FORCE Structural Geology Group
Fault Compartments Webinar 14 – 15th of April 2021

Key Note Presentation

Fault displacement partitioning in natural normal faults and in reservoir modelling

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Normal faults in clastic reservoirs are usually visible only as single surfaces in seismic data, and generally can be represented only as single surfaces in reservoir models due to cell size limitations. Examination of reservoir-scale faults at outcrop, however, shows that they often contain regions in which the fault displacement is partitioned between numerous fault segments. This segmentation can significantly influence cross-fault juxtaposition and cross-fault or along-fault flow, and therefore should not be ignored in either exploration or development modelling studies. For the last decade we have been researching segmentation and displacement partitioning in normal faults with a view to establishing a quantitative conceptual model of fault zone structure that can be parameterised from seismic data and subsequently incorporated in reservoir modelling to better constrain faulted-related uncertainties. This presentation describes some of the results of this research, including: the geological basis of the quantitative fault zone model, methods for calibrating it for specific reservoir studies, a software tool for constructing stochastic models of the sub-seismic structure within specific reservoir faults, an analytical tool for risking cross-fault juxtaposition and spill-point depth, and geometrical upscaling approaches for including effects of fault segmentation in production flow simulation models.

Low- versus high-resolution assessment of reservoir compartmentalization in the Wisting field, Norwegian Barents Sea

