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INTRA-SURVEY RESERVOIR FLUCTUATIONS - IMPLICATIONS FOR QUANTITATIVE 4D SEISMIC ANALYSIS

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Summary

During the time taken for seismic data to be acquired, reservoir pressure may fluctuate as a consequence of field production and operational procedures and fluid fronts may move significantly. These variations prevent accurate quantitative measurement of the reservoir change using 4D seismic data. Modelling studies on the Norne field simulation model using acquisition data from Ocean Bottom Seismometer (OBS) and towed streamer systems indicate that the pre-stack intra-survey reservoir fluctuations are important and cannot be neglected. Similarly, the time-lapse seismic image in the post-stack domain does not represent a difference between two states of the reservoir at a unique base and monitor time, but is a mixed version of reality that depends on the sequence and timing of seismic shooting. The outcome is a lack of accuracy in the measurement of reservoir changes using the resulting processed and stacked 4D seismic data. Even for perfect spatial repeatability between surveys, a spatially variant noise floor is still anticipated to remain. For our particular North Sea acquisition data we find that towed streamer data are more affected than the OBS data. We think that this may be typical for towed streamers due to their restricted aperture compared to OBS acquisitions, even for a favourable time sequence of shooting and spatial repeatability. Importantly, the pressure signals on the near and far offset stacks commonly used in quantitative 4D seismic inversion are found to be inconsistent due to the acquisition timestamp. Saturation changes at the boundaries of fluid fronts appear to show a similar inconsistency across sub-stacks. We recommend that 4D data are shot in a consistent manner to optimise aerial time coverage, and that additionally, the timestamp of the acquisition should be used to optimise pre-stack quantitative reservoir analysis.
**Introduction**

Measurements of pressure change across the reservoir are useful for evaluating well performance, in particular the reservoir connectivity that relates to the degree of aquifer/injector pressure support, barriers, fault seal/non-seal, and compartments. Saturation measurements are also useful for assessing sweep efficiency, barriers, the risk of breakthrough, and optimal monitoring of production and recovery. This information is typically provided using production logging tools and down-hole gauges, or subsurface fluid flow simulation models. 4D seismic data have also been proposed as a way of sensing these changes, with the added benefit of access across the inter-well space. However, despite significant improvements in processing and acquisition over the past ten years, accurate quantitative estimation of changes in the reservoir using 4D seismic data (using amplitudes, time-shifts or some other attribute), especially that of pressure, remains technically challenging (Eiken and Tøndel 2005; Røste, Dybvik and Søreide 2015) for a wide variety of accepted reasons (Alvarez and MacBeth 2014). The limitations for pressure estimation include most significantly the uncertainty in obtaining a precise description of the rock stress sensitivity and geomechanical response. The ability of 4D seismic data to detect pressure and saturation changes is dependent on the 4D data non-repeatability (i.e. magnitude of non-production related effects or ‘noise’) versus the 4D signal (i.e. the magnitude of the change in the reservoir’s elastic properties due to the induced production) which not only depends on how significant the production is but mainly on the seismic properties of the reservoir (Johnston 2013). Current published data from a number of case studies indicate that large increases in pressure of 5 to 15 MPa from fluid injection into isolated compartments are readily visible, whilst field-wide pressure fluctuations of less than 5 MPa may be difficult to detect with accuracy in
many reservoirs (Omofoma and MacBeth 2016). Fluid saturation, on the other hand, is measured on stacked data with more accuracy in general - although the impact of pressure uncertainty on saturations remains unclear.

In this study we contribute to this research topic by suggesting yet another factor of relevance, the time scale of the seismic data acquisition relative to that of the reservoir dynamic fluctuations themselves. During seismic acquisition (either offshore or onshore) over many weeks, the inevitable rapid variations induced in the field are captured in a non-obvious and irregular way across the pre-stack volume. The stacked data therefore do not accurately reflect the spatial distribution of the pressure difference between the two-time images of the reservoir, but provide instead a complicated, smeared and distorted average over the survey duration. The purpose of this study is to determine whether this effect could be significant, assess the impact it may have on current 4D seismic interpretation practices and suggest possible solutions. The work utilises seismic modelling with real field acquisition geometries and shot timings, and a modified history-matched simulator predictions from the Norne field.
Seismic acquisition versus production time-scales

