrodynamic aquifer.

Evidence for Hydrodynamics in Miocene Reservoirs in the Gulf of Mexico

As summarized above evidence for lateral drainage, systematic variation in FWL/overpressure, fluids that do not conform to structure and common hydrocarbon/multiple aquifer gradients on a P-D plot are required to provide proof for active hydrodynamics. There are multiple pieces of such evidence for hydrodynamics in the Miocene-aged reservoirs of the Gulf of Mexico which are summarized below.

Lateral Drainage

Lateral drainage has been identified in individual wells such as K2, (Green Canyon (GC) 562; Sanford et al., 2006) and Knotty Head (GC 512; Williams et al., 2008) and as a regional trend through north-east Walker Ridge (WR), south-east GC and the majority of Atwater Valley (AT) in an area known as the Tahiti Embayment (IG/IHS, 2010; Hauser et al., 2013). The regional trend includes the fields noted above as well numerous other fields, e.g. Tonga, Mad Dog, Neptune, and Sturgis.

The individual wells presented show pressure regressions, based on direct pressure data, by comparing overpressure taken within thin reservoirs that demonstrate the shale pressure and thicker laterally connected sands the record low overpressure. In the K2 discovery well the direct pressure data show a variation in overpressure from 6004 psi at 22000 ftTVDss down to 1326 psi at 23500 ftTVDss before increasing to 6831 psi at 25400 ftTVDss (Figure 6). The pressure regression recorded is significant (~4700-5500 psi). Notably the sand with the lowest overpressure (most drained) is 50-75 feet which is not significant in comparison to the underlying Wilcox reservoir but is comparable to the distal portion of the laterally draining and hydrodynamically active Paleocene reservoirs of the North Sea. Hydrodynamic effects are small and hard to detect where sands thick and regional, i.e. Wilcox reservoirs, but are easier to see when sands thinner, i.e. Miocene reservoirs. Similar magnitudes of pressure regression are recorded in other fields, e.g. Knotty Head (~ 3800 psi), Tonga (~5500 psi), and Sturgis (~3400 psi). In other fields located slightly further south, the pressure regressions are smaller but still significant, e.g. Big Foot (~2200 psi) and Shenzi (~2300 psi).

Detailed resistivity-based pressure predictions for these wells show pore pressure in the shales that remain highly overpressured above and below the draining reservoirs (Figure 6). The predicted pore pressure in the shales shows a minor regression over the interval that the reservoirs are highly drained due to some influence of the reservoir drainage on the shales. The implication is that the drainage is a recent process as the shales have yet to reach equilibrium with the reservoirs.

Variation in FWL/Overpressure

The maximum overpressures recorded (6000-7000 psi in K2/Knotty Head/Sturgis) are located to the north of the Tahiti Embayment. The lowest overpressures are recorded in the southern fields such as Shenzi and Neptune (<3300 psi). Moore et al. (2001) presented an overpressure map that recorded a systematic decrease in overpressure from Puma (~3000 psi) in south-east GC through Mad Dog and Frampton (~2950 psi), Shenzi and Atlantis (~2900 psi), Neptune (~2800 psi) to Everest (~2600 psi). Clearly the overpressure values systematically decrease to the north-east. There are no associated FWL values to corroborate a hydrodynamic model.

Hauser et al. (2013) present a 2D basin model that includes a significant shallowing of the Mid-Miocene laterally draining interval where beds have been upturned against the Green Knoll salt diapir (south-east GC). The shallowing of the reservoir against the potentially fractured rocks around the diapir could be the fluid escape mechanism by which lateral drainage is facilitated. Hauser et al. (2013) speculate that each field could be leaking through fracturing of the crest of the structure but this unlikely be a cause of hydrodynamics on a field-scale as the depressuring is likely to be uniform.

Non-Standard Fluid Distributions

Dias et al. (2010) presented evidence for hydrodynamics in the Mad Dog Field based on the semi-regional overpressure map presented in Moore et al. (2001) and structural and fluid distributions across the field. The Mad Dog Field was brought online in January 2005 and in the years since pressure support due to aquifer influx has been noted with no water injection wells drilled to date (Dias et al., 2010). Critically, the oil-water contact (OWC) was intersected 400 feet deeper than the mapped structural spill point. By combining the regional overpressure gradient with known oil and water densities within the field the magnitude of tilt was calculated and the hydrodynamic spill point mapped, calibrated to the deep OWC noted in the appraisal well. As noted by the authors, a regional hydrodynamic model most easily explained the observed OWCs, observed natural aquifer pressure support and the known fluid distributions.

Multi-Well Pressure-Depth Plots

To date no multi-well P-D plots have been published for review within the Miocene of the Gulf of Mexico. Several fields have multiple penetrations; hence the data should be present to build such a multi-well P-D plot as described above. The work of Dias et al. (2010) discusses a variation in overpressure on a field scale and presents tilted contact therefore a multi-well plot for this field should record a common oil gradient with multiple aquifers.

In summary, the Miocene reservoirs of the central Gulf of Mexico demonstrate multiple pieces of evidence for hydrodynamics on both a regional and a field scale.

Evidence for Hydrodynamics in the Lower Tertiary of the Gulf of Mexico

The deep-water Wilcox trend is an evolving exploration target. New penetrations and new data acquisition techniques are increasing the understanding of this exciting and potentially lucrative play. The trend is laterally extensive comprising 1000's of feet of thickness of sand across 100's miles from Alaminos Canyon in the west as it thins towards Atwater Valley in the east. The majority of sands are a result of high energy deposition resulting in stacked sand fans and channel complexes which has resulted in lateral and vertical connectivity of the Wilcox trend.

