A REVIEW OF POST-STACK 4D SEISMIC TIME-SHIFTS,
PART 1: VALUES AND INTERPRETATION

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A review and analysis of post-stack time-lapse time-shifts has been carried out that covers published literature supplemented by in-house datasets available to the authors. Time-shift data are classified into those originating from geomechanical effects and those due to fluid saturation changes. From these data conclusions are drawn regarding the effectiveness of post-stack time-shifts for overburden and reservoir monitoring purposes. A variety of field examples are shown that display the range and magnitude of variation for each class of application. The underlying physical mechanisms creating these time-shifts are then described, and linked to a series of generic and field-specific rock physics calculations that predict their magnitudes. These calculations serve as a guide for practitioners wishing to utilise this information on their own datasets. Conclusions are drawn regarding the reliability of this attribute for monitoring purposes, and the extent to which further development is required and how it should be reported by authors.
INTRODUCTION

The measurement of time-shifts between two closely spaced signal waveforms is a general challenge met by a wide range of physical disciplines in medicine, geosciences, computer science and electrical engineering, and cosmology (for example, gravitational wave shifts - Gonzalez 2016). Such measurement is also a popularly accepted practice in seismic data interpretation, forming part of the post-processing and analysis of time-lapsed seismic volumes of different vintages employed for reservoir monitoring purposes. These 4D seismic travel-time shifts are time-variant in nature and typically between 0.5 and 25ms (based on the range of data observations available to the authors). They arise due to the time-saving practice of migrating successive seismic volumes (baseline and monitors) with a smooth common velocity model and for 4D seismic interpretations carried out in the time domain after depth migration and depth-to-time conversion. Post-stack analysis by alignment correction for these small time-shifts is currently employed in practice to be the preferable and least costly option, versus the more expensive option of migrating with individually updated velocity models where the velocity updates are uncertain and ill-defined. Misalignment shifts due to time-lapse velocity perturbations may be calculated and quoted as a time shift or a depth shift, depending on the domain (time or depth) in which the seismic data are required to be interpreted, although the time domain is most commonly used. It is typical for monitor data to be corrected for these time-shifts to yield separate amplitude differences for reservoir interpretation purposes (Figure 1). Lateral shifts may also accompany these time-shifts, however the potential of these has not been fully realized to date.
An important point in the evolution of this topic, is that whilst small time-shifts between vintages of 4D seismic data may also arise due to a variety of causes such as acquisition inaccuracies, water velocity variations, rough seas, differential statics (Ross and Altan 1997), significant advances have been made over the past twenty years to improve the quality and repeatability of data acquisition and processing. This has been achieved by careful measurement of the many controllable and avoidable influences on acquisition to deliver high quality co-processing solutions in the pre-stack domain that drive down the non-repeatability noise. Thus, there is now an established confidence that the time-shifts measured on the post-stacked migrated data are directly attributable to the underlying reservoir, overburden or underburden changes. Importantly, these time-shifts have now also been shown to have proven interpretational value, particularly for subsurface geomechanics (for example, Hall et al. 2002, Hatchell and Bourne 2005a) but increasingly also for assessing fluid saturation variations (for example, Falahat, Shams and MacBeth 2010). Velocity changes associated with time-shifts are considered to be long wavelength in nature if they correspond to stress/strain changes due to depletion or injection in the reservoir, but are more localized when influenced by fluid saturation and contact movement. The measurement and conversion of time shifts to velocity changes and physical subsurface strain, or to saturation changes is currently the focus of much attention in the literature. Importantly also, these time shifts obscure amplitude interpretation of the seismic signal associated with reservoir production changes, more noticeably in vertical sections (see Figure 1 for the example of Alsos, Osdal and Hoias 2009) and less conspicuously in maps. Time-shift correction is also an essential ingredient for further use of seismic data in impedance inversion or the updating of the simulation model via seismic history matching (Stephen and MacBeth, 2006).
In the seismic monitoring literature, the topic of time-shift analysis is now very active with over 100+ case studies, theory papers and presentations published in the open literature. A dedicated workshop on this topic was held at the EAGE conference in June 2017 attracting over 90 participants. With this in mind, the purpose of this article is to provide a practical overview that describes and highlights the role of time shifts in 4D seismic interpretation to date and analyses their magnitude and origin. We show how they may be related to subsurface property changes, and discuss what issues may still be outstanding to advance this topic further as a tool for dynamic reservoir characterization. The focus for this current work is the magnitude of these time-shifts and the mechanisms for creating these values. The points discussed in this study are illustrated by a number of worked data examples from field datasets. In a companion paper we describe and evaluate the algorithms and methods that are used to measure time shifts, together with the errors and uncertainties (MacBeth and Amini 2018).
THE MAGNITUDE OF 4D SEISMIC TIME-SHIFTS

The causative mechanisms for time-lapse time-shifts are separated into three main categories. The first relates to production-induced strain deformation in the overburden and underburden, and the second to pore-pressure or strain changes within the reservoir itself. Time-shift measurements in the rocks surrounding the reservoir are particularly informative, as they are solely influenced by the strain changes and can be utilized in data inversion schemes to estimate reservoir pressure (Hodgson *et al.* 2007). However those shifts in the producing reservoir itself are also affected by fluid saturations – the third category of mechanisms. Estimation of strain deformation from 4D seismic data is a solid practical tool for providing a better understanding of subsurface geomechanical behaviour such as well failure, sanding or fault slip, but also provides calibration for the geomechanical model. Commonly observed production mechanisms that create distinct fluid change signals visible on the seismic data are the reinjection of hydrocarbon gas, injection of CO₂, the liberation of gas from solution due to pressure drop, and water displacing oil during improved oil recovery. The effect of pressure fluctuations in the pore fluid itself has not been reported in any publication to date. The magnitude of these small changes is predicted by the Batzle and Wang (1992) equations. We conclude from calculations using these equations that changes are insignificant (less than 0.1%) for most black oil reservoirs provided the fluid pressure and temperature conditions are sufficiently far from critical points. Knowledge of pore pressure and fluid saturation changes is important when updating the fluid-flow simulation model and time-shifts measured as a function of two-way time through the section offer a good complement to amplitude analysis when estimating these changes.
**Strain-related time-shifts observations**

Injection or production of fluid volumes from the hydrocarbon reservoir induce displacements both in the reservoir itself and also the surrounding rocks. Thus, for example, pure pressure depletion due to inadequate pressure support will cause reservoir compaction and create corresponding extensions in the overburden and underburden in addition to some degree of surface subsidence. Thus there is a physical displacement at each subsurface interface and also a change in the seismic velocity within each layer itself. Measurement of overburden time-shifts due to strain from this mechanism was first reported by Hall *et al.* (2002) and Hatchell *et al.* (2003). The time-lapse time-shift $\Delta t$ can be generally expressed as

$$
\Delta t = \int_{\ell'} \frac{dl}{v_m} - \int_{\ell} \frac{dl}{v_b},
$$

(1)

where $\ell'$ and $\ell$ are raypaths from source to receiver through the subsurface to a common event of interest, and $v_m$ and $v_b$ the subsurface velocity distribution for the monitor and baseline surveys respectively. In practice, a simple working formula for post-stack data may be obtained by considering vertical displacement $\Delta z$ of a subsurface event initially positioned at a two-way time $t$ on the baseline trace (and corresponding depth location $z$), and an overburden velocity changing from $v$ to $v + \Delta v$.

$$
\Delta t = \int_0^{z+\Delta z} \frac{2}{v + \Delta v} dl - \int_0^z \frac{2}{v} dl,
$$

(2)

where the integrals are evaluated along a vertical raypath. For a homogeneous velocity field and small strains, equation (2) simplifies to
where the quantity $\Delta z/z$ is the vertical strain $\varepsilon_{zz}$, and $t = \Delta z/v$. This equation reveals the interplay between physical displacement and velocity change, and also the simple relationship between subsurface parameters and an observed time-shift in the seismic volumes. If material displacement can be ignored (which can be seen from the calculations below to be a reasonable assumption in an overburden under extension), then the time-shift can be converted into a fractional velocity adjustment $\Delta v/v$ to the seismic velocity model. Unfortunately strain and velocity change compete in equation (3) and both must be known before the time-shift can be calculated. To solve this issue, Hatchell and Bourne (2005a) and Røste, Stovas and Landrø (2005) simultaneously proposed a linear relation that connects the fractional velocity change to the vertical strain change $\varepsilon_{zz}$

$$\frac{\Delta v}{v} = -Re_{zz}$$

(4)

where $R$ is the Hatchell-Bourne-Røste (HBR) factor that is a constant for a particular lithology, and stress path. Although (4) has proven to be very useful in practice, the fundamental origin, applicability and lithological variation of the $R$ factor are still under investigation (MacBeth, Kudarova and Hatchell 2018). Inserting (4) into (2) and re-arranging yields a simple relation for the time-shift

$$\Delta t = t(1+R)\varepsilon_{zz},$$

(5)
that directly links a measurable quantity in the seismic domain on the lefthand side of this equation to the physical strain in the geomechanical domain on the righthand side of the equation via a material constant. This permits free movement between the seismic and geomechanical domains, and use of the seismic time-shift data as a proxy for vertical strain changes between survey dates, thus accessing information with which to calibrate the geomechanical model. Equation (5) indicates that time-shifts are positive when differencing monitor from baseline (velocity decrease or slowdown of the seismic wave travel-time) when the subsurface is in extension ($\epsilon_{zz}$ is positive), and are negative (velocity increase or speedup of the seismic wave travel-time) when the subsurface is in compaction ($\epsilon_{zz}$ is negative). The terms slowdown or speedup are typically used when communicating 4D descriptions instead of the time-shift sign as they are less ambiguous or misleading. For a uniform strain field, time-shifts are predicted to linearly increase within the overburden, linearly decrease within the reservoir where the polarity of the strain change is reversed, before linearly increasing again in the underburden (see Figure 2(a)). Although in reality there are clearly many layers of contrasting mechanical strength in the subsurface and the resultant strain field will vary accordingly, a linear trend for time-shift behavior has been demonstrated universally in many datasets (for example, Hodgson 2009).

