Horse Hill Developments Ltd

Title: Geological Reservoir Parameters

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1. REGIONAL GEOLOGY

The Horse Hill Oil Field is situated in the Weald Basin in South Eastern England, south of London and extends from Southampton and Winchester in the west to Maidstone and Hastings in the east across the counties of East and West Sussex, Kent and Hampshire.

The Weald Basin is one of three sedimentary basins within a system of post-Variscan depocentres and intra-basinal highs that developed across central southern England and adjacent offshore areas between the Triassic and Tertiary periods.

The Weald Basin is located to the east of the Wessex Basin and to the south east lies the Paris Basin (Fig. 1). The Weald Basin is bounded to the north by the London-Brabant Massif and is separated from the Wessex-Channel and Paris Basins by a regional arch called the Hampshire-Dieppe High.

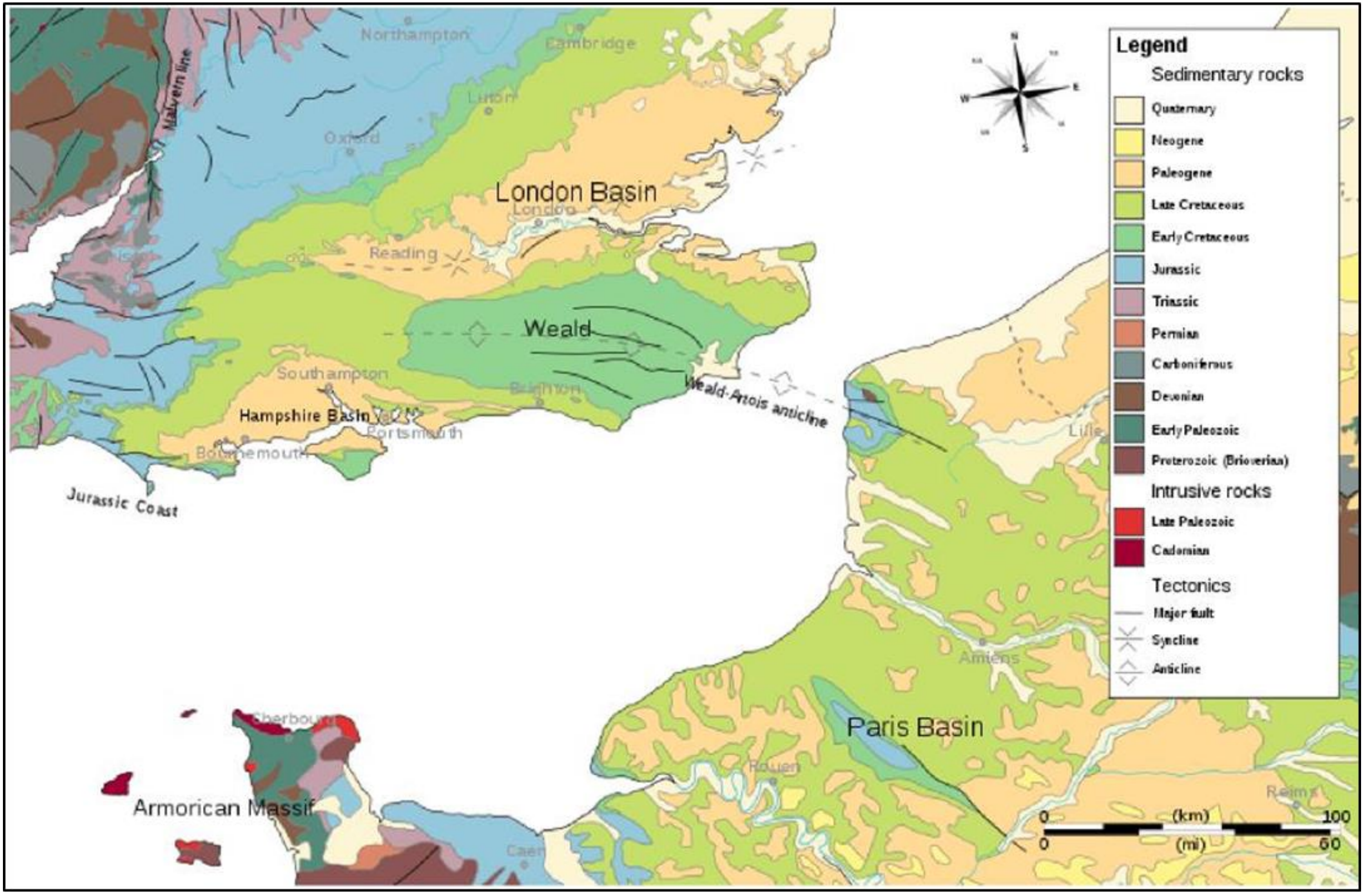


Figure 1: Geologic Map of Southeast England and the English Channel Region

1.1 Structural History

The structural history of the Weald Basin can be divided into three main phases:

1. A pre-Mesozoic phase associated with the culminating in a platform of Palaeozoic rocks;
2. A Mesozoic phase of subsidence and sedimentation; and
3. A Tertiary phase of uplift.

The Weald Basin itself was formed in phase two by rapid subsidence associated with thermal sag following early Mesozoic extensional block faulting.

The basin appears initially to have taken the form of an easterly extension of the Wessex Basin but became the major depocentre during the Upper Jurassic and Lower Cretaceous, with associated active faulting.

These movements appear to have ceased prior to Albian times and a full Upper Cretaceous cover is believed to have been deposited in a gentle downwarp, which extended far beyond the confines of the Weald and Wessex Basins.

Major inversion of the Weald Basin took place in the Tertiary, with both gentle regional uplift, which in the eastern part of the basin is estimated to have exceeded 5,000 feet (1525 metres) and may have been significantly larger, and intense local uplift along pre-existing zones of weakness, which led to the formation of compressional features such as tight folds and reverse faults. Zones of Tertiary deformation appear to have been strongly influenced by underlying, particularly Variscan, structural trends.

1.2 Petroleum Systems

The Weald Basin is a proven petroleum system (Fig. 2) with several commercial producing fields and discoveries, mostly on the flanks of the basin. Since the early 1980s, oil field production has been from Goodworth, Horndean, Humbly Grove, Palmers Wood, Singleton, Stockbridge and Storrington, and gas production from the Albury field.

Jurassic source rocks reached thermal maturity in the Early Cretaceous and initial migration occurred at this time, often over long distances, into traps closed by pre-Aptian faults. Tertiary tilting and uplift led to the breaching of many of these pre-existing traps and the formation of large folded closures. A second phase of hydrocarbon migration, particularly of gas, took place at this time, with significant vertical migration along fault zones.

Major reservoirs located to date occur in Middle Jurassic carbonates and Upper Jurassic sandstones, but deep burial in the basin has caused considerable destruction of primary reservoir characteristics; changes in the temperature and pressure regimes and the mobilization of fluids within the basin resulting from the Tertiary uplift caused further diagenetic changes, particularly in the carbonate reservoirs.