Apart from areal coverage, the time taken to acquire seismic data depends on a broad range of practical operational and logistical considerations, which also influence to some extent the sequence and timing with which the surveys are shot. For example, towed streamer data are dependent on boat speed, boat turn-around, offset coverage, the effect of tides, platform and facility obstructions, additional field activity and bad weather downtime. As a consequence, a typical North Sea survey of 250 km$^2$ can take six to eight weeks to complete (Campbell et al. 2005; Ross et al. 2010). Ocean-bottom cables covering a similar area can also take months to complete. Whilst reservoir monitoring with ocean-bottom nodes is not restricted by large streamer or cable dimensions, nevertheless such surveys can still take a few weeks to a few months to cover a much smaller but higher fold area of 20 km$^2$ to 143 km$^2$ (Eriksrud 2014; Farmer et al. 2015; Bertrand et al. 2014) due to weather and operational restrictions. On land, survey time is strongly affected by the complexity of terrain, weather conditions, equipment availability, physical obstructions and environmental constraints. Land surveys are clearly expected to take longer than towed streamers to cover a comparable area (Aouad, Taylor and Millar 2012; McWhorter et al. 2012).

In the reservoir, a range of independent activities such as injector or producer well shut-off or re-start/start, alteration of a rate/choke setting, well tests, bumping/slugging, and squeeze treatment (Watts and Marsh 2011) are known to cause reservoir pressure fluctuations. Pressure is also affected by turn-around, production optimisation, work-overs, evolving water cuts, and the introduction of new wells or re-introduction of old wells. Field average or bottom-hole pressure fluctuations due to natural day to day field operations are usually between 0.05 and 0.5 MPa/day, and
therefore so small that they are below noise level (Omofoma and MacBeth 2016). However, well operations that involve well shut-off, restart or variation in choke setting can generate changes of as much as 1.5 to 15 MPa for typical offshore fields injecting between 10,000 and 25,000 stb/day. Production or injection into small compartments or isolated zones will induce bigger changes than those in larger compartments. For each distinct pressure change due to a fluid volume discontinuity, there emerges a pressure transient that spreads across the reservoir. Over time this is followed by a semi-steady state and then subsequently an equilibration period (Dake 1997). Whilst pressure is generally detected quickly and across the entire connected volume in a matter of hours, the phenomenon of pressure diffusion takes much longer to stabilise. Eventually pressure is expected to be uniform across a compartment and evolve linearly in time for constant rate wells after equilibration. However pressure can take tens to hundreds of days to equilibrate, depending on the dimensions of the reservoir boundaries and compartments, easily as long as, or longer than, the seismic survey acquisition time.

By comparison to pressure, fluid saturation changes generally evolve laterally at a slower but nevertheless significant rate. For example, depending on the mobility (relative permeability divided by viscosity), a waterfront may move typically at a velocity of 0.3 to 1.5 m/day (Tjetland, Kristiansen and Buer 2007), whereas hydrocarbon gas, steam or CO₂ fronts can propagate at up to 5 m/day (Michou et al. 2013). It is observed that in some cases CO₂ propagation can exceed 13 m/day (Lu et al. 2012). Only the boundary of the fluid distribution will experience significant change during the survey, and thus the acquisition survey will generally sample fluid movement in a halo of 50 to 500 m in width during the acquisition itself. So, this
covers an acquisition time of 30 to 70 estimated days. Vertical fluid contacts will move much more slowly and are unlikely to change much during the survey duration. For example, in the Nelson field, the oil-water contact moved vertically by 30 to 60 m after 10 years of production (MacBeth, Stephen and McInally 2005) and in the Troll field, the gas-oil contact moved by 10 to 12 m after 5 years of production (Bertrand et al. 2005). Another example is in a chalk field where the gas-water contact is interpreted to have moved by 25 m in 4 years (Barker et al. 2008). Another possible process, gas out of solution, is relatively quick and responds to pressure drop within a day (Falahat et al. 2014), and thus there can be significant variations in gas caps, trapped gas or gas remaining at critical saturation within the reservoir during a survey period of 60 days. Other processes that might be relevant to this study include compaction in highly porous chalk reservoirs (Barkved, Kristiansen and Fjaer 2005), evolution of strain deformation in geomechanically active reservoirs, the sudden breakdown in faults due to depletion which may occur in days, or the creation of baffles during fluid flow which could appear in weeks.