Given the above, a key question is how big are these time-shifts for any given reservoir change? Figure 3 displays a field-wide selection of measured maximum time-shift values attributable to geomechanical effects in the overburden and reservoir rocks, and for a range of clastic, soft rock carbonate chalks, and also hard rock carbonates (limestone). Time-shifts vary according to the production period over which they are measured, the type of rocks, and the depth and thickness of the reservoir. Included in this database of mainly normally
pressed fields are several high-pressure high-temperature fields (i.e. Shearwater, Elgin, Franklin, Kristin, Skua, and Mars), for which geomechanics is particularly critical to field management. This selection of time-shifts is fully representative of most available published data but is not an exhaustive list of all projects to date (which would include those conducted internally by companies). Interestingly, there is a scarcity of reported underburden values – indeed, whilst the underburden is occasionally discussed in literature, specific time-shift values for underburden intervals are rarely mentioned. Table 1 provides additional detail on the reservoir depth and thickness, and the time period over which the time-shift measurements in Figure 3 are made. In the data presented here, time-shifts are assigned only to the dominant mechanism influencing the seismic response, and therefore no effort has been made to separate responses due to overlapping mechanisms (e.g. saturation and geomechanics). Most time-shifts have been measured on post-stack migrated data, predominantly using cross-correlation methods (Hodgson 2009) or non-linear inversion (Rickett et al. 2007), and applied on a trace-by-trace basis (more details on these methods and many others, and their response to error and uncertainty can be found in MacBeth and Amini (2018). Time-shifts measured at the top of the reservoir level are attributed to the entire overburden, whilst reservoir-related time-shifts are estimated or measured as those accrued only over the reservoir interval. The data are from acquisitions that are predominantly offshore towed streamer, although some points are possible from land data or permanent reservoir monitoring over short time periods of several months (for example, Ekofisk LoFS or Peace River SeisMovie). Whilst it is difficult to make a relative comparison between fields due to the diversity of geological environments, the data do display consistent overall trends for the maximum expected values across the fields and for distinct production mechanisms.
The most noticeable feature of the time-shifts in Figure 3 is the high occurrence of slowdowns, may be explained due to the preponderance in the literature of geomechanical extension in the overburden due to reservoir depletion, but also some well reported examples of reservoir inflation due to pore pressure increase from fluid injection. Field examples of overburden extension are shown in Figures 4(a), 5(a), and 5(b), and for the pore pressure build-up response in Figure 6(a). The $\Delta T$ signals are visible and fairly coherent, ranging from 2ms in deep (> 3km) reservoirs over a short time period of several years (e.g. Curlew-D and Skua fields) to the more dramatic 24ms or more for compacting chalk reservoirs (Valhall field: Barkved et al. 2005, Hall et al. 2005 and Ekofisk field: Guilbot and Smith 2002, Bertrand et al. 2014) over five to ten years. Some of the most challenging fields are in the Southern Gas Basin, where imaging difficulties arise due to the overlying Zechstein carbonate sequence combined with a weak noisy signal. Despite this, small but significant overburden time-shifts of approximately 2ms are still visible due to this depletion-related extension (Hall et al. 2006, Brain et al. 2017, Brain 2017). In contrast, compressions in the reservoir due to pore pressure depletion have small signals of at most 2ms and are more sparsely reported. This may be in part because observations of reservoir-related time-shifts are mostly inferred from measurements across the reservoir interval. These time-shifts are in general difficult to measure with accuracy from the seismic data as velocity speedup due to compaction reduces the time thickness of the reservoir. As an example, Figure 6(b) shows an unusually clear and distinct time-shift speedup from reservoir depletion. Finally, although the dominant overburden signal appears to be extension, it is evident that speedups (compressions) are seldom recorded in field studies. However compressional responses in the overburden are predicted above elevated changes of pore pressure at injectors or from the complex deformations arising due to stress-arching at the edges of the reservoir. In one of the
few published examples to date, Røste and Ke (2017) observe evidence for such stress arching effects on the Snøre field (see Figure 4(b)).

**Time-shifts related to reservoir pore pressure changes**

An important question when interpreting time-shifts induced by solely pore pressure changes in the reservoir is: how much pore pressure change can generate how much time-shift in either the overburden or reservoir? Changes in pore pressure due to production, induce stresses and hence strains, inside the reservoir units and also the surrounding rocks. The magnitude of the resultant reservoir compaction or inflation is directly proportional to the reservoir compressibility. The link between pore pressure variations and the effective stress changes that drive the subsurface deformations involves both the Biot-Willis effective stress coefficient and the arching coefficients, and is a strong function of the reservoir geometry, size, depth, the heterogeneous distribution of mechanical properties (Young’s modulus and Poisson’s ratio) and their contrasts (Fjaer et al. 2008). In reality the geology is complex, and for a complete answer to our question it would be necessary to run a full geomechanical simulation followed by seismic modelling (see, for example, Hodgson 2009). To simplify the problem, in this current study we choose to approximate the geomechanical processes to focus on a better understanding of the relationship with the time-lapse time-shifts and to provide a rough guide to the expected magnitudes.

In the reservoir, the uniaxial strain model is often regarded as a good approximation. This condition is particularly valid in the case for which the thickness, \( h \), of the producing unit is much smaller than its lateral extent, \( L \). For the uniaxial model, the deformation is vertical in
response to a drop, or rise, in fluid pore pressure i.e. no lateral deformation, no stress arching and the full weight of the overburden is experienced by the reservoir. The vertical strain $\varepsilon_{zz}$ in the reservoir generated by a fluid pore pressure change $\Delta P_p$ is (Fjaer et al. 2008)

$$e_{zz} = \frac{\Delta h}{h} = -C_{uni}\Delta P_p$$

(6)

where $C_{uni}$ is the uniaxial pore volume compressibility (defined as the fractional change in volume with pore pressure change when lateral strain constrained to be zero), and $\Delta h$ the reduction in thickness. According to Zimmerman (2017), in a porous rock the uniaxial pore volume compressibility, $C_{uni}$, is related to the hydrostatic pore compressibility, $C_{pp}$ (defined as the fractional change in volume with pore pressure change with no constraints) via the relation

$$C_{uni} \approx \left(1 - \frac{2(1-2\nu)\alpha}{3(1-\nu)}\right) C_{pp},$$

(7)

where $\nu$ is the Poisson’s ratio (Zimmerman 2017) and $\alpha$ the Biot-Willis coefficient. The approximation is valid when the compressibility of the pore space is much larger than the grains constituting the rock matrix. Under the often made assumption of incompressible grains, $\alpha = 1$, and the term in brackets becomes $(1 + \nu)/3(1-\nu)$. Pore volume compressibility, $C_{pp}$, values will be quoted in our calculations below for a number of fields. This is because the quantity $C_{pp}$ is also the reservoir or rock compressibility used in flow simulation studies and production engineering. It is estimated from laboratory studies and adjusted during model maturation to provide an agreement between injected, produced and stored volumes in the reservoir. $C_{pp}$ is known to be a function of pore pressure, porosity, effective pressure, and
lithology. It increases with increasing pore pressure, decreases with increasing effective confining pressure, and increases for shales and chalks relative to sandstones. Note that in this current review, only isotropic compressibility will be considered. Also, in our calculations we use an elastic $C_{pp}$ extracted from the simulation model that has been measured in the laboratory and adjusted to satisfy fluid flow considerations – it is understood that in practice this will be an underestimate of the actual effective $C_{pp}$ which includes the effects of inelastic damage. $C_{pp}$ (elastic) could well be much smaller than $C_{pp}$ (inelastic).

Typical pore volume compressibility values at low effective pressures (less than 1000psi) for clastic reservoirs are in the range 3 to 8x10^{-6} psi^{-1} (4.4 to 11.6x10^{-4} MPa^{-1}). However for strongly compacting chalk reservoirs (such as Ekofisk and Valhall), compressibility values can reach 50 to 100x10^{-6} psi^{-1} (72.5 to 145x10^{-4} MPa^{-1}). These values allow us to calculate approximate values for reservoir strain given a pore pressure change, using equations (6) and (7). Thus, for example, a clastic with $\phi = 0.25$, $\alpha = 1$ and $v = 0.28$ (or $V_P/V_S = 1.8$) gives $C_{uni} = 0.59 C_{pp}$. A pore volume compressibility of 5x10^{-6} psi^{-1} (7.25x10^{-4} MPa^{-1}) with 10MPa depletion will therefore generate a uniaxial reservoir strain $\Delta h/h$ of 4.3x10^{-3}. This ball-park figure is broadly consistent with geomechanical modelling studies for a variety of fields from our own computations and, for example, those of Doornhof et al. (2016) who consider variations of subsurface strain. Observations from well logs and subsidence analyses indicate that average vertical strains in the subsurface typically lie between $10^{-3}$ and $10^{-5}$ in the overburden. In the reservoir these could be an order of magnitude higher as the pore pressure change has greater influence over the smaller volume. These strain magnitudes are not, however, applicable close to wells, where we would instead anticipate strong non-linear fluctuations and larger strain values. From (5) the time-shift accumulated under compaction, for a reservoir of thickness, $h$, and seismic velocity, $V_{res}$, is
\[
\Delta t_{\text{res}} = \left( \frac{2h}{v_{\text{res}}} \right) \left( 1 + R_{\text{res}}^{-} \right) \frac{\Delta h}{h},
\]

where \( R_{\text{res}}^{-} \) is the \( R \)-factor in equation (4) relevant to compaction (given by the minus symbol) in the reservoir. This gives a relative time-shift of

\[
\frac{\Delta t}{t}_{\text{res}} = \left( 1 + R_{\text{res}}^{-} \right) \frac{\Delta h}{h}.
\]

Consider the above case of \( C_{pp} = 5 \times 10^6 \text{psi}^{-1} \) \( (7.25 \times 10^4 \text{MPa}^{-1}) \) and 10MPa pressure depletion evenly spread across a 150m reservoir interval. A seismic velocity of 3km/s and \( R_{\text{res}}^{-} \) value of 2 will yield a time-lapse time-shift of 1.3ms. However 10MPa pressure build-up over the same interval, for which an \( R^{+} \) value of 5 is relevant, gives a time-shift of 2.6ms. Higher pore volume compressibility, Poisson’s ratio and porosity values for chalks could magnify the time-shifts by as much as a factor of 20, whilst the lower compressibility for more consolidated rocks could lower these predictions.