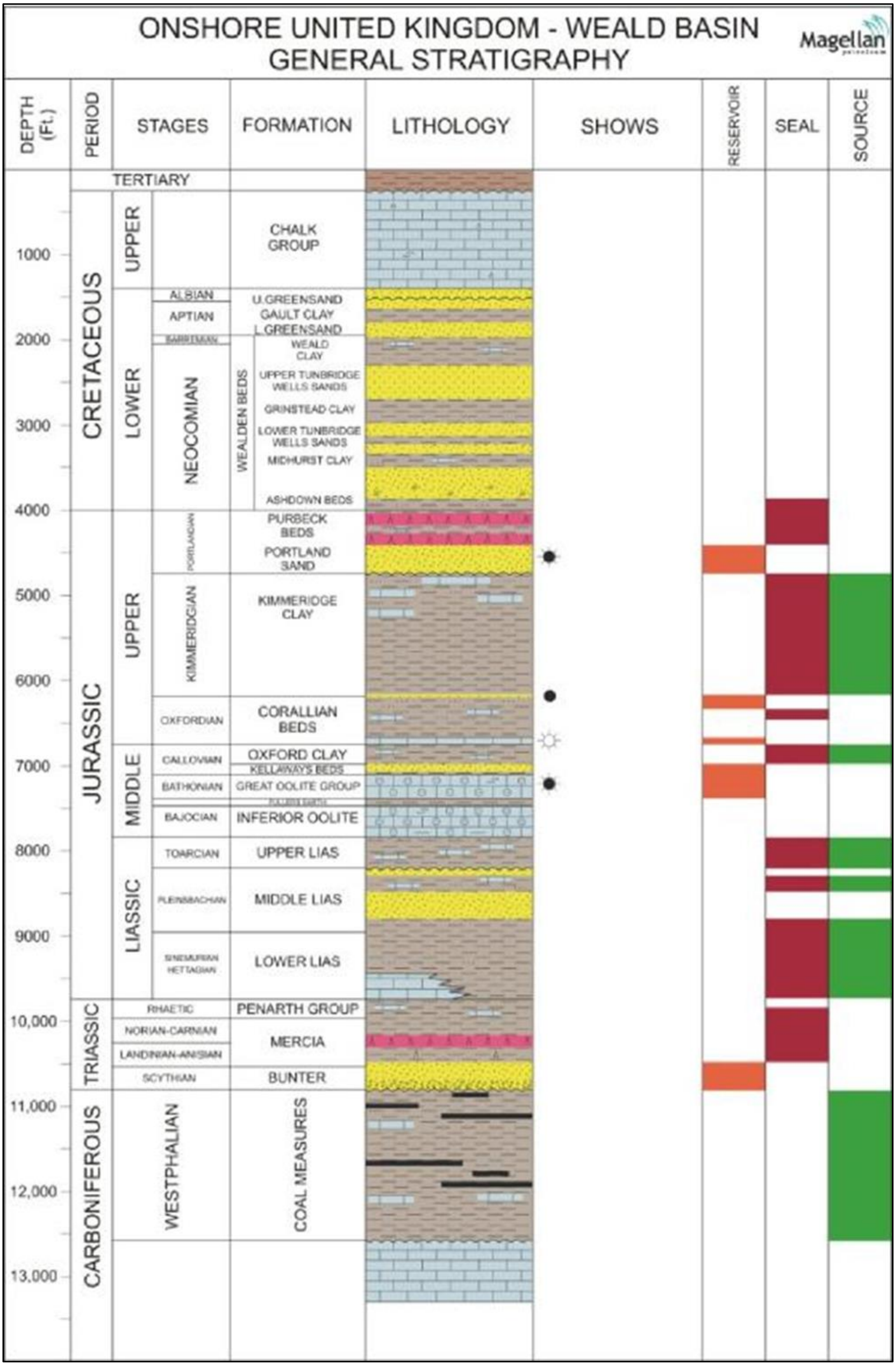


Figure 2: Primary Weald Proven Oil Play Details

2. HORSE HILL FIELD

2.1 Location

The Horse Hill discovery is located in licenses PEDL137 and PEDL246 and is operated by Horse Hill Developments Ltd ("HHDL").

The Horse Hill discovery comprises several prospective intervals; however, only the Upper Portland Sandstone and the Kimmeridge Clay Formation are considered as possible resources at this time.

2.2 Structure

The Horse Hill-1 and Collendean Farm-1 wells lie within an overall E-W trending Cretaceous aged tilted fault block, some 6km in length and 3km wide. The Horse Hill Top Portland Sandstone depth structure map shows a north-south trending feature formed by a 3-way dip closure in the footwall of a major east-west trending fault system, combined with an extension of this feature in the hanging wall to the north. The hanging wall section appears to show evidence of structural rejuvenation by post-Oligocene Alpine compression. The HH-1 and CF-1 wells were drilled close to the crest of the footwall closure. HH-2 and 2z have been drilled towards the south-east along seismic line BP-85-74. The crestal part of the feature, as mapped, extends to approximately 4 km east-west by 3 km north-south.

Structural mapping is controlled by 5 or 6 seismic lines of various vintages. The key area of closure is controlled by only 4 lines. Well locations and seismic coverage are shown in Figure 3, and a more detailed view of coverage over the crest of the structure.

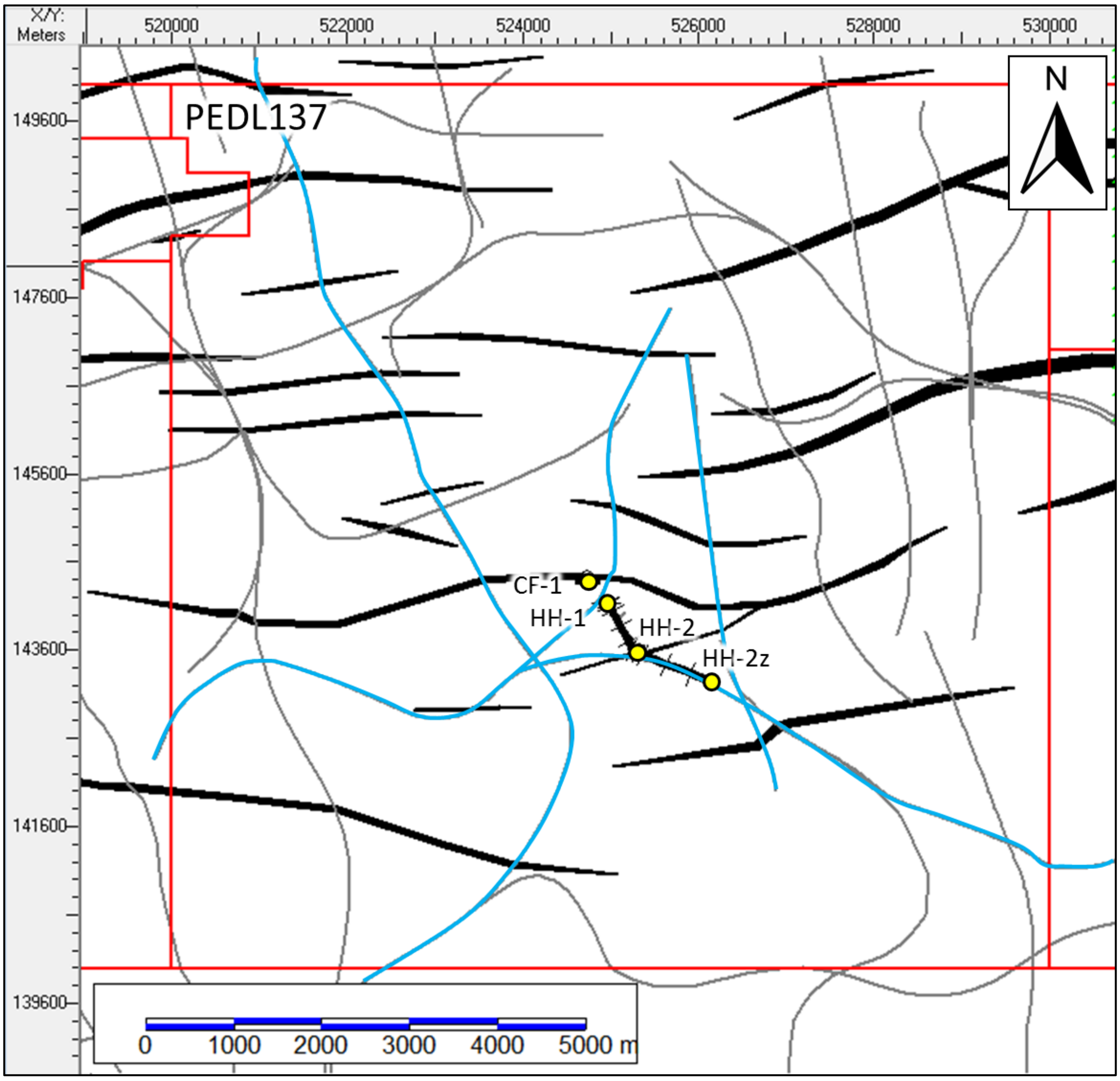


Figure 3: Seismic Lines Extending Across the HH Structure, Existing Wells and Fault Framework.

2.3 Seismic

The most recent seismic dates from the 1980s, the oldest data were acquired in the 1960s. There is an approximate north-south / east-west grid, but line orientation is very variable, spacing averages around 2-3km. Some lines have been reprocessed since original acquisition, with a substantial improvement in data quality. There is no seismic line in the Kingdom project, which passes directly through either well. Well CF-1 is 250m from the nearest seismic line (C80-130) and well HH-1 lies 85m from the nearest line (C85-74). Despite this, there is sufficient confidence in Vertical Seismic Profile (“VSP”) and synthetic character ties to seismic to ensure that the horizon identification is sound. An example of the key seismic lines is shown in Figure 4.

VSP data is available from wells HH-1 and HH-2 and there is a 1960’s check shot survey from CF-1. Seismic to well ties have been carried out to correlate the key well markers to the seismic events. The HH-1 well has some uncertainty because the VSP was stopped at the 9 5/8” casing shoe and it does not cover the shallow section above the Purbeck Anhydrite. However, the VSP acquired at HH-2 ran from surface to TD giving a good correlation between the well and the reflectors corresponding to the Purbeck Anhydrite and the Portland Sandstone along seismic line BP-85-74.

