Figure 10 – Mupe Rock

As the trip drew to a close the group thanked Maurice for a very informative and enjoyable field trip.

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"Directional Drilling – From Geometry to Geology"
By Phil Burge

Introduction

Within the upstream oil and gas industry there has been, and to some extent remains a tension between the drillers and the geologists. The former are driven by a "can do" attitude where the aim is to drill and complete the well as quickly as possible (within the necessary bounds of safety and well integrity), while the geologists would like to extract as much information as possible about the formations being drilled, which requires time and adds to costs. Horizontal drilling and geosteering has brought the two disciplines together such that drilling performance and well productivity are increased by geological interpretation in real time.

Old time drillers attempted to keep the wells vertical. This is not easy, creating problems as wells tended to intercept or end up draining a neighbouring property, intentionally or otherwise! Directional drilling, pioneered by John Eastman began in the 1930's. Enabled by simple surveying tools providing inclination and azimuth data and using mechanical properties of the drillstring, drillers could drill away from the rig location in a preferred direction. These methods were used until the 1970's and early 1980's when bent sub motors and then steerable downhole motors provided greater control of the well path.

Steerable motors in conjunction with Measurement While Drilling tools (MWD) allowed more complex directional wells to be drilled leading to horizontal drilling and multilateral drilling. In the mid 1990's Rotary Steering Tools (RST) were developed. These tools greatly increase the efficiency of directional and horizontal drilling in particular, allowing geologists to target more complex reservoirs and drillers to plan more complex well paths.

Introduced in 1939, mud logging was the main information gathering method. Samples of drilled cuttings were examined at surface, indications of hydrocarbons noted and a log of the formations drilled compiled. The mud loggers worked closely with the wellsite geologist. Geological and formation fluid data lagged drilling by some time as mud loggers and geologists had to wait for samples to appear at surface.

Beginning in the 1920's through the work of the Schlumberger brothers, and developed continuously ever since, electric logging, or wireline logging has been used to gather geophysical information providing detail on rock and fluid properties. Electric logs are deployed into the well by wireline and as such the data is collected after drilling an interval of the well.

From the early 1980's electric logging sensors were, along with existing directional sensors added to Measurement While Drilling (MWD) tools. The initial benefit of MWD was in improved directional drilling performance. As geophysical measurements became more reliable and sophisticated, FEMWD (Formation Evaluation MWD) began to add to or in some cases replace electric wireline.

A real game changer was the combination of RST (a drilling tool) and FEMWD (a geophysical measurement tool) and the development of remote real time data centres. Real time geophysical data is now interpreted away from the wellsite and decisions on steering the well and are made by collocated multi discipline teams. The history of these developments are shown in the time line in **Figure 1.**

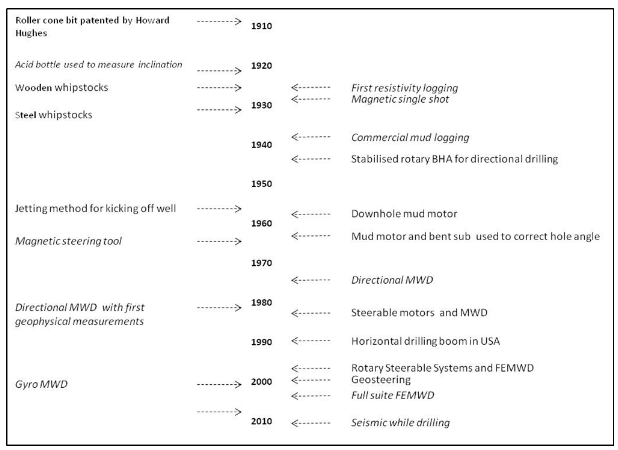

Figure 1: *Time line of major drilling and measurement technologies. Measurement technologies shown in italics*

The industry has moved from drilling based on geometry to drilling based on geology and from interpretation days or hours after drilling to seconds. The consequences in terms of performance and productivity have been game changing.

