Hydrocarbon Potential of Nontraditional Reservoirs of Heidrun Field, Offshore Norway

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1. INTRODUCTION AND OBJECTIVES
The Heidrun field is one of the most mature and prolific oil fields found in the Norwegian Sea. According to Norse mythology, Heidrun is a goat which aids fallen warriors with mead in the kingdom of the dead Vikings. As the Heidrun goat provides mead for Vikings, the Heidrun field also has played an important role of sustaining the hydrocarbon industry of Norway.

The discovery of Heidrun field can traced back to 1985 when an appraisal well was drilled by Conoco and partners on the Halten Terrace, middle Norwegian shelf. It’s about 190 km away from Norway’s shore in water depths of 350m. It is estimated that the field contains 755 million recoverable bbl of oil and more than 1 tcf of gas (Whitley, 1992). The economic production of hydrocarbons began in 1995 and has produced over 114 MSm³ of oil to date (Thrana et al., 2009). Most of the hydrocarbons in Heidrun are derived from the Middle Jurassic Fangst group (Garn, Ile Formation), which has good reservoir quality. However, the production rate has fallen gradually from 1997 to 2007 (Figure 1).

The decline of hydrocarbons has encouraged petroleum geologists to find new exploration targets in order to sustain Norwegian energy, and get more “mead” from Heidrun. The reservoirs of the Are Formation contain thick sandstones with high porosity and permeability. They are more complex and largely underestimated in comparison to traditional Jurassic reservoirs of the Fangst group and Tilje formation (Whitely, 1992). Additionally, a well 6507/7-12 drilled north of Heidrun field found in the Lower Cretaceous Cromer Knoll group, suggests there might also be reservoir potential in the southern extension of Heidrun field. Our main objectives of this project are: (1) explore hydrocarbon potential of Cromer Knoll Group and Are Formation, which are largely underestimated in comparison to traditional Jurassic reservoirs; (2) Propose five new prospect wells to sustain the hydrocarbon production of the Heidrun Field using 3-D seismic data analysis with some well log/core constraints.

2. LOCATION AND DATASET
The Heidrun field is located in Halten terrace on the mid-Norwegian continental shelf in water depths of approximately 350 m. It lies 190 km from shore (Figure 2). A general north to south trend of oil and gas is observed in this production field. Our study is mainly focused on the southern part of Heidrun field (Figures 2 and 3).

The dataset is mainly from the available seismic volume which covers 48 km² in the southern part of the Heidrun field (Figure 3). The seismic survey is zero phase and has a dominant frequency of 30 Hz in the interval of interest. This study also uses cores and well logs to help understand lithology and depositional facies of major reservoir intervals. The cores and well logs are from Norwegian Petroleum Directorate and the literature.

3. GEOLOGICAL BACKGROUND
The Heidrun field is located on the southernmost extension of the predominantly southwest-northeast trending Nordland ridge, which is an intensely faulted high that separates the
Helgeland Basin from the more westernly Voring basin (Figure 4). The major faults in this study area are normal faults which suggest a rift basin in the Norwegian shelf. A major horst structure is confined by two major faults in the western and eastern portion of the study area and is extensively cut by several secondly faults (Figures 3 and 5). The traditional Jurassic Fangst group reservoir is located within this horst high structure.

The Mid-Norwegian shelf has experienced multiple episodes of basin evolution, starting from a Middle Devonian-Late Carboniferous intramontane basin to Tertiary passive margin basin. In this study we only focus on the major tectonostratigraphies that have an important influence on hydrocarbon generation, migration, and seal. We use seismic data, mainly from TWT 1400ms to 2900ms, to reveal major basin evolution events with emphasis on Are Formation and Cromer Knoll Formation. Generally, we divide the study area into 5 tectonostratigraphies from late Triassic to late Pliocene (Figure 6).

3.1 PRERIFT TO SYNRIFT (UPPER TRIASSIC TO LOWER CRETAUCEOUS)
During the early prerift period, thick halite sequences and red beds of Middle to Late Triassic age were developed (Figure 7). Similarly, this can also be seen in The Gulf of Mexico basin when the basin just started to open and there was restricted water circulation with open sea. As the basin continued to rift the climate changed from arid to more humid conditions. This led to the deposition of coals, sands, silts, and shales of the Are Formation. The Are Formation is both an important source rock and reservoir intervals.