To address the above, we perform a modelling study based on real acquisitions and a field model to consider the impact of intra-survey fluctuations on the final migrated 4D seismic data. Specifically, reservoir pressure and fluid saturation changes are simulated using a history-matched model of a structurally complex field. The geometry and time sequence of shooting from a towed streamer and an Ocean Bottom Seismometer (OBS) survey acquired in the North Sea are then used to reconstruct the time-lapse seismic changes. The exercise allows us to assess the areal impact of unexpected fluctuations during the survey acquisition.
Reservoir details and acquisition timing

The reservoir model for this study is that of the Norne field, which is a horst block of approximately 9 x 3 km and is located in the southern part of the Nordland II area in the Norwegian Sea (Osdal et al. 2006). The reservoir is enclosed and segmented by major faults with three segments (C, D and E) in the main field area and the fourth segment, G, an isolated compartment of size 3.6 km². Four sandstone formations of Lower and Middle Jurassic age make up the reservoir rocks at a depth of 2500 to 2900 m. Our analysis is based on the top reservoir formation which has an average thickness of 28 m and shows variations in effective porosity from 12 to 32% (Figure 1). Horizontal and vertical permeability also vary from 80 to 1300 mD and 10 to 250 mD respectively. Segments C, D and E predominantly contain gas with most of the oil (with an API gravity of 32.7°) in segment G. For the simulations, six water injectors and producers with a well spacing of 500 to 2000 m in the field model are chosen and a pressure maintenance scheme is operated.

Figure 2 shows the timestamp of the shots for both acquisition geometries used in the modelling. The acquisition data consist of individual shots and receiver coordinates during the shooting, and importantly, the timings of each shot. The towed streamer takes 58 days to complete for a shot coverage of 67 km² and an overall streamer coverage of 110 km² (Figure 2(a)). The OBS survey (Figure 2(b)) takes 45 days to shoot an area of 143 km² with sea bed sensor coverage of 60 km². The time sequence of shooting for both acquisitions is very different, and their patterns appear different too. The race-track pattern for the towed streamer shooting is clear, whereas, a
pseudo-random pattern for the OBS survey could be assumed, despite that fact that both surveys have been shot in a race-track pattern. The OBS data was also not acquired in swathes. Survey acquisitions aim to optimize the time available and negotiate field operations and weather windows. This can be observed in our particular data, as there are gaps of inactivity that last for up to 5 days for our OBS survey but for many weeks (30 days) in the case of the towed streamer survey. We therefore expect both acquisitions to image the changes in the reservoir differently.

Production and water injection (from injectors I2 and I3) starts two years prior to the monitor survey. Additionally, we choose for water injection in the new wells I1, I4 and I5 to be scheduled to commence close to the time of the monitor acquisition (Figure 3). The field acquisitions considered in this study takes either 45 or 58 days to complete. Within this time, Injector I1 starts on day one as a consequence of injector I6 being turned off five days before the acquisition and Injector I4 is started on day twelve to support producers P4 and P5. Finally, Injector I5 is introduced twenty one days later to support producer P6, where mild gas breakout occurred prior to the monitor time. All water injectors operate at an average rate of 16,800 stb/day but fluctuations of up to 4180 stb/day occur. As a result, pressure also fluctuates at these wells; with injectors I4 and I5 exhibiting the biggest changes when compared to the start of the survey (Figure 3). With the exception of well P6 from which most of the oil is produced, pressures at the remaining, predominantly gas producers, are similar to the overall field average pressure which is relatively constant during this time, due to their smaller production rates. During the acquisition, the wells remain in transient
flow, due to the non-constant flow rates, near well interferences and boundary conditions.

Figure 4 shows the simulated reservoir changes that occur between the start and end of the acquisition time frame for 58 days. Spatially, pressure fluctuations are smaller in the gas leg (segment C and D) with the majority of the pressure changes being in segment E and G where injectors I4 and I5 are located. Flood front growth can also be tracked from the two mature injectors I2 and I3, and the new injectors I1 and I5. In segment G, mild gas breakout is also observed, although pressure increase at injector I5 restricts the gas to lie close to the producer P6. For the injectors, the magnitude of pressure fluctuations range from 0.15 to 4.5 MPa between 30 seconds intervals from the start to the end of the acquisition, but are less than 0.1 MPa for the producers. By comparison, the saturation floods progress at a rate of between 0.9 and 2.1 m/day.