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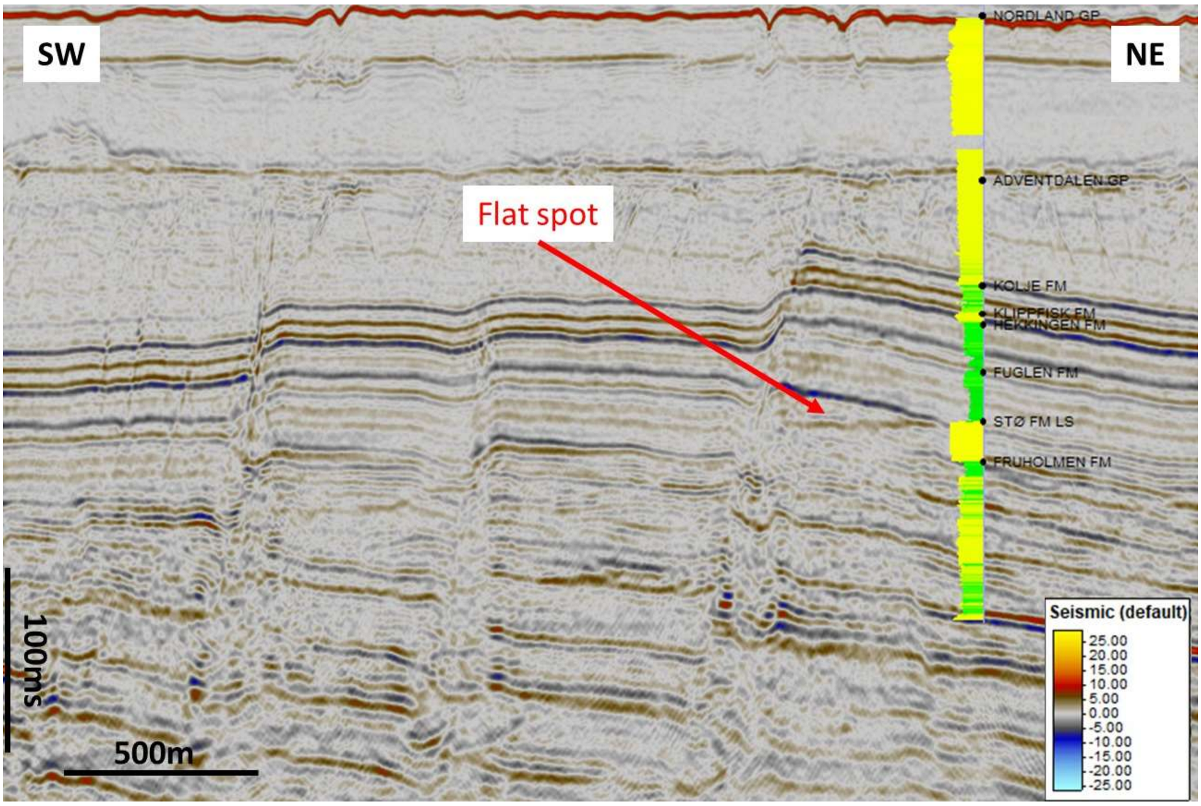
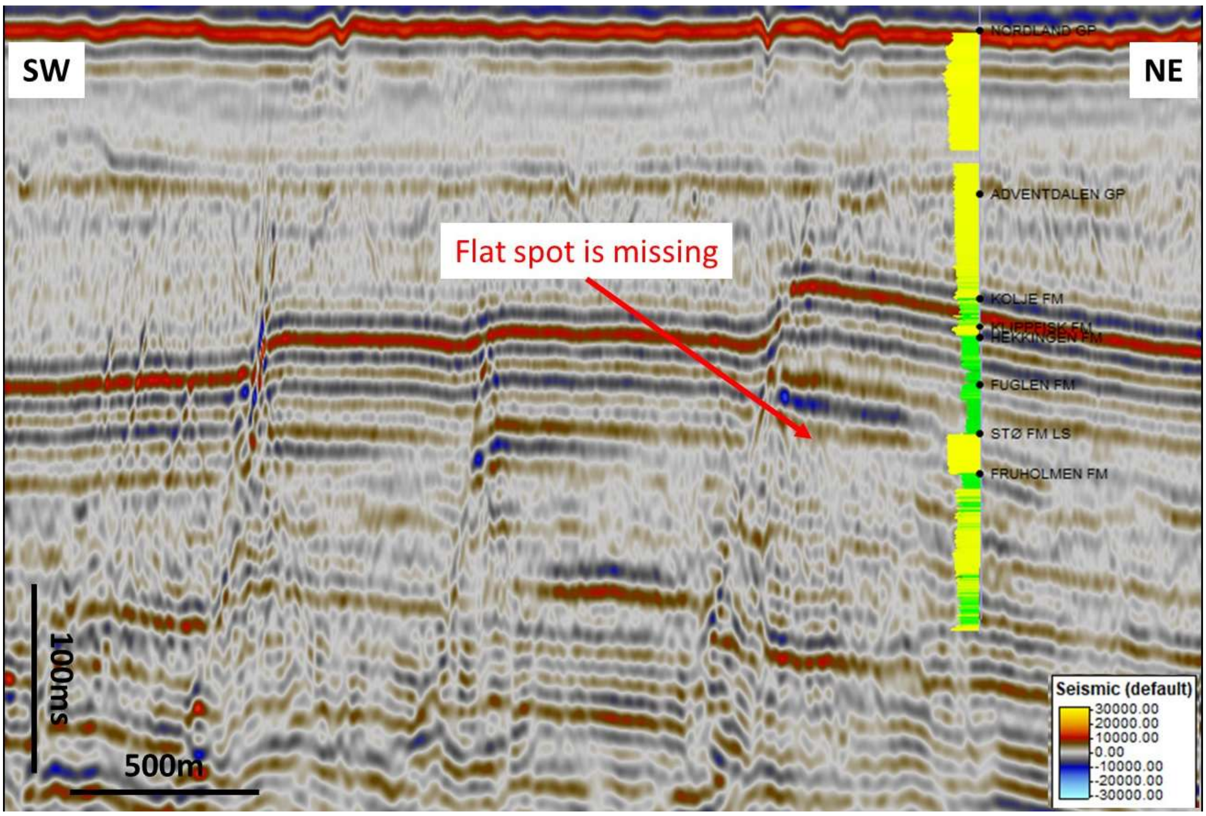
Wisting is Norway's northernmost oil field to be developed. With ~500 mmboe in shallow marine to fluvial Upper Triassic to Lower Cretaceous reservoirs, which are highly faulted and are just 250-300 m below the sea bottom, this field is quite unique. Wisting sits between the Maud Basin and the Hoop fault complex and is affected by an orthorhombic fault system consisting of NE-SW and ESE-WNW trending faults. Polygonal faults affect Cretaceous shales above the reservoir interval. Since the reservoir units are so shallow and the area is heavily faulted, evaluating fault sealing and the impact of fluid injection on fault reactivation are crucial for the safe, future development of the field. In this study, we use publicly available (via DISKOS) low- (10 to 70 Hz frequency) and high- (7 to 185 Hz frequency) resolution seismic data from the Wisting field, to better understand the impact of seismic resolution on structural interpretation, reservoir volume, and reservoir compartmentalization. In addition, we integrate the information from two exploration wells with GR, sonic, density and neutron porosity logs, and formation tops. Well-correlation and seismic-well tie are the two initial steps to identify the formation tops and link the wells log signature to the seismic. The variance attribute is used to guide the fault interpretation. The high-resolution data image the faults with impressive detail (although there are fault shadows issues in the footwalls), and even in some cases fault smearing is detectable. Moreover, flat spots can only be identified in the high-resolution seismic, and they appear to terminate at the faults. Depth structure maps from the low- and high-resolution datasets are constructed, and uncertainties are evaluated by subtracting these maps. Low- and high-resolution fault throw maps and juxtaposition (Allan) diagrams are also constructed, compared and analysed. These observations provide guidelines for the structural interpretation and fault sealing analysis of the Wisting field, as well as highlight potential uncertainties in the assessment of reservoir compartmentalization.