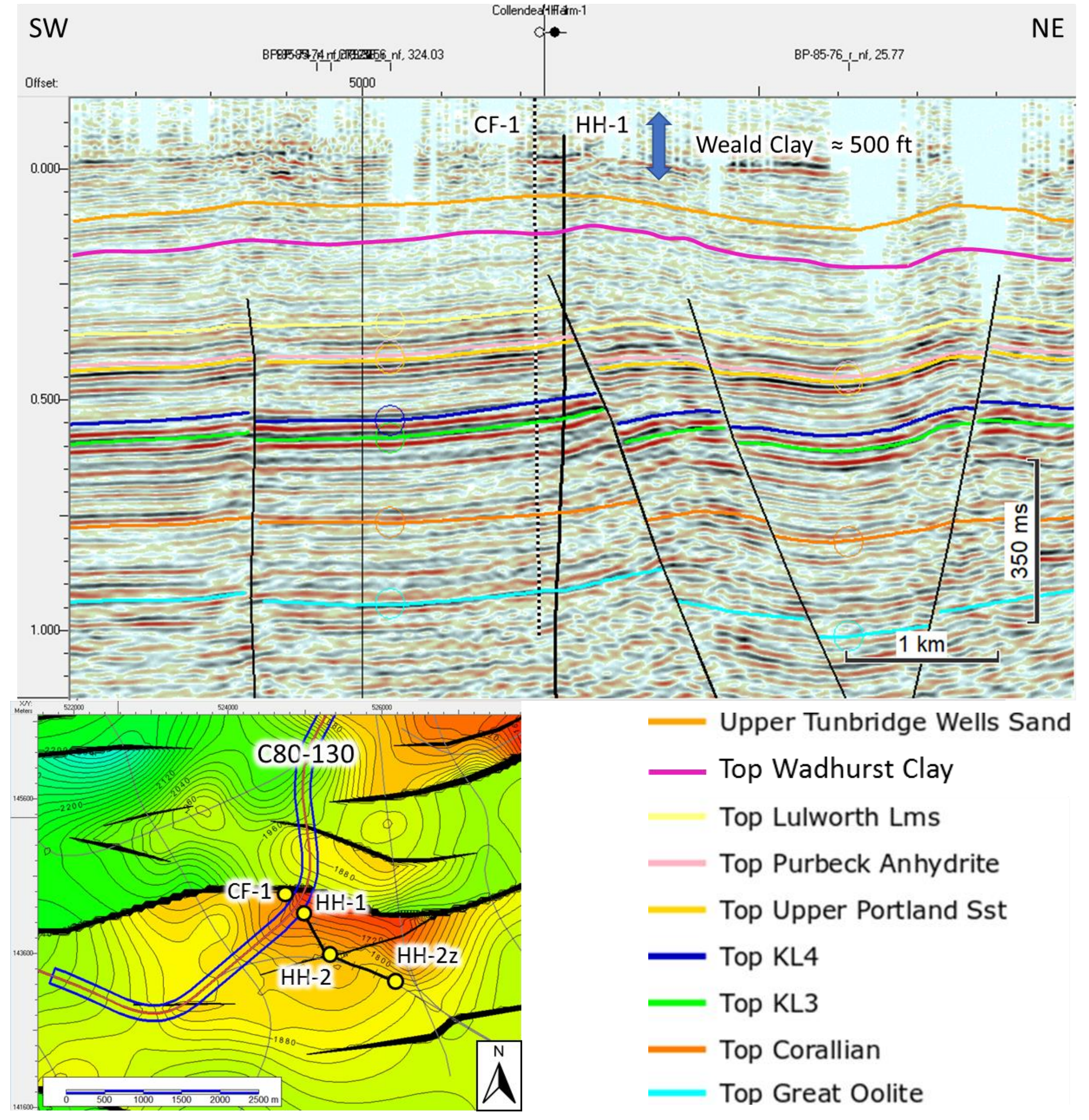


Figure 4: Example of Seismic Line Showing the HH Tilted Fault Block. The HH-1 and CF-1 Wells and the Interpreted Horizons are Displayed in the Section.

2.4 Reservoir - Portland Sandstone

The Upper Portland Sandstone, as penetrated by CF-1, HH-1 and HH-2, comprises a number of sandstone units separated by mudstone beds, which can be correlated between the three wells. The sandstone units show a coarsening upwards pattern consistent with the interpretation of shallow marine depositional setting. The sandstones are described as being very fine and well sorted with an argillaceous matrix and traces of glauconite. HH-2z has been drilled horizontally within the thicker sandstone unit identified in the Upper Portland Sandstone.

The top of the Portland Sandstone is well defined, being beneath the Purbeck Anhydrite and is capped by a thin fossiliferous limestone interval. The gross thickness of the sandstone in the wells is 150ft and 164ft in CF-1 and HH-1 respectively.

The Portland Sandstone structural map is shown in Figure 5. The existing wells (CF-1, HH-1, HH-2 and HH-2z) are displayed in the figure together with the trajectory of HH-3 which represents a potential infill well. The shaded wedge around HH-3 shows the area where the well can be drilled.

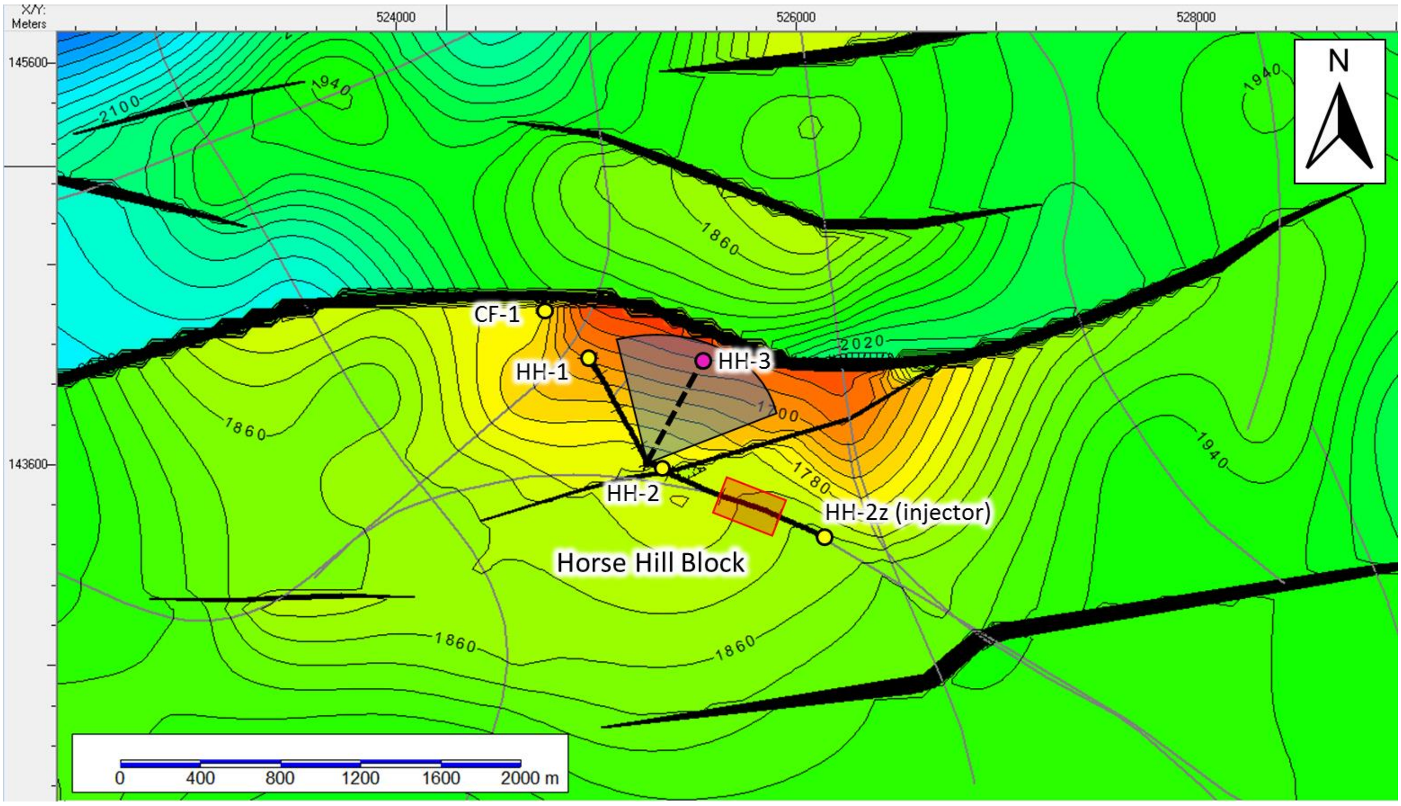


Figure 5: Top upper Portland Sandstone depth map in ft (TVDss). The HH-3 well is a potential infill well targeting the upper Portland Sandstone and the Kimmeridge Clay. The image shows the injection area (red box) within the Portland Sandstone at HH2z. The injection area is located between the 4 ½ inches slotted liner (2990 ft MD) and the Thermatek plug encountered at 3964 ft MD.

