Use of pore pressure data from the Norwegian Continental Shelf to characterize fluid-flow processes in geological timescales

FRIDTJOF RIIS* & ANKE WOLFF
Norwegian Petroleum Directorate, PO Box 600, N-4003 Stavanger, Norway

Abstract: A dataset with pore pressures from more than 1000 exploration wells has been used to investigate the dynamics of aquifer systems in the Norwegian Continental Shelf (NCS). Variations in aquifer pressures reflect flow of porewater through permeable rocks over geological time. Strongly overpressured regimes are formed within confined aquifers in subsiding areas, where fluid flow out of the aquifer is controlled by vertical seepage. In transitional pressure regimes, fluid flows within permeable beds towards areas with hydrostatic pressures. In the hydrostatic regime, pressure differences result from density differences due to varying formation water salinity and by hydrocarbon columns. An underpressured regime has been encountered in confined aquifers in the platform areas of the Barents Sea, and is related to net uplift and erosion. In the case studies, pressure differences are interpreted in the context of the relevant pressure regime, and with a dynamic approach where segment boundaries and cap rocks are regarded as low-permeability restrictions rather than barriers. The present distribution of pressure regimes was developed over the last few million years due to rapid Pleistocene sedimentation and erosion processes.

In the reservoirs and aquifers of the Norwegian Continental Shelf (NCS), areas of overpressure, under-pressure and regional overpressure gradients are widespread. Regional compilation and interpretation of pore pressure data and two case studies were conducted to study fluid-flow processes over geological timescales. The interpretation is based on many years of regional mapping and field studies of the NCS, where studies of pore pressures have been integrated with seismic interpretation and well correlation (Riis et al. 2010). The NCS is characterized by high rates of sedimentation and erosion through the Pleistocene glacial-interglacial cycles of the last 2.8 myr (Ottesen et al. 2009, 2018). Rapid Pleistocene burial has strongly affected compaction and hydrocarbon generation in the subsiding domains (Karlsen et al. 2004). The approximate boundary between a subsiding domain and a domain with net uplift (Riis & Jensen 1992) is shown in Figure 1. It was mapped where the base of the Pleistocene section is truncated by the upper glacial unconformity.

In a subsiding domain, increased load and temperature lead to compaction. Reduction of pore volume results from the physical rearrangement of grains and/or chemical processes such as recrystallization of clay minerals (Lahann & Swarbrick 2011), and by dissolution and reprecipitation of quartz (Bjørkum 1996; Stricker & Jones 2016) and other minerals. Pressure will also build up if the volume of fluid in the rock unit increases (Swarbrick et al. 2001). Increase of fluid volume in a subsiding basin can be caused by thermal expansion of the pore fluid and/or by the expulsion of hydrocarbons from kerogen and migration of hydrocarbons into the rock unit (Osborne & Swarbrick 1997; O’Connor et al. 2011). A slower process associated with osmosis has also been suggested (Swarbrick & Osborne 1998; Smalley et al. 2004). Pore pressure will increase in a compacting unit if the permeability of the rock is not sufficient to allow a rate of fluid expulsion which matches the rate of compaction. In the subsiding domains of the North Sea and Norwegian Sea, overpressures are common below 3000–4000 m depth (Fig. 2). This situation appears to be analogous to overpressure build-up in other actively subsiding regions such as the Gulf of Mexico and the Caspian Sea (e.g. Nadeau 2011; Javanshir et al. 2015).

In the net uplift domain of the Barents Sea, most observed pore pressures are hydrostatic (Fig. 3). Underpressured aquifers have also been encountered in this region. Underpressuring related to topography is well known from onshore regions (Swarbrick & Osborne 1998; Pashin 2016), where possible mechanisms for its creation are cooling and the reduction of vertical stress by the unloading of sediments (Swarbrick & Osborne 1998; Wangen et al. 2015) and gas leakage from aquifers with poor aquifer support (Law

From: Chiarella, D., Archer, S. G., Howell, J. A., Jackson, C. A.-L., Kombrink, H. & Patruno, S. (eds) Cross-Border Themes in Petroleum Geology II: Atlantic Margin and Barents Sea. Geological Society, London, Special Publications, 495, https://doi.org/10.1144/SP495-2018-176

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both in the subsiding and the net uplifted domain. In the oil industry, it is common practice to use a static approach in reservoir modelling: an equilibrium situation is assumed, and segments with different pressures are interpreted to be delineated by tight barriers. Such a static approach is a simplification that is valid for time periods relevant to production from a field (<50 years) but it will not capture the dynamic nature of the aquifer on a longer timescale (Smalley et al. 2004; Smalley & Muggeridge 2010; Dickson et al.

Fig. 1. Topography of Scandinavia and the shelf, showing the boundary between areas with glacigenic deposition to the west, and net uplift and erosion to the east. The map is based on the IBCAO grid (Jakobsson et al. 2012).
Over geological timescales, segment boundaries could be regarded as low-permeability restrictions rather than barriers (Smalley et al. 2004). Smalley et al. (2004) and Smalley & Muggeridge (2010) used analytical models to investigate the time taken for fluid pressure and fluid composition to equilibrate within a formation across a low-permeability boundary. In their models, time to equilibration depends on distance, pressure difference, thickness and permeability of the baffle, porosity, compressibility, and viscosity. The modelling shows that pressure equilibration in permeable reservoirs is typically fast, of the order of years to hundreds of years, while equilibration of fluid contacts and fluid composition are orders of magnitude slower.