High-resolution seismic



Low-resolution seismic



A new method for addressing fault compartmentalisation uncertainty using probabilistic/stochastic linear regression analysis from raw fault interpretations and accompanying throw point data

Dan Hemingway

The utilisation of fault throw profiles to estimate likely fault tip extension is clearly documented in various outcrop examples (Peacock and Sanderson, 1991; Nicol et al., 1996; Pickering et al., 1997; Manzocchi et al., 2009). These studies, along with many others, demonstrate how linear regression analysis of known fault throw data points allow us to make the best possible technical assumptions on the probable fault extension length, and true fault tip-out point.

It is commonplace for uncertainty analysis to be carried through most phases of the geomodelling space, tending to focus on more repeatable workflows that allow for the manipulation of input parameters around a known range and distribution with relative ease. However, such workflows are typically anchored to a single structural base case, ignoring the variability and associated uncertainty with fault connectivity, particularly within the bounds of seismic imaging uncertainty.

In addition, during reservoir modelling, sub-seismic fault extension is generally considered following the generation of a structural or geocellular model, that has undergone various phases of data filtering and conditioning, which often results in a miss-guided or inaccurate result.

In this contribution we present the results of modelling P10, P50 and P90 compartmentalisation uncertainty scenarios in the Ameland Noord (AMN) concession of the Greater Ameland Area, NL, Southern N Sea.

We draw particular attention to the connected static and dynamic reservoir volume of the AMN-01 well, where uncertainty related to the extension length and segmentation extent of the nearby intra-reservoir fault is greatest. Each modelled uncertainty scenario represents the same fault at a different phase of fault growth and evolution.

We demonstrate a workflow that uses raw seismic interpretation data to stochastically populate fault tip extensions and rank uncertainty scenarios into compartmentalisation cases that are used to automatically generate alternative structural models, allowing for compartmentalisation uncertainty to be more reliably understood and captured within reservoir modelling workflows.

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Fault compartmentalization in carbonate reservoirs

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Faults have a major impact on subsurface fluid flow, which is important to understand for a range of applications such as oil and gas exploration and development, groundwater flow, as well as CO_2 storage and radioactive waste disposal. Significant advances have been made developing the tools and databases to allow the impact of faults rocks on fluid flow to be predicted in siliciclastic sediments (i.e. sand – shale sequences). Equivalent tools had not been developed for carbonate reservoirs. To fill in this knowledge gap, a joint industry project was established with the aim of creating a step-change in our ability to model the impact of fault rocks on fluid flow in carbonate reservoirs.