The strain in the overburden is not in general uniaxial - indeed, for no mechanical contrast between the reservoir and the overburden, the overall volumetric strain is predicted to be zero (Fjaer et al. 2008). For mechanical contrasts and heterogeneity it may be more complex. However from geomechanical principles, in a compacting reservoir the decrease in reservoir thickness is balanced by the surface subsidence and the surrounding rock (underburden and overburden) expansion. Geertsma (1973) provides displacement solutions for variously shaped reservoirs in a homogeneous half-space, which have proven to give an accurate
understanding of strain deformation (Hodgson 2009). Evaluation of the solution along a vertical axis through the centre of a disc-shaped reservoir indicates that the top and base reservoir experience almost identical displacements of \( \frac{1}{2} \Delta h \), but in opposite directions (i.e. roof subsides and floor rises). When the ratio of the reservoir depth to size is greater than 2 and the overburden homogeneous, the surface subsidence is small and the overburden strain is given approximately by \( \frac{1}{2} \frac{\Delta h}{H} \) where \( H \) is the overburden thickness (Hatchell and Bourne 2005b). Clearly overburden strain is smaller than this value if surface subsidence increases, or if mechanically stiff layers sit above the reservoir, so this will be an overestimation of overburden strain. The solution also changes for reservoirs whose depth relative to size is less than 2. Continuing with this assumption, the time-shift accumulated over an extending overburden of thickness \( H \) due a reservoir compaction of \( \Delta h \) can now be approximated by

\[
\Delta t_{ob} = -\left( \frac{2H}{v_{ob}} \right) \left( 1 + R_{ob}^+ \right) \frac{1}{2} \frac{\Delta h}{H},
\]

(10)

where \( v_{ob} \) is the overburden velocity, and \( R_{ob}^+ \) is the \( R \)-factor of equation (4) relevant for the extending overburden. In terms of relative time-shift, this becomes:

\[
\left( \frac{\Delta t}{t} \right)_{ob} = -\left( \frac{h}{2H} \right) \left( 1 + R_{ob}^+ \right) \frac{\Delta h}{h}.
\]

(11)

Thus, from inspection of equations (9) and (11) it can be seen that the relative time-shift in the overburden is much smaller than that in the reservoir. Importantly, the ratio of the
reservoir to overburden time-shift is predicted to be \[ \Delta t_{\text{res}} / \Delta t_{\text{ob}} = 2 \left( \frac{V_{\text{ob}}}{V_{\text{res}}} \right) (1 + R_{\text{res}}^-) \left( 1 + R_{\text{ob}}^- \right) \]. As the time-shift accumulated throughout the overburden is of opposite polarity to that measured across the reservoir, time-shift reversal is expected when propagating through the reservoir as sketched in Figure 2(a). For this reversal to fully compensate for the time-shift from overburden propagation, the requirement from equation (11) is that \( R_{\text{ob}}^+ \leq \frac{2 V_{\text{ob}}}{V_{\text{res}}} (1 + R_{\text{res}}^-) - 1 \).

This means, for example, that with an \( R_{\text{res}}^- = 2 \) and \( \frac{V_{\text{ob}}}{V_{\text{res}}} = 2.0/3.0 \), \( R_{\text{ob}}^+ \) must be no greater than 3 if this time-shift reversal is to occur. For a smaller overburden to reservoir velocity contrast, such as \( \frac{V_{\text{ob}}}{V_{\text{res}}} = 2.5/3.0 \), \( R_{\text{ob}}^+ \) must be no greater than 4 for time-shift reversal. Interestingly, if \( V_{\text{ob}} \) is greater than \( V_{\text{res}} \), then reversal can indeed occur at even greater \( R_{\text{ob}}^+ \) values. In practice, an overburden extension - reservoir compression polarity reversal is not commonly observed at top reservoir or in the immediate underburden (Hatchell and Bourne 2005b). This observation supports the growing conclusion that R-factors in the overburden must be large – it is observed that they must be around 5 or greater (MacBeth et al. 2018). Indeed recent work by Røste and Ke (2017) has suggested that overburden factors of up to 17 may be possible. An additional factor that might affect this result is the presence of saturation-related time-shifts in the reservoir – this is discussed further in the next section.

Clearly larger strains (and hence time-shifts) are experienced if the reservoir is thick and shallow. In reality, stress arching, overburden heterogeneity, mechanical dispersion and the pressure connectivity of the reservoir would dilute and dissipate the direct contribution of the pressure to the overburden strain (Fjaer et al. 2008). Additionally, the presence of layers or zones with stiff or weak mechanical strength will redistribute the strain between the overburden and underburden. These overlapping phenomena would complicate the problem of interpreting time-shifts with data of different levels of non-repeatability (see MacBeth and
Amini 2018 for examples). A similar argument follows for the case of time-shifts developed by injection into the reservoir or aquifer. In all literature examples to date the slowdown in the reservoir appears to persist below the zone of injection (see Figures 1(d) and 6(a)), suggesting that the polarity cannot be reversed by the underburden compression. The condition for this is that \( R_{ub} \) must be less than 7, which is easily fulfilled if the \( R \)-factor for compression is 2.

Based on the above, it is clear that in the simplest case reservoir and overburden time-shifts are both proportional to the product of the pore pressure change, reservoir thickness and reservoir compressibility. This provides a way of assessing the data extracted from the literature. From the existing database, publications are sought that also record the pressure change. Twenty five of the forty two data points also cite pressure change in the reservoir. Table 3 summarises the available data for the fields that are included in our study. Figure 7 plots predicted relative time-shift \( \Delta t/t \) against pore pressure based on the calculations outlined in the previous section. In the computation, low, medium and high compressibilities are considered: respectively 5, 20 and \( 120 \times 10^6 \) psi\(^{-1} \) (7.25, 29 and \( 174 \times 10^{-4} \) MPa\(^{-1} \)). Trends are shown for extensional and compressional regimes with their corresponding \( R \) factors, \( R^+ = 5 \) and \( R^- = 2 \), respectively. \( \Delta t/t \) follows a roughly linear trend with respect to \( \Delta P_p \), with a gradient proportional to reservoir pore volume compressibility \( C_{pp} \). The observed data from Table 3 are also plotted in Figure 7. For the overburden, the measured values from the table must be normalised to a common \( h/2H \) value – chosen in this instance to be 0.02 (for example a 150m thick reservoir and 3750m thick overburden). This ensures that the observations and the predictions can be directly comparable. For publications in which thicknesses are not available, these are estimated from the seismic section using a reference velocity of 3km/s. As a consequence, this normalisation process may contain some error. The data for HPHT
reservoirs with pressure changes of up to 53MPa determine the maximum range in the horizontal axis of the plot. In Figure 7(a) for the reservoir data, points distribute as expected and are mostly bracketed by the defined trend lines. The exception however are three compaction-related points for the Shearwater (HPHT), Elgin (HPHT) and Curlew-D fields which lie below the low compressibility trend. This mismatch may relate to lack of accuracy for relative time-shift or an abnormally low reservoir compressibility. The poorly consolidated sands and chalks have the largest response, and lie between the high and medium compressibility trends. In Figure 7(b) for the overburden, no data points for compression are available and only those for overburden extension are shown. Despite this, trend lines for compression are still shown for completeness. The data points for the Sarawak, Genesis, Europa and Mars fields appear to lie close to the high compressibility trend. Elgin (HPHT) and Curlew-D fields, both indicating a possible low compressibility from Figure 7(a), also appear to lie slightly below the low compressibility trend for the overburden data. As previously mentioned, the effect of stress-arching or stress shielding at stiff layers above or below the reservoir, and subsurface heterogeneity will contribute to some considerable variability about these predicted trends.

Finally, to close the loop on the observations in Figure 3, time-shifts are calculated for the medium-range reservoir pore volume compressibility of 20x10^{-6} psi^{-1} (29 x 10^{-4} MPa^{-1}) and 10MPa pressure change. A representative reservoir thickness of 150m and a mean overburden thickness of 3000m is used. With an average reservoir velocity of 3km/s and overburden velocity of 2km/s, equations (8) and (10) together with R factors of $R^+ = 5$ and $R^- = 2$, give a 5.2ms speedup in the reservoir for depletion, and 10.4ms for pressure build-up. For the overburden these generalised predictions are 3.9ms for compression and 7.8ms for extension. These are drawn in Figure 3 as red dashed lines for guidance only – as it is known that the
reservoir compressibility, pressure change, geomechanical properties, $R$-factors, thicknesses and reservoir/overburden velocities vary quite considerably from field to field. It appears that these simple calculations are roughly correct for overburden and reservoir extension (the more compressive chalks lying above the prediction and less compressive reservoirs lying below). Speedups in the overburden and reservoir are over-predicted, but this could well be taken into account by the lowering the reservoir compressibility – this variability is considered in Figure 7. This may relate to the scatter in reservoir thickness, value of compressibility and pore pressure change. The role of measurement accuracy of reservoir time-shifts or geomechanical properties of the rocks surrounding the reservoir and hence the nature of the transference of strain deformation to the overburden must also be considered to evaluate these comparisons with more accuracy.