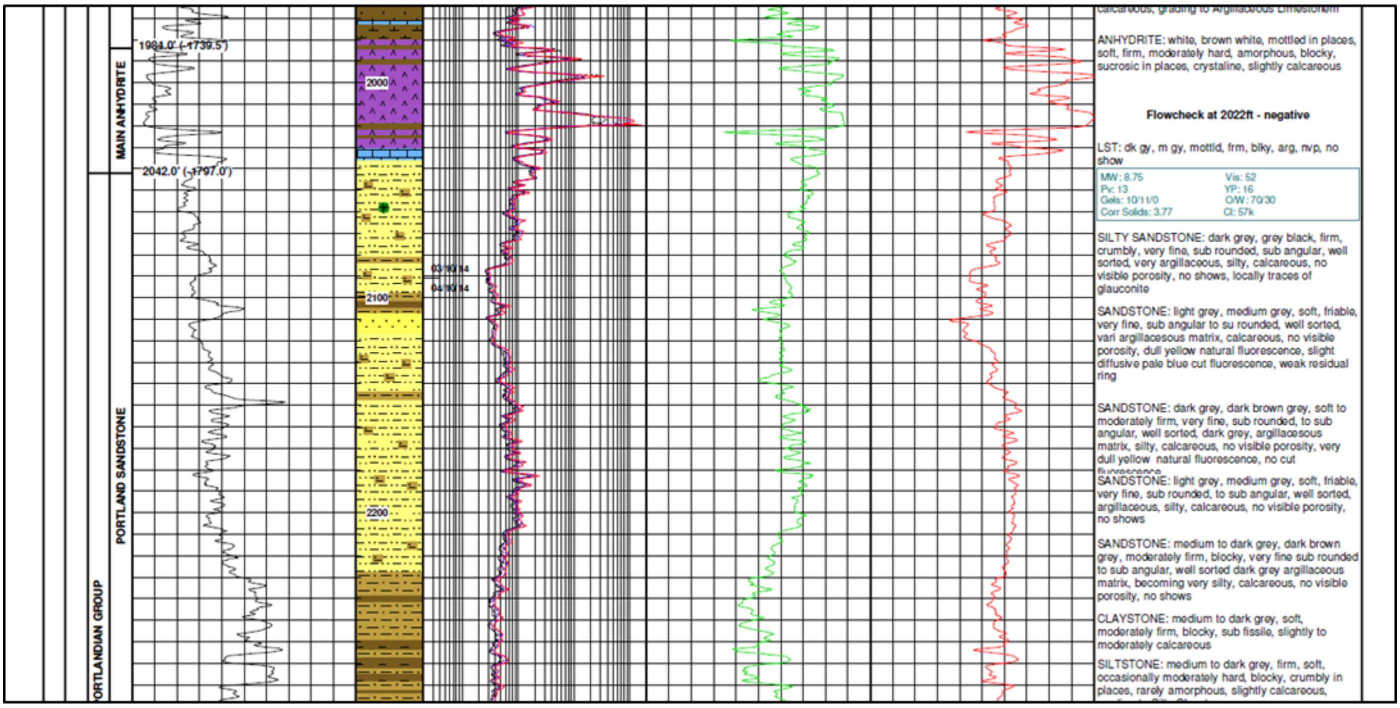


Figure 6: Horse Hill 1 Composite Log – Portland Sandstone

Regional data shows the sandstones thickening to the north into what was probably an active growth fault, the sandstone correspondingly thins to the south. An isopach map of the Upper Portland, shows the discovery to sit in an area of rapidly changing thickness. The thickness of the Upper Portland sandstone in the region of CF-1, as mapped, changes in thickness by 50ft over a distance of approximately 5km. The discovery covers an area of approximately 6 by 4km when considering the spill points of the structure as the limits. The variation and range of thickness observed in the wells may therefore not be truly indicative of the thickness variation in the reservoir across the area. HHDL have applied a narrow thickness range in which is justified by the wells but may not capture full range of possible reservoir thickness in this area.

2.5 Petrophysical Interpretation

Petrophysical interpretations carried out by Nutech Energy Alliance Corporation ("Nutech"), are available and the current interpretation is based on information gained from the well test carried out on the Portland Sandstone in HH-1 in early 2016 and the initial results from the 2018-2019 Extended Well Test, which is still underway.

The Nutech interpretation of HH-1 (Fig. 7) following the results of the test of the Portland resulted in a significant improvement in the net pay compared to conventional, older, evaluations. In the earliest (2014/15) interpretations; the net pay was estimated at approximately 48% of the total reservoir, although it was observed that the entire thickness of the Portland was oil bearing. The 2015 interpretation of net pay was based on the prediction that in zones where water saturation is high, only water would be produced. During the HH-1 well tests in 2016 and 2018-19 no water has been produced from the Portland, proving that either the log derived water saturation are correct but immobile or they are incorrect, core calibration will help to resolve this issue. The net pay interval is therefore significantly greater than previously thought.