The project conducted field work at over 50 outcrops in 10 countries to improve understanding of fault zone architecture in carbonates. Over 600 samples if fault rock and their associated protolith were collected and their microstructural, petrophysical and geomechanical properties were analysed. Overall, the results indicate that fault rocks with extremely low permeabilities (<<0.001 mD) and very high threshold pressures (Hg-threshold pressure of >10,000 psi are common. However, field work indicates that these low permeability fault rocks are often cut by later fractures. In many cases, the number of fractures that cut the faults are lower than are present within the reservoir as a whole. Numerical modelling and flow simulation suggest that it is possible that this relationship between faults and fractures could mean that pressures equilibrate quickly across faults in carbonate reservoirs during production. However, the fact that not all fractures propagate through the low permeability fault rocks means that faults could still reduce sweep efficiency. In other words, fault rocks in carbonate reservoirs that cannot be easily identified from pressure data could still significantly reduce oil recovery.

Case study: Goliat Field fault seal and sand juxtaposition analysis

Authors: Søndergaard, M.K.B., Van Noorden, M., Castillo, I., Musca, C., Tosi, G. & Sismondini, B.; *Vår Energi*

The Goliat oil field is located about 85 km NNW of Hammerfest in the Goliat structure formed by a large complex faulted anticline located in the south-western part of the Barents Sea, west of an area where the Troms-Finnmark Fault Complex bends.

A series of SW-NE trending faults, parallel to the Troms-Finnmark Fault Complex, and WNW-ESE trending faults, play an important role in compartmentalizing the field.

A fault juxtaposition and seal study for the Realgrunnen and Kobbe reservoir units was recently initiated with the purpose of improving reservoir models history matching. The study includes control points where faults are proven to be sealing by well results and shows the importance of a robust structural model and control of facies distributions.

A new control point was added in 2021 by the first development well of the Goliat West segment as the well was drilled through a small intra-segment horst in which gas was found below the Goliat West GOC.

Reservoir compartmentalization in the Iris Discovery, Norwegian Sea

Samantha Taggart

OMV

The Iris high pressure high temperature discovery is located in production licence PL644/PL644B/PL644C in the Norwegian Sea. The reservoir is the Middle Jurassic, shallow marine, Garn Formation of the Fangst Group. The Iris discovery evaluation is based on the results from the gas condensate discovery and appraisal wells 6506/11-10 and 6506/11-11 S respectively. The Iris discovery is structurally complex and consists of two drilled segments, Segments A and B, and three un-drilled segments, Segments E, G and H.

A pressure gradient difference was observed in wells 6506/11-10 and 6506/11-11 S indicating these segments are not in communication. However, both wells are gas condensate bearing with similar fluid composition. The discovery well 6506/11-10 (Segment A) drilled a thick Garn Formation interval and two distinct, sandstone dominated, facies associations were encountered. A free water level was identified and fluid samples were taken. Appraisal well 6506/11-11 S (Segment B) drilled a Garn Formation interval with two coarsening upward sandstone packages. A gas down to was observed in this well. Two drill stem tests performed on the lower and upper sandstone intervals indicated that there may be stratigraphic compartmentalisation or/and partially sealing faults/fractures.

Well, core and seismic data has been integrated to assess the reservoir compartmentalisation and to optimize the field development plan.

Modeled fault sealing at the Njord Field: dependence on shale model, and consistency with subsurface observations

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The shale gouge ratio (SGR) is a frequently used method for fault seal and capacity prediction studies and is based on calibration towards known sealing faults. Due to the dependency on calibration, this method requires consistency between the shale model used for the calibration and the application. The shale models for published SGR calibration curves are often not fully documented and the impact of shale calculations methods on the SGR results have apparently been given little attention.

In this study, we calculated SGRs for 23 sealing fault rocks in the Njord field at the southern Halten Terrace. The faults are at 2.6 to 3.1 km of burial depth. The SGR was calculated for two different shale models, one computed by assuming 100% of shale at GRmax and another one calibrated to the total amount of shale and the clay types by 4 exploration wells. This last model suggests that the clay content is approximately 70% for the rocks with the highest GR value in our data set.

The difference of the calculated SGR between the two models depends on the total amount of SGR. Calculated SGR values (<0,02) in low GR rocks (35 to 60 API) typically differ with ±0,03 between the models, while SGRs calculations including intervals with high GR values (up to 150 API) can differ up to 0.17 SGR.