The regional stratigraphic framework demonstrates that the Wilcox reservoir is likely to act as a single hydraulic unit, Meyer et al. (2005) show this is true in the Perdido Fold Belt as the reservoir thickness is greater than the throw on the faults. The Upper Cretaceous Nise Formation in Mid-Norway is a deep-sea fan complex, consisting of stacked, amalgamated sands bodies that have few internal seals similar to the Wilcox play. There is a strong correlation between high magnitudes of overpressure and shale-rich facies, e.g. basin-plain deposits. In contrast, the sand units of the Nise Formation have only low overpressure, and are interpreted as basin-floor fans, slope feeder channels that exit on the shelf. In parts, where data is sufficiently abundant, systematic changes in reservoir overpressure are observed, relating to hydrodynamic flow.

In Atwater Valley the Wilcox reservoir is thinner and there is potential for some juxtaposition of reservoir against shale across large scale salt-cored anticlinal thrust faults. However, the three-dimensional connectivity of these sands is likely to maintain a single hydraulic unit for the Wilcox as a whole. If the Wilcox reservoir is acting a single hydraulic unit then lateral drainage within a single well cannot be observed as it was in the intra-Miocene sands, e.g. K2. However, it should be possible to map out regional variations in overpressure and FWL given enough well control and areal extent.

The map in Figure 7 shows the results of detailed overpressure analysis for all publically available wells released before January 2010. Care was taken to only plot aquifer overpressure values to remove any effects of hydrocarbon buoyancy. The highest overpressure recorded was

10242 psi in south-east Green Canyon. The overpressure values systematically decrease away from this well. In the south of Keathley Canyon the overpressure has reduced to approximately 7800 psi implying fluid flow (lateral drainage) outboard towards the Sigsbee Escarpment.

The overpressure values across Walker Ridge range from 7700 psi to 6800 psi but still conform to a systematically varying overpressure magnitude. The lowest overpressure values noted are in Atwater Valley close to the Green Knoll diapir. As discussed above the movement of the Green Knoll diapir may be an escape mechanism for fluids in the Miocene and given the proximity of the lowest overpressure values in the Wilcox the same escape mechanism may be applicable to the Wilcox reservoir too. Overpressure contours have been fitted to the data (Figure 7) and whilst the drainage is not completely uniform a simple set of overpressure contours can be applied much as they can be for other proven hydrodynamic reservoirs, e.g. Paleocene, Central North Sea (Figure 2). A similar variation in overpressure has been noted in the Miocene, both locally (Mad Dog Field; Moore et al., 2001) and regionally (Tahiti Embayment; Hauser et al., 2013).

The alternative explanation would be each overpressure value represents an isolated static overpressure compartment bounded either by faulting or by sedimentalogical barriers. Based on the published understanding of the depositional setting of the Wilcox play (stacked sand fans) it is unlikely that either structure or sedimentology could compartmentalize such a thick sand-rich unit over the horizontal scales noted. Drainage of a regionally communicating aquifer would explain the overpressure variation observed and the Wilcox play is hydrodynamically controlled.

If the Wilcox play is hydrodynamically active it should be possible on a field scale to observe variations in the FWL as discussed above and presented by Dias et al. (2010) in the Mad Dog Field. To date, only two fields have three or more penetrations (minimum required to assess hydrodynamics); the fields are St. Malo and Jack. The individual well data was not available to this study at the time of publication so an assessment on a field scale could not be made. It would be expected that these fields would show a local systematic variation in overpressure with overpressure reducing outboard. The FWL values should deepen in the same direction. If local structural variation cannot explain the variation in overpressure/FWL then a hydrodynamic assessment should be made based on the observed regional variation in overpressure.

Conclusions

Overpressure in shale-dominated sedimentary sequences increases with depth when generated by ineffective dewatering in response to vertical stress (Swarbrick et al., 2009). Reversal in overpressure magnitude with depth is contrary to this simple pattern, and implies lateral flow. There are a number of ways that these reversals can be recognized. Fluid escape to the surface through reservoir formations and/or faults involves lateral fluid flow, which in turn can create conditions for tilted hydrocarbon-fluid contacts in hydrodynamic traps. Massive dewatering of reservoirs can lead to significant overpressure contrast between reservoirs encased in shales adjacent to laterally drained regional aquifers. The local dewatering of shales above laterally drained reservoirs improves the sealing potential of these shales to hydrocarbons trapped in the reservoir beneath (Underschultz, 2007).

Compaction-driven hydrodynamic flow is confirmed where overpressure differences exist in a laterally communicating reservoir, i.e. differences are not explained by static boundaries such as sealing faults or facies change. The principal evidence is provided by overpressure maps for the same stratigraphic level where lateral seals are known to be absent, e.g. in an extensive and thick sand body, and by local/regional pressure reversals. Lateral overpressure differences and pressure reversals have been noted at several stratigraphic levels and in several different regions.

The effects on the petroleum system of hydrodynamic flow include:

- More effective vertical barriers to fluid flow, and more effective hydrocarbon seals;
- Long hydrocarbon columns, due to increased pressure differences across seals;
- Up-dip migration of hydrocarbons;
- The filling of stratigraphic traps;
- Tilting of hydrocarbon-water contacts;
- Fluid distributions controlled by hydrodynamic rather than structural spill-points leading to either increased or decreased reserves.