This paper will review the development of directional drilling and data collection technologies in the context of the geology.

Fundamentals of drilling

Drilling for oil and gas uses many of the same principles as drilling a hole in a wall using an electric drill. Ever tried this and placed the hole in the wrong place, drilled into the wall at the wrong angle, broken the drill bit or got it stuck in the wall, hit something you didn't mean to hit like a water pipe? If so, then you have encountered the same problems facing oilfield drillers!

What do you need to drill a well? As a minimum:

- A drill bit – These come in three types; roller cone, diamond and PDC (polycrystalline diamond compact). The selection of the drill bit is determined by the geology (hardness, abrasiveness, homogeneity and variation).
- Drill string – The drill string comprises numerous types of pipe that connect the drill bit to the surface and provides: a fluid path for the drilling fluid (mud) from the surface through the drill bit and back to the surface (hydraulic energy), weight and rotation at the drill bit (mechanical energy)) and stabilise the drill string in the well. The drill string includes drill collars, stabilisers, measuring tools as required and usually a directional control device either a steerable motor or a rotary steerable tool. All the components below the drillpipe comprise the Bottom Hole Assembly (BHA)
- Drilling fluid – The drilling fluid (mud) has numerous functions including lubrication and cooling the bit, controlling downhole pressure, providing support to the wellbore to prevent collapse, and controlling chemical reactions between the mud and the rock and transport drill cuttings to the surface for examination.

To drill a well path along a prescribed trajectory to a specific target requires a means of initiating the well in the correct direction and adjusting the well direction and inclination as required to avoid intersecting other wells and to reach and remain within the geological target. We shall now look at how these technologies have evolved.

How geology determines drilling performance
Drilling Hazards

Rock types present a range of potential drilling hazards, some of which are summarised below:

- Mud rocks from claystone to shale are the most common rocks drilled in a sedimentary basin. Major basins outside of the Middle East include the Gulf of Mexico, the North Sea and the Niger basin in West Africa. In many parts of the North Sea a well would need to be drilled 3,000 meters through Quaternary and Tertiary clay and shale before reaching potential reservoirs in the Cretaceous and Jurassic. Shale causes problems due to swelling of hydrophilic clay minerals (smectite) and collapse (sloughing) due to insufficient pressure exerted by the drilling fluid.
- Salt can cause problems either by plastic deformation into the wellbore which causes the drillstring to become stuck or by dissolving into water based drilling fluid. An enlarged borehole can lead to problems running and cementing casing. Salt can be drilled easily with the correct drilling fluid density and chemistry, commonly a salt saturated fluid.
- Chert and anhydrite can be difficult to drill given their hardness. Problems arising include damage to the drillbit and shock and vibration leading to damaged drillstring components and even to failure (snapping) of the drillpipe.
- Conglomerates, due to their heterogeneity present similar problems to those of chert.

Stresses within the formations due to local or regional tectonics, from small scale faults to Andean tectonic stresses can lead to wellbore failure characterised by collapse and in the latter case severe wellbore enlargement[1]. This problem is more apparent in high angle and horizontal wells.

Then there is geological uncertainty particularly in exploration drilling. Included in this category are uncertainties in pore pressure regime (higher than anticipated) and uncertainties in geological prognosis (subsalt plays for instance).

Crooked hole country

Figure 2 shows an oilfield from the early days of the industry; fields were developed by drilling hundreds of densely packed wells. Not only is this inefficient but the drillers had no way of knowing where the well was actually being drilled. It might well be drilling into a neighbour's well and it was might well be drilled into a neighbours part of the field. It is in fact very difficult to drill a vertical well. This is in large part due to geology. Drillers used the expression "crooked hole country"[2] to describe areas where the well deviates from vertical and back again as each successive formation is drilled. Imagine a sequence of rock formations each of different hardness and dipping at some angle. The drill bit will get deviated towards the harder formation as the drillbit starts to drill the up dip hard formation and vice versa as the drillbit starts to drill the down dip soft formation. This is analogous to the refraction of light.