The coal bed which is identified in the seismic data as a key horizon marker is an important gas-prone source rock. Also the Are Formation has fluvial sandstones interbedded with coal beds as an important source rock in Late Triassic and Early Jurassic time (Figure 8). The lower Are formation is dominated by fluvial-deltaic deposits, which is about 490 m thick. The overlying upper Are Formation and Tilje Formation consists of marginal marine and marine shale deposits and is capped by a major transgression of the Ror Formation marine shale. An upward transgression can be inferred by the depositional facies changes from Lower Are to Ror Formation. The Are Formation has a thick reservoir sandstone with average porosity 28% and average permeability 1788md and could be an important hydrocarbon potential for next phase of exploration. Detailed information of the Are formation will be discussed later in this paper.

During the Jurassic synrift period, strong sediment influx began to come back to Heidrun field caused by regional updoming. The lower Fangst group is dominated by a tide influenced delta system and has changed to wave dominated delta systems in the middle and fluvial system in the upper part. A general upward regression can be concluded from the facies stacking pattern vertically. Thick Fangst group sandstones are deposited and formed the major reservoir for traditional hydrocarbon accumulation. Most produced oil and gas from the Heidrun field are from this interval. The thickness of Fangst group is highly variable due to synsedimentary faulting and erosion associated with the Cimmerian diastrophism. On some major highs the Fangst Group even completely eroded. The erosion was terminated by a rapid transgression and the deposition of Melke shales and Spekk Formation. These marine shales are very stable and widely distributed in the Haltenbanken and persisted for the remainder of the Jurassic. The Spekk Formation shale, which is deposited in deeper water with anoxic bottom conditions, is the primary source rock in Heidrun field (Figure 9). The continued Cimmerian block faulting in the Late Jurassic and Early Cretaceous has also caused local erosion of Spekk Formation (Figure
6). A significant erosional surface, the Basal Cretaceous Unconformity (BCU), can be identified by the surface truncated underlying seismic reflection (Figure 6).

3.2 EARLY POSTRIFT (LOWER CRETACEOUS)
Early postrift marks the reactivation of Triassic rift faults and rapid subsidence created large accommodation space and deposited thick shales with few sandstone in this interval. The deposition is mainly restricted in the east of study area and formed a wedge shape pinching out to the major fault structures in the west. It's generally shows a thickening trend southeast in study area. Although this interval is dominated by marine shale deposits in a general transgressive system tract, the local erosion of horst highs may have provided good reservoir sandstones to study area. This interval will be discussed in further detail later.

3.3 LATE POSTRIFT (UPPER CRETACEOUS)
Late postrift succeeds the Jurassic rift phase and marks the deposition of the Shetland Group. The top of Shetland Group is easily recognizable on the seismic volume as a high amplitude continuous reflector (Figure 6). The generally transparent and very little amplitude contrast and drilling descriptions on completion and composite logs (relative high GR ray) from the wells both suggest the deposits are mainly calcareous shales and claystones with trace amounts of sandstone. Large onlap features of marine shale on Cimmerian structures can be seen on seismic data in the west of study area. This marine shale is widely distributed and is a very good seal to trap the hydrocarbon below.

3.4 RIFTING (PALEOCENE)
This rifting interval is easily identified in the seismic data, with its top and bottom characterized with amplitude-continuous reflectors (Figure 6). Based on the drilling data, the Paleocene Tare Formation is mainly hemipelagic clays indicating a deep marine environment. The Tang Formation is mainly tuffaceous sandstone from explosive volcanic activity. The constant thickness in study area and majority of shale deposits suggest a low sediment input from source terranes.

3.5 POSTRIFT (EOCENE TO LATE PLIOCENE)
Postrift after the Paleocene is mainly composed of the Hordaland and Nordland groups, which consist of marine claystone. Features of polygonal faults pattern can be observed from the seismic data. It has been postulated that these polygons are dewatering structures that formed by fluid expulsion at the time of deposition (Berndt, Bünz et al. 2003).