Figure 8 shows a cross-section from a deep-sea fan from the Central North Sea. There are two structural traps present with the structural spill point highlighted in red. A detailed overpressure/FWL study across the area indicated a regional hydrodynamic flow to the left of the image. The associated tilt was calculated to be 25 ft/km and is shown in green. The FWL contact was calibrated to measure FWLs from individual wells. The hydrocarbons in the right-hand structural trap have migrated out of the trap due to the degree of tilt reducing the reserves, possibly making the trap uneconomical. The hydrocarbons have migrated into the left-hand trap which now has a significant increase in reserves due the hydrodynamic trapping of hydrocarbons against the flank of the structure. The hydrodynamic trapping of hydrocarbons corresponds to an amplitude anomaly (hydrocarbon indicator) that is offset from structure in the direction of hydrodynamic tilt. Therefore, offset from structure of seismic attribute data can be used as a “remote” aid to establish if hydrocarbons have moved in the direction of aquifer flow (as defined by the overpressure gradient). These seismic responses to fluids in reservoirs are observed to be offset from structural closure in published data from fields in the North Sea, e.g. Arbroath and Montrose Fields (Dennis et al., 2005).

Therefore, by assessing the regional overpressure variation the general direction of tilt can be determined (Figure 5). Combination of the regional overpressure map with careful evaluation of the seismic attribute data can help to plan efficient exploration and appraisal wells. For example, a well drilled on the high overpressure side of a hydrodynamically active trap could result in a FWL shallower than the structural contour possibly leading to the decision to relinquish an asset. Whereas, drilling on the low overpressure side could lead to a contact deeper than the structural contour, e.g. the Mad Dog Field. Without the overpressure analysis the offset in the seismic attribute may be interpreted erroneously.

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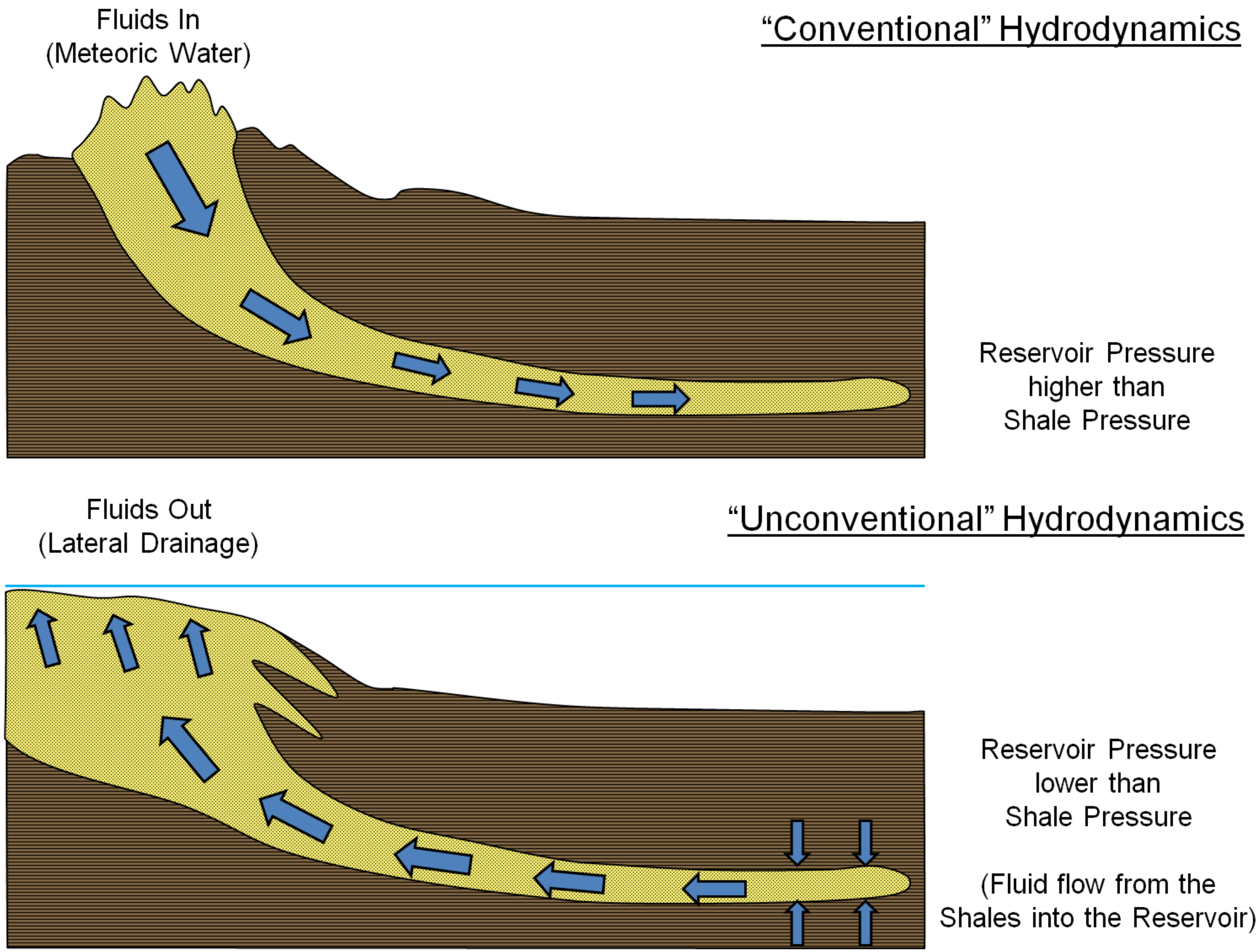

Figure 1. Hydrodynamic systems can be considered "conventional" and driven by a hydraulic head (upper image) or "unconventional" and driven by association of laterally drained sands with overpressured shales (lower image).