***Figure 2**: Drilling at Signal Hill, Long Beach California in 1920's. The large number of rigs (and hence wells) shows that this field was drilled before the advent of directional drilling and before much of an appreciation of reservoir engineering.*

Similarly, drilling across a fault can cause the drill bit to be deviated. In the early days drillers fought the geology to keep a wellbore close to vertical. Local knowledge on the part of the driller was essential.

The development of directional drilling

Directional drilling as a discipline started once drillers appreciated that wells were not vertical! Thus a key aspect of directional drilling is measurement of inclination (angle of the well from vertical) and azimuth (compass direction from north).

The first magnetic single-shot and multi-shot instruments using magnetic compass and plumb bob were developed in 1929 by John Eastman to measure inclination and azimuth. These sensors were dropped down the drillstring to land on a muleshoe. After a set time, a photo was taken to record the compass direction and angle of the plumb bob. It was soon realised that wells which were thought to be vertical could have inclinations up to 50 degrees! [3]

Once the inclination and azimuth at a particular point in the well is known, the well path between two survey points can be calculated using trigonometry. The mathematics of survey calculations became more complex and accurate as the mathematics moved from simple tangential methods to more advanced radius of curvature methods first used in the 1970's. Even with advanced mathematics various errors, such as sensor calibration, distance between surveys and magnetic interference cumulate to provide an overall "ellipse of uncertainty", that is a range of possible actual wellbore position characterised by an ellipse around the wellbore as shown in **Figure 3**. We shall return to this problem later in the story.

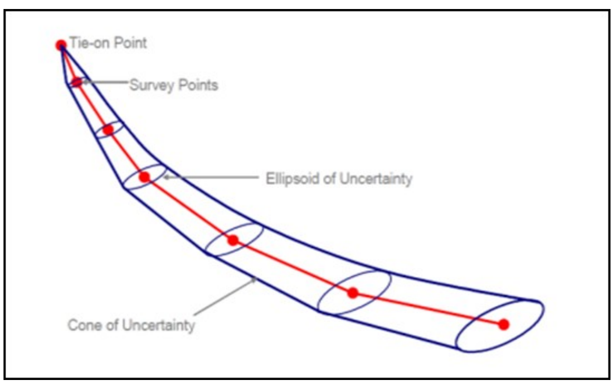

Figure 3: *The "ellipse of uncertainty" – how far off you can be if you rely on geometric placement of the wellbore.*

Although directional drilling started as a means of keeping a well near vertical, intentional directional drilling has many applications, not least of which must be the capability of drilling 10 – 30 wells from an offshore platform. Without directional drilling offshore fields would not have been developed.

An initial direction for the well was achieved either through use of a whipstock or by jetting. A whipstock is a metal wedge placed in the hole with the hypotenuse of the wedge oriented in the preferred azimuth. Jetting, first used in the 1950's is where the drill bit is held at a particular depth and, without rotating the drillstring high pressure drilling fluid washes out the side of the wellbore. (**Figure 4**). This creates a ledge that is used to nudge the well in the desired direction. A reasonably useful method in soft formations.

Figure 4: *Use of drill bit nozzle in jetting and whipstock. Both used to initiate a directional well*

From the early 1940's, controlling direction and azimuth while drilling was achieved by adjusting the location of stabilisers along the BHA as shown in **Figure 5**. Three different assemblies were used[4]:

- To build angle (inclination) a fulcrum assembly is used. In this assembly a stabiliser is placed directly above the drillbit and a second stabiliser placed 20 – 30 metres above the first. If the well has any inclination then this BHA will bend creating a side force at the drill bit and bit tilt.
- To drop angle a pendulum assembly is used. Here the near bit stabiliser is removed and gravity acts on the bit and lower drill collars causing a downward tilt of the bit.
- To hold angle a packed hole assembly is used. This assembly has up to five stabilisers located at around 10 metre intervals in the BHA. The packed hole assembly limits bit side force and bit tilt to nearly zero.