**Aquifer and pore pressure: concepts and definitions**

An aquifer is defined by hydrologists as a permeable geological formation or a group of hydraulically connected formations that can store and transport groundwater (Kresic 2006). For analysis of pressure development in a sedimentary basin, this definition is extended to include saline brines (Fig. 4) (NPD 2014). An aquifer is separated from other aquifers by sealing rocks (tight formations or other barriers to flow).

When fluids (oil, gas and water) are extracted from a deposit in such a way that the produced volume exceeds the injected volume, formation water will flow from the surrounding aquifer towards the depleted zone. The aquifer strength driving this influx is an important parameter for the planning of an optimal drainage strategy for a hydrocarbon field. The aquifer strength depends on its pore volume, permeability and connectivity, as well as the degree of communication with the hydrocarbon accumulation. These aquifer properties are also important for studies of basin development and petroleum migration. In a mature petroleum province like the North Sea, knowledge of aquifers and aquifer management becomes increasingly important for the petroleum industry, because many hydrocarbon fields share and interact with the same aquifer. As
Points
+ Leak-off pressure
□ Pore pressure

Lines
Lithostatic gradient
Fracture gradient
Hydrostatic, salinity 200 000 ppm
Hydrostatic, salinity 120 000 ppm

Fig. 3. Pore pressure plot for the Barents Sea study area, based on data from exploration wells shown as black dots in the map. Red crosses are leak-off pressures (LOP). The red line is the LOP bounding line.

Fig. 4. Conceptual sketch of an aquifer consisting of several reservoir formations (yellow). From NPD (2014).
part of an evaluation of the CO2 storage potential of the NCS (NPD 2014), the main regional aquifers were defined and their pore volumes were estimated.

Hydrostatic pressure \( (P) \) increases with depth \( (z) \) according to the formula: \( P = \rho_w g z \), where \( \rho_w \) is the density of the formation water and \( g \) is gravitational acceleration. Brine density increases with increasing salinity and decreases with increasing temperature. The latter effect is, to some degree, offset by the depth-dependent pressure increase (Rowe & Chou 1970). For the Barents Sea, where aquifer salinities are high and variable, three reference pressure–depth functions for hydrostatic pressure were calculated, using brine densities calculated by an iterative procedure based on the correlation of Rowe & Chou (1970). For the study area in the Norwegian Sea, a linear gradient was used as a reference line for hydrostatic pressure.

In pressure–depth plots (Figs 2 & 3), overpressure and underpressure are identified as points that are displaced along the horizontal pressure axis relative to the hydrostatic reference line. The difference (hydraulic head) between water pressures measured in a well and a reference hydrostatic pressure gradient is referred to as delta pressure, and written \( \Delta_P \). Plots of \( \Delta_P \) v. depth display the water gradient as a vertical line if the brine density at each depth is equal to the density used for the calculation of the reference pressure. Such plots are useful to visualize small deviations in pressure and density, and have been used extensively. Hydrocarbon zones in these plots will display as straight lines with a positive slope (up to the right: Fig. 5).

**Data and methods: pore pressure database**

The most reliable source for pore pressure measurements is from wireline tools like repeat formation tester (RFT) and modular dynamic tester (MDT). Such measurements have been performed in the main reservoirs in most exploration and production...
wells since the early 1980s. In cooperation with IHS Markit, the NPD has compiled a database which includes pore pressure data from more than 1000 exploration wellbores on the NCS. The method used in this study is to first quality-control the data, then plot pressure–depth relationships, and finally correlate the plots with petrophysical well logs, maps and geomodels. Pressure measurements are integrated with other data and evaluated in a regional context.

The uncertainty in pressure measurement is generally higher for old wells (1980s) than for more recent wells. These older wells are, however, important in basins where hydrocarbons have been produced, as more recent wells are potentially affected by pressure drawdown associated with production.

Pressure regimes

The classification of pressure regimes used in NPD (2014) for Jurassic reservoirs has been slightly modified and extended in this study to cover the NCS in general. This can be summarized as follows:

- The hydrostatic regime: \( \Delta P \) is zero or close to zero.
- The strongly overpressured regime: the shallowest part of the aquifer has a pore pressure that is close to the fracture pressure (Figs 2 & 3). \( \Delta P \) is a function of burial depth and will typically be greater than 200 bar. The aquifer can be referred to as a pressure cell.
- The transitional regime is found in geographical areas lying between the strongly overpressured and the hydrostatic pressure regimes (Fig. 6). \( \Delta P \) values increase with depth from about 2400 m and typically range between a few bars and up to 150 bar (Fig. 2).
- The underpressured regime: \( \Delta P \) is negative. This includes some relatively small aquifers in the Barents Sea which are moderately underpressured. Another group of aquifers, located in the deep part of the Bjørnøysyrenna Trough (Fig. 1), has severe underpressures ranging between 10 and 60 bar (Fig. 3). This regime does not include aquifers that have been depleted by human activity.

Pressure regimes in the Norwegian Sea

The shelf area west of the Trøndelag Platform (Fig. 7) is an important petroleum province. It comprises fault-bounded ridges and highs separated by collapse graben, with the Grinda Graben as the most prominent (Fig. 7) (Blystad et al. 1995). It is bounded by faults towards the tectonically more stable Trøndelag Platform to the east and by deeper basins to the west.