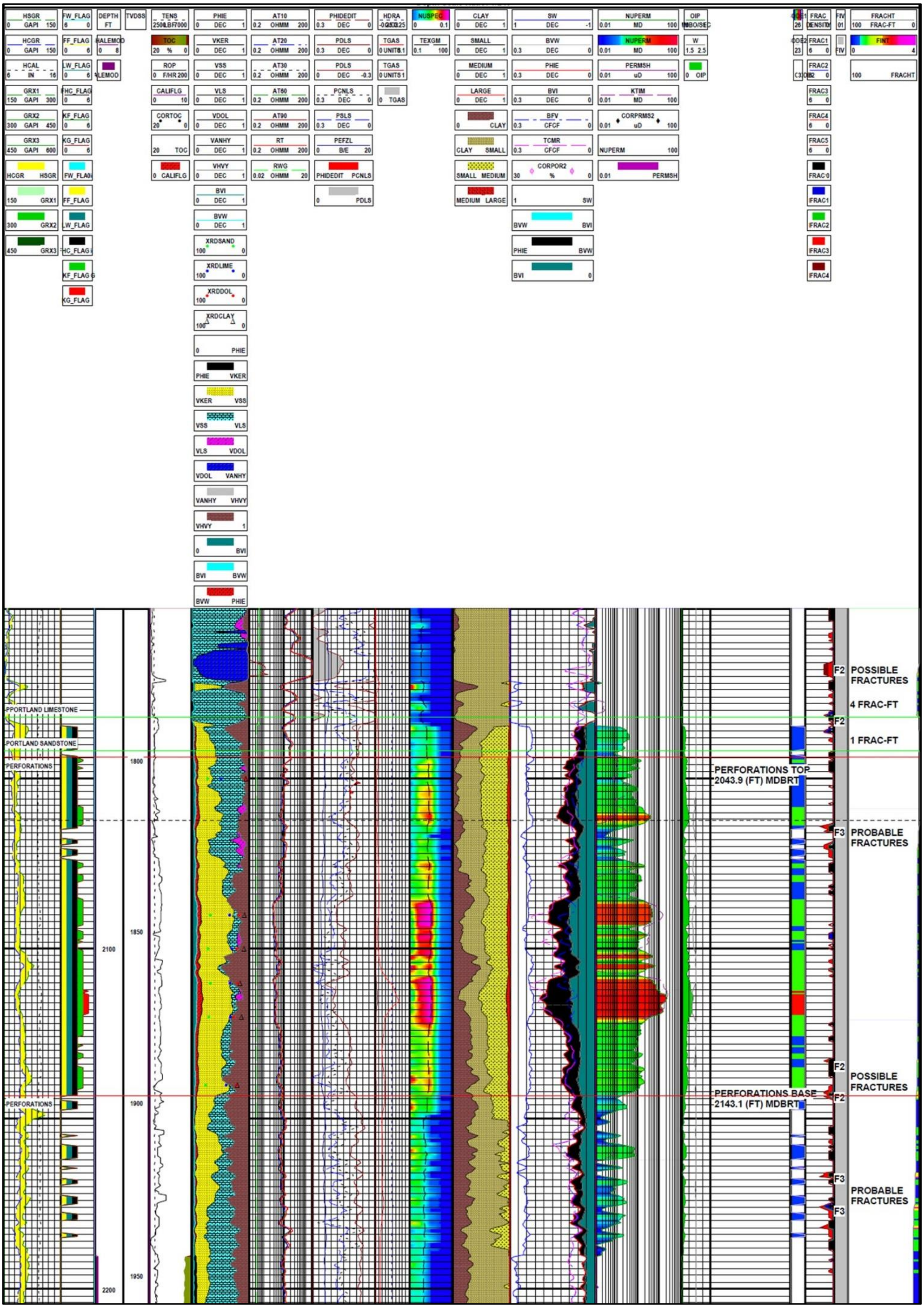


Figure 7: NUTECH CPI of Portland Sandstone

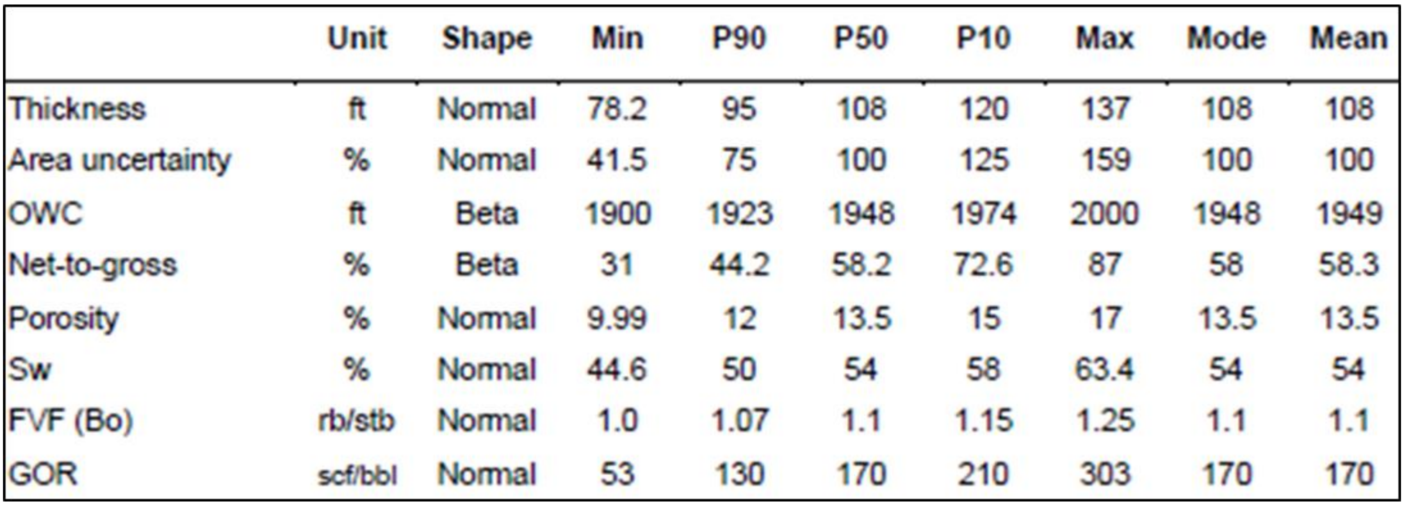
The 2016 well test was conducted over the entire Portland interval. In this zone conventional analysis shows the water saturation is relatively constant between 40 and 60% but unconventional analysis indicates that an Sw of 34% maybe more appropriate. Depending on rock quality, permeability is predominantly above 0.1mD with an average of about 2mD with some zones (4-10ft) of around 10mD and a high of 20mD.

Given the permeability profile and other available data it is a reasonable assumption that the entire Portland zone has contributed to flow, as in the model suggested by Nutech. However, there is no definitive evidence at this time. Further technical work is ongoing.

Using a realistic porosity cut-off to determine net reservoir and net pay; results in net to gross estimates that are similar to those reported in 2015. In line with the revision of the bound water model we have not applied a water saturation cut off in determination of net pay.

HHDL applied a range of cut offs to determine a range of NTG for the probabilistic volumetric estimation. The interpretation of porosity has remained unchanged from the previous Nutech interpretation, log porosity varies from 5.9% to 18.7% with an average of 13.3% in the CF-1 well and from 6.7% to 14.2% with an average of 10.2% in the HH-1 well. Resulting in a net to gross ratio of 58% in Horse Hill-1 assuming a 10% porosity cut off.

Water saturation has improved slightly in the latest interpretation by virtue of a more accurate assessment of Rw, Log data shows that the entire gross thickness of the Upper Portland Sandstone as penetrated in the wells is oil bearing, giving an ODT in both wells. The water saturation was determined for the pay zones giving averages of 56.4% and 46% with an overall range of 39% to 70%. The lowest water saturation corresponds with the highest gas readings on the mud log and is recorded approximately 60ft below the top reservoir in the HH-1 well. Fig. 8 below shows the current range of Portland reservoir parameters based on the conventional log analysis. These are currently being revised.



	Unit	Shape	Min	P90	P50	P10	Max	Mode	Mean
Thickness	ft	Normal	78.2	95	108	120	137	108	108
Area uncertainty	%	Normal	41.5	75	100	125	159	100	100
OWC	ft	Beta	1900	1923	1948	1974	2000	1948	1949
Net-to-gross	%	Beta	31	44.2	58.2	72.6	87	58	58.3
Porosity	%	Normal	9.99	12	13.5	15	17	13.5	13.5
Sw	%	Normal	44.6	50	54	58	63.4	54	54
FVF (Bo)	rb/stb	Normal	1.0	1.07	1.1	1.15	1.25	1.1	1.1
GOR	scf/bbl	Normal	53	130	170	210	303	170	170

Figure 8: Reservoir Parameters for the Horse Hill Oil Field

The parameters and results are consistent with previous interpretations and information from other wells in the basin. The interpretations of water saturation and porosity from logs also tie well to the measurements from core available in the CF-1 well.

2.6 Pressure & Fluid Data

Fig. 9 & 10 below summarise the reservoir pressure & fluid data.

Formation	Minimum Formation Pressure (psia)	Maximum Formation Pressure (psia)	Depth (ft TVD brt at 25 ft AGL)	Depth (ft TVDBGL)	Max Formation Gradient to Ground Level (psi/ft)	Max Equivalent Mud Weight (ppg)
Upper Portland	600	630	2034	2009	0.31	6.0
KL4	502	509	2827	2802	0.18	3.5
KL3	600	619	3102	3077	0.20	3.9

Figure 9: Formation Pore Pressures HH-1 Based on 2020 Well Test Gauge Data

Formation	Perforations (ft MDbrt)	Bubble Point (psia)	Temperature (deg F)	Gravity API	GOR (scf/stb)	Sample Depth (ft MDbrt)
Upper Portland	2034 to 2147	515	79.7	36	Solution GOR ~120, current prodcuing GOR ~ 180	Surface Recombination
KL4	2827 to 2848 & 2865 to 2930	785	96	41	312	Surface Recombination
KL3	3102 to 3185	815	99	40.6	287	2725

Figure 10: Well Test Pressure and GOR data 2018 Well Test

2.7 Fracture and Stress

Several studies have been carried out on fracture and stress gradients ranging from those focusing on a single well bore up to studies covering the whole of Southern England.

Fig. 11 shows a summary of the stress magnitudes across the Weald Basin. Fig 12 shows stress orientations across the basin – it can be seen that the primary stress pattern is NW-SE.

Fig 13 shows at the predicted reservoir properties through the section based on log data, offset core data and the well test data.