**Seismic modelling**

Seismic modelling is performed to compute the expected post-stack migrated data acquired in the presence of the intra-survey fluctuations described above. This is achieved in two main steps, first, by spatio-temporal binning of the acquisition midpoints and reservoir fluctuations, and second, by seismic forward modelling of the binned data. The spatio-temporal binning computes geometric midpoints (together with the offsets and corresponding shot time of the midpoints) using the surface locations of the shots and receivers. On the assumption that the image point of reflection at the reservoir level is directly below the geometric midpoint at the surface, CMP binning of the acquisition midpoint data is performed. This is then followed by timestamp sorting of the simulator predictions by allocating pressure and saturation values to each midpoint on the reservoir grid according to the time that each midpoint
was shot during the survey. This requires grid pressures and saturations for all the shot times from the start to the end of the acquisition from the flow simulator. The binning process can be simplified if the CMP bin grid is co-located and matches the grid of the reservoir model. At any CMP location, the binned midpoint data now include: (1) time of shot for all midpoints, (2) pressure and saturation values at each time of shot, and (3) the acquired offsets for all midpoints. Such CMP data can be further grouped into the acquired offset ranges. For the acquisition geometries used for this work, this yields binned data for offset classes 0 to 1500 m (near), 1500 to 3000 m (mid), and 3000 to 4500 m (far), in addition to the full offset - up to 5600 m for the towed streamer, 14600 m for the OBS. It is assumed here that all acquired offsets can be utilised to produce the full offset class. Any differences in shot times between offset groups is only as a result of the irregularity of the acquired fold across the offset groups. The consequence is that in addition to the effects of amplitude variation with offset (AVO), discrepancies in shot times will cause the resultant response between offset groups to be different, simply because the reservoir’s pressure and saturation are changing across shot times during the acquisition.

The seismic forward modelling involves converting the offset-grouped and CMP binned pressure and saturation data into $V_P$, $V_S$ and $\rho$ using a petroelastic model specifically calibrated for this particular field (Briceno, MacBeth and Mangriotis 2016). Reflectivity series are then computed using Zoeppritz equations (Aki and Richards 1980), assuming a flat overburden with uniform properties, and the reservoir at 4500 m depth. Irrespective of the offset group at each CMP bin, the reflectivity data per offset class are computed using the same incidence angle. This omits any AVO effects, leaving behind only the effects of the temporal sampling of the intra-survey
fluctuations by the acquisition (at each offset class). Seismic traces for each offset group are then obtained by 1D convolutional modelling using a data-derived wavelet. At each CMP bin location, the mean of the traces corresponding to the acquired offset class are then calculated to yield a single trace per offset class. Over the survey area, this resulting mean per CMP location gives rise to stacked data per offset class.

In order to create a dataset with the typical seismic resolution, we follow the work of Amini (2014), where the effect of a post-stack time migration is simulated by convolving the post-stack seismic volumes with a migration operator. In our modelling, this applies to all image points (i.e. CMP locations) obtained from the 1D convolution, irrespective of where the reflections are generated. The migration operator depends on the acquisition geometry, reservoir depth, wavelet and overburden velocity (Toxopeus, Petersen and Wapenaar 2003) and it is calculated using the equation of Chen and Schuster (1999) for post-stack seismic data. It may be argued that the applied migration operator could magnify the intra-survey effect by introducing more distortions; however, the migration only smooths the 4D seismic response. This modelling approach has been found to yield identical results to a more sophisticated finite difference and processing workflow (Amini 2014) under the assumption of a flat and thin reservoir (but above tuning thickness), uniform overburden, and noise-free and multiples-free seismic data.

For the above modelling, properties defined on the reservoir grid are transformed onto the acquisition CMP grid. This results in a uniform property grid where the size of each cell is the same as the fixed bin size of 67.5 x 50.25 m used for the survey data. Table 1 details the survey statistics for both the towed streamer and OBS monitor acquisitions. Shots on each line are activated at 8 to 11 seconds interval, and
decimated to 30 seconds for our study, to reduce storage space in the computation.

Simulator results are output at 10 minute time-steps from start to end of the monitor acquisitions and predictions at finer times (determined by the shot time intervals) are obtained by linear interpolation. The baseline surveys for the OBS and towed streamer are acquired preproduction and assumed to be of exact geometric repeatability to the monitor acquisitions. The baseline seismic data is modelled using the pre-production conditions of the reservoir from the fluid-flow simulation model. Its acquisition shot times are irrelevant since there are no intra-survey reservoir fluctuations prior to production start. As both monitor and baseline geometry is assumed to be the same, noise due to geometric non-repeatability is not considered in the modelling. Overburden changes such as those in the water layer for offshore acquisitions (tides and water velocity) are also ignored. This leaves intra-survey reservoir fluctuations in pressure and saturation at the monitor time as the only influence on the resulting 4D seismic data.