Footnote: Note that we have attempted to select time-shift examples in this paper that are displayed with a consistent colourbar. Unfortunately this was not possible for all cases – indeed, two different Red-Blue bars are shown and one Pink-red-blue-Green. Note that colour bars in published literature also show differing gradations in intensity, making quantitative evaluation difficult in many cases. Our preference is for a green-blue-cayan/yellow-red-pink colourbar (see Figure 8) in which hardening signals are represented by cold colours and softening signals by warm colours. Oversaturated red-white-blue colours (for example, Figure 6(a)) are less favourable for quantitative analysis as the time-shift increments are not readily detectable. An axis on the colourbar should provide time-shifts values that can be clearly quantified.

Time-shifts from saturation changes

The signature of reservoir saturation-related time-shifts is a zero response in the overburden followed by a linear increase within the reservoir zone itself and maintenance of this value as
a constant in the underburden (see Figure 2(b)). Such responses are frequently observed in 4D seismic data due to water flooding, gas flooding, steam injection into heavy oil reservoirs, and also when gas is liberated from solution (see the examples in Figures 8(a), (b) and 9(a), (b)). Figure 3 also displays observed saturation-related values for a range of fields (details of which are listed in Table 2), and these should be compared against those from the geomechanical origin described above. The magnitude of the gas-related effects is often comparable to the slowdowns from overburden extension. The following observations are noted:

- The largest saturation-driven values are found to be as a result of injection of hydrocarbon gas, CO₂ or steam (Figure 8(b)) which appear as a slowdown. This is because for CO₂ projects such as at the Sleipner or Snohvit fields or methane injection at An’Teallach (Falahat et al. 2010), thick subsurface intervals of 200 to 300m are saturated at maximum gas saturation resulting in significant slowdowns of up to 20ms. Pressure increase helps to exaggerate the impact of this effect.

- Moderate slowdown effects of up to 12ms are also observed due to steam injection into heavy oil or injection of EOR solvents.

- Reservoir gas liberated from solution by pressure drop below bubble point (Svale in Figure 9(b), also for example the Emeraude, Baobab or Schiehallion fields) is observed to also exhibit a more moderate range of slowdowns of up to 10ms, as the gas tends to occupy most of the reservoir volume at the critical gas saturation (Falahat et al. 2014).

- By comparison, saturation-related speedups (hardening) due to water replacing oil (or gas), water flooding or an upward progression of the aquifer water are typically of up to 2ms (for example, Figure 9(a) – note here that a small pressure increase has been over-ridden by the speedup response due to water increase, although there is evidence
of a small localised decrease in slowdown around the well due to pressure. As with pressure depletion, these small time-shifts are infrequently observed as speedup renders the reservoir thinner in time, thus making the time-shifts harder to detect and more erroneous to measure on noisy data. Another reason for the lack of speedup measurements is that the time-lapse response around water injectors is usually dominated by the pore pressure increase (Amini and MacBeth 2015). Also, for seismic surveys shot only a few months apart rather than year, saturation-related speedups may not be observed as saturation needs years of elapsed time to grow. Water-fronts typically move at between 0.1 and 2m/year and gas fronts between 5 and 13m/year, thus are slow to develop and more localized in nature compared to the fast diffusion and equilibration of pressure (Omofoma and MacBeth 2016).

Inside the reservoir, saturation-driven time-shifts are either enhanced or diminished by geomechanical effects - both gas saturation increase and pressure increase signals create a slowdown; whilst water saturation and pressure increase signals compete. An interesting effect was observed in the Valhall field where compaction appeared to cancel out time-shifts due to gas out of solution (Huang et al. 2011).

A saturation-related time-shift $\Delta t$ can be estimated from equation (1), on the assumption of a uniform saturation change over a specified depth interval or cumulative reservoir thickness $z$

$$\Delta t = z \left( \frac{1}{v'} - \frac{1}{v} \right)$$

(12)
where $v$ is the initial pre-production velocity and $v' = \Delta v + v$ the velocity for the new post-production saturation state. This equation can be re-written in terms of the time-shift normalised by the specific time thickness or relative time-shift

$$
\frac{\Delta t}{t} = \left(\frac{v}{v + \Delta v} - 1\right).
$$

(13)

The time-thickness $T$ may correspond to an entire reservoir interval, as for example in the case of gas/water injected to fill an entire reservoir unit or the depth interval over which a fluid contact moves. The relative time-shift $\Delta t/t$ provides a direct measure of the impact of the velocity change (as $\Delta v/v \approx -\Delta t/t$ and the approximation becomes an equality when subsurface displacement is small), and may be compared across a range of fields. The relative velocity change $\Delta v/v$ depends on the lithology of the rock (predominantly the porosity) and also the magnitude of the saturation change. To provide a guide to the expected magnitudes of $\Delta t/t$, the velocity, $v$, and velocity change, $\Delta v$, are calculated using the simple relation above for a clean North Sea reservoir rock with 25% initial porosity. The properties are selected to be representative of the clastic fields in our database, and reservoir rock E in Table 4 is chosen for this purpose. The mean elastic properties extracted from the logs through this reservoir give $\rho=2.25$ g/cm$^3$, $v_p=2.70$ km/s and $v_S=1.45$ km/s. These values are assumed to represent the dry sandstone rock frame properties also, as fluid saturations are not known with accuracy and any back substitution is likely to be erroneous. Next, this ‘dry’ rock frame is saturated with the fluid saturants present before, and then after production using Gassmann’s equation (Gassmann 1951). In addition to the dry rock properties, Gassmann’s equation also requires the mean mineral bulk modulus $\kappa_g$. This is back-calculated from $\kappa_{dry}$ using the critical porosity model of Nur et al. (1998)
\[ \kappa_{\text{dry}} = \left(1 - \frac{\Phi}{\Phi_c}\right) \kappa, \]  

(14)

where \( \Phi_c \) is the critical porosity. For these moderately consolidated sandstones the critical porosity \( \Phi_c \) is selected as 0.35.

A typical North Sea brine, oil and gas are now considered at a reservoir temperature of 60°C and pore pressure of 3000psi. Their fluid properties are calculated using the FLAG3 software. The brine has a salinity of 20,000ppm, the oil (light) has an API of 38° and a gas-oil ratio of 555 scf/scf. Finally the gas has a specific gravity of 0.8. These give \( \rho_{\text{wat}} = 1.01 \text{g/cm}^3 \), \( \kappa_{\text{wat}} = 2.58 \text{GPa} \), \( \rho_{\text{oil}} = 0.74 \text{ g/cm}^3 \), \( \kappa_{\text{oil}} = 0.98 \text{GPa} \), \( \rho_{\text{gas}} = 0.24 \text{ g/cm}^3 \) and \( \kappa_{\text{gas}} = 0.06 \text{GPa} \). These fluids are mixed using Wood’s law on the understanding that this will give a lower limit on the predicted time-lapse effects we consider. The particular fluid constituents and overall magnitude of saturation change in the reservoir are controlled mainly by the production mechanisms and rock type. The calculation of time-shift changes is therefore classified according to these mechanisms as below. Here it is important to recognise that fixed critical saturation points determine the maximum attainable saturation change at the pore scale. We understand that in practice these pore-scale values should translate into larger field-scale values.

Gas displacing oil – during the process of enhanced oil recovery, treated hydrocarbon gas may be injected into the gas cap of a reservoir to enhance natural drive and improve production performance. During water alternating gas (WAG) treatment, water injection is cycled with that of gas. Another treatment involves CO\(_2\) injected to flush out the remaining
oil. Injected gas gravitates to the top of the reservoir, where it accumulates and pushes down to displace the oil. Gas may also create channels or fingers within the oil-saturated zone. These processes lead to an overall change in the depth-averaged saturation inside swept intervals. Within the swept oil zone, a residual oil saturation \( S_{\text{org}} \) remains and therefore the gas saturation is \( S_g = 1 - S_{\text{wirr}} - S_{\text{org}} \) when fully swept - where \( S_{\text{wirr}} \) is the irreducible water saturation. The change in gas saturation \( \Delta S_g \) is simply the final gas saturation \( S_g \). The quantity \( S_{\text{org}} \) is known to vary at the pore scale with porosity, permeability, initial oil saturation and at the larger scale with injection rate (Skauge and Ottesen 2002; Alvarez, MacBeth and Brain 2016) and typically lies in the range 0.03 to 0.20 (Vrachliotis 2012). \( S_{\text{org}} \) for gas cap expansion due to gas out of solution is slower and more efficient than gas injection, and thus may be at the low end of his range. However rapid injection leaves bypassed oil and residual values that are at the higher end of the range. \( S_{\text{wirr}} \) depends on the size and distribution of pore heterogeneity and is typically 0.10 to 0.35 (Vrachliotis 2012). From the ranges for \( S_{\text{org}} \) and \( S_{\text{wirr}} \), we predict that maximum gas saturation change should lie between 0.45 and 0.87 in our data. To avoid complications, we consider only the case of immiscible displacement. Figure 10(a) shows the variation of \( \Delta t/t \) with porosity for our generic sandstone using our predicted gas saturation changes. Relative time-shifts increase from 0 to 0.05 for porositites between 10 to 35%. As expected, large maximum gas saturation changes show the strongest effects. Reservoirs in our database have an upper limit on interval thicknesses of 300m (roughly 300ms in two-way time thickness, see Table 2) and a mean porosity of close to 30%. Assuming a fully saturated interval, relative time-shifts calculated at this mean porosity are up to 0.024, which corresponds to absolute time-shifts of up to 7.2ms for the data in Table 2. This is comparable to the values recorded from the data in Figure 3 and in Table 2. We would expect time-shift magnitudes for CO\(_2\) and Nitrogen injection. Our calculations also show that time-shift can grow by approximately 0.016ms for every 1m of downward gas-oil contact
movement in a 30% porosity rock. Finally, one un-anticipated consequence of this mechanism is the strength of the density term, which creates a slight negative speedup time-shift (i.e. speedup) for lower porosities and saturation changes.