The Heidrun field has experienced multiple tectonic episodes and evolution. In this study we are primarily interested in the prerift to synrift Are Formation and early postrift Cromer Knoll Group, because we think there is higher hydrocarbon potential in these intervals that are underestimated.

4. PETROLEUM SYSTEM
The Heidrun has a very good combination of source rock, reservoir, migration pathways, and seal on the top. Previous hydrocarbon production in the region solidifies a proven petroleum system (Figure 9).
4.1 SOURCE ROCK
The major source rock of the study area is from the Spekk Formation, which was partially eroded on the topographic high by the BCU. The Spekk Formation has the highest gamma ray readings in the Haltenbanken area and is a rich source rock with a total organic carbon content of up to 13% (average, 4%) (Whitley, 1992). The geochemical reports indicated that the kerogen type was amorphous type II with few type III. The Spekk shale is considered the major oil contributor to Fangst reservoir.

The secondary source rock is located in the Are Formation of the Middle Jurassic. The coal bed marker can be traced on seismic data and may provide natural gas to the study area. The coal bed was deposited in a fluvial-coastal plain environment and interbedded with sandstone. There are multiple layers of coalbeds, but it's hard to distinguish them from seismic data. Considering the thickness of the Are Formation (up to 600 m), the total thickness of coalbeds could be large and may be a good source of natural gas.

4.2 RESERVOIR
Traditional reservoir rocks are Fangst sandstone where deposited in marginal marine and fluvial depositional environments (Figure 10). Porosities of the sandstones are high, and are commonly in excess of 30%, and locally as high as 35%. Permeabilities range from 100 md to as high as several darcys.

The more complex reservoir rocks are of the Are Formation sandstone, which is interbedded with coalbeds. The Are Formation is quite thick and is up to 500 m. The Are Formation can be further divided into three sections, Are 1-2, Are 3-5 and Are 6-7. The Are 1-2 is non-marine coastal plain, Are 3-5 is marginal-marine lower delta plain and Are 6-7 is estuarine and open marine. The oil recovery of the Åre Formation is the lowest among the reservoir formations, which makes this an important interval when it comes to remaining reserves potential. The Are Formation reservoir will be further discussed later.

4.3 MIGRATION PATHWAY
Fault systems are effective way for hydrocarbon migration to occur. The major reservoir Are Formation and Fangst Group in Heidrun field are intensively cut by fault systems, which may connect the reservoir to the source rock, if the fault system is not sealed. As indicated by figure 9, the fault system can transport hydrocarbon both from the underlying Are coal beds and lateral Spekk source rock.

4.4 SEAL
The marine transgression in the Cretaceous has resulted in the deposition of the thick Shetland Group shale. This shale is quite stable and is consistently distributed in study area capping the BCU and Fangst Group reservoir. From the seismic data (Figure 6), no penetration from faults is observed in this seismic interval. The Shetland Group is also proven as a regional seal from production activities. However, local variation could fail to seal and promote vertical fluid escape.
4.5 PRESERVATION
Although there is a period of rifting during Paleocene, the general tectonic environment after deposition of major reservoir is relative stable passive margin. It's quite favorable for hydrocarbon preservation.

4.6 TIMING
Although the deposition of the major Spekk source rock is later than Fangst reservoir sandstone, the reactivation of faults has made hydrocarbon migration possible. The Shetland Group shale has the potential to cap the reservoir and effectively trap the hydrocarbon. The secondary coalbed source may have migrated upward through fault and trapped by Shetland Group seal too. The Are Formation sandstone can also be a good reservoir to store the gas generated from coalbed.

5. HYDROCARBON POTENTIAL OF THE CROMER KNOLL GROUP
Most Norwegian continental shelf fields have been producing from these Jurassic reservoirs for the past 30 years (Moscardelli, 2013). The exploration Lower Cretaceous formation becomes more appealing because of three reasons. First, the Jurassic reservoirs in Heidrun field have already been deliberately discovered. Second, the farther offshore explorations of Jurassic reservoirs towards the rift axis become highly risk. Third, discovery of Cretaceous turbidities indicates the presence of a working petroleum charging moment is not unreasonable. Thus, based on the presumption of the turbidities moment, the sediments source of the Cromer Knoll formation is presumably the sandy material from the localized eroded Jurassic highs.