The above modelling exercise aims to compare a surface towed streamer to an OBS monitor acquisition. Specifically, how reservoir processes that are of a different temporal nature, for example, pressure (being quickly diffusive) versus fluid saturation (being almost stationary) are captured by the acquisitions. In addition, it will be shown how the averaged 4D seismic responses per offset class, 0 to 1500 m (near), 1500 to 3000 m (mid), and 3000 to 4500 m (far), in addition to the full offset-up to 5600 m for the towed streamer, 14600 m for the OBS, could vary when AVO effects are omitted and only intra-survey reservoir fluctuations are considered.
Monitoring of pressure changes

During the monitor acquisition, the wells exhibit pressure transient behaviour due not only to fluctuating flow rates but also near-well interferences and boundary conditions. Even if constant well rates are maintained, the field would equilibrate well beyond the survey duration. Traces in each seismic bin will therefore sample the pressure field during different stages of its evolution. Importantly, the time sampling of the reservoir varies across bin locations and also across offsets. Therefore, the process of stacking over offsets mixes together distinctly different pressures, and the resultant seismic image does not represent the pressure at one particular time, but is a complex pre-stack combination of all pressure changes that have occurred during the shooting. This weighting of these pressures is a function of the spatio-temporal sampling across the survey, which depends on the particular survey and how it has been shot.

Acquisition imprints due to the time-sequence of shooting can be seen on the top reservoir full-offset stack responses (Figure 5 (a) and (c)). This appears as smearing, which is severe for the towed streamer but weaker for the OBS - both could easily be mistaken for genuine reservoir features. When interpreting the towed streamer response for example, the softening signals surrounded by the hardening signals in segment G could instead indicate a local compartment. Using the NRMS* error, a quantitative comparison is made against a reference seismic dataset (Figure 5 (b) and (d)) obtained by modelling using an average of the saturation and pressures over the acquisition time-frame. Figure 6 and Table 2 detail this comparison. Against their reference seismic dataset (Figure 5 (b) and (d)), the full-offset stacks result in an NRMS error of up to 16.3% for the towed streamer (Figure 6 (a)) and 5.2 % for the
OBS (Figure 6 (c)) surveys. The full-stack and reference results for the OBS survey (Figure 5 (c) and (d)) are similar, whereas, for the towed streamer (Figure 5 (a) and (b)), there are clear differences (see also Figures 6(a) and 6(c)). This observation is related to the way in which this particular OBS and towed streamer survey have been shot. The OBS survey experiences short but repetitive downtimes of up to 5 days, whilst the towed streamer has a long downtime of 30 days that misses some of the pressure signal. Additionally, the OBS configuration covers more reservoir area per shot, and hence is more suitable to providing an instantaneous reservoir snapshot. Figures 7(a) and (c) compare time-stamp differences between the modelled data for both acquisitions by differencing the mean of the shot times in each bin with a single mean for the entire survey (day 29 for the towed streamer and day 22 for the OBS). The shot time mean for the full-stack data differ by up to 27 days for the towed streamer whilst the OBS shows less divergence with 6 days.

Next, we compare the pressure-only, top reservoir amplitude response for the near and far offset stacks. The image of pressure on the nears and fars is observed to be quite different as indicated by the NRMS error between them (Figure 6(b) and (d)). This is also due to large timestamp discrepancies between these offset stacks (Figure 7(b) and 7(d)). The NRMS error between the near and far offset amplitude responses is up to 7.3% for the towed streamer response and 7.5% for the OBS response. Areas of very small pressure fluctuations still show an error of 0.5% which may add to the “noise floor” associated with 4D seismic data. Whilst these offset-related errors do not

*The normalized root mean square, NRMS, error (Kragh and Christie 2002) calculates the normalized difference between two datasets. Typical NRMS values for non-repeatability noise are around 15 to 45% for towed streamer and 2 to 15% for OBS.*
appear particularly large (as we have exclusively modelled only pressure changes), a separate exercise (not included here) to invert for pressure and saturation changes has shown that they can amplify in the calculation to produce significant inaccuracies.

We have analysed pressure fluctuations for a variety of different scenarios of injection before and during the seismic surveys, and for varying compartment sizes in our model. All yield similar conclusions to the above, thus suggesting these findings can indeed be generalized. The biggest impact is for large compartments in the earliest stages of production, as pressure in this case is not stabilised. For a single injector in a small isolated zone of pressure around the well location, the pressure signal will be imaged accurately in space, but the absolute magnitude of pressure will remain poorly determined. For equilibrium established in a compartment, pressure is now uniform but evolves linearly with time according to the well rate. In this case a variation in pressure measurement error across the compartment is still observed due to the time sampling of the surveys. This error is proportional to the daily pressure change induced by the well rate and survey duration, and inversely proportional to the compartment pore volume. For example, a constant rate of 16,400 stb/day injected into a 6 km$^2$ reservoir of thickness 25 m and porosity 25%, gives a pressure rise of 0.2 MPa/day.