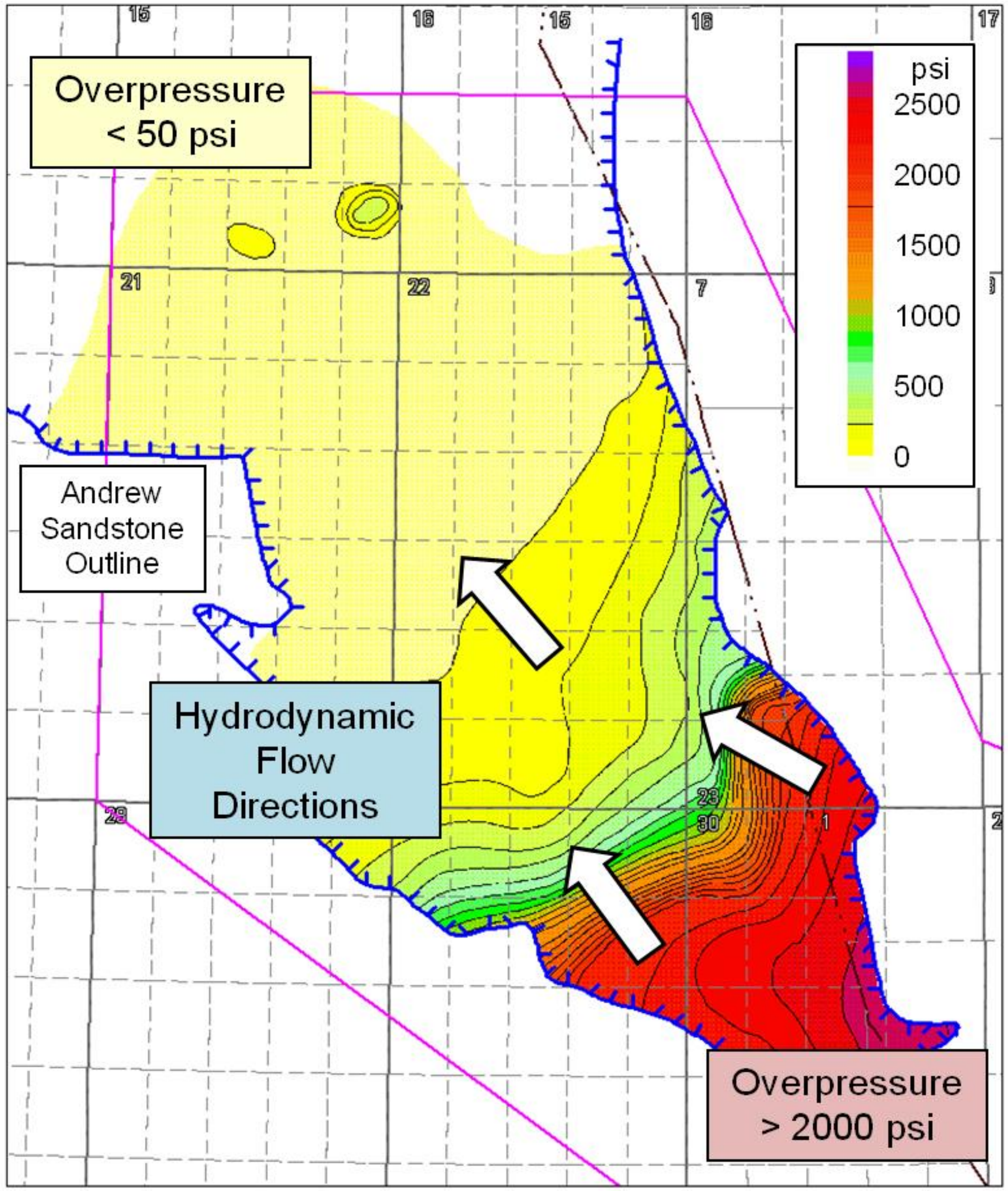

Figure 2. Example of Paleocene sands in the Central North Sea with a large overpressure gradient across the full length of the sand and with proven hydrodynamically active fields, e.g. Pierce Field.