![Fig. 6. Pressure regimes in Jurassic reservoir rocks in the North Sea and the Norwegian Sea, based on internal NPD studies (NPD 2014).](image-url)
2005). Figure 9 shows that there are many valid pressure points in these formations at great depth. This is also the case for the more locally developed Tofte Formation sandstones. The mainly fluvial Åre Formation is deeply buried in most of the area. At moderate burial depths, however, the reservoir quality in the Åre Formation can be excellent in major channels (Koch & Heum 1995), while connectivity between channel belts is variable.

Pressure data compiled from released exploration wells in the Halten Terrace area are shown in Figures 9 and 10a, b. Delta pressures were calculated relative to a hydrostatic gradient with a constant water density of 1.027 g cm$^{-3}$. This gives a good match to the interpreted water gradients and to the hydrostatically pressured wells.

The boundary between aquifers in the transitional regime and the strongly overpressured regime was drawn along major fault lines using pressure data information (the red line in Fig. 10). The blue line in Figure 10 shows the boundary to the hydrostatic regime in the shallower Trøndelag Platform and Nordland Ridge. The Trøndelag Platform is tilted up towards the coast in the east (Fig. 7). Here the entire Jurassic section subcrops beneath a thin Pleistocene overburden and is likely to be in communication with seawater.

The strongly overpressured regime

In order to classify and interpret strongly overpressured aquifers, regional fracture pressure must be estimated. Following Gaarenstroom et al. (1993), a smooth lower boundary line of all leak-off pressures (LOPs) from the Halten Terrace wells was constructed and slightly adjusted to match the trend of the upper boundary of pore pressure measurements (Fig. 2). In Figure 9, the interpreted fracture pressure line based on LOP is indicated. Jurassic aquifers exhibiting pore pressures with an upper boundary close to fracture pressure are numbered and shown with blue vertical lines (Fig. 9). Strong overpressure
Fig. 8. Stratigraphic type well 6507/11-3. Wireline logs, pressure data and stratigraphy. The red line is the gas gradient; the green line is the oil gradient; and the blue line is the water gradient. Transitional pressure regime, a small delta_P difference is indicated by an offset in water gradients between the Ile and Tilje formations.

Fig. 9. Delta_P plot for the Norwegian Sea study area. Reference pressure: constant water density of 1.027 g cm$^{-3}$. Delta pressures in brine plot as vertical lines. Seventeen such lines in the strongly overpressured regime (red) show the large variation in delta_P and how it varies with depth.
also occurs in Cretaceous reservoirs (green vertical lines). Each of these aquifers constitutes a pressure cell, generally with Delta_P exceeding 200 bar. Delta_P increases with depth of burial to the top of the cell. Pressure cells next to each other typically have tens of bars difference in overpressure.

Figure 9 indicates that the pressure at the top of each cell is 10–50 bar lower than the LOP boundary line. A similar trend was described from the North Sea by Gaarenstroom et al. (1993). This relationship was used to estimate the sealing capacity of Jurassic cap rocks (NPD 2014). Fracture pressure estimates are also important for well planning (Nadeau 2011; Dickson et al. 2014). For drilling purposes in strongly overpressured regimes it is necessary to estimate the fracture pressure line in more detail, taking into account the properties of the sealing rocks at the locality (Hermanrud & Nordgård Bolås 2002; O’Connor et al. 2013).

Large pressure differences (tens of bars) between the pressure cells in the strongly overpressured regime show that the lateral flux between cells is very limited (Hermanrud & Nordgård Bolås 2002). The relationship to the fracture gradient indicates that pressures in strongly overpressured regimes build up to a certain limit where fluids vent out of the pressure cell through the seal. The top of the shallowest structure in a strongly overpressured cell is closest to the fracture pressure and most likely to vent, unless there are weak areas in the cap rock at other locations. Hermanrud et al. (2014) concluded that leakage rates in the hydrostatic system in the Hammerfest Basin...
were higher from areas where the seal is weakened by fault intersections. Since overpressures in the strongly overpressured regime are preserved, it must be assumed that venting takes place over a geological timescale. Consequently, the limit for strong overpressure cannot be directly compared to the fracture pressure determined by leak-off tests.

The smallest differences between pore pressure and fracture pressure are found in the pressure cells within Jurassic aquifers 1–7 (Figs 9 & 10), which are sealed by the organic-rich shales of the Melke and Spekk formations. Cretaceous aquifers (11, 13 and 16: green pressure points) appear to have somewhat larger differences, indicating a slightly more permeable seal. Aquifers 8 and 9 have high overpressures but plot farther away from the fracture gradient. They are located at the boundary with the transitional regime, and it is speculated that some lateral fluid flow can take place across the boundary (yellow arrows in Fig. 10b).

The transitional regime

In Figure 9, the transitional regime occupies a triangular region with aquifer delta_P values above zero and below the strong overpressure. The plot for this regime is dominated by hydrocarbon gradients, and traps may have high hydrocarbon columns.

The different delta_P values observed in the Garn and Tilje formations (Fig. 10a & b) indicate that they behave as individual flow units. Figure 10 also shows that small pressure steps are common between adjacent structures and segments. The arrows in Figure 10b show pathways with aquifer delta_P decreasing in the direction from the overpressure regime towards the hydrostatic regime. Such pressure trends indicate that in the transitional regime, fluids escape by lateral flow within each formation.