Gas displacing water – CO₂ may be injected into saline aquifers for storage and sequestration, this is a popular practice that is readily monitored using 4D seismic data. Although the monitoring of hydrocarbon gas disposal in water saturated formations is less well documented, several examples do exist. Hydrocarbon gas dissolves very little in water unless pressures are high. However it is known that CO₂ is more reactive and will dissolve in the water thus lowering the seismic velocity. It may also dissolve the cements causing a weakening of the rock frame. Methane dissolution is known to create only 1 to 2 percent velocity change whilst CO₂ dissolution can be up to 5 percent (Han and Sun 2013). To obtain ball park figures for the time-shifts from this process, we assume in our calculations that the injected gas is immiscible and thus there are no physico-chemical interactions. We focus only on the saturating gas volumes, therefore our calculations will be an underestimate of the true physics. Displacement of brine by the less viscous CO₂ will create fingering whilst capillary effects may cause trapping - this combines with a general upward movement of the gas due to gravitational forces. Whilst the displacement process itself is not efficient, a cumulative gas thickness will eventually settle over time at a maximum gas saturation. The maximum gas saturation \( I - S_{\text{w irr}} \), results in high saturation changes in a narrow range between 0.65 and 0.90 according to Vrachliotis (2012). Figure 10(b) gives the relative time-shifts expected from this process. It appears that there is only a small difference in the seismic velocity for this range of gas saturations, and thus the time-shifts are similar. The predictions show that time-shifts generated from the displacement of water by a light gas are much bigger than those from any of the other saturation-driven mechanisms. Indeed, relative time-shifts of up
to 0.09 are generated for 35% porosity. In our database there are several clear examples of CO$_2$ injection into clastics (Sleipner, Ketzin and Snohvit fields) and one of hydrocarbon gas injection (An’Teallach) with large reservoir thicknesses of up to 200m. Assuming the reservoir fills to capacity with gas, the upper limit on time-shifts for a 35 percent porosity is predicted to be 18ms (falling to 9ms for an average porosity of 30%). These predictions are in general agreement with the data in Figure 2, where large values are observed for the thick Sleipner reservoir and An’Teallach, although Ketzin and Snohvit fields have smaller values as their average porosity is lower. Although all of the above fields are clastics, we would expect similar time-shift values to be present for CO$_2$ injection into carbonate fields (if chemical interactions are ignored). That is, according to Figure 10(b) no more than a few milliseconds time-shift will be generated over 100m thick, low to moderate porosity rocks. Such values are indeed noted by our only two carbonate examples: water replacing gas in the Sarawak field (Barker et al. 2008) and solvent injection in Rainbow Lake (Ng et al. 2005).

*Gas out of solution* - in a reservoir with imbalance between produced and injected volumes, pressure can drop below bubble point and light elements of hydrocarbon gas are liberated from solution. The gas mobilizes and moves to the top of the reservoir to be produced at the wells, becomes trapped in structure, and also remains in the pore space at critical gas saturation. This leads to a clearly visible amplitude brightening and distinct time-shift slowdown due to the small amount of gas at critical saturation but also the trapped gas or gas caps (Falahat *et al.* 2014). The pressure drop will produce a speedup, but this is usually very small in comparison to the gas effects. Liberated gas creates a clear time-shift slowdown as gas at the critical gas saturation $S_{gc}$ fills the entire pressure-connected reservoir volume and $\Delta S_g = S_{gc}$. Laboratory, pore-scale and simulation studies suggest critical gas saturation values as low as 0.05 and as high as 0.38 (Falahat *et al.* 2014). Low values are more common in
moderate porosity reservoirs, although there is no definite trend. Relative time-shifts for this mechanism are plotted in Figure 10(c). This indicates weaker time-shifts than gas injection into water, with a maximum value of 0.048 ($S_{gc}=0.38$). This gives an upper limit on time-shift of 7.2 ms for the upper reservoir thicknesses of 150m found in the four fields (Baobab, Svale, Emeraude and Schiehallion) in our database (Figure 3). A final thought is that as time-shift is linked strongly to the values of critical gas saturation, if reservoir thickness, porosity and rock properties are known then perhaps $S_{gc}$ itself, a useful parameter for flow simulation purposes, could be evaluated by time-shift analysis.

Water replacing oil – increases of water saturation may arise from water injection or upward movement of the oil-water contact due to aquifer support. Injection of seawater into the reservoir itself may be necessary in situations in which the aquifer or natural drive is unable to fully support the production. If injection is into the reservoir, a water flood is created to displace the oil, and time-shifts could exhibit a speedup response as the water replaces oil (note that all other previous mechanisms have been slowdowns). However pore pressure inflation creates a slowdown that could counteract this saturation effect (see details in the next section). If water injection is into the aquifer, this leads to elevated pressure and little or no water saturation change (4D seismic changes due to the salinity variation are known to be small – Salako, MacBeth and MacGregor 2015). Pore pressure inflation from this mechanism gives rise to a slowdown with no competing saturation effect – see Figure 6(a). For water flooding in the reservoir or upward movement of the oil-water contact, a residual oil saturation $S_{orw}$ remains in the swept zone and the overall change in water saturation is $\Delta S_w = 1 - S_{orw} - S_{wirr}$. Residual oil saturation $S_{orw}$ varies between 0.05 and 0.45 and is a function of the reservoir, its heterogeneity and wettability (Alvarez et al. 2016). Relative time-shift is plotted as a function of porosity in Figure 10(d) for different values of $\Delta S_w$ ranging from 0.20
to 0.85 (when using the same $S_{wirr}$ as before). As expected, the speedups from water replacing oil are much smaller than the slowdowns due to the gas-related mechanisms above. The largest speedups are for the highest porosity rocks, with $\Delta t/t$ values of -0.007 for the lowest water saturation changes, to -0.045 for the highest. For the four fields in our database for which slowdowns exist, water thickness changes are up to 100m in rocks with an average porosity of 30%. Our predictions give maximum speedups of 2.5ms, which are similar to our observed values. Finally, as oil-water contacts can move as much as 1m over a year, these are predicted to generate only 0.03ms speedup per year at most (Omofoma and MacBeth 2016). Figure 11(a) shows a possible example of contact movement (the small blue anomaly on the lefthandside of the reservoir at well F3-H is believed to relate to an upward movement of the OWC), whilst Figure 11(b) highlights the stronger time-shift signal from water replacing gas.

Steam injection – well developed time-shifts can be observed from enhanced oil recovery in heavy oil (predominantly bitumen) reservoirs. In such reservoirs, thermal recovery is performed by in situ combustion, cyclic steam stimulation, steam assisted gravity drainage, or toe to heal air injection. The objective of steam injection is to mobilize the oil by lowering its viscosity. The precise pressure and fluid distributions involved depends on the configuration of the injectors and producers together with the recovery cycle rates and timings. The effects of such production are highly case-specific with a range of different phase transitions however there are a number of common physical effects. These include slowdown due to pore pressure increase, heating of the reservoir, steam displacing pore fluids and subsequent development of a steam chamber (see Figure 8(b)). Speedups can occur when steam condenses to hot water and replaces the gaseous contents (Figure 11(b)). Particularly large time-shifts are observed from the development of the steam chamber (7 and 14ms in Figure 3) and this effect is clearly of benefit in mapping steam thickness for investigating sweep
efficiency (Jenkins, Waite and Bee 1997, Benguigui, Roberts and Shaw-Champion 2012). The magnitude of this slowdown can be modelled in a similar way to the gas injection case described previously. In addition to these mechanisms a large 8ms slowdown has been observed from gas breakout (Benguigui et al. 2012). Smaller time-shifts of a few milliseconds have also been observed: such as slowdown due to pore pressure increase at the injectors and also water saturation effects in Peace River (La Follet et al. 2015), or pressure increase pushing free hydrocarbon gas back into solution (Jenkins et al. 1997). Temperature effects in the examples of Figure 3 are often found difficult to isolate independently of the saturation effects in data, but modelling suggests large $\Delta v/v$ values of up to 0.10 i.e. 6.7ms over an interval of 100m (Han, Yai and Zhao 2007). Both the fluid and the rock properties are altered during the heating process. More destructive thermal mechanisms such as the in-situ combustion (see the Balol field) also generate several milliseconds of slowdown signal. Finally, it appears that non-thermal recovery processes such as miscible gas and solvents (see Rainbow Lake field) can also create a slightly smaller slowdown of 1 or 2ms – such effects are currently more difficult to predict through modelling.