However, Well #6509/8-7, which is the only well penetrates through Cromer Knoll group in Heidrun Field, has no sand interval to be interpreted from either wireline logs or core samples. But the absence of sand interval in #6507/8-7 does not invalidate the presumption on the presence of sand boy in Cromer Group for two reasons. First, from previous study, Moscardelli (2013) points out well #6507/8-7 does not penetrate directly through the high-amplitude zone, which might imply the location of the potential reservoir. Second, well#6507/7-12 (Figure 11), approximately 10 mile north of Heidrun field, is located in a structural configuration analogous to the position of well#6509/8-7 (Moscardelli, 2013). Rare sandy interval does exist from the wireline log of well#6507/7-12 within Cromer Knoll group. Thin rare sand interval might indicate that the sand boy in Heidrun field Cromer Knoll formation might be volumetrically insignificant. However, #6507/7-12 is located in a position more proximal to the hanging wall than well#6507/8-7 in Heidrun field. Thus, the presumption on the presence of a volumetrically significant sand boy in a more distal area to the hanging wall as a basin floor fan is unreasonable.

The application of RMS (Root Mean Square) function in Petrel between horizons is a sufficient tool to locate the potential reservoir in Cromer Knoll formation. RMS attribute emphasizes variations in acoustic impedance over a selected sample interval. Thus, the high RMS in a channel results from either a high impedance contrast of channel fill with surrounding lithology, or acoustic impedance contrasts with infill (Holdaway, 2014).

The Cromer Knoll Lower Cretaceous wedge overlies the BCU and is overlaid by the Upper Cretaceous Shetland Group and is bounded by the hanging wall of the Jurassic horst. The Cromer Knoll wedge is divided into eight evenly-spaced intervals (top to bottom: K1 to K8).
The first round investigation includes the imaging of the RMS attribute maps between each of the eights evenly-spaced intervals. From (Figure 12), K1, K2, K3 presents the fan-like anomalies. Thus, they are further subdivided into K1.1, K1.2, K2.1, K2.2, K3.1, and K3.2 (Figure 13). The location of the point source become more distinctive, which further consolidate our presumed depositional processes.

Two areas are optimal for exploration well placements. (1) In (Figure 14), the cross points at a proximal location to the point source on a topographic high. The proposed exploration well targeting this location is named as CK#1. (2) In (Figure 14), the cross points at a center-north area that would also penetrate the thickness part of the sand body. The proposed exploration well targeting this location is named as CK#2.

There are three risks associated with drilling in the Cromer Knoll. First, the quality of the migration pathways might be sacrificed because hydrocarbon might mostly migrate along the faults that directs to the Jurassic reservoirs (Figure 15). Second, the quality of the reservoir rocks might be reduced because of cementation. Third, the sealing integrity might be uncertain because the hydrocarbon might escape through the 4th and 5th order sequence on the transitional interval between the upper Shetland and the sand body. However, even if there were no hydrocarbon discovered in the sand body, a better understanding of the depositional processes of submarine fan within the Cromer Knoll group for future exploration.

6. HYDROCARBON POTENTIAL OF THE ARE FORMATION
The oil recovery of the fluvialdeltaic (Rhaetian to Early Pliensbachian) Are Formation is the lowest amongst reservoir formations, which makes this an important stratigraphic interval when it comes to remaining reserves and Improved Oil Recovery (IOR) potential of the Heidrun field. (Thrana et al., 2014). However, the reservoir characterization of the Are Formation faces many challenges and requires utilization of more complex well/seismic solutions and the evaluation of smaller and economically marginal drilling targets. Continued efforts to improve the stratigraphic control of the interval are necessary for drilling operations to more accurately predict the spatial distribution and geometry of hydrocarbon bearing facies (Thrana et al., 2014). Significant business opportunities may still exist within the heterogeneous and low-productivity Are Formation, extending the life length of the Heidrun field.