An interpretation of dominant lateral flow is supported by the pressure trends in the western part of the transitional regime (e.g. the Åsgard fields and discoveries). Here, the overlying Lower Cretaceous reservoirs (Lange and Lysing formations) have pore pressures of the order of 100 bar higher than the Jurassic aquifers (Fig. 11) (O’Connor et al. 2008). In this area, any vertical seepage of fluids would be directed from the Cretaceous downwards, and the only natural flow out of the Jurassic reservoirs is by lateral movement towards the hydrostatic aquifers. O’Connor et al. (2011) described analogous hydrodynamic traps generated by lateral flow (e.g. in the Ula area of the North Sea).

The main conduit for fluid flow is interpreted to be the pathway with the lowest delta_P. A comparison between Figure 10a and b shows that the Garn Formation in the Åsgard area (Å) has higher delta_P values than the Tilje Formation. This indicates a lower-permeable baffle within the Garn aquifer, whereas the lower delta_P in the Tilje aquifer suggests a more permeable pathway for water escape (Figs 10a, b & 11). This may suggest that lateral flow in the Garn Formation is restricted by the tight quartz-cemented reservoir between 4500 and 4800 m depth.

Towards the Sør High, in the Heidrun Field area, the aquifer system is more complex due to deep erosion into the Jurassic section and juxtaposition across faults. In that area, the large hydrostatic aquifer of the Åre Formation in the Sør High on the Nordland Ridge may be connected across baffles to the aquifers in the transitional regime.

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**Fig. 11.** Conceptual cross-section through the strongly overpressured, transitional and hydrostatic regime in the Åsgard area.
Skarv Field case study

In hydrocarbon accumulations, fluid contacts adjust to aquifer pressure. The Skarv Field illustrates the complexity of pressure and fluid contacts that can be expected to occur in a segmented oil and gas field in the transitional regime. Skarv is located in the narrow SW–NE-trending Dønna Terrace (Fig. 7), between the deeply buried strongly overpressured basins to the west and the hydrostatic shallow Sør High to the east. The terrace is bounded by the Revfallet Fault Complex to the east and by complex fault zones to the west. The vertical displacement of both fault complexes is of the order of 2000 m, and they consist of faults, ramps and strongly tilted layers. Structurally, the field is divided into three segments (A, B and C) by two NW–SE-trending faults, and it is separated from the Idun Field by a structural saddle (Fig. 12). There are possible migration paths from the deep basin towards the southern Skarv Field (C segment) and towards the Idun structure. Possible spill towards the Sør High can occur along two saddle structures between the field and the Revfallet Fault Complex (Fig. 12b). The B and C segments contain oil zones with gas caps in the Garn and Ile formations, while the A segment and the Idun structure contain gas in the Garn Formation and oil with a gas cap in the Tilje Formation (Fig. 13). The gas in Idun is drier than the gas in the Skarv segments. Pressures in the water, oil and gas zones are generally different in different segments and in different formations.

Figure 13 shows pressures from four exploration wells in the Skarv Field with water, oil and gas gradients. Segments and formations have different pressures and different contacts. The oil pressure in the Garn Formation in the B segment (red) is slightly higher than the oil pressure in the Tilje Formation in the A-segment (blue). This correlation is consistent with the juxtaposition between the Garn and Tilje formations across the fault marked Fa (Figs 12b & 14). The distribution of oil and the pressure correlation indicate that the field has two main hydrocarbon–water systems: the Garn Formation gas–water system in the A segment; and a system with oil and gas in the Tilje Formation (A segment) and Garn Formation (B and C segments). A gas–water contact was penetrated at approximately 3630 m in the northern gas–water system (Fig. 13). This is consistent with the depth to the spill point towards the Sør High in the Garn

![Figure 12](http://sp.lyellcollection.org/article-graphics/) (a) Two-way time map of the BCU in the area of the Skarv and Idun fields. Black dots are penetrations of wells which are not depleted by production. (b) Two-way time map of the top Garn Formation in the Skarv Field with segments A, B and C.
Fig. 13. Pressure plot for Skarv exploration wells. Pressure gradients in the Garn Formation gas zone (red lines) are coincident in wells 6507/5-1 and 6507/5-4, and in the Ile Formation in well 6507/5-1, but pressure is lower in well 6507/5-2. Between individual segments and reservoir zones, pressures differ by a few bars. In the A segment there is oil in the Tilje Formation (6507/5-1) but not in the Garn Formation (6507/5-2). Water was encountered with different pressures in the Garn Formation in well 6507/5-2 and in the Ile Formation in well 6507/5-4.

Fig. 14. Seismic composite section in two-way time (TWT: in ms) with interpreted reservoir formations. The location of the section and Fault Fa is shown in Figure 12b. Seismic data are courtesy of Skarv PL 212.
Formation in the northern saddle (Fig. 12b). Deeper oil–water contacts occur in the Garn Formation in the B and C segments (Fig. 13). The interpreted contacts are shallower than the mapped deeper saddle. This means that the northern saddle is the spill point for hydrocarbons.

**Fig. 15.** Pressure gradients interpreted for the Garn and Tilje formations in several exploration and production wells drilled prior to start-up of production in the Skarv Field. Most of these gradients are defined by more than one well. Ile Formation and Idun Field pressure gradients are not included. Gradient colours are as in Figure 13.