*Dependence of time-shift on reservoir velocity and density* – to evaluate the fluid saturation dependence further we consider the displacement of water by gas in a generic low quality hard rock reservoir (porosity of 18 percent) evolving to a high quality soft rock reservoir (porosity of 30 percent). The resultant relative time-shifts are shown in Figure 12 for the same range of gas saturations as in the calculations of the previous section. Time-shift is observed to decrease monotonically with reduced rock quality, and interestingly there is a cross-over point at which the slowdowns turn into a small speedups. This can be explained by approximating the velocity change $\Delta v/v$ to isolate the time-lapse changes in fluid bulk modulus $\Delta k$ and density $\Delta \rho$
\[-\frac{\Delta t}{t} = \frac{\Delta v}{v} \approx \frac{1}{2\rho} \left( \frac{6.25\varphi\Delta \kappa_f}{v^2} - \Delta \rho \right), \tag{15}\]

where the Gassmann approximation of Han and Batzle (2004) has been utilised. The equation shows that there is an interplay between changes due to the fluid bulk modulus and density. The fluid bulk modulus term is inversely weighted by \(v^2\) which means that it is smaller for harder rocks, and this opens up the possibility of the density term dominating. This does appear to be the case for the property values we have chosen in this example, the cross-over point being at \(v = 3.5\text{km/s}\). Clearly this point also depends on magnitude of the saturation change, thus as the gas-displacing-water mechanism has the strongest saturation contrast. For other saturation change mechanisms the cross-over could occur at a lower values of \(v\). The result is rather counterintuitive, as small speedups would now be observed where strong slowdowns are expected. The density effect on seismic velocity is a well-known phenomenon, although it has not been reported to date in the 4D seismic literature in the context of time-shifts. Anomalies or confusions in the sign of time-shifts have however been observed by some, and polarity changes could well exist but remain currently unidentified.

**Pressure versus saturation**

In the reservoir, time-shifts may be influenced by both saturation and pressure, and the result is a composite response \(\Delta t = \Delta t_{\text{sat}} + \Delta t_{\text{pr}}\). For example, at a water injector a pressure increase creates reservoir extension which tends to slow down velocity whilst the injected water replacing the oil itself will speed up the velocity. Thus the time-shift effects compete and may partially or completely cancel. Locations away from the injector where the saturation signal outweighs the pressure have been used in the past to calibrate the stress sensitivity of the
reservoir (Amini and MacBeth 2015). Note that the same is not true of a gas injector for which the time-shifts from pressure and gas saturation reinforce - this is why we record such large time-shift values for gas injection. However for most cases we find that pressure is observed to easily dominate around the water injection well when changes are large. Indeed it is clear from Figure 7(a) that the levels of time-shift that can be produced from geomechanics are far greater than those created by the saturation mechanisms by a factor of 4 for the most compacting reservoirs. This is supported by evidence from studies of amplitudes which suggest that it requires pressure changes of only a few MPa to swamp the water replacing oil mechanism (Omofoma and MacBeth 2016). We also predict that for highly compacting chalk reservoirs in particular this will most certainly be the case. In practice the exact transition point depends on the particular reservoir, its compressibility and porosity. As mentioned earlier, it is interesting to note the observation of Huang et al. (2011) who found that the response to gas breakout in Valhall was outweighed by the seismic effects of pressure depletion. Pressure dominance may also be possible with lower compressibility more consolidated sandstone reservoirs as their porosity is small. The understanding that geomechanics trumps saturation is not unexpected as a large proportion of Figure 3 and the literature in general is filled with geomechanically-related time-shift observations. In practice which dominates depends on the reservoir rock compressibility (a function of porosity) in addition to saturation thickness, porosity and seismic properties.

**Cross-field comparison**

To provide a more case-specific study of the expected relative magnitudes for time-shifts from the pressure and saturation mechanisms above, seven representative fields are selected covering varying geological environments and geographical locations. These consist of a North Sea HPHT, West Africa soft rock clastic, a North Sea hard rock clastic, North Sea soft
rock clastic, a Norwegian Sea chalk, a Brazilian carbonate, and a shallow North American heavy oil field. A brief reservoir description for each field is given in the Appendix. Data for each calculation are determined from available in-house project datasets. For each case, average reservoir rock properties are estimated from the sonic and density logs (see Table 4) to obtain $V_P$, $V_S$, $\rho$ and porosity. Table 4 also shows critical and residual saturations extracted from published laboratory data and the fluid flow simulation model, compressibility values from the simulation model, and the thickness of the main reservoir interval estimated from the seismic field data. Two-way time to top reservoir and water depth are also used to calculate the time thickness of the overburden. The fluid substitution exercise performed previously is repeated and these results are also compared against time-shifts from the geomechanical calculations of equations (9) and (10). As shown above, time-shifts due to strain are dependent on the reservoir compressibility, $R$-factor, reservoir thickness and depth. For our selected field cases we have chosen to set $R$ at 2 in the reservoir and 5 in the overburden as we lack information to do otherwise, and to compute the strains in the reservoir and overburden for a pressure change of 10MPa. The exception is the HPHT example, for which a pressure of 50MPa is used in the calculation. $R$ is held constant, despite the understanding that it must vary with lithology and stress path, as the precise nature of the variation is not yet clearly established (MacBeth et al. 2018).

Estimated time-shifts and relative time-shifts for both the reservoir and overburden effects are shown for these specific fields in Table 5. The saturation-related estimates are found to be generally consistent with our database in Figure 3, Tables 1 and 2, and also the calculations from Figures 7 and 10. As expected, the smallest time-shifts are for the thinnest reservoirs, highest velocities or lowest porosities. For the clastic reservoirs, time-shifts due to saturation changes are generally comparable (and often slightly larger) than those generated by
geomechanical effects in either the reservoir or overburden. For the chalk reservoir which experiences large strains, the geomechanical effects dominate due to the high pore volume compressibility of the chalk. For saturation effects, time-shifts are largest for gas displacing water, followed by gas out of solution and then water displacing oil. Gas displacing water generates particularly large time-shifts in the soft, thick tertiary sands of field D (11.94ms), whilst the chalk field F exhibits the lowest values (0.58ms). Finally, for the water displacing oil, and gas displacing water mechanisms, the carbonate field C indicates that the (small) time-shifts may reverse in sign i.e. a hardening appears as a softening and vice versa. This was discussed above as related to a competition between density and velocity effects in the saturation calculation. For the geomechanically-induced effects in Table 5, all show that the polarity reversal of slowdowns from overburden extension, or speedup from overburden compression, is not possible. Also, time-shifts from reservoir extension are typically always bigger than those from overburden extension. Overall, the time-shift predictions from these calculations are only slightly lower than those measured on comparable fields in Figure 3 – for example, for the chalk and HPHT reservoir the overburden time-shift estimates are 20.44ms and 4.30ms compared with 24ms and 5ms for the measurements. For the hard-rock carbonate, significant effects are also not expected. This difference may relate to an underestimate of the reservoir compressibility or the effective geomechanical interval in the reservoir, the $R$-factors being too low, layers of contrasting stiffness, or to approximate nature of the equations used. The most likely candidate to explain the scaling discrepancy is that the elastic pore volume compressibility values used in this calculation should be adjusted to include the effect of inelastic deformation in the reservoir.

**Observed lateral shifts**
In addition to the vertical time-shifts, 3D cross-correlation or warping methods spatially realign the baseline and monitor volumes and hence measure horizontal or lateral shifts (for example Hall et al. 2002, Hale 2007). These lateral shifts have been observed in compacting chalk reservoirs (Hall et al. 2005), an HPHT clastic (Hale, Cox and Hatchell 2008), and below a normally pressured clastic reservoir (Aarre 2008). Beyond these, there are limited values published from case studies compared to the extensive list of vertical time-shifts we encountered. Observations are generally consistent with shifts that are 5 to 10m in magnitude and outwardly pointing. Spatial shifts are, of course, anticipated due to physical displacement and velocity change in the subsurface, however their exact mechanism is not yet clearly identified (Cox and Hatchell 2008). Modelling suggests that physical movement due to production-induced strain contributes to smaller, inwardly directed shifts (Garcia, MacBeth and Domes 2010). Raypath modifications due to the velocity changes appear to provide the most satisfactory solution and the correct polarity of response. More discussion of the methods employed to measure lateral shifts together with processing and acquisition errors will be given in MacBeth and Amini (2018).

**Observations of offset-dependent time-shifts**

As geomechanical effects are three dimensional and tensorial, it is expected that time-lapse time-shifts should vary with offset in pre-stack or limited offset stacks, even if the time-lapse velocity changes themselves are isotropic (Landrø and Stammeijer 2004). It is also theoretically possible for time-shifts to vary with azimuth if anisotropy needs to be included. However, to date observations of time-shifts with offset/angle have been published by only a small number of authors. For example, Herwanger, Palmer and Schiøtt (2007) measure time-shifts on the compacting chalk of the South Arne field, and conclude that they decrease with angle, being 50% smaller at the further offsets. Hawkins (2008) on the other hand measures
an increase with offset in the high pressure-high temperature (HPHT) Elgin field. Interestingly, Røste et al. (2007) measure time-shifts in permanent reservoir monitoring systems and towed streamer data for the compacting chalk of the Valhall field using 2D seismic lines, finding a non-monotonic time-shift variation related to localised stress changes at a slipping fault. More recently Kudarova et al. (2016) presented examples of time-shifts obtained with angle sub-stacks of marine seismic data acquired in ocean bottom node (OBN) surveys in deep water (Gulf of Mexico, Mars) and narrow-azimuth streamer surveys in shallow water (North Sea, HPHT Shearwater). They did not observe a strong variation of time-shifts with offset as reported in previous publications. Additionally, despite OBN delivering a wide range of azimuthal coverage, they have observed no clear azimuthal dependence of the time-shift with offset behaviour to date. A single mechanism that predicts both the polarity and magnitude of these observations has not yet been identified. A theoretical model to explain these has been proposed by Fuck, Tsvankin and Bakulin (2010), although this predicts only an increase with offset. A suggestion has been offered by MacBeth et al. (2018) based on the original conceptual model of Hatchell and Bourne (2005a) that predicts both positive and negative gradient. High quality acquisitions are now available with sufficient offset and azimuth coverage to attempt to measure time-shift variations, and thus these observations remain to be clarified in the future.