The Are Formation of the Early Jurassic Bat Group is approximately 670 m thick and comprises of mudstones, coals, and coastal to deltaic plain sandstones (Figure 16). The overall transgressive character of the Are formation reflects the gradual tectonic development of the Halten Terrace Basin during the development of the North Atlantic rift system in the early Jurassic, opening northward to the Tethys Sea (Figure 17) (Thrana et al., 2014). The overall transgressive development of the Are Formation is reflected in the stratigraphic framework proposed by Thrana et al., (2014). Analysis of facies correlation and vertical stacking patterns within a framework of key surfaces was used to subdivide the Are Formation into seven main reservoir zones, with a further 17 subzones (Figure 16). The oldest part of the Are Formation consists of a succession of fluvial channel sandstones, peat swamp coals and floodplain mudstones, interpreted to correspond to deposition in a low lying and wet coastal plain environment (Are 1 and 2 zones). A gradual change into a lower delta plain setting is confirmed by repeated incursions of marginal-marine interdistributary bay, marsh and distributary channel fill facies associations in the middle part of the Are Formation (Are 3 and 4 zones). A progressive transition into more open marine conditions is recorded in the uppermost Are
formation and is sustained throughout deposition of the lowermost Tilje Formation. (Are 5, 6, and 7 zones, Figure 16) (Thrana, et al., 2014). This transition is attributed to significant changes in the basin geometry related to the establishment of a marine seaway between the Tethys Sea in the south and the Boreal Sea in the North (Thrana et al., 2014).

Through a better understanding of the depositional model and stratigraphic framework, updated reservoir modelling strategies may be implemented in order to classify previously unidentified opportunities for increased oil recovery from the Are Formation. In particular, the strata slicing methodology can be used to extract reflection amplitudes in order to build a stratigraphic time domain based model of the interval. One challenge associated with the Are Formation is that there are few marker beds identified, specifically, the best and most continuous horizon is the correlative interval of coal separating the Are 1 and 2 zones associated with a maximum flooding surface (Figures 6 and 16). Through a series of Root Mean Square (RMS) surface attribute maps above and below the coal bed marker one can begin to identify amplitude anomalies which may indicate the presence of sands or hydrocarbons due to the variation in acoustic impedance. Specifically, the RMS surface attribute maps from 5 msec below the coal bed to 25 msec above the coal bed highlights robust amplitude anomalies (Figure 18). The surface 20 msec above the coal bed illustrates the strongest amplitude anomalies of the attribute maps and will be the basis for the remainder of our study. However, we cannot rely on surface attribute maps alone to highlight areas of hydrocarbon and sand body potential. Verification is needed from other sources such as seismic data, core, cross sections, and other attribute maps.

When utilizing surface attribute extractions it is important to reference the seismic reflection data to quality check the resultant maps. In Figure 19 the coal bed marker was identified as a bright red reflector (positive) and is overlain by a bright blue reflector (negative). Because a negative impedance value is overlying the high impedance coal marker, this may be an indicator of high quality and clean sandstone with high porosity and permeability overlying the coal bed.

In addition to the seismic data, stratigraphic correlation and detailed reservoir modeling derived from core and log interpretations has created a revised reservoir zonation scheme of the Are Formation (Figure 16). In this reservoir zonation model the signature coal bed separates the Are 1 and 2 zones. This coal bed indicates a maximum flooding surface within the non-marine coastal plain that was the indicative depositional environment at this time. From Figure 16 the presence of fluvial channels are clearly illustrated above the coal bed. Similarly, the presence of fluvial channels is illustrated in paleogeographic maps showing a possible scenario from the fluvial coastal plain setting of the Are 2.1 sub-zone (Figure 20).