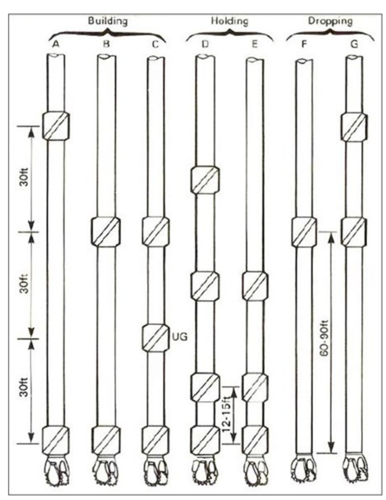

Figure 5*: Bottom Hole Assembly design for build, hold and drop. Used from 1940's to 1980's. Placement of the stabilisers creates either a build, hold or drop tendency.*

In the early 1960's downhole mud motors were used for the first time in conjunction with a bent sub. The downhole motor is an inverted Moineau pump. Pumping mud through the motor causes the drill bit to rotate which means the drill bit will rotate when the drillstring is not rotating. The motor is around 12 metres long and on top is placed a bent sub (a short length of drill collar) . This sub has an offset connection which gives a tilt to the motor of a few degrees. This creates a bend between the drillbit and the top of the bent sub, which if the drillstring is held in the same orientation, will drill a known curve (radius of curvature), either up or down or left or right.

Measurement of inclination and azimuth was initially by single shot sensors and then by steering tools. Steering tools use magnetometers and inclinometers to provide continuous data along an electric wireline running inside the drillstring and through a side entry sub at the surface. With this method the drillstring cannot be rotated and once the change in hole inclination and or azimuth has been effected the entire drillstring is removed from the well and replaced by a packed hole assembly as described above.

A major breakthrough in both measurement and directional drilling control came in the late 1970's and early 1980's with the introduction of Measurement While Drilling (MWD) tools and steerable motors. The first MWD tools consisted of the same sensors as used in the steering tool with the addition of a means to transmit data via pressure pulses through the drilling fluid. This is done by partially restricting the flow of drilling fluid to create a positive pressure pulse and opening the valve to return the pressure to normal, thus a simple binary code can be transmitted to surface.

The steerable motor is a downhole motor but the bent sub has been moved from above the motor to above the bit. Doing this means that a much smaller angle of tilt creates the same radius of curvature as the larger angled top bent sub. With a smaller tilt angle the steerable motor can be rotated from surface once the required change in hole inclination and or azimuth has been achieved. This means that the motor does not have to be removed from the well and replaced by a packed hole assembly but can, by a sequence of non-rotating and rotating drill along a prescribed well path. **Figure 6** demonstrates the way in which three points of contact along the length of the steerable motor define the arc creating the change in wellbore inclination or direction.

Perhaps the most significant advancement in directional drilling was horizontal drilling using steerable motor/ MWD combinations, which rejuvenated the Austin Chalk play in 1989. The Austin Chalk, a late Cretaceous formation in West Texas had been producing since the 1920's from vertical fracture porosity. Production had been maintained and even increased by the use of acidisation and hydraulic fracturing, Even so, drilling was a bit hit and miss. However, with horizontal drilling a well could be drilled that intersected numerous fractures and increased production rates.

Horizontal drilling and hydraulic fracturing is now being used to develop the underlying Eagle Ford shale.
At the end of the 1980's the prevailing wisdom was "why drill horizontal wells", after the success of the Austin Chalk and similar field redevelopment in the USA, this switched to "why not drill a horizontal well?". As the statistics show in **Figure 7** almost 90% of wells drilled in the USA are horizontal. The same is rue for many other areas of the world.