Figures 8 and 9 show two North Sea field examples of full stack time-lapse seismic data, where injectors are active in compartments. In both cases the effects we have discussed above are superimposed on the non-repeatability effects, but we maintain that the intra-survey effect should still be prominent. In the first example, the field compartment is a relatively small area of 0.7 km$^2$ and the water injector is switched on
14 months before the first monitor survey (2004) and switched off 8 months before a second monitor survey (2006). The pressure is therefore in equilibrium before the surveys. The water injection rate and resultant pressure fluctuations are shown in Figure 8(a), and the corresponding time-lapse seismic images in Figure 8(b) and 8(c). Between the start and end time of the first monitor acquisition, the magnitude of pressure change is around 10 MPa (as observed from the bottom-hole pressure). However, between one shot time to the next during the same acquisition, pressure fluctuations of up to 4 MPa are present. We would therefore expect a spatially varying measurement error of 2 MPa for the high pressure in this compartment (discounting the effects of water saturation), and this may account for some of the observed variations that may be inadvertently attributed to geology. For the second monitor acquisition the compartment pressure is much lower, and errors are at most 0.6 MPa. The second example in Figure 9 is for a larger compartment of 3.6 km² in Norne field (segment G), where the water injector has already an established injection rate prior to the first monitor survey (2003) and continues beyond the second (2006). There are injection rate fluctuations during the survey acquisition, and corresponding pressure changes. Pressure drops during 2003 and linearly increases by 10 MPa during the 2006 survey when the pressure change at the well is 30 MPa. On the 4D seismic maps we observe a softening due to pressurization from the injector. We suggest that the observed variability in the softening response however is not just a function of reservoir heterogeneity but a combined spatially variant intra-survey noise floor plus non-repeatability noise.
**Monitoring of fluid changes**

Saturation-only top reservoir amplitudes from our modelling are shown in Figure 10. Errors are again calculated for the full stack data relative to our reference. In this case the errors are localised to the flood front edges where saturations are changing during the survey - the waterflood front moves by between 50 m and 135 m during the shooting of both acquisitions. Movement of gas in segment G is confined to the structural high close to the horizontal producer P6, from which most of the exsolved gas is immediately produced (due also to the action of I5, see Figure 3). Consequently, only small errors (< 0.7 %) result from mild gas breakout (Figure 10 (c) and 10(d)). In segments C, D and E, the initial gas is displaced by water flood during the shooting. NRMS errors are only 0.8% for the OBS survey but up to 3.3% for the towed streamer survey. The mismatch between the near and far offset stacks is now up to 2% (OBS) and 2.5% (towed streamer), which is smaller than the pressure errors (Figure 10(d)). New floods which commence as the survey is being shot are likely to show larger errors behind the flood-front than a more mature floods. The above errors suggest true quantitative evaluation of saturation change from offset stacks from 4D seismic data should take time-stamp variations into consideration. Our result also has strong implications for the imaging of fluid movement along high permeability channels, where fluid moves rapidly and for which the exact position may not be accurately determined with current time-lapse seismic data. This is particularly important for a more mobile fluid such as injected or liberated gas.
Discussion

It is common in practice for well production and injection rates to fluctuate or for wells to be shut-in, re-started or turned off during acquisition of seismic data for time-lapse studies. Additionally, in any field, numerous wells affect pressure locally and at field-scale while the seismic survey is ongoing. This means that the reservoir is typically not in pressure equilibration during the acquisition (if at all during its lifetime), and pressure will fluctuate in and around wells, and also between wells. As the reservoir always remains active, there are also many fluid changes occurring during the duration of the survey. We therefore believe that the phenomena that we have observed in this study are possibly prevalent across many 4D seismic field datasets, and have remained unobserved due to the coarse way in which we compare time-scales between the simulator and seismic domains. This may add a general floor of small-scale fluctuations within the non-repeatability noise attributed to processed 4D seismic data. For wells with significant responses during or close to the start of the survey, the impact has been demonstrated to be significant. It is typical to match the simulation results to the start, middle, end or median time of the seismic survey, however, it is suggested in this study that perhaps the best comparison may be achieved by averaging fine timescale simulation predictions between the start and the end of the survey.