The calculated SGRs by both shale models correlate with across fault pressure difference, and both suggest higher sealing capacities than what was proposed by Yielding (2002). Calculated fault sealing from the SGR model of Yielding (2002) would therefore have underestimated fault sealing capacity in the Njord field.

Day 2

Webinar Sub-theme: Calibration of Fault Seal Predictions

Stochastic Fault Seal and Compartment Analysis

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Fault compartmentalisation is a significant issue for exploration assessment of prospects and understanding the development of oil and gas fields. There are often significant uncertainties in both fault geometry and stratigraphy. We use case studies to highlight examples where the geometric uncertainties are probably of greater importance than the stratigraphic uncertainties, and conversely, examples where the stratigraphic uncertainties are probably more important.

Using examples from the Osseberg, Tune and Gulfax fields, this talk will illustrate critical elements in a workflow that includes analysis of stratigraphic information, pressure information, geological style, and 3D positions of key structures such as faults, folds, closures, and top seals.

Although it seems obvious, we reiterate that it is essential to avoid cognitive bias in fault seal and compartment analysis. A key danger is isolating stratigraphic analysis from structural geology or classic fault seal analysis in separate, perhaps discipline-related siloes or workflows, and making the assumption that one of these stories is all-important.

Reproducible case studies are a vital part of assessing algorithms and methods. We note that Norwegian North Sea examples have been used as calibration points for the widely used SGR (shale gouge ratio) and related algorithms for fault membrane seal analysis. We comment that alternative explanations are equally appropriate for Tune and Osseberg, and because of this, we call for a re-evaluation of these algorithms and related methods.

Finally, we comment that in many cases the data are insufficient to conclusively discern which features or mechanisms cause compartmentalization, and it may be appropriate to entertain multiple hypotheses until additional data become available. Keeping a clear focus on what is certain versus what is still unknown is appropriate, especially as we progress towards other activities such as CO2 Sequestration and wastewater injection activities.

TITLE: **Are current Fault Seal Calibrations suitable for estimating CO_2 column heights?**

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ABSTRACT:

A key component in assessing the potential of a fault bounded trap for the storage of atmospheric CO_2 is to evaluate the likelihood of sealing and/or leakage across faults. Case studies use SGR-pressure relationships derived from hydrocarbon bearing traps to estimate the height of CO_2 columns that could be supported by fault-rock membrane seals.

Fault seal calibrations are derived by cross-plotting fault-zone clay content (estimated using SGR) against in-situ pressure data. Plotting data from numerous datasets onto one plot enables general trends to be identified (e.g. "Fault Seal Envelopes") that represent maximum seal capacity of the fault seal for the given set of input data.

In terms of trapped column height, ca 70% of gas-only traps is close to the maximum seal capacity compared to only 14% of oil-only traps. Oil traps are typically interpreted as being under filled relative to their maximum fault seal capacity, either as a result of fill to maximum seal capacity followed by leakage (fault is not at seal capacity) and/or by leakage into sub-seismic scale thief sands.

Data from oil-only traps have a limited vertical range of buoyancy pressure (less than 3 bars) over a wide range of SGR values (20-70%). The upper edge of the data cloud defines an almost horizontal fault seal envelope above SGR values of ca. 20%. This would imply limited increase in seal strength for SGR values >20% for oil bearing traps.

Industry standard empirical calibrations are derived from low density gas-only traps and therefore may not be suitable for predicting column heights for much high density phases such as oil and injected CO_2.

On the Long-Term Integrity of Structural Traps in CO_2 Storage Sites

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Abstract

There have been many studies attempted to evaluate the long-term integrity of seals in CO_2 storage sites. This is mainly due to the fact that faults in depleted reservoirs/storage sites are often capillary seals and therefore, insufficient knowledge of their capacity to withstand the injection pressure may result in creation of leakage paths. CO_2-rock geochemical reactions, surface wettability alteration and reduction of capillary pressure are major concerns on these occasions which have not been deeply understood. We examined the changes in the mineralogy and surface wettability of shales with different clay content once exposed to supercritical CO_2 for 6 months. The results indicated that quartz surface dissolution and kaolinite precipitation can be induced in the presence of supercritical CO_2. Changes of surface wettability in the storage sites were observed and linked to the affinity of clays to absorb CO_2, and the dissolution of non-polar (oil) components from the shale surface. We applied our findings to a depleted gas field in Nigeria, as a potential storage sites, and noticed the reduction of the maximum column height of CO_2 that can be sustained by the faults before failure. It also appeared that faults may exhibit slow slip and velocity strengthening behaviour once reactivated in this field.