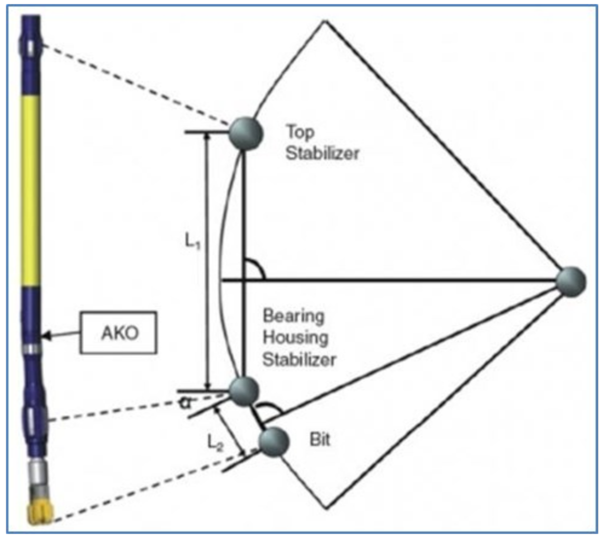

Figure 6: *Principle of steerable motor using 3 point geometry to create an arc. From Baker Hughes.*

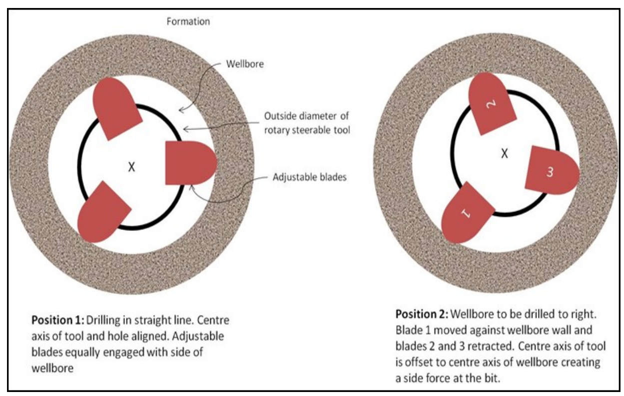

Figure 7: *Representation of operation of rotary steerable tool.*

While we have focussed on the directional sensors in MWD tools, geophysical measurements were also being developed, initially simple Gamma Ray sensors measuring natural radiation and used to identify shale, and basic resistivity measurements used to identify formation fluids. In the late 1990's developments took off! Logging While Drilling (LWD) tools incorporate the necessary directional sensors and a full range of geophysical sensors from Gamma Ray to NMR (nuclear magnetic resonance) to provide a complete interpretation of the geology and fluid properties.

The modern era
From vertical drilling to rotary steerables

Before we get too deep into the modern era we need to revisit the fact that drilling a vertical well is difficult. In the mid 1980's the German government sponsored a project, the Kontinentales Tiefbohringprojekt (KTP) which ran between 1986 and 1995[5] . The aim of this project was to drill to the *Erbendorfkörper* – a deeplying mass that is believed to be on the boundary of a former continental plate and is identified by its characteristic reflection of seismic waves. The target depth was between 10 and 14 Km at a location in northern Bavaria. Previous deep hole drilling on the Kola project in Russia had shown that deviations in wellbore inclination led to excessive friction between the rotating drillstring and the wellbore. To avoid this, a "vertical drilling machine" was designed and developed by Eastman Christensen (taken over by Baker Hughes in 1989). This drilling tool used the same principles of side force at the bit and measurement using on board inclinometers, with the side force achieved by the use of a near bit adjustable stabiliser. When the inclinometers measured a deviation from vertical in a certain direction, the stabiliser blade in that direction was extended creating a side force in the opposite direction. By using three stabiliser blades 360 degrees of freedom can be realised. The basic principle of is shown in **Figure 8** . This well was drilled to 9,101 metres with inclination deviations less than 2degrees. **Figure 9** shows the complexity of the geology and highlights the hazards to vertical drilling of dipping beds and faults.