**Fig 16.** Two-way travel time map of the top Garn Formation (a) and Tilje Formation (b). The lowest water pressure in the B and C segments is used as reference. The reference for the oil pressure gradient is the oil pressure in the B segment. The delta pressure of 5 bar in (b) was measured in the Åre Formation. The map has been rotated, as shown by the north arrow.
Drilling of development wells revealed an even higher degree of complexity, in both the water and hydrocarbon zones. The pressure gradients in Figure 15 include pressure data from the production and injection wells that were drilled prior to production start-up. Four water gradients can now be interpreted. Pressure differences were also found between some of the gas caps. When delta_P values are plotted on a map for the Garn and Tilje formations (Fig. 16a, b), a trend from higher pressures in the south and west to lower pressures in the east is revealed. This general trend is found in both the Garn and Tilje formations, and in both the oil and water zones. The aquifer and the pathway with the lowest pressure are interpreted to be the ones which have the best contact with the open hydrostatic system in the Sør High. Restrictions to fluid flow may be associated with faults and formation boundaries, and can create pressure steps with a typical magnitude of a few bars.

Production and injection wells in the Skarv Field were positioned to drain each segment and flow unit separately (Fig. 16). This is an effective drainage strategy when segment boundaries behave as tight barriers over production timescales. Over longer, geological timescales, the relationship between pressures, contacts and segments in the field and in the region suggest fluid flow from overpressure to hydrostatic pressure.

The Skarv Field offers an interesting possibility to correlate the timescale of fluid flow with recent structural geological events. After a discovery of dropstones, an overburden core in well 6507/5-J-1 H (Fig. 17) was studied and biostratigraphically and

![Gamma Ray Deep Resistivity](image)

**Fig. 17.** Well logs showing the Lower Pleistocene and Upper Miocene section in well 6507/5-J-1 H. The analysed samples were taken from cores in well 6507/5-J-1 H (black rectangle). Photograph of dropstone from the cored interval. Well tops are based on micropalaeontology and Sr isotopes.
radiometrically redated a unit which was previously interpreted as belonging to the Late Miocene Kai Formation. The unit is now dated to the Pleistocene (Unit P1: Fig. 18). Consequently, the Pleistocene overburden of the Dønna Terrace and the adjacent hydrocarbon-generating basin is 230 m thicker than previously interpreted in the Skarv area. The total Pleistocene sediment thickness exceeds 1200 m (Figs 17 & 18). This has implications for the timing of hydrocarbon generation. Further, seismic interpretation indicates that the Lower Pleistocene strata were tilted up towards the Nordland Ridge in a tectonic event post-dating the early Pleistocene clinoforms (Fig. 18). The reactivation could have caused a redistribution of fluids due to the rotation of reservoir strata.

Fig. 18. Geoseismic section in two-way travel time (TWT: in ms) from the Dønna Terrace to the Sør High. (for the location, see Fig. 12). Pleistocene 1 (previously interpreted as Upper Miocene) has a seismic expression typical for contourites. Pleistocene 2 exhibits low-angle clinoforms prograding to the west. Pleistocene 3 was deposited under glacial conditions on top of the upper regional unconformity. The box shows the location of the seismic section. Seismic data are courtesy of Skarv PL 212.
Pressure regimes in the Barents Sea

Hydrostatic regime

In the Hammerfest Basin in the southern Barents Sea (Fig. 19), the Early–Middle Jurassic Realgrunnen Subgroup constitutes the largest aquifer system. The Realgrunnen aquifer includes the Stø, Nordmela, Tubåen and Fruholmen formations (Dalland et al. 1988) (Fig. 20), and locally the upper Snadd Formation. Vertical communication between the formations is restricted by claystone-rich zones, such as in the lower part of the Nordmela Formation. The Fruholmen and Snadd formations are channelized, and the sands are generally not as well connected as the upper formations. The lower part of the Fruholmen Formation (Akkar Member: Fig. 20) and the middle part of the Snadd Formation are shale-rich seals. The aquifer is structured by normal faults.

The Realgrunnen aquifer is strongly saline. Water samples of variable quality from tests indicate total dissolved solids (TDS) of between 100 000 and 170 000 ppm (http://www.npd.no). Analysis of a good sample of brine from the Stø Formation in injection well 7121/4-G-4 H yielded 170 000 ppm (Tyvold & Risa 2016). Reference curves for hydrostatic pressure were calculated for 120 000, 160 000 and 200 000 ppm TDS. In these calculations, a constant salinity was assumed in the aquifer from the seafloor to the reservoir. Brine salinity can be interpreted from the slope of the delta_P plots. If the formation water is denser than the reference curve (i.e. it has a higher salinity), the gradient will have a negative slope (down to the right). In the southern Barents Sea, most wells show pressures close to the hydrostatic reference line (Fig. 3). Two wells at the SW margin of the eroded platform encountered strong overpressures, indicated by O in Figure 19. The reason for these overpressures has not been investigated. The hydrostatically pressured Realgrunnen aquifer in the Hammerfest Basin was referred to as overpressured by Tsikalas et al. (2018), presumably because they used a sea-water (low-salinity) gradient as a reference line.