Summary

Geological storage of carbon dioxide (CO_2) is regarded as a key solution to reduce the amount of greenhouse gas released to the atmosphere. Structural trapping is the most important mechanism for the success of Carbon Capture and Storage (CCS) projects. Faults, as a major structural trap in geological storage sites, are often capillary seal where the interfacial tension between CO_2 and water together with the rocks surface wettability prevent CO_2 from entering the fault zone. However, CO_2 is a reactive fluid (in its supercritical state or once dissolves in formation water), can interact with rocks, decrease the capillary entry pressure, and reduce the integrity of fault. Although there have been many studies on the surface wettability alteration in the presence of CO_2, the reasons behind this alteration has not been fully understood.

What Does it Mean for your Faults to Seal: Considerations in Carbon Storage

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Faults play an important role in CO_2 storage but in ways we might not expect.

Carbon Capture and Storage is considered a viable method to remove CO_2 from the atmosphere and store it in the subsurface to mitigate some of the risks of climate change. CO_2 is typically injected in reservoir conditions in a supercritical state with a density lighter than the brine. In the initial injection, the CO_2 is immiscible in the brine and migrates up-dip from the injection well. As a lighter immiscible fluid, typical capillary controls on the top seal and fault seal capacity are expected, and standard methods for fault seal apply. The CO_2 interfacial tension and wettability are more complex and change with brine salinity, temperature and pressure, however, which makes the capillary seal analysis more complicated. In many cases, capillary seal is not the most relevant process for CO_2 trapping as faults acting as a primary seal for the CO_2 is risky. Faults, however, can play a role in the injection simulation separate from the seal in acting as baffles that redirect the injected CO_2 or in impacting brine migration that may contaminate drinking water, for example. Correctly mapping and characterizing the faults in CO_2 storage projects is critical but standard practices in oil and gas do not always apply. Applications for fault characterization for CO_2 and comparisons to oil and gas reservoirs will be discussed.

Top and lateral seals for CO_2 storage in Jurassic saline aquifers of the Horda Platform

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Abstract:

Full-scale CO_2 storage within the Norwegian Continental Shelf is scheduled to commence in 2024 at the Aurora site under project Longship and the Northern Lights consortium. While tens of megatonnes of injected CO_2 are anticipated over the project lifespan, many more storage locations are required in order to meet international climate mitigation targets. In the event of success at Aurora, the Horda Platform could be further developed into a larger North Sea CO_2 storage hub.

Lower and Upper Jurassic sandstone aquifers offer ample pore space for sequestration, and structural mapping within the region reveals a collection of possible storage traps distributed within three large-scale fault blocks. As it is imperative to characterize seals enveloping potential CO2 storage traps, we have undertaken a regional screening of top seal presence and lateral seal types associated with Lower and Upper Jurassic intervals of the Horda Platform.

The solitary top seal formation above the Lower Jurassic aquifer thins considerably to the northwest, lowering confidence in seal presence above traps in those parts of the study area. In contrast, a culmination of several top seal formations provide a relatively thick regional seal above the Upper Jurassic aquifer. Fault-bound traps in the study area exhibit two lateral relationship types; 1) fault juxtapositions where the envisaged storage aquifer is in contact with downthrown top seals or 2) juxtapositions where the storage aquifer is in contact with sandstone aquifers above the top seal. Though the first type represents simple juxtaposition seal, the second implies that fault membrane seal is required at sandstone-to-sandstone contacts.

Type two relationships are prevalent along Lower Jurassic traps, but SGR analyses and recent aquifer pressure measurements in the region suggest that such faults may enjoy some membrane seal potential. All Upper Jurassic faulted traps express type one relationships, and are perceived to possess lower-risk seals based on analogous relationships observed at nearby hydrocarbon fields (e.g., Troll East). However, fewer Upper Jurassic traps are readily available for CO_2 storage due to the risk of up-dip contamination of hydrocarbon accumulations, and are therefore restricted to the eastern-most fault block until the end of production.