The range of possible significant reservoir IOR/EOR mechanisms that have time constants smaller than the seismic survey acquisition time open up the question of what might be the ideal survey to measure these phenomena for geomechanics, pore pressure, water, hydrocarbon gas, CO$_2$ or steam injection? Most 4D seismic surveys tend to be large and have field-wide coverage that takes months to complete and are
repeated every few years. Permanent reservoir monitoring offers the alternative of a smaller survey size, more frequent repeats and higher fold. In practice the added noise suppression and lower non-repeatability noise of the OBS acquisition would also make such acquisitions attractive. Our study suggests that an ideal seismic survey should be very quick to acquire with little or no gaps during the shooting, high coverage with each shot, and repeated frequently to sample the rapid reservoir changes adequately. Possible choices for such surveys include the specialised i4D surveys (instantaneous 4D using a sparse and highly repeatable OBN) that take only a day to a few weeks depending on the survey size (Stammeijer et al. 2013; Hatchell et al. 2013). These would provide a more reasonable temporal sampling of reservoir changes than a full 4D survey. Another acquisition possibility where rapid physical effects may be more sharply defined than in normal surveys is highlighted on land with the SeisMovie technology enabling six hour sweeps and four shots per day in an almost continuous sequence over a small localised pad of reservoir activity (Hornman and Forgues 2013). A further possibility involves the use of time-lapse (3D) VSP to provide highly accurate images over a small image area (Tøndel et al. 2014; Pevzner, Urosevic and Grevich 2015).

Finally, our analysis using the Norne field simulation model has shown that fine-scale fluctuations can lead to errors in detecting consistent pressure or saturation signals across sub-stacks of seismic data, and this should not be neglected. Of particular concern here therefore is the quantitative inversion approach for pressure and saturation change (as popularised by for example: Landrø 2001; Lumley et al. 2003; MacBeth, Floricich and Soldo 2006) all of which could be adversely affected by this phenomenon. This is because they require that the near, mid and far offsets will
measure the same pressure and saturation signals, which is not the case. Our study has indicated that the saturation flood front is difficult to position accurately in migrated data, and the time-stamp of the acquisition can imprint false features in the 4D pressure response which could be mistaken for genuine geological heterogeneities.
Conclusions

Reservoir fluctuations that occur during the shooting of a seismic acquisition can create a complicated spatio-temporal imprint on the pre-stack data, and can create errors when attempting a quantitative interpretation of time-lapse seismic data in the post-stack domain. This signature does not translate into a clear seismic image of the pressure, even when geometric non-repeatability is perfect. Both pressure and fluid changes are affected by this phenomenon – both suffer from lack of spatial location of the change, and quantification of the absolute value of that change. With fluid changes the main errors are concentrated around the fluid fronts, but with pressure the errors are more widely spread across field compartments. Near and far-offsets sample pressure and saturation differently and this affects the ability of time-lapse analysis to accurately separate changes of saturation and pressure.

This modelling study with real field acquisition data and fluid flow simulation from the Norne field model reveals a number of important considerations:

- Quantitative analyses of reservoir changes are best performed in the pre-stack domain, as they are smeared in the post-stack volume.

- The time-scale of the survey relative to the well behaviour and simulation time period needs to be precisely defined in a time-lapse project – usually only one exact time is quoted for the survey, which is incorrect. For example, when matching simulation and stacked seismic data, it is best to use the average of fine timescale simulation predictions from the start to the end of the survey.

- Pressure and saturation (gas, water, steam) change separation using partial offset stacks should be avoided in situations of rapid change during the acquisition. The modelling relay that the NRMS errors between offset stacks
(up to 7.5%) caused by the intra-survey effects are likely at the limit of 4D seismic measurements using towed streamer technology, but are potentially observable, particularly for OBS technology.

- **Repeatability** should also be assessed in terms of the time sequence and order of shooting across monitor surveys when evaluating non-repeatability noise. Whilst this is common practice for monitoring overburden changes (water layer or land statics), it also needs to be done at reservoir level.

- **Ideally** time-lapse acquisition must be performed during a quiet period of pressure equilibration in the reservoir lifecycle, if this is possible i.e. sufficiently far away from well start-up or shut-down. However, fluid fronts will still continue to move due to pressure gradients and production. Consequently, wells should be properly monitored during the acquisition, and appropriate measures taken during data processing.

- If a quiet period of pressure equilibration cannot be guaranteed, then the seismic data must be processed differently for quantitative time-lapse studies. In addition to CMP binning which only accounts for the spatial location of each trace, a secondary binning which sorts the data according to the time of shot of each trace should be performed before migration or stacking. Thus, the migration or stacking of CMP data is done on traces with similar timestamp.