Fig. 19. Depth map of the Base Cretaceous horizon in the southern Barents Sea, modified from NPD (2014). Water densities in wells were calculated from pressure gradients in the Realgrunnen aquifer.
In the Hammerfest Basin, maximum burial is estimated to have been of the order of 900 m deeper than present (Henriksen et al. 2011; Ktenas et al. 2017). A large part of this erosion can be assumed to be glacial (Elverhøi et al. 1998). Due to erosion, the aquifer has been unloaded and cooled. It subcrops to the Pleistocene below seafloor at the SE part of the Loppa High (Fig. 19, dashed line). Large volumes of residual oil and gas encountered in the reservoir sandstones in the Hammerfest Basin suggest that there is net leakage from hydrocarbon-bearing structures (Henriksen et al. 2011; Tsikalas et al. 2018).

Figure 19 shows brine densities estimated from pressure gradients in wells in the area. The highest densities are found in the Hammerfest Basin (H) and Nordkapp Basin (N). Lower-salinity brines are estimated in the Troms–Finnmark Platform (TFP) and the Maud Basin (M).

**Underpressed regime**

The aquifer belonging to Permian carbonate reservoirs on the Loppa High is highly saline and underpressed relative to the calculated reference pressure gradient. The shallow part of the aquifer is also underpressured relative to seawater salinity (Fig. 21). Hence, the Permian pressures can be described as a high-salinity underpressed trend. In the Goliat Field, the Kobbe Formation and parts of the Snadd Formation can be said to have a tendency towards underpressure (Figs 5 and 22), although they are not underpressured relative to a seawater gradient. Poor-quality pressure points in Kobbe sandstones east of the Loppa High on the Bjarmeland Platform can also indicate a tendency to underpressure. Underpressured reservoirs are associated with aquifers that are characterized by
low permeabilities, residual hydrocarbons, small pore volumes and which cover areas typically less than 100 km$^2$.

Another group of wells encountered severe underpressures ranging from 10 to 60 bar below hydrostatic pressure in the Fingerdjupet and Maud basins in the deeper parts of the Bjørnøyrenna Trough (Figs 1, 19 & 21). These severely underpressured aquifers are found in Triassic and Jurassic formations at depths of between 1000 and 2000 m (Fig. 23). The water depth ranges from 400 to 500 m. The underpressured reservoir in the Maud Basin consists of oil- and gas-bearing sandstones deposited in lower Snadd Formation channel systems which are up to 20 m in thickness and have permeabilities up to a few tens of millidarcies.

Underpressures of more than 50 bar in Triassic reservoirs have been reported from onshore Svalbard (Braathen et al. 2012; Wangen et al. 2015). In the deep offshore, occurrences of severe underpressures have not, to our knowledge, been described from areas other than the Barents Sea.

**Goliat Field case study**

The Goliat Field is located on a large structural closure which is bounded by the Troms-Finnmark Fault Complex to the south and SE (Fig. 19), and slopes down to the Hammerfest Basin to the NW (Fig. 22). The field is segmented by intersecting faults (Fig. 23).
In the exploration wells, oil and gas were encountered in four reservoir levels (Fig. 20):

(1) Realgrunnen Subgroup (Late Triassic–Early Jurassic): the interval contains highly permeable sandstones several metres in thickness in some wells, while it is heterolithic in others. The shale of the Akkar Member forms a seal to the underlying Snadd Formation. Different structural closures have different gas–oil contacts. Aquifer delta_P values on the crest are 2 bar higher on the west flank in well 7122/7-5 than in the other wells (Fig. 23a).

(2) Snadd Formation (Carnian): the upper part of this interval contains channel sandstones interbedded with shales and heterolithics. The connectivity is expected to be good within the channel belts but it is uncertain between the bodies. Aquifer delta_P values are similar to the Realgrunnen Subgroup in the NW but significantly lower to the south and 1 bar lower to the NE (Figs 22 & 23b). There are indications of small vertical pressure differences between the Snadd sandstones in 7122/7-4 S, indicating poor connectivity. The water gradients in the Snadd wells indicate a lower brine density than in the other formations. Gradients from hydrocarbon columns have a gentle slope down to the left.

(3) The Kobbe Formation (Middle Triassic) is sandy in the Goliat area due to deltaic input from northern Scandinavia (Tsikalas et al. 2018). The formation coarsens upwards, with better reservoir quality and a higher net/gross ratio in the upper part. The lower part is heterolithic and interpretation of pressure data shows small pressure offsets between permeable layers in the oil zone (Fig. 24). The Kobbe reservoir contains wet gas and light oil, and constitutes the main reservoir of the Goliat Field. Delta_P values in the Kobbe aquifer

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**Fig. 22.** Delta pressures from wells in the Hammerfest Basin and Goliat Field (black dots in the map). The reservoirs in the Realgrunnen Subgroup plot along a strongly saline trend which is different from the Kobbe reservoir in the Goliat Field. Pressures in the Snadd reservoir in Goliat are scattered, indicating poor communication, and the gradients indicate lower salinity than in the other formations. Gradients from hydrocarbon columns have a gentle slope down to the left.
Fig. 23. Delta_P plots for Goliat exploration wells, with reference to a gradient calculated for a salinity of 160 000 ppm. (a) Top of the Realgrunnen Subgroup in the Goliat structure. (b) Top of Snadd Formation. (c) Top of the Kobbe Formation.
are a few bars lower than in the overlying reservoirs, and the southern part has 1–1.5 bar lower delta_P than the northern part (Fig. 23c).