Scaling up CO_2 storage on the Horda Platform: recent insights from the fault seal perspective

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The Northern Lights CCS project is under development in the Aurora area. The first phase is to inject ~1.5 Mt of CO_2 per year for an operational period of 25 years starting from 2024, with the potential second phase planned to increase the capacity to ~5 Mt per year. The Horda Platform not only provides the storage capacity for the current design of the Northern Lights project, but it is also in a strategic position for future scale-up potentials because of a) the existing and planned CCS infrastructures (i.e., cost-efficient) and b) its large geological storage capacity.

Our study on the Smeaheia Viking Group shows the Beta structure has large containment risks associated with the Øygarden Fault System (ØFS). Storage in the Alpha and Gamma structures are possible, but storage capacity has higher uncertainties because of their across-fault communications with the depleting Troll East via the Vette Fault System (VFS). The Gladsheim well (32/4-3S) on the Gamma structure proved our pre-drill predictions of reservoir depletion.

The Gladsheim well, together with the Eos well (31/5-7) drilled in Aurora, have further illustrated good storage potentials of the Dunlin Group in Smeaheia and Troll East:

1) Dunlin Group in the southern Smeaheia area has ~50 m of Johansen Formation with good sand properties, and ~75 m of shale as the top seal. The near-hydrostatic pressure in the Gladsheim well suggests that the across-fault communications between the Smeaheia Dunlin Group and the Troll East Viking Group are very limited. The east-ward pinch-out of the Dunlin Group means that the containment risks associated with the ØFS are low.
2) The Dunlin Group in the Troll East also has storage potential. The Troll East Dunlin Group is juxtaposed with the Viking Group of TWGP across the Tusse Fault System (TFS), like the Smeaheia Dunlin Group setting. Beside of the fault juxtaposition, the fault rock properties of the TFS should also be similar to the VFS, which has shown across-fault flow barrier/baffling.

Further VFS fault seal calibration and history matching of the Gladsheim well data can help mature these Dunlin Group storage concepts.

Evaluation of fault seal for Co_2 injection in the Norwegian Northern Lights CCS project.

Signe Ottesen, Long Wu and Rune Osland, Equinor ASA.

The Northern Lights project is the transportation and storage part of the Longship CCS demonstration project recently adopted in the Norwegian Parliament - Stortinget. The Northern Lights joint venture owned by Equinor, Total, and Shell will inject and store CO_2 in the Lower Jurassic Dunlin Group within the exploitation license EL001 located South of the Troll field. CO_2 will be injected in the Johansen Fm. and will, with time, migrate slowly up-dip to the north driven by buoyancy. According to regulations, the stored CO_2 shall be contained within the storage complex.

Understanding the effects of the faults are important for predicting CO_2 migration within the storage units and for analysis of potential migration pathways for CO_2 out of the storage complex. Faults represent potential barriers or baffles for migration of CO_2 within the reservoirs and provide potential across fault flow paths between reservoir units. The fault seal evaluation is based on SSF and SGR calculated on triangle diagrams, together with juxtaposition maps made in a new Equinor proprietary RMS plugin FaultRoom.

The Eos well 31/5-7 was the first well drilled into the Dunlin Group in the exploitation license in 2019/2020. Until then the nearest well to the injection site was 18 km to the North. The Eos well was drilled to confirm the reservoir presence, properties, pressure depletion and injection potential of the storage units. The Eos well proves the existence of good reservoirs in high energy shallow-marine sandstones of the Johansen and Cook formations within the Dunlin Group. Furthermore, the well proves the sealing properties of the Drake Formation which constitutes the primary caprock of the reservoir.

Conclusions from the fault seal analysis prior to results from the Eos well had large uncertainty. Applying the data from the Eos well reduced this uncertainty. The post Eos well fault seal analysis confirmed that there is nearly no, or very low, risk for migration through the major faults or upwards migration along faults into shallower stratigraphic units.