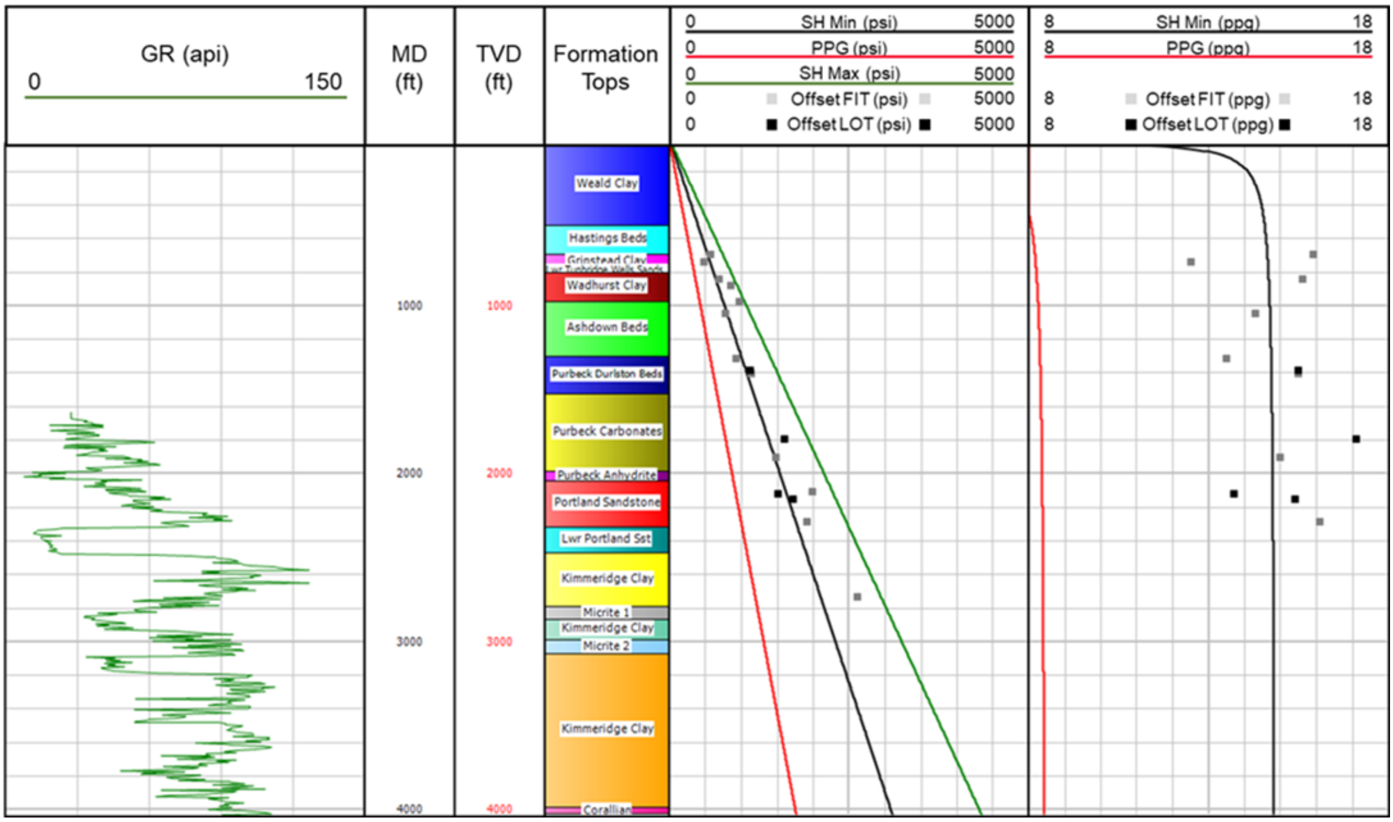
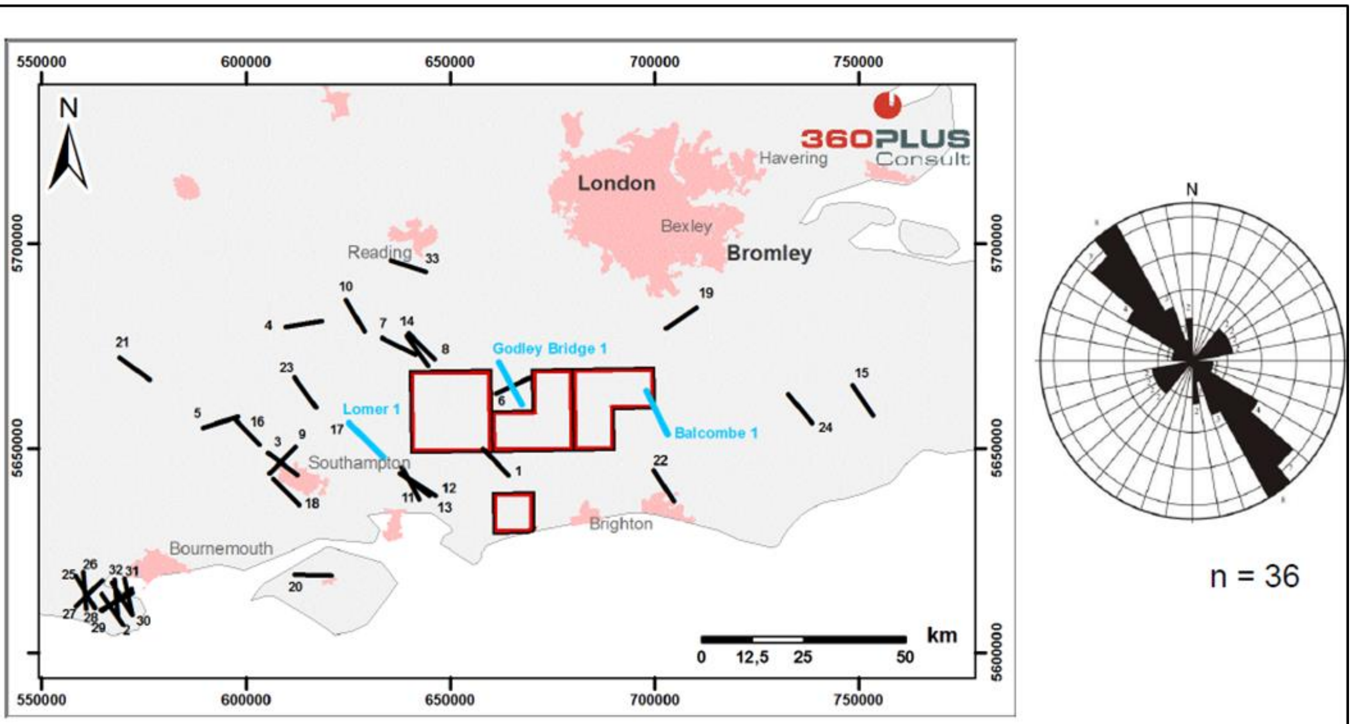
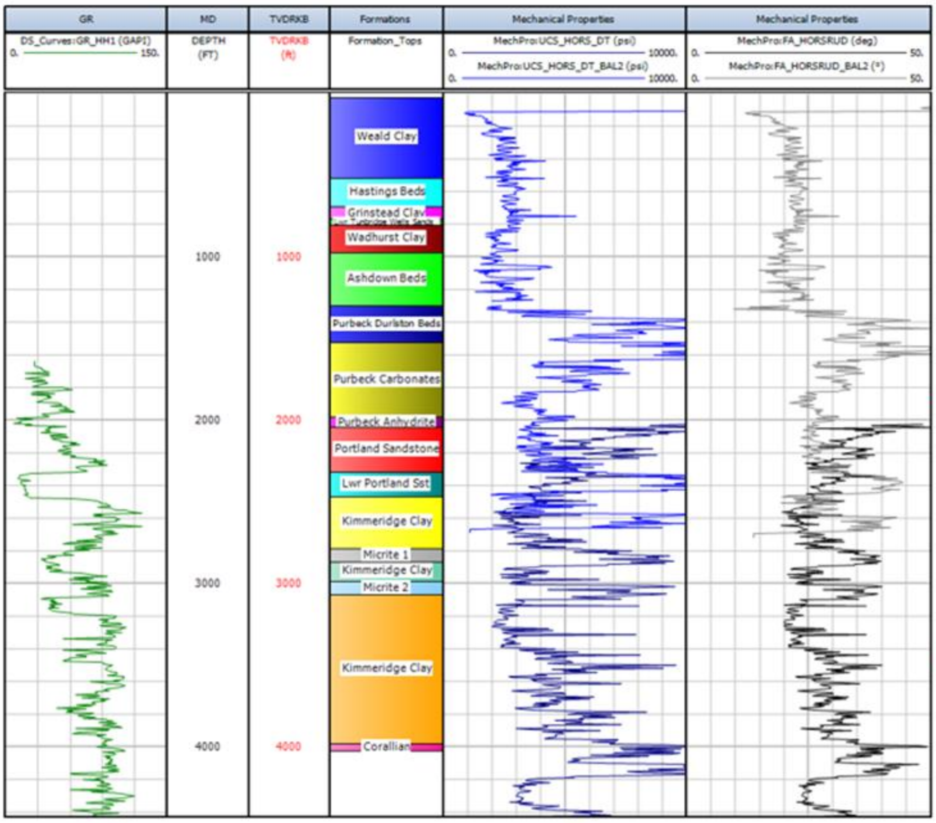


Figure 11: Stress Magnitudes in the Weald Basin



Average principal horizontal stress orientation: 140±18°

Figure 12: Regional Stress Orientation



Properties taken from HH-1 & BAL-2 and depth-shifted to prognosis

Relatively weak claystones indicated

Figure 13: Predicted mechanical properties of the section through Horse Hill 1

2.8 Faulting and Seals

The area is not heavily faulted and seismic data demonstrates that few faults penetrate to the surface. Most faults terminate at or close to the unconformity at the base of the Weald Clay group. Fig. 14 below shows a North-South seismic line across the Horse Hill Field. The main bounding fault near the Horse Hill 1 well is clear in the center of the section. Regional stress analysis indicates that these major faults have been closed for a significant period since the onset of basin inversion c. 38 mybp. The absence of surface oil seeps and the sub-surface data on pressures and the composition of oils from different reservoirs clearly prove that no vertical mixing has taken place for several million years and that even the largest faults must be sealing. The extensive and thick Weald Clay unit also forms an effective top seal to vertical hydrocarbon migration.