(4) In well 7122/7-4 S, there is a deeper oil reservoir in the Klappmyss Formation which lies below the heterolithic part of the Kobbe reservoir. Figure 24 illustrates that water pressures in the Klappmyss and Kobbe formations are similar. This supports a pressure equilibration laterally in the aquifer.

The Realgrunnen Subgroup and the Snadd Formation are locally juxtaposed along faults, while they are not juxtaposed with the Kobbe Formation. This geometry suggests that there may be communication between the Snadd and Realgrunnen aquifers.

Both the Skarv and Goliat fields exhibit subtle pressure differences across segment and stratigraphic boundaries but, unlike Skarv, the Goliat delta_P values do not have obvious directional trends. Another difference is that the small and poorly connected Snadd aquifer has lower delta_P than the Realgrunnen aquifer above. In the transient pressure regime where Skarv belongs, the lower pressure is expected to occur within the larger, more permeable and well-connected aquifer.

In Goliat, leakage from the reservoirs is supported by reports of oil shows below the oil water contacts (NPD FactPages https://factpages.npd.no/, wells 7122/7-1, 7122/7-4 S and 7122/7-5). Brightening that is probably related to segmenting faults can be interpreted in the seismic data. In the Kobbe Formation, there is a small pressure step in the oil column in well 7122/7-4 S, where pressure is lower in the upper part. Stepwise and an upward pressure decrease in a well can be interpreted as leakage through the cap rock from a weak aquifer. Subtle variations in oil pressure occur in all wells and between wells (Fig. 24), suggesting moderate to poor communication.

Discussion

The case studies illustrate that aquifers belonging to different regimes have different characteristics.

**Pressure equilibration in the hydrostatic regime**

In the last 25 kyr since the late glacial maximum, the hydrostatic pressure on the NCS has changed...
from having a thick ice cover to a eustatic low after deglaciation and then to present-day water depths. Despite these changes, there are only minor variations in aquifer pressures in this regime in the North Sea and Norwegian Sea. Jurassic reservoir formations subcrop at the sea floor with a thin Pleistocene cover along most of the Norwegian coastline (documented by geological maps available at http://www.ngu.no). In the Barents Sea, a thin Realgrunnen aquifer subcrops beneath a 100 m-thick Pleistocene cover below the sea floor. In this setting, aquifers are apparently sufficiently open and have enough permeability to allow equilibration of pore pressures in a timescale shorter than glacial cycles. Aquifers which are presently hydrostatically pressured but have been subjected to erosion could have been overpressured at maximum burial. Erosion and net uplift would allow aquifer communication with the seafloor and facilitate pressure equilibration.

**Reasons for subtle pressure differences**

Some of the observed pressure differences in Goliat can be explained by differences in brine density. Figure 22 shows that the pressures of the Realgrunnen aquifer (delta_P of 3.5 bar on the crest of the structure) plot along the same trend as the saline aquifer of the Hammerfest Basin. The Kobbe Formation sandstones shaley out to the north and there is no likely connection to hydrostatic aquifers in that direction. The most likely connection for the Kobbe Formation to a larger aquifer is to the south, towards the source area of the sand. This would explain the measured pressure in Kobbe if the Kobbe salinity is typical for a regional Permian–Triassic aquifer. The lower delta_P in Kobbe in the southern segment of Goliat could be explained by fluid flow towards the south. Alternatively, gas leakage from the Kobbe reservoir could have contributed to a pressure reduction.

In the Snadd Formation, the high delta_P to the west and NW suggests a pressure communication with the Realgrunnen reservoir (Fig. 22). The low pressures in the southern part, combined with small internal pressure drops in well 7122/7-4 S, are best explained by leakage, since the aquifer in the channelized and segmented Snadd Formation is likely to be small and it is unlikely that pressure can be reduced by connection to an external aquifer with a lower pressure. An alternative interpretation could be pressure reduction by unloading but this hypothesis does not explain the observed variation between wells.

In the hydrostatic regime, pressure is in equilibrium with seawater. In a simple hydrostatic setting, delta_P is not expected to vary and fluid contacts should be horizontal. In the more complex Goliat case, salinity difference between the Realgrunnen and Kobbe aquifers are responsible for differences in delta_P. In addition, the Kobbe aquifer and parts of the Snadd aquifer have a tendency towards underpressure, as described above for the Permian aquifer on the Loppa High. Possible mechanisms for subtle underpressuring in the Hammerfest Basin that could be consistent with the observations are gas leakage, unloading processes or a delay in equilibration with the Holocene sea-level rise. An alternative explanation for some cases would be to assume a lower salinity of formation waters in the shallow parts of the aquifer. If this is the case, the calculated reference pressure would be lower and the estimated underpressure would be reduced.
Hydrocarbon trapping in the strongly overpressured regime

In this regime, aquifer pressure builds up to a maximum pressure which is controlled by the sealing capacity of the cap rock on a geological timescale. These aquifers are pressure cells that are confined by lateral seals that are more efficient than the top seal. In the Norwegian Sea, aquifers in this regime typically occupy areas of between 50 km² and a few hundred square kilometres. They may be separated by faults or sedimentological boundaries. Hydrocarbon columns in a structural trap will reach a maximum height which is controlled by the aquifer pressure, the fracture pressure and the elevation of the top of the structure. Within one pressure cell, theoretical hydrocarbon column heights increase with the burial depth of the prospect (Hermanrud & Nordgård Bolås 2002). This principle can be illustrated by the first years of exploration in the Norwegian Sea. From 1984 to 1987, five structures located at the top of strongly overpressured structures were drilled and found dry. After these failures, it was generally considered that strongly overpressured structures were leaking and could not trap hydrocarbons. No new wells were drilled in this play until 1994, when the gas/condensate discovery in the Kristin structure proved that the new strategy of exploring in the deeper part of the pressure cell was successful.