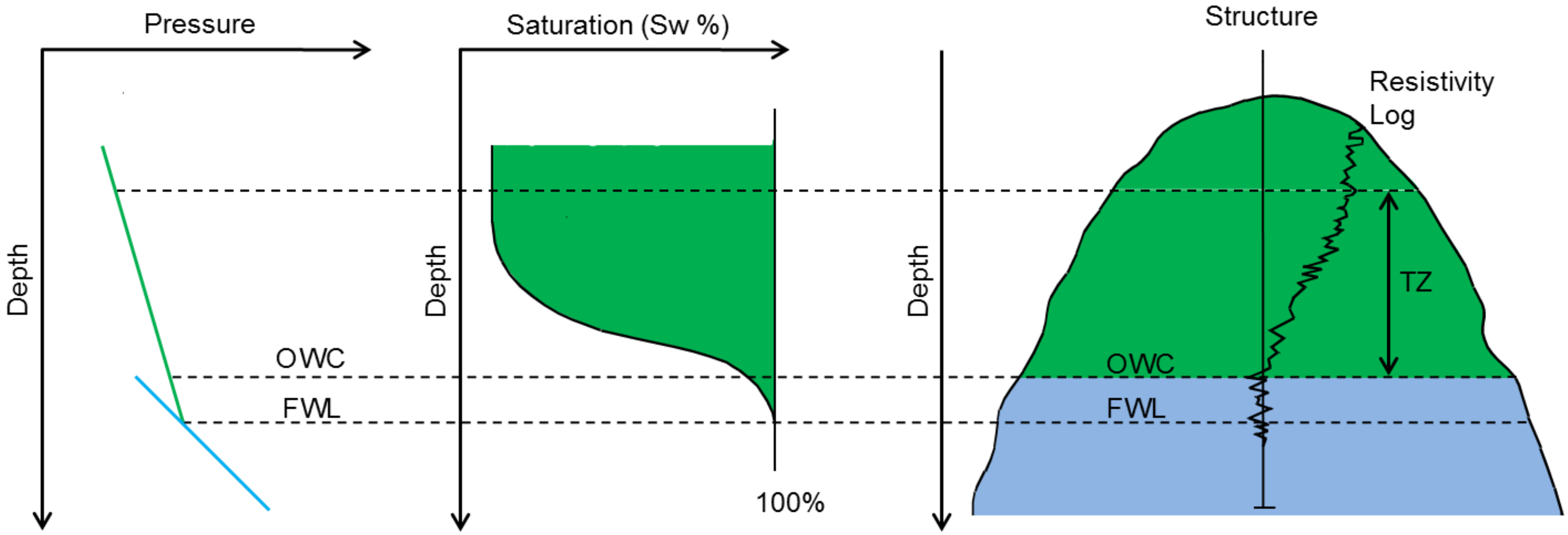

Figure 3. Cartoon illustrating the effects of capillary pressure on hydrocarbon water contact. Note the difference between the Oil-Water Contact (OWC) and the Free Water Level (FWL). The resistivity log shows a transition zone (TZ) from 100% water saturation (Sw) at the FWL to the depth at which the Sw% becomes irreducible. Image redrawn from Dennis et al. (2000).

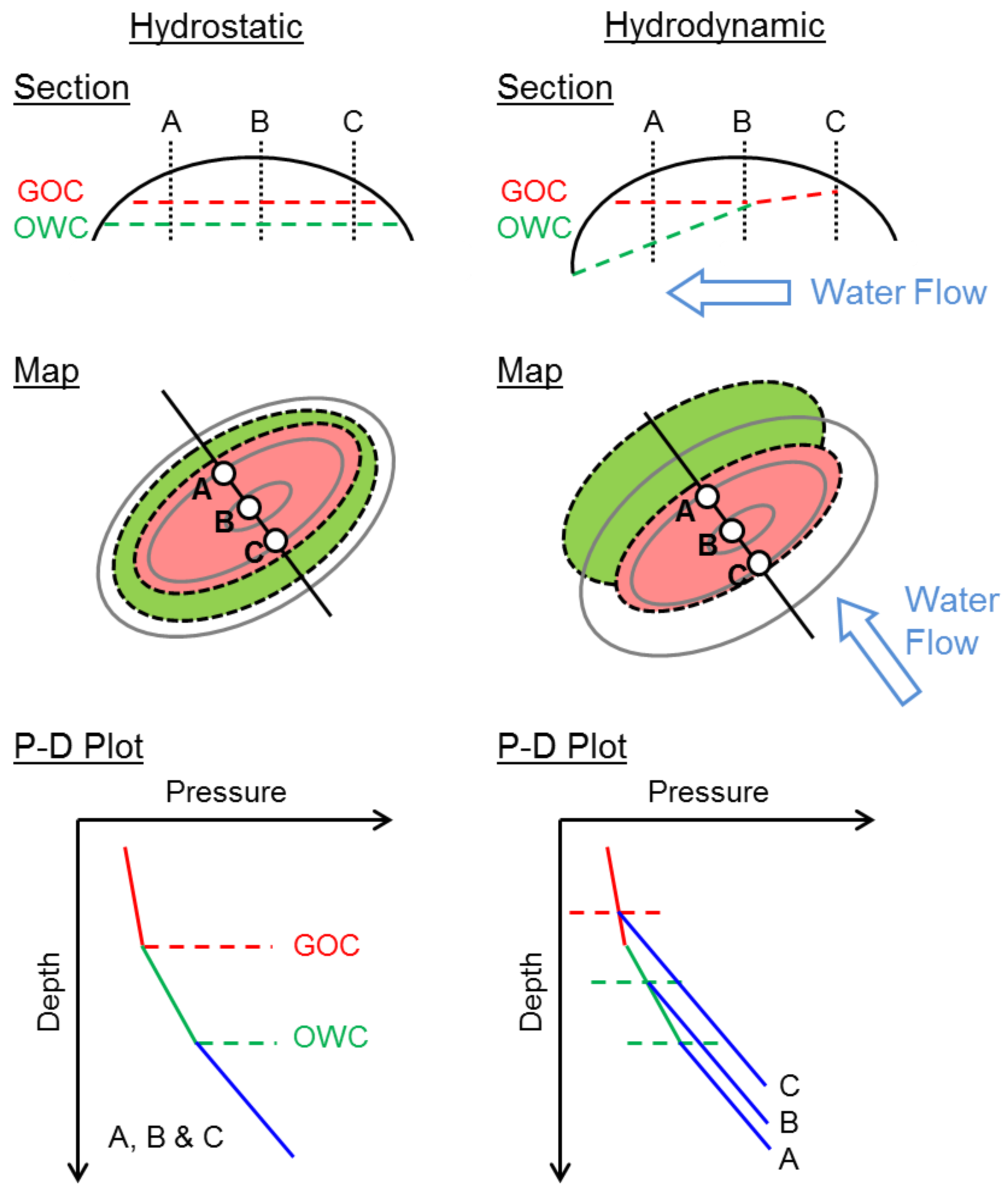

Figure 4. Hydrostatic vs. hydrodynamic aquifer systems, redrawn from Dennis et al., 2000. Note the hydrodynamic system leads to tilted fluid contacts (a - top), hydrocarbons non-conformable with structure (b - middle), and multiple aquifers for a common hydrocarbon gradient on a P-D plot (c - bottom). The water flow arrows correspond to a change from high overpressure to low overpressure in the direction of flow.