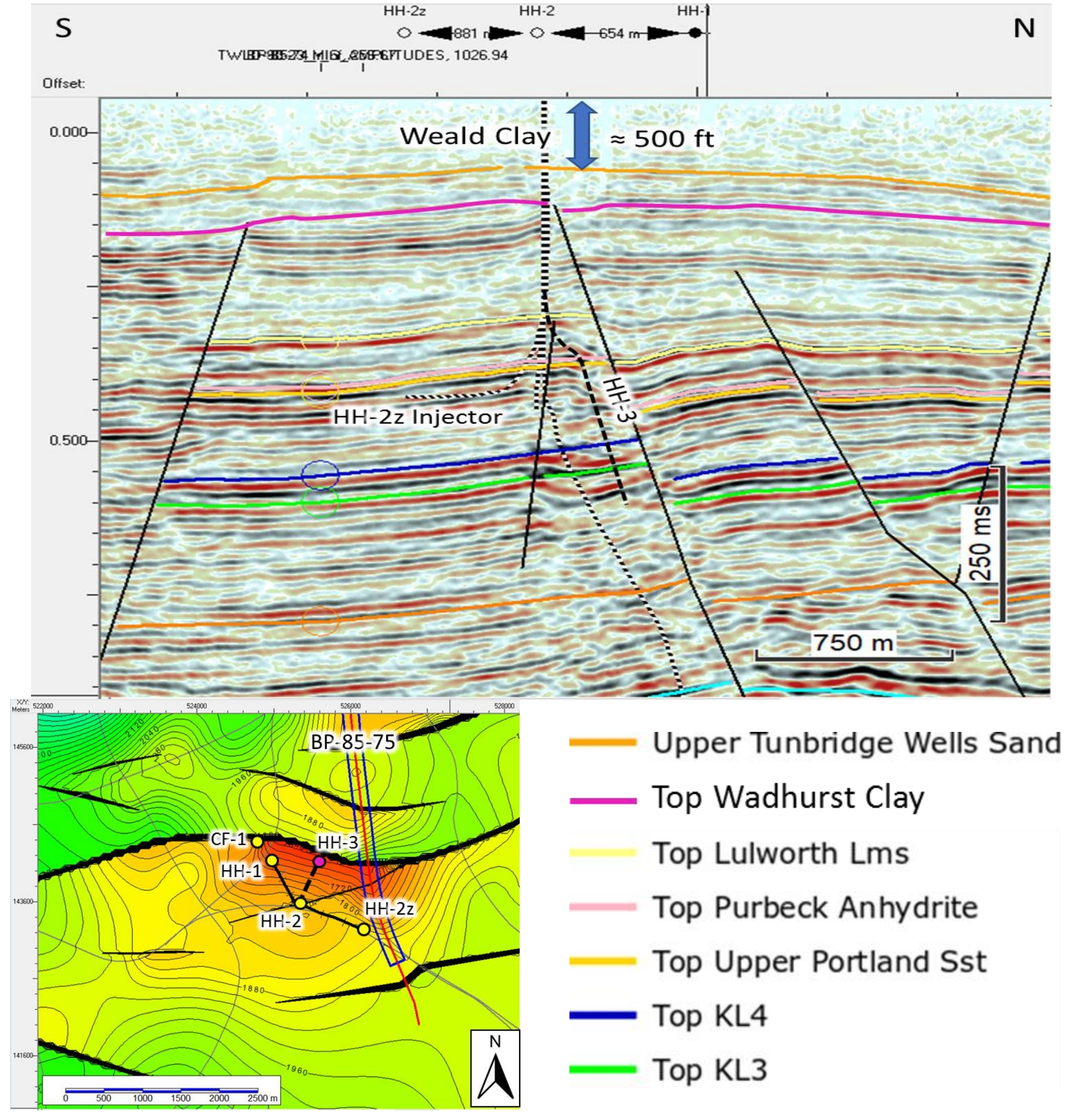


Figure 14: Seismic line showing the HH structure and the interpreted fault located between HH-1 and HH-2z. The image shows that the fault terminates against the Lulworth Limestone. The HH-3 infill well is displayed in the image.

The sandstones are overlain by a thick sequence of impermeable beds. Immediately overlying the sandstones are 50ft of totally impermeable Purbeck Anhydrite, then 700ft of interbedded impermeable claystones, siltstones and tight limestones before reaching the Ashdown Sands at circa 1300ft below surface.

The image shows that the fault terminates against the Lulworth Limestone. The HH-3 infill well is displayed in the image.

There are no records of any shows or occurrences of hydrocarbons in the sealing formations nor are there any recorded hydrocarbon seeps in the area, so the top seal is considered to be of excellent quality with capillary entry pressures far exceeding those of any available hydrocarbon buoyancy forces.

3. 2.9 Reservoir Geology for Re-injection

The Portland Sandstone Formation is a known oil and gas producing reservoir in the Weald Basin. The formation has produced oil from both the Brockham and Horse Hill oil fields and flowed gas on short term test from the Godley Bridge-1 well. The formation is also an established water disposal target, the Stockbridge oil field currently disposes of its produced water into the Portland Sandstone.

The formation is laterally continuous and is penetrated by wells throughout the Weald Basin. Several of these wells took cores within the formation and UKOG have data from 15 of these wells. This data has shown that the Portland Sandstone exhibits very high porosities and permeabilities (see figure 15 below).

The electric log data from the Horse Hill-2z well show that the formation has good porosity (circa 15% - 20%) and the well achieved initial flow rates of up to 1,087 barrels of fluids per day, indicating a good level of permeability. This provides solid evidence that the well will accommodate injection rates in line with current and projected water production rates from the Horse Hill reservoir.

These data from the Horse Hill-2z well and the offset core data, coupled with production and injection at multiple sites around the Weald Basin, demonstrates that the Portland Sandstone can accommodate significant levels of fluid flow, both into and out of the formation.

Not only is the Portland Sandstone an ideal water disposal target from a fluid dynamics perspective, it is also known to be hydraulically sealed. Therefore, there is no risk of fluid migration into groundwater sources. The formation is overlain by the Purbeck Anhydrite, a 50ft - 60ft thick laterally continuous unit of impermeable rock (permeability too low to measure). The efficacy of the Purbeck Anhydrite is evident as there are no active oil seeps in the vicinity of the Brockham and Horse Hill oil fields. If the faults which cut across structures were conductive fluid pathways or the Purbeck Anhydrite was breached in any locations, then oil seeps would be seen at surface.

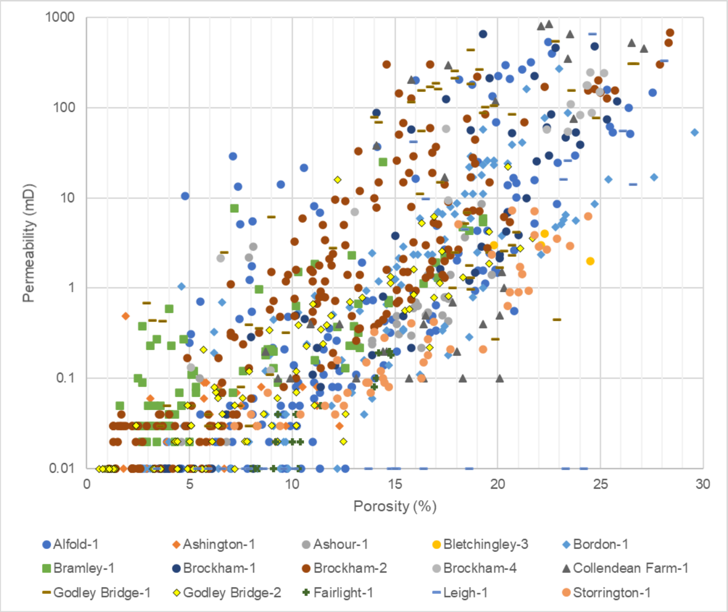


Figure 15: Porosity & permeability core data from the Portland Sandstone Formation.