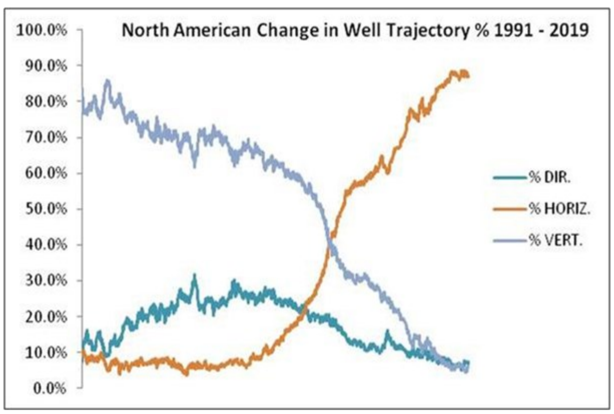

Figure 8: US Well Trajectory Changes 1991 – 2019. Clearly shown is the change in percentage of wells drilled horizontally versus vertical and directional wells. This is largely driven by the oil shale drilling boom. Data from Baker Hughes Rig Count.

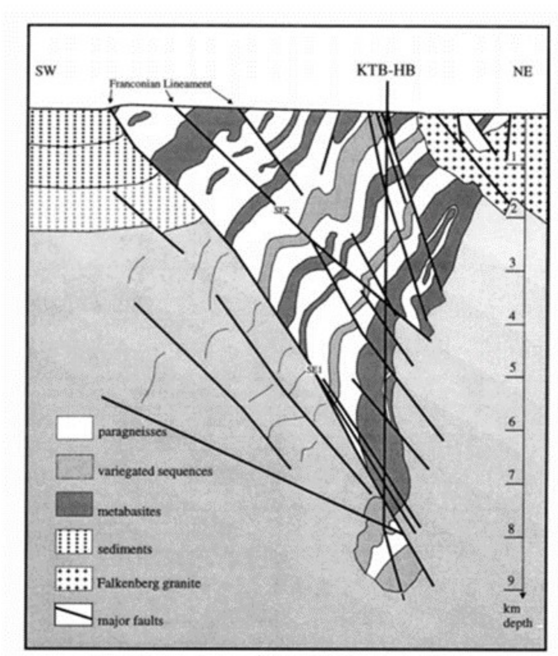

Figure 9: Cross section of KTP borehole showing dipping beds and faults. Impossible to drill a vertical well in this geological and structural environment.

Having established the principle of closed loop control of inclination of the wellbore it is a logical step to employ the same principles to control both inclination and azimuth. Thus was born the rotary steerable tool (RST). This technology allows the wellbore to be steered in a continuous smooth path making the drilling process more efficient and providing a high quality wellbore.

Geosteering

So far in the story, directional drilling regardless of technology has been concerned with the geometric placement of the wellbore in 3D space.

As reservoirs become thinner and more complex, geometric placement becomes more problematic due to calibration errors, sensor resolution, and magnetic interference amongst others. Significant errors in wellbore position particularly at higher angles of inclination are the result. Suppose the cumulative error of azimuthal measurements is +/- 1 degree. By geometry this will lead to a positional error of +/- 5.25 after 300 metres of well drilled.

When drilling long horizontal wells, even holding the well inclination at 90 degrees and maintaining a constant azimuth means that the actual well lies within a range of uncertainty that could be quite substantial. From the example above, a 3,000 metre horizontal would have a positional error of +/- 52.5 metres.

Until the advent of geosteering, geologists had to rely on data that arrived long after the formation was drilled. Drill cuttings could take 2 – 3 hours to return to surface for examination and FEMWD data lagged actual drilled depth as the sensors are located 15 – 30 meters behind the drill bit.

To drill into a small target and remain within the target means that you have to overcome the positional uncertainty and the time lag in data.