Hydrocarbon trapping in the transitional pressure regime

Figure 6 shows that the strongly overpressured pressure regime in Jurassic aquifers is surrounded by a transitional pressure regime. Several hydrocarbon accumulations in the North Sea and Norwegian Sea were found in Jurassic systems with aquifers in the transitional regime. In parts of the transitional regime there are high delta_P values in the Cretaceous Lysing and Lange sandstones in the overburden. The reason for the overpressured Cretaceous reservoirs is the stratigraphic pinchout of the Lysing sandstones to the east and the localized development of the Lange sandstones. These sandstones have no connection to hydrostatically pressured formations.

The observations of pressures and fluid contacts imply that the lateral gradient in delta_P creates a fluid flow directed towards the hydrostatic regime. Several pressure steps and a complex distribution of fluid contacts is typical for this regime and show that pressure distribution has not reached equilibrium. Lateral fluid flow can take place in aquifers consisting of one formation: for example, west of the Grinda Graben, where one Garn, one Ile and one Tilje aquifer are interpreted (arrows in Fig. 10b). Skarv shows a case of combined aquifers consisting of the Garn and Tilje formations juxtaposed by faults. Such observations are important to understand and model the transmissibility of faults.

The Skarv study and Figure 9 indicate that in the transitional regime structural traps are commonly filled to spill, and that hydrocarbon column heights can reach several hundred metres. There is sufficient sealing capacity for pressure build-up in such columns because of the combination of high overburden pressures and much lower reservoir pressures.

The Skarv case study presented abundant pressure steps with decreasing delta_P towards the east, and several fluid contacts. The trap can be described as hydrodynamic in a geological timescale. In addition, the gas composition has not equilibrated between the Skarv and Idun segments. Smalley et al. (2004) showed that equilibration of composition is slower than equilibration of pressure. For traps in the transitional pressure regime, a concept of dynamic trapping is appropriate (Fig. 25).

Another learning from the Skarv and Goliat case studies is that small steps in pressure, even those of less than 1 bar, contain information about the properties of restrictions and the development of the accumulation over geological time. This information may become important in the development and production phases of a field.

The severe underpressured regime

There is no generally accepted explanation for the enigmatic severe underpressures in the Bjørnsøyrenna Trough. Considering that there are large variations in pressures from well to well and that pressure equilibration is a rapid process over a geological timescale, it is likely that the severe underpressures are recent, in a geological perspective. Riis & Deryabin (2016) suggested that the abnormal pressures in the Maud Basin might be related to gas hydrate formation and dissolution. At shallow depths, the volume of gas hydrate is significantly smaller than the volume of the gas and water which combine to form the hydrate. It is documented that formation and dissolution of large volumes of gas hydrate have taken place during the last glaciation and deglaciation in Bjørnsøyrenna. Large subsea craters formed where gas hydrate pings at the seafloor dissolved shortly after the last deglaciation (Andreasen et al. 2017). The Triassic section which is underpressured in the Maud Basin is outcropping at the seafloor in the crater area north and east of the basin. Consequently, the hypothesis of Riis & Deryabin (2016) was that hydrate formation could be a mechanism to remove fluid volume from the pore systems and create underpressure.
Conclusions

Regional mapping of aquifer pressures in the subsiding domains in the NCS reveals a pattern of fluid flow in the Pleistocene timescale from the strongly overpressured basins to the hydrostatic coastal areas. On such a timescale, the trapping of hydrocarbons is dynamic. Hydrocarbons are continuously generated, migrated and spilled, and hydrocarbon is seeping out of the traps (Fig. 25).

Regional- and field-scale pressure data are important sources of information for analysis of the dynamic traps.

The domain with net uplift in the Barents Sea is mainly in the hydrostatic pressure regime. The dynamics of some aquifers are revealed by subtle pressure steps which can be related to differences in salinity, gas leakage, unloading or a combination of these factors. Severe underpressures occur in Mesozoic reservoirs in the Bjørnøyrenna Trough. There is no consensus as to how these enigmatic underpressures can be explained.

Acknowledgements We acknowledge IHS Markit for their work in maintaining, improving and expanding the pressure database for the Norwegian Continental Shelf. The Skarv Production Licence 212 is thanked for permitting the use of seismic data from the Skarv Field. We would also like to thank the reviewer and editor for constructive comments and suggestions which have improved this paper.

Author contributions FR: conceptualization (equal); AW: conceptualization (equal).

Funding This research received no specific grant from any funding agency in the public, commercial, or not-for-profit sectors.

Data availability statement The digital pressure data base cannot be released by the NPD. Pressure plots for individual wells are available at: https://factpages.npd.no/en/wellbore/pageview/exploration/all.

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