Perhaps one of the most imperative pieces of evidence in identifying potential sand reservoirs is access to core data (Figure 21). In the Are 2 zone evidence from core indicates that channel sandstones display consistent depositional characteristics (in terms of bedform thickness, presence of internal scour surfaces, grain size and sorting) in most wells (Thrana et al., 2014). In particular, the Are 2.2 Sub-zone comprises a relatively thick interval (typically 10-15 m, maximum 34 m; Figure 16) of fluvial channel sandstones, with a minor component of crevasse splay sandstones and floodplain mudstones. The base of the Are 2.2 sub-zone is also erosive and typically characterized by pebble lag. This erosional surface may reflect field-wide downcutting forming an incised valley filled by braided channel deposits (Thrana et al, 2014).
To qualify the presence of sands and hydrocarbons in areas showing significant amplitude anomalies additional attribute extractions needed to be performed. To help illuminate the spatial distribution and connectivity of these potential reservoirs a sum of negative amplitudes attribute map was created from the coal bed to 40 msec above the coal bed (Figure 22). When contours are applied to this map, areas illustrating the greatest magnitude of negative amplitudes are noticed to be constrained within the same contours and generally follow structural highs. This may be explained by the formation of a stratigraphic trap, when deposition creates a topographic high and is encased by impermeable lithology. This scenario is a possibility due to the rapid lateral migration of the fluvial channels and facies changes. In attempts to detect some of the channels in the coastal-plain setting a sweetness seismic attribute volume was created (Figure 23). Sweetness is a useful attribute for detecting channels or other stratigraphic features when those features can be distinguished from a “background” lithology by a combination of instantaneous frequency and reflection strength (Hart, 2008). Therefore, given the fluvial-deltaic depositional setting, applying a sweetness attribute volume is helpful in delineating subtle discontinuities such as pinch-outs and channels in stratigraphic traps. In Figure 23 high sweetness amplitudes are observed and may be due to the deposition of sand by a channel. Potential fluvial-deltaic systems are outlined in figure 23 in red. These interpretations remain consistent with the north to south orientation of fluvial systems presented the paleogeographic maps and depositional models presented in Figure 20.

Despite the prevailing evidence presented supporting the presence of potential reservoirs above the coal bed, one must heed caution and assess the risks associated with drilling in the Are formation. One must always take into consideration the vertical and horizontal resolution of the seismic data. The vertical resolution refers to the ability to distinguish two close seismic events corresponding to different depth levels, and the horizontal or spatial resolution is concerned with the ability to distinguish and recognize two laterally displaced features as two distinct adjacent events (Chopra et al., 2006). Heterogeneous reservoir intervals characterized by facies associations with large contrast in reservoir properties, the challenges related to reservoir modelling are associated commonly with realistic representation of dimensions, distribution, and orientation of fluvial successions (Jones et al., 1995). The Are fluvial successions (Are 1 and 2 zones) in particular comprise a range of such heterogeneous deposits and the seismic data from the Heidrun Field cannot resolve these individual fluvial channels (Figure 16) (Thrana et al., 2014). Furthermore, there are few marker beds identified in the Are formation, limited access to core, and little understood about the timing and seal potential of the faults.

7. PROSPECTIVE NEW WELLS
The location for well CK#1 (Figures 16 and 17) is on the topographic high of the Cromer Knoll sand body, which is higher than that of CK#2 (Figures 18 and 19). Thus, CK#1 has less risks to discover hydrocarbon than CK#2. However, CK#2, which penetrates the center-most and thickest portion of the sand body would have a better chance to locate the water-oil contact if hydrocarbon was present. The depth of water-oil contact will lead to a volumetric analysis of the reservoir. Also, the absence of hydrocarbon in this center-most thickest portion of sand body would indicates that further exploration of this sandy body would be uneconomical.