Even if we hit the top of the target zone there is still geological uncertainty for instance a channel sand or lagoonal environment, and structural complexity (dipping formations, faults). What is needed is a means of controlling the direction of the wellbore so as to keep the well within the "sweet spot" to optimise production. The "sweet spot" might be defined as a vertical distance below the top of the formation or a vertical distance above the oil-water contact. Every metre of horizontal drilled outside the "sweet spot" means reduced production.

Resistivity and gamma ray FEMWD sensors allow the drilling team to recognise changes in geology before the drill bit has entered the target formation and while drilling the target formation. We have now moved away from geometry as our means of determining where the well is and where it is to go, to the use of geological parameters. This is called geosteering.

Resistivity logs measure the ability of rocks to conduct electrical current and are scaled in units of ohm-meters. The resistivity measurement is a function of the formation fluids, water having low resistivity and oil higher. Resistivity tools are designed with a range of depths of investigation with modern FEMWD resistivity sensors having a depth of investigation of over 60 meters and provide measurements in multiple (32) discrete directions. This is called azimuthal measurement, where azimuth refers to high side of the hole. Using the combination of deep and shallow measurements oncoming bed boundaries or faults or proximity to the oil – water contact can be predicted and the well steered in the appropriate direction.

Nowadays many geosteered wells are coordinated from a Real Time Operations Centre. Data from the rig is sent to an office facility manned by geologists, geophysicists, directional drillers and FEMWD analysts. All the expertise necessary to drill a complex well are collocated and can collaborate to achieve the objectives of the well. A spin off of this technology is that a group of experts can collaborate on a number of wells simultaneously reducing the demand for expertise at the rig site.

Summary

The combination of directional drilling and downhole sensor technology has been a game changer in terms of the types of well that can be drilled, the size of targets, the redevelopment of older fields, the capability of horizontal drilling and the development of shale plays. The latter has been instrumental in driving the development of many technologies in addition to directional drilling.

The industry has moved from individual disciplines, and tension between these disciplines, to a much more of a collaboration brought about by the move away from geometry and towards geology as the deciding factor in placing a wellbore.

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Tintern Geology Field Trip – Led by Dave Green
By Bob Mustow.

The discussion over the first sample Dave showed us, a stone off the path he had just broken open, went like this:
Dave: “You can see what this is…”
Me: “Limestone”
Dave: “…Sandstone”
So don’t expect anything too technical in the following article!

The Wye Valley at Tintern is 217m at a trig. point near the car park north of Tidenham Chase, and 10m at the river, so about 207m or 680ft deep and covers a period from the end of the Devonian, (about 340mya), to the beginning of the Carboniferous, (about 360 mya).

Two theories of the way the Wye meanders ignoring any geological or geographical features. The generally accepted one is that the curves of a mature river formed in some higher material subsequently eroded way and, helped by uplift, caused the path to be eroded into the underlying strata. Or, secondly, the route may have been carved by huge volumes of glacial melt water loaded with debris perhaps flowing from a collapsed lake dam. Whatever the cause, it has given us easy access to the geological sequence here.

Fig 1: Heathland

We started by walking from the free car park just north of Tidenham Chase, through the wood and, crossing Miss Grace’s Lane, (which leads to the second longest cave system in the Forest of Dean area), out onto the plateau grassland towards Offa’s Dyke and the Devil’s Pulpit [Fig 1]. This area is Dybrook Sandstone; a free-draining, porous, non-cemented material, grey in colour as it is free of iron which would colour it red. Soluble bases leach down to lower strata leaving the quartz rock free of basic minerals, so the soil is acidic giving rise to areas of heathland here which are the subject of a project to restore these to their natural state [Fig 2].

As we approached the trees above Offa’s Dyke we crossed thin bands of Whitehead Limestone and then Crease Limestone. The Whitehead Limestone formed in quiet lagoons over the Crease Limestone around 340 mya. It is fine grained and was known as ‘Chinastone’ by quarrymen because of this and the white colour.