**Converted P-S time-shifts**

This review paper has focused only on time-lapse time-shifts from $P-P$ data, as this occupies the majority the available field examples from the literature. However it should be noted that multi-component data from marine acquisition, via Life of Field Seismic (LoFS), OBS or OBN, or land surveys with multi-component sensors, will provide both $P-P$ and $P-S$ converted wave time-shifts. Although the processing of $P-S$ data is recognized to be more
problematic than for $P-P$ data (Gaiser 2016), it is possible to observe large time-shifts (roughly twice the size of the $P-P$) that correlate with reservoir production or recovery. For example, on land Bishop and Davis (2014) saw $P-S$ time-shifts that could be attributed to pressure effects and also to some degree to saturation for CO2 injection in the Delhi field. In heavy oil reservoirs, $P-P$ and $P-S$ time-shifts can also be combined to yield changes in $v_p/v_s$ to image the effects of heat and pressure outside the reservoir at the Long Lake field (Schiltz et al. 2014). For marine acquisition, Zwartjes et al. (2008) demonstrated on the Valhall LoFS data that after correction for the shallow overburden, $P-S$ time shifts could provide consistent top reservoir information to $P-P$ time shifts. One further use of well-defined $P-P$ and $P-S$ time-shifts is that they can be jointly interpreted to separate pressure and saturation effects (for example, Trani et al. 2011). Whilst $P-S$ data do provide an additional dimension to reservoir interpretation, they are not yet commonly used in industry practice.
DISCUSSION

Post-stack time-lapse time-shifts have been well documented over the past ten to fifteen years, and there are now many clear examples in the literature. This paper has attempted to overview these with a view to understanding the range and relative magnitude of the measured values, and the production mechanisms that link to these responses. Whilst we have been able to find fifty-nine sets of field data to date there is a clear lack of key quantitative information recorded in the literature, which makes such studies challenging. In particular, there are very few direct mentions of absolute time-shift values directly associated with particular mechanisms and the reader must instead inaccurately infer values from the colour bars. In addition, supporting data such as pressure changes or saturation changes, critical saturation values, and reservoir compressibility values would be essential to the overall understanding. Assigning these would help to provide a better quantitative evaluation and development of this topic, and assist in further field applications. In addition, colour bars often lack axis labelling and are inconsistent across the published examples from many different ‘stables’. We propose therefore that a standard should be established across the community. From our experience of the examples in this paper and the subsequent review we recommend green-blue-cyan/yellow-red-pink with linear gradation in intensity – Figure 8 shows a good example of this proposed colour bar. This also provides a more intense colour for higher values, with white representing the zone of noise. It is intuitive that red should represent slowdown (softening, hence gas or pressure up), whilst blue represents speedup (hardening, hence water or pressure down).
The main focus of this current paper has been on the magnitude of time-shifts, and the rock and fluid physics changes that cause these delays. The time-lapse effects are found to be easy to predict and to agree well with the observations. No anomalous behaviours are found in published data examples although there are a few notes of inconsistency in polarity conventions. This reflects the general stability and directness of time-shifts as a dynamic reservoir attribute. Indeed, it is interesting that in some cases time-shifts still realize value whilst amplitudes cannot (Byerly et al. 2006) albeit at a lower spatial wavelength. Overburden measurements have value in understanding drilling risk, whilst reservoir measurements clearly identify produced or injected regions. Time-shifts have revealed not only the obvious in terms of spatial distribution of geomechanical effects or saturation changes, but also some surprises such as possible out of zone saturation responses, uncommonly low prevalence of overburden compressions and fault reactivations. Time-shifts are a cumulative measure of the subsurface and thus do not directly relate to localized subsurface properties such as velocity change or physical strain. In addition, pressure/strain and saturation effects do overlap in the reservoir to some extent. Inversion is thus an important step in interpretation and is essential when estimating velocity change or physical strain from these measurements. There are a spectrum of methods to solve this inversion problem, ranging from simple layer stripping using vertical differentiation of the time-shifts to yield ‘time-strain’ or velocity change, to more sophisticated algorithms that preserve image consistency or invert for pressure changes in the reservoir using overburden strain (Hodgson et al. 2007). The results of these procedures clearly depend on the quality of the resultant time-shifts which in turn is a function of the level of noise on the seismic signal and the measurement technique – the current examples in Figures 4,5,6,8,9, display a range of noise levels and some differences in the measurement technique. This interesting aspect is pursued
further in the review of the many different methods for time-shift measurement and inversion given in a companion paper MacBeth and Amini (2018).
CONCLUSIONS

Post-stack time-lapse time-shifts are observed to fall into six main categories: extension and compression in the reservoir and non-reservoir rocks, plus saturation-related hardening and softening in the reservoir. Slowdowns due to overburden extension, pressure increase in the reservoir, gas exsolution and gas displacing oil/water display the largest and most prevalent responses. In these cases time-shifts can reach up to 24ms, depending on the reservoir thickness and rock properties. Speedups due to water displacing oil/gas in the reservoir and compressional strain in the overburden are at most 3ms and much less commonly observed. The reasons for the difference in prevalence of slowdown and speedup is not entirely clear (perhaps velocity-strain asymmetry, measurement difficulties or complex overlapping effects), and requires further research. The magnitudes of these time-shifts appear to be predicted well by rock physics calculations and show some variation with reservoir thickness and compressibility, porosity, velocity, and to a limited extent critical fluid saturations such as residual oil, critical gas saturation, and maximum gas saturation. Despite this variability, time-shifts can be fairly easily generalised across a broad range of reservoirs. Time-shifts have clear interpretative value and appear a robust and stable dynamic seismic attribute for reservoir evaluation. Further development of this topic can be assisted if researchers publish more quantitative information and supporting data, and also work with a consistent colourbar (as proposed in the footnote).
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APPENDIX
DETAILS OF SPECIFIC FIELD EXAMPLES

This appendix provides a brief description of the fields used as references for the time-shift calculations in this work. A select number of these field are also supported by in-house 4D seismic data for which time-shift measurements have been made. However in some cases data are available, but non-repeatability noise levels are too high to support reliable measurement. A full discussion on the detection of time-shifts in terms of non-repeatability, and the correction for overburden variations can be found in MacBeth and Amini (2018). More reservoir-related details can be found in the references cited under each category.

Field A – North Sea Jurassic field, HPHT
This is a high pressure high temperature gas condensate reservoir in the central North Sea. The main reservoir is a tilted fault block of Jurassic age, lying between 4700 to 5700m below sea level. It consists of clean stacked shoreface and shallow marine sandstone with a mean thickness of 92m, and porosity between 20 to 30%. There are some dispersed shale and calcite cemented intervals in these sands. Pressure depletes by 3,000psi after two years, and by 7,500 - 9,000psi after a further two years. The time-shift signature in this field is therefore strongly driven by geomechanical effects (see Staples et al. 2007b, Ji 2017), which display a complex slowdown overburden signal of 5ms at top reservoir with some identifiable reservoir hardening of 3ms.

Field B – North Sea, Jurassic sands
The field is a Horst block with the reservoir enclosed and segmented by major faults into three major and one minor segment. Reservoir rocks are lower to middle Jurassic dominated
by fine-grained and well sorted fluvial deposits. Reservoir formations are buried at depths of 2300 to 2700m. Reservoir quality reduces as a function of depth, with the upmost formation having a porosity in the range 25 to 32% and a mean thickness of 30m. There is some evidence of carbonate cementation. Both slowdowns and speedups are observed across the field. Strong pressure up time-shift signals of 4ms are observed at the injector and also there is some evidence of gas out of solution, water flooding and pressure depletion. However the 4D seismic data are not sufficiently repeatable to delineate all of these effects clearly. More details of the 4D analysis of this field may be found in Omofoma (2017).

**Field C – Jurassic carbonate, Hard rock carbonate, Campos Basin**

This field is an Albian carbonate with reservoirs lying 3200m subsea. It has a thick sequence of variable facies with an overall thickness of 50 to 130m, and average porosity of 19%. The field is under water drive, and 4D amplitude effects are visible due to water replacing oil but there is also some evidence of geomechanical effects in the reservoir and overburden. Unfortunately indistinct time-shifts are observed on measurements from the 4D seismic data due to high non-repeatability noise. We would suggest however that these effects can be detectable with better repeatability.

**Field D – Tertiary sands, West Africa**

This field is composed of several stacks of turbidic channel complexes and channel-levee complexes and sand sheets, 1100m below the seafloor in 1400m of water. The highly amalgamated channel complexes are the main units of the reservoir, consisting of four sub-channel stories of 30 to 40 m thick with porosities of up to 40%. Production gas is re-injected into the top of the reservoir and seawater injected into the flanks almost from the start of production. A complete range of 4D effects are observed due to: gas out of solution, gas injection, pressure
increase, pressure depletion and water increase (Tian 2014). There are strong amplitude effects and also large time-shifts of up to 15ms observed.

**Field E – Tertiary deepwater turbidite sands, UKCS**

This turbidite field is composed of thin, multiple stacked Paleocene turbidite channel and sheet-like sands compartmentalised by East-West oriented faults (Rangel 2016). The reservoir sands lie at 2000m depth, range in thickness from 5 to 30 m and have porosities in the range 25 to 30%. The field has been monitored extensively over the years from production start-up as the reservoir pressure is close to bubble point. The distinct signatures of gas out of solution and waterflood signal have been clearly observed in the amplitude data. There are also strong signatures due to pressure increase in localised compartments and some evidence of pressure depletion. As the reservoir is thin, time-shifts are small (< 1ms) and barely visible on the seismic data. This example is included in our list to represent the boundary of what is possible.