- **Finally**, the intra-survey effect raises particular concerns (as to the true magnitude and spatial extent of the reservoir’s response) when interpreting 4D seismic data, and, thus, should be considered during 4D survey planning as well as during data processing and analysis. For example, pre-stack processing with migration performed shot by shot could help avoid the intermixing of traces with different timestamp, as each shot gather has a unique time of shot.
References


Acknowledgments

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Figure 1 The Norne field reservoir model bounded by two major faults (in grey) with smaller faults (in grey) acting as local barriers to flow. Property shown is the effective porosity (PHIE) which varies laterally across the model. Wells used in this study are coloured blue for water injectors and black for producers. Inset map shows the main reservoir segments.
Figure 2 Shot geometry colour coded by the time sequence of shooting (in days) of each shot line for real North Sea acquisitions overlapped on the Norne field (a) Towed streamer survey (b) OBS survey. Displayed to the right of the colour bar are activity histograms for both acquisitions.
Figure 3 Simulated bottom-hole-pressure (BHP) fluctuations and overall field average pressure (in bold) from the Norne field model. Water injectors, I1, I4 and I5 are started on day 1, day 12 and day 21 respectively, within the time frame of a monitor acquisition for an OBS and towed streamer survey shot in the North Sea. Larger pressure fluctuations are induced from the water injectors than the producers. With the exception of P6, the remaining five producers fluctuate only mildly around the field average pressure.
Figure 4 Differences between simulation predictions for the start and end of a monitor survey which took 58 days. Displayed for (a) Pressure changes, $\Delta P$ (b) Water saturation changes, $\Delta Sw$ (c) Gas saturation changes $\Delta Sg$. Water injectors are in blue and producers in black. Fluid front changes are localised, whereas pressure changes are widespread.
Figure 5 Modelled Post-stack migrated time-lapse amplitudes for the pressure-only response for towed streamer (top) and OBS (bottom) surveys. The 4D amplitudes are expressed as a percentage change (monitor-baseline) relative to baseline. Displayed in (a) or (c) full offset stack response and (b) or (d) the reference determined from the average pressure response from the simulator over the survey duration. Smearing and striping is evident on (a) and (c) relative to (b) and (d). See Figure 6(a) and 6(b) for the NRMS error, a measure of the difference between the full offset and the reference response. In Figure 6, the acquisition imprints can be better visualised as stripes.
Figure 6 NRMS error in pressure response as a result of intra-survey pressure fluctuations shown for the towed streamer (top) and OBS (bottom) surveys. Displayed in (a) or (c) is the error between full stack response and the reference, and in (b) or (d) the error between the near offset and far offset stack response modelled for the same incidence angle. Areas experiencing larger pressure fluctuations result in larger errors (see Figure 4). The colour scale emphasises smaller NRMS errors, but areas in red go up to an NRMS error of 16.3% for the towed streamer results in (a) and (b).
Figure 7 Discrepancy in time-stamps (in days) across offset stacks for the towed streamer (top) and OBS (bottom) acquisition. (a) or (c) compare the shot time mean at each bin location for the full stack traces. (b) or (d) compare shot time mean between the near offset and far offset stacks.
Figure 8 Field example of pressure injection into a small compartment of a clastic reservoir. (a) Simulated bottom-hole pressure fluctuations and historical water injection rate for an injector active during two monitor acquisitions. RMS amplitude difference maps of full stack data are shown for (b) 2004 and baseline seismic data (c) 2006 and baseline seismic data.
Figure 9 Field example of pressure injection into a large compartment in a clastic reservoir. (a) Simulated bottom-hole pressure fluctuations and historical water injection rate for the injector active during two monitor acquisitions. Maps of the difference of RMS amplitude for the full stack data are shown for (b) 2003 and baseline seismic data (c) 2006 and baseline seismic data. The pressure-dominated seismic signals are enclosed by the dashed black polygons.
Figure 10 Post-stack migrated time-lapse amplitudes for saturation-only response from our modelling shown for the towed streamer survey. The 4D amplitudes are expressed as a percentage change (monitor-baseline) relative to baseline. Displayed are (a) full offset stack response (b) near offset stack response. Note that the simulated migration blurs the flood front. The resultant errors are shown in (c) for full stack response compared against a reference (d) for near offset compared against far offset stack response. Errors are largest at the fluid fronts, and for new floods activated during the acquisition (for example, I1).
## Tables

<table>
<thead>
<tr>
<th>Survey statistics</th>
<th>OBS Original</th>
<th>OBS Reduced</th>
<th>TOWED STREAMER Original</th>
<th>TOWED STREAMER Reduced</th>
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Table 1 Survey statistics for the OBS and towed streamer monitor surveys, highlighting the reduced number of parameters after decimating the original shot and receiver time interval to around 30 seconds. Bin size is chosen as half the shot point spacing and half the spacing between receivers on a line. An optimum fixed bin size of 67.5 x 50.25 m was used, giving a total of 5,404 CMP bins which represent the reservoir grid cells.
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Table 2 Maximum NRMS errors in seismic imaging of pressure and saturation changes for the OBS and towed streamer surveys, evaluated over the reservoir area. The top two rows are for the full stack seismic response compared against the reference and the bottom two rows are for the near offset compared against the far offset stacks modelled with the same angle of incidence.