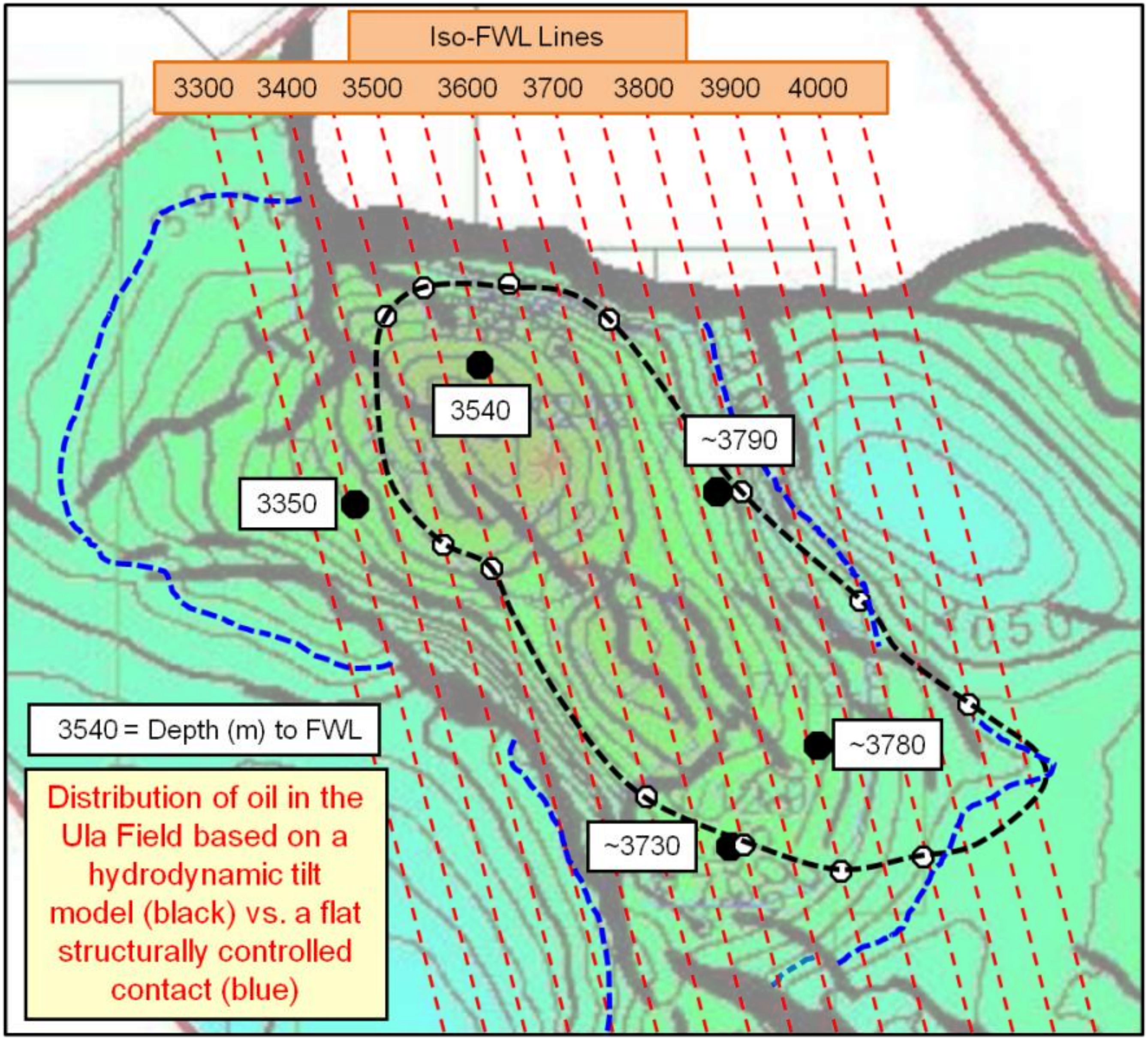

Figure 5. Oil distribution for the Ula Field if controlled by a hydrodynamic spill point (black dashed line). Hydrodynamic spill-point is coincident with the structural spill point (dashed blue line) at 3930 m on the SE of the Ula Field (see text). White dots are intersection points between Top Reservoir contour depths and iso-FWL depths. Orange dashed lines are depths to FWL calculate using the tilt model.