4. PRODUCTION AND INJECTION

4.1 Modelling

Portland production profiles have been generated using Petroleum Experts MBAL software, to determine optimum hydrocarbon recovery. The results are summarised below:

Depletion drive Recovery Factors (without water injection) range from 8.6% using oil-wet relative permeability curves to 10% using water-wet relative permeability curves.

Water injection to provide production support was also modelled using a single water injection well. The modelling assumed full voidage replacement for the injector, however this has never been achieved onshore UK to our knowledge. Voidage replacement theoretically increases recovery factor and range from 14.6% to 45% as highlighted in Figure 16.

Figure 16 shows the Recovery Factor depending on initial production rates (Qi), the relative permeabilities and with or without water injection (WI).

Oil Recovery Factors (%)	Water-Wet Rel Perms		Oil-Wet Rel Perms	
	No Water Injection	With Water Injection	No Water Injection	With Water Injection
Qoi = 150 bopd	10	20	8.6	14.6
Qoi = 360 bopd	10	41	8.6	19
Qoi = 1000 bopd	10	45	8.6	22

Figure 16: Hydrocarbon Recovery Factor - With and Without Water Injection

The modelling concluded that water injection would be beneficial, enhancing production.

4.2 Water Injection Plan

Water will be re-injected into the Portland Sandstone at a bottomhole pressure below the Portland fracture pressure in order to ensure formation integrity. The top of the Portland Sandstone at HH-1 is at 2042 ft TVDBRT and Figure 11 shows the estimated fracture pressure (SHMin) to be ~1600 psi at this depth. The water injector will have a bottomhole injection limit of 90% of formation fracture pressure to ensure injection is always lower than the fracture pressure. These numbers are indicative and subject to revision upon performing injectivity tests within the Portland post future injection well drilling and completion.

Current plans are to re-inject any produced water and any collected rain water from the site. Water will need to be cleaned to injection quality (solids, bacteria control etc.) and injection placement to be considered. The water will be re-injected at rates up to a maximum required to achieve full reservoir voidage replacement, which would restore the reservoir pressure to close to pre-production levels. However, this is unlikely to be achieved from the water resources on site.

Based on the permeability of the formation, the injectivity of an injection well is expected to be good and high pressure injection is not anticipated. There will be no plans to increase reservoir pressure over and above initial reservoir pressure condition (no overpressure).

The location of the injector well (HH-2z) is shown in Figure 15

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APPENDIX 1 - RESPONSE TO ENVIRONMENT AGENCY QUESTIONS

Confirm the:

- *Location of identified faults in the reservoir with respect to the location of the re-injection well; and*
- *Lateral and vertical extent of these faults.*

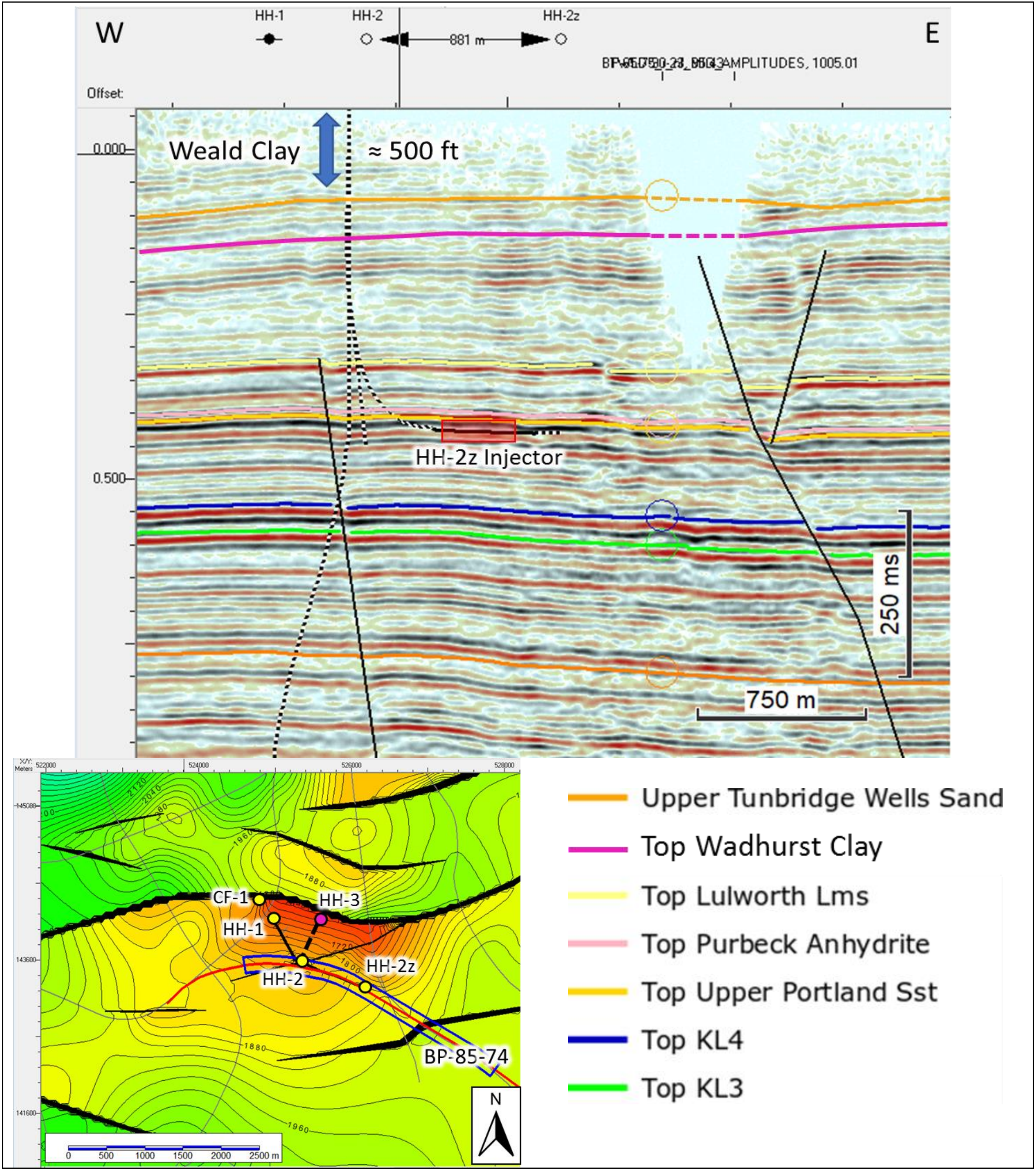

Figure 17 – Seismic line parallel to the HH-2z injector. The length of the injection area is highlighted by the red box. The fault located to the west of HH-2z terminates against the Lulworth Limestone. The seismic interpretation suggests that the fault located between HH-1 and HH-2z unlikely provides a pathway for transmission of fluids between re-injection and shallow formation containing groundwater.

The structural map (Fig. 17) shows that the lateral extension of the fault interpreted between HH-1 and HH-2 is circa 2.4 km. The offset of the fault based on the top Upper Portland Sandstone depth map varies between 5 and 15 metres, suggesting that fluid injection from HH-2z would allow to pressure support HH-1 via lateral migration.

Vertical migration of oil from the reservoir formations into the shallower formations, such as the Upper Tunbridge Well Sand, through fault pathways is unlikely in this area, as confirmed by the oil accumulations at Kimmeridge and Portland levels. Moreover, the absence of surface oil seeps and the composition of oils from different reservoirs clearly prove that no vertical mixing has taken place and that even the largest faults must be sealing.

Provide an explanation why geological faults are unlikely to provide a pathway for transmission of fluids between the re-injection reservoir and shallow formations containing groundwater.

The fault bounding the Horse Hill structure to the north provides an effective seal which allowed an oil column to be accumulated at Portland Sandstone and Kimmeridge levels. Consequently, the faults across the area unlikely provide a pathways or conduits for the re-injected fluids to reach the shallow bearing water formations. The absence of oil seeps at the surface also indicate that the faults across the Horse Hill field are sealing faults.

Confirm the key seismic lines which have been re-processed and when the data was re-processed to confirm the structural geological setting of the oilfield.

Seismic line	Year of Acquisition	Re-processed	Year of reprocessing
BP-85-75	1985	No	
BP-85-74	1985	No	
C80-130	1980	Yes	1984
C79-36	1979	Yes	1984, 1988, 2009
V81-51	1981	No	

The table shows whether the seismic lines have been reprocessed or not according to the UK Geophysical Library. They don’t have a re-processed version of line BP-85-74 and BP-85-75.

In addition, at the request of the Environment Agency Figures 4, 7, 14 have been revised so as to be easier for the reader.