The shift in focus from producing form high quality Fangst reservoirs to the low productivity Are formation may provide new opportunities for increased oil recovery. Based on the
prevailing evidence presented supporting the presence of potential reservoirs in the Are formation, will propose three wells in this interval. The first well is located at the intersection of inline 420 and crossline 1056, the second at the intersection of inline 288 and crossline 1065, and the third at the intersection of inline 206 and crossline 1049 (Figures 28, 29, and 30). In all of these wells we will be targeting the sand channels of the Are formation located above the coal bed. Due to their similarities in depositional setting and time, they will share many aspects of the petroleum system. The traps of these potential reservoirs are all combination traps, with the stratigraphic component being associated with the facies changes and the structural component being the fault. Likewise, the seal of these reservoirs would also be associated with the rapid facies change in the Are formation. The migration pathway may be explained by the vertical migration through faults that are not associated with its seal, connecting the reservoirs with the Are coal bed as their source rock. Are well #1 has a thickness of approximately 60 meters and an area of approximately 130,674 m^2. Are well #2 has a thickness of approximately 52 meters and an area of approximately 101,736 m^2. Lastly, Are well #3 has a thickness of approximately 60 meters and an area of approximately 151,592 m^2. The thicknesses of these wells were calculated by measuring the change in time of where the amplitude anomalies first appear, and where they disappear. Then, using the equation distance = velocity * time we were able to calculate the thicknesses of these wells (A velocity of 4200 m/s was used. From Moscardelli et al., 2014: Velocities of Jurassic intervals may range from 3800-4900 m/s). The areas of these wells were calculated very simplistically using the equation of a circle, $\pi \times \text{radius}^2$.

8. SUMMARY AND CONCLUSIONS
The Heidrun Field is located approximately 190 km offshore mid Norway and has produced in excess of 135 million standard cubic meters of oil (per 2010) since its discovery in 1985. However, production rates of the Heidrun Field are declining and one of the main challenges today is to target and rain efficiently the remaining oil reserves. In particular, a relatively large fraction of the remaining reserves is allocated in the heterogeneous and lower productivity reservoirs within the Lower Jurassic Are Formation (Thrana et al., 2014). Additionally, the Cromer Knoll may represent a potential new reservoir interval containing high-quality Cretaceous sandstones due to the possibility of the upper part of the Cromer Knoll being preserved as part of a deep-water sedimentary conduit transporting sediments eroded from localized erosions of Jurassic rifted highs.

The ranking of the prospects, taking into account the balance between reservoir risk and potential is the following:

1) CK Well #1: Would penetrate the uppermost submarine sandy fan. Lower risks of finding HC than CK well #2
2) CK Well #2: Penetrates the thickest portion of the sandy fan. Could locate the water oil contact for further volumetric analysis. It might not hit Hydrocarbons if secondary migration occurred through the spill point. However, no Hydrocarbon in thickest center portion of the sand body could also indicate further exploration would be uneconomical.
3) Are Well #1: A stratigraphic trap may have formed when deposition created a topographic high and was encased by impermeable lithology. Follows contours very well and deposited on topographic high. Unknown sealing/migration potential of fault
4) Are Well #2: Located slightly downdip from Are well #1. Also appears to have a good amount of enclosure within the contours, but not as good of enclosure as Are well #1.
5) Are Well #3: Located much further down dip than Are Wells #1 and #2. This reservoir is the least enclosed within the contours.

To form a more precise and comprehensive study of the hydrocarbon potential for non-traditional reservoirs of the Heidrun field additional data and research is needed: 1) More core and well log data with seismic ties is needed to provide constraint to our interpretations. 2) The study of timing, seal, and migration potential of the fault network would help elucidate if hydrocarbons are in-fact contained within potential reservoirs. 3) Assess the seal integrity for reservoirs located in the upper part of the Cromer Knoll. 4) Assess the interconnectivity of channels within the Are formation. Revision of these concepts and others is required in order to exploit these intervals as business opportunities.

9. REFERENCES
3. Harris, N.B., Reservoir Geology of Fangst Group (Middle Jurassic), Heidrun Field, Offshore Mid-Norway, AAPG Bulletin, November 1989, v. 73, p. 1415-1435
4. Hart, B. S., Channel detection in 3-D seismic data using sweetness, AAPG Bulletin, v. 92, No. 6 (June 2008), pp 733-742
10. FIGURES

**Figure 1.** Production rate of Heidrun field from 1996 to 2007. The gross production include oil, gas and condensate.

**Figure 2.** Location map of Heidrun field and our study area. The study area is located in the south of Heidrun field and is highlighted with bold red polygon.
Figure 3. (A) Location map of Heidrun field in Norwegian Sea. The highlighted yellow polygon outlines the seismic data used in this study. (B) Map shows major faults and contour of study area. Shaded area is above the oil-water contact. Several exploration wells are also listed. (From Moscardelli et al., 2013).