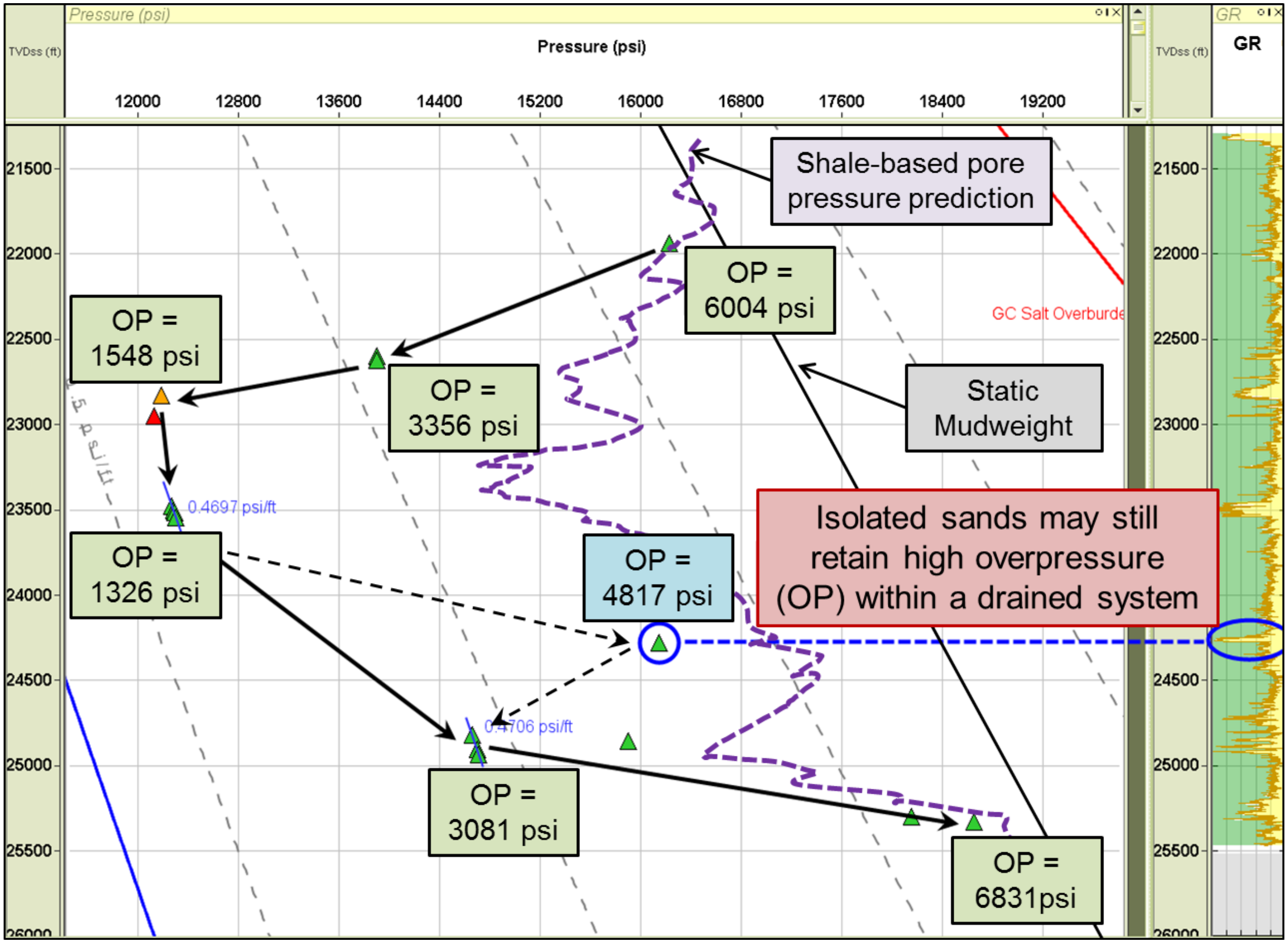

Figure 6. A single-well pressure-depth plot for the K2 discovery well (GC 0562). The plot focuses on the laterally drained reservoir pressure data of the Miocene. The overpressures range from 6004 psi to 1326 psi at the maximum pressure regression and then build out to 6831 psi. The dashed black arrows show the possibility for local variation in the pattern of overpressure variation. Within the depth range of lateral drainage are isolated pressure tests with much higher overpressure than the laterally drained reservoirs, indicating that thin isolated sands that represent a potential drilling hazard are present. Symbol reflects data quality; green = good, orange = fair, and red = poor. The purple dashed line is a resistivity-based pressure prediction for the shales based on a regional normal compaction trend. The shale pressures predicted record some minor regression of overpressure due to the major overpressure regression in the sands but show that the shales remain highly overpressured.