**Field F – Paleocene Chalk, North Sea**

This is a naturally fractured chalk field with two strongly compacting chalk reservoirs separated by an impermeable tight zone. The reservoir interval has an average thickness of between 175 and 300m, with top reservoir being located at approximately 3050m. Massive compaction occurs due to pressure depletion in this 30 to 40% porosity chalk, with visible surface subsidence. Compaction drive is supported by gas re-injection and water injection. The field has been monitored extensively with repeat survey frequencies of a few years and also several months. The high reservoir compressibility results in significant geomechanically-related time-shift signatures with overburden slowdowns of up to 20ms, and depletion related reservoir speedups of up to a few milliseconds over several years of activity.
Saturation-related time-shifts of 4ms are also evident for water replacing oil over a few years of production, and less than 1ms over a period of only several months (Wong 2017).

Field G – shallow heavy oil, North America
This particular example is Cretaceous age sediments deposited in a shallow marine setting lying at 550m depth. The sands of thickness 22 to 27m and porosity 27 to 30% are filled with heavy oil (bitumen). In this case several designs of EOR have been employed including cyclic steam stimulation and top down steam drive, which lead to a complex sequence of pressure, temperature and fluid (steam, condensed water, and hydrocarbon gas) and mixture-related effects. There is some evidence of geomechnical effects in the overburden also. The mechanism that we will consider is the well-developed and easily recognisable steam chamber. Time-shifts of a few milliseconds are clearly identified on frequently repeated surveys associated with pressure up signals in the reservoir modulated by temperature effects.
**Table 1** Summary list of time-shift measurements reported in the published literature for a variety of geomechanically-active fields. Time-shifts marked by an asterisk are estimated from published figures, otherwise the values are cited directly from the text. The values above relate directly to Figure 3. Abbreviations are: NS – North Sea; NNS – Norwegian North Sea; GERM – Germany; BS – Barents Sea; IC – Ivory Coast; CONG – Offshore Congo; UKCS – UK continental shelf; CAN – Canada; HO – Heavy Oil; NWA – North West Arctic.

<table>
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<th>Time-shift (ms)</th>
<th>Field Name</th>
<th>Location</th>
<th>Reservoir</th>
<th>Duration</th>
<th>Depth SS (m)</th>
<th>Thickness (m)</th>
<th>Reference</th>
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<td>4 months</td>
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</table>
Shelf, Australia; GOM – Gulf of Mexico; MAL – Malaysia. Field names in red refer to land data.

Table 2 Summary of saturation-related time-shift measurements obtained from the published literature. Time-shifts marked by an asterisk are estimated from published figures, otherwise the values are cited directly from the text. The values above relate directly to Figure 3. Abbreviations are as in Table 1. Field names in red refer to land data.

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<th>Time-shift (ms)</th>
<th>Field Name</th>
<th>Location</th>
<th>Reservoir</th>
<th>Duration</th>
<th>Depth SS (m)</th>
<th>Thickness (m)</th>
<th>Fluid effect</th>
<th>Reference</th>
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<td>CO2 injection</td>
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<td>Obidegwu, 2015</td>
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<td>INDO</td>
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Table 3 Subset of observed data in Tables 1 and 2 for which pressure change measurements are available. Time periods for each pressure change vary. Also shown are the time-thicknesses of the reservoir and overburden estimated using a mean velocity of 3km/s together with the resultant relative time-shift. Reservoir lithologies are poorly consolidated sand (PC sand), consolidated sand (Con sand), chalk, carbonate or consolidated sands under HPHT conditions. These data are plotted in Figure 7.
Table 4 Mean seismic, fluid and geomechanical properties for the reservoir from seven selected fields from which time-shifts are calculated. P-wave velocity ($v_p$), shear-wave velocity ($v_s$), density ($\rho$) and porosity are determined from averages of the logged reservoir intervals. Reservoir thickness refers to the total cumulative interval, and not an individual producing unit. Pore volume compressibility is evaluated at the initial reservoir pressure.
Table 5 Time-shifts (in milliseconds) and relative time-shifts (bracketed number, in units of $10^{-4}$) calculated for the three saturation change mechanisms using the data from Table 4. For comparison, time-shifts from reservoir and overburden strain are also shown for a pressure change of 10MPa (50MPa for the HPHT field). Red highlighted numbers refer to a response of opposite polarity to that expected – i.e. speedup instead of slowdown, or vice versa. No entry implies that the calculation is inappropriate for this field.

<table>
<thead>
<tr>
<th>FIELD</th>
<th>MECHANISM</th>
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<th>OVERBURDEN</th>
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<td>Speedup</td>
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<td>Gas</td>
<td>Compressional strain R=2</td>
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<td>(376.00)</td>
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<td>(125.00)</td>
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<tr>
<td>G Shallow ho</td>
<td>...</td>
<td>1.16</td>
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</tr>
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<td>(652.00)</td>
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Figure 1 Example vertical sections for: (a) 3D baseline survey reflectivity for guidance; (b) 4D difference data before time-shift correction; (c) after time-shifts correction; (d) the corresponding time-shifts (maximum time-shift is 7ms). These time-shifts are generated from velocity slowdown due to pressure build up from seawater injection into the reservoir interval over 7 to 8 months of production. Time-shifts are evaluated using the algorithm of Lie (2011). Examples are for the Svale field after Alsos et al. (2009).
Figure 2 Schematic illustration of the expected time-shifts and corresponding velocity changes associated with: (a) compaction in the reservoir due to pressure depletion plus extension in the overburden; (b) saturation changes in the reservoir.
Figure 3 Time-shifts measured in the overburden or reservoir across a select range of fields. Tables 1 and 2 give these measurements in detail. Sleipner time-shifts are divided by 2 for visualisation purposes. Light red vertical bars for Valhall and Ekofisk signify measurements made on data from the LoFS. Reservoir time-shifts are interval time-shifts. Field names in red are for land data. Red dashed lines are reference values calculated in the main text for an average reservoir/overburden and 10MPa pressure change.
Figure 4 Examples of measured time-shift responses from strain in non-reservoir rocks. (a) Slowdowns of up to 6ms (in red) due to overburden and underburden extension from the HPHT Shearwater field after 60MPa of reservoir depletion between the 2004 and 2001 surveys. The time-shifts are evaluated using the NLI algorithm of Rickett et al. (2007) - from Ji (2017). (b) Strong slow-down and pressure build-up in a reservoir from gas injection and speedup in the overburden due to compression. Signature is between 2006 and 2009 surveys. Figure adapted by Thomas Røste from Røste and Ke (2017).
Figure 5 Two further examples of time-shift responses due to strain in non-reservoir rocks due to reservoir pressure depletion. (a) Distinct slowdowns in a North Sea chalk field from reservoir depletion between 1992 and 2002. (b) Deep water Gulf of Mexico examples for depletion between 1993 and 2004. Re-drawn from Hatchell and Bourne (2005a) courtesy of Paul Hatchell. No lateral or vertical scale bars are available for these examples. Maximum time-shifts are 10 and 15ms respectively.
Figure 6 (a) Slowdowns (in red) due to a pressure increase from seawater injection into the aquifer of the Norne field. A maximum time-shift of 10ms is observed between the baseline in 2001 and monitor in 2006. Time-shifts are estimated using the cross-correlation method (Santos et al. 2016). (b) Speedups (in blue) associated with pressure depletion (hence hardening) around a producer in a North Sea chalk. Time-shifts are again estimated using cross-correlation (Wong 2017). Maximum of time-shifts is 2.5ms.
Figure 7 Relative time-shift $\Delta t/t$ versus pore pressure change $\Delta P_p$ (either pressure up or down): (a) for the reservoir interval; (b) for the overburden interval. Straight lines correspond to predictions based on equations (9) and (11) for low to normal (lines a and d), moderate to high (lines b and e) and high (lines c and f) pore volume compressibility. Solid lines correspond to estimates for extension, whilst dashed lines are for compression. Available data points (see Table 3) are also plotted – open symbols for extension and solid symbols for compression.
Figure 8 Examples of time-shift measurements due to: (a) hydrocarbon gas injected into a saline aquifer. There is a clear maximum of 15ms. Measurements are derived from the NLI algorithm of Rickett et al. (2007). (b) slowdowns from a steam chamber developed as a result of steam-assisted gravity drainage EOR in a Canadian heavy oil reservoir. Solid circles denote the producers. Maximum time-shift is 8ms. Calculations using a cross-correlation algorithm with a time-gate of 60ms.
Figure 9 Examples of time-shift response for: (a) a rare example of water saturation increase from seawater injected into chalk. Time-shifts are up to 2ms in magnitude. Courtesy of Ming Yi Wong. (b) Slowdown around producer due to gas liberated from oil in the Svale field (Alsos et al. 2009). Here there are clear softening signals of up to 8ms. Time-shifts calculated using the cross-correlation method. Courtesy of Trine Alsos.
Figure 10 Relative time-shift plotted against porosity and fluid saturation for our generic North Sea reservoir rock. The calculations predict slowdowns due to: (a) gas injection into oil, (b) gas injected into water; (c) gas out of solution; and speedups for (d) water displacing oil.
Figure 11 Examples of time-shift measurements due to saturation changes: (a) slowdowns (red) due to pressure build-up from water injection (from wells F1-H and F3-H) into the aquifer - 2001 and 2006 surveys of the Norne field. Estimated using the cross-correlation method by Santos et al. (2016). (b) Speedup due to water replacing gas (hydrocarbon and steam) during the complex process of recovery in a heavy oil reservoir of 25m thick. The red slowdown response to the left is due to pressure increase. Method used is based on a Taylor series expansion.
Figure 12 Relative time-shift with maximum gas saturation and as a function of reservoir rock quality, for gas displacing water. Velocities vary from those typical of a moderate quality reservoir rock with 30% porosity to those of a harder, more cemented, rock with 15% porosity. There is a polarity change at approximately 3.5km/s where the density changes overtake the bulk modulus changes – a speedup is now expected instead of a slowdown.