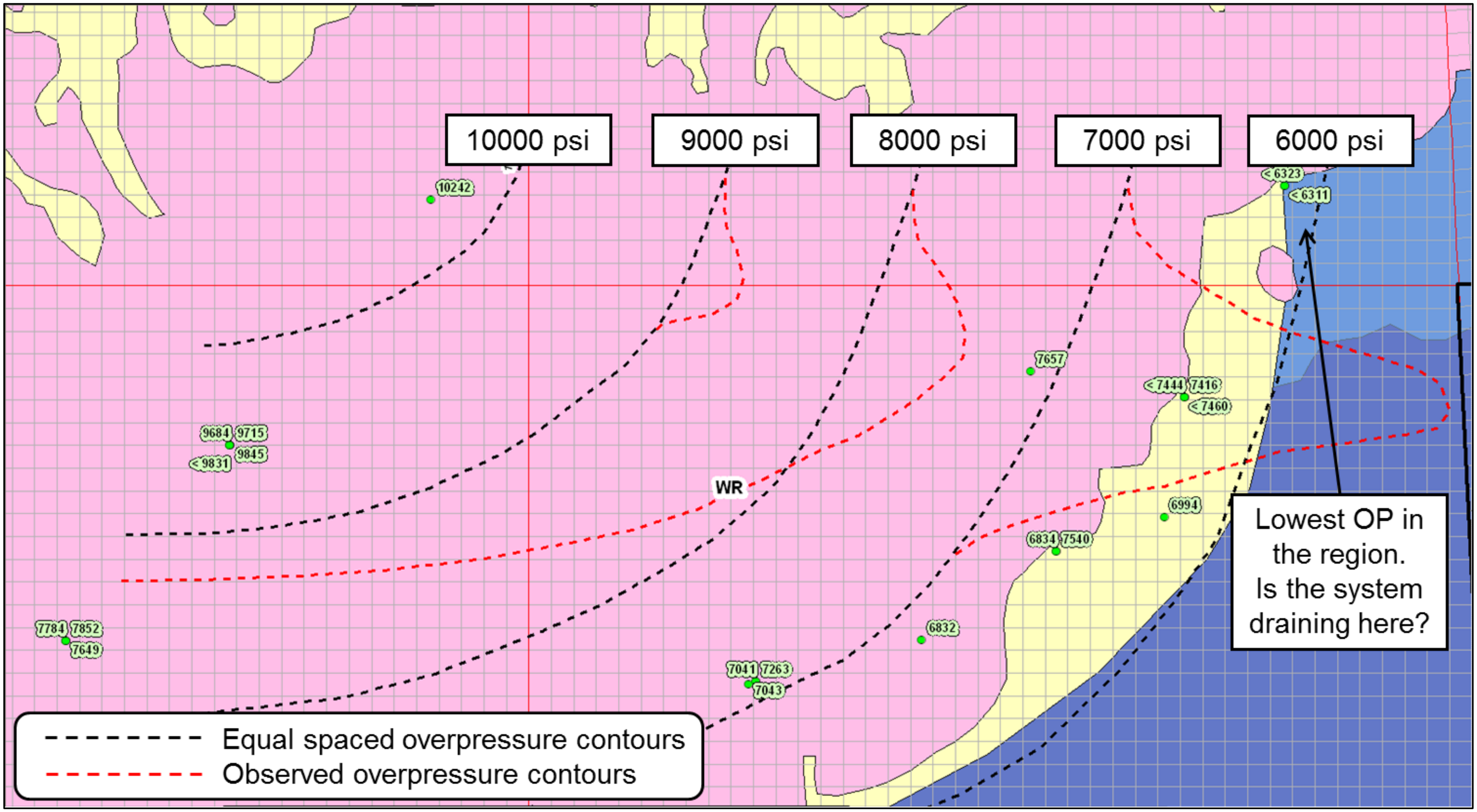

Figure 7. An overpressure map for the Wilcox reservoir across western Keathley Canyon (KC), Walker Ridge (WR), and the southern blocks in Green Canyon (GC) and Atwater Valley (AT). The overpressure numbers show a systematic reduction in overpressure from a high in south-east GC through KC and WR. The black dashed lines show equi-spaced contours and the red dashed lines show the contours that fit the overpressure values recorded. The lowest values are in AT and are located close to the Green Knoll salt diapir, a proposed cause for fluid escape in the laterally draining Miocene reservoirs in this paper.

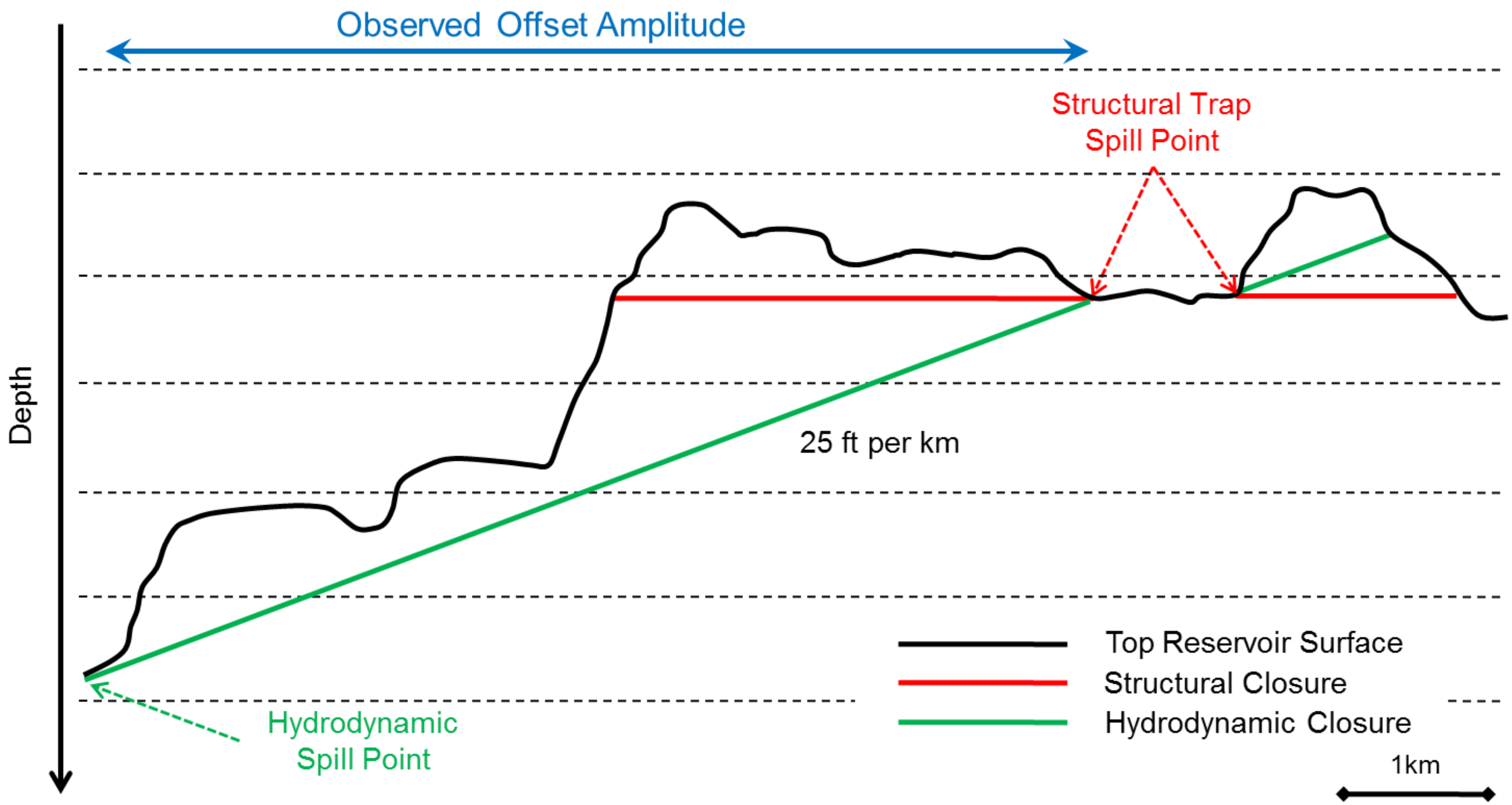

Figure 8. A cross-section through a field located in a deep-sea fan in the Central North Sea. The field is proven to be hydrodynamically active leading a reduction in reserves in the right-hand trap but a significant increase in the reserves in the left-hand trap due to hydrodynamic trapping against the flank of the structure. The hydrodynamically controlled reserves correspond to an offset in seismic attribute consistent with hydrocarbons proving such phenomena may be observed from seismic during a phase of frontier exploration.