Figure 4. Geological map of Heidrun field in Haltenbanken. The structural features were assembled on the basis of seismic stratigraphic analyses of the NPD seismic data and plate tectonic reconstruction.
Figure 5. West-east cross section of Heidrun field. Study area is highlighted in yellow rectangle.

Figure 6. Tectonostratigraphic chart of Heidrun Field, Offshore Norway.
**Figure 7.** Stratigraphic column for Heidrun field, From Whitley (1992)

**Figure 8.** Jurassic stratigraphy in Haltenbanken area, showing correlation of Fangst Group to Fangst reservoir units at Heidrun field. (From Harris, 1989)
Figure 9. Petroleum system elements in Heidrun field. (From Moscardelli, et al., 2013)
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<td>160</td>
<td>100</td>
<td>—</td>
</tr>
<tr>
<td>Oil-water contact, m (subsea)</td>
<td>2468</td>
<td>2429-2450</td>
<td>2414</td>
<td>—</td>
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<tr>
<td>Productive closure, km²</td>
<td>37.0</td>
<td>23.1</td>
<td>8.0</td>
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<tr>
<td>Gravity of oil, °API</td>
<td>29</td>
<td>22-28.6</td>
<td>22-28.6</td>
<td>—</td>
</tr>
<tr>
<td>Gas cap</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>—</td>
</tr>
<tr>
<td>Gas/oil ratio, std. ft³/STB</td>
<td>628</td>
<td>332-641</td>
<td>332-641</td>
<td>—</td>
</tr>
<tr>
<td>Pour point, °F</td>
<td>&lt; -50</td>
<td>&lt; -50</td>
<td>&lt; -50</td>
<td>—</td>
</tr>
<tr>
<td>Water resistivity (R_w) at 60°F, ohm</td>
<td>0.185</td>
<td>—</td>
<td>0.160</td>
<td>—</td>
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<tr>
<td>Reservoir pressure</td>
<td>Normal</td>
<td>Normal</td>
<td>Normal</td>
<td>—</td>
</tr>
<tr>
<td>Drive mechanism</td>
<td>Water,</td>
<td>Water,</td>
<td>Depletion (?)</td>
<td>—</td>
</tr>
<tr>
<td></td>
<td>Gas cap expansion</td>
<td>Gas cap expansion</td>
<td></td>
<td>—</td>
</tr>
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</table>

Figure 10. Reservoir data from Heidrun Field. (From Whitley, 1994)
Figure 11. Well correlation between 6507/8-7 and 6507/7-12 (Moscardelli, 2013)

Figure 12. RMS surface attribute of Cromer Knoll K1 to K2.
Figure 13. RMS surface attribute of Cromer Knoll K1.1, K1.2, K2.1, K2.2, K3.1, K3.2.

Figure 14. RMS surface attribute 20 ms above and below the top of Cromer Knoll correlated to seismic image.
Figure 15. The migration pathway of Cromer Knoll formation.
Figure 16. Reservoir zonation scheme of Are Formation, Heidrun Field, showing sedimentary characteristics and associated wireline log signatures of each reservoir zone (based on well 6507/7-A-46). (GR, NPHI/RHOB, PERM. Refer to gamma ray; neutron/density; permeability, respectively). From Thrana, et al., (2014)
Figure 17. Paleogeographic map of the early Jurassic North seaway during deposition of the Are Formation. Modified from Dore, 1991. From Thrana et al., 2014.
Figure 18

Root Mean Square (RMS) surface attribute maps of Are Formation from 5 msec below coal bed to 25 msec above coal bed. Amplitude anomalies indicating potential of sands and hydrocarbons outlined in red.
Figure 19. RMS surface attribute map 20 msec above coal bed correlated to seismic data
Figure 20. Paleogeographic maps showing possible depositional scenarios for selected intervals. The position of subenvironments is based on well data red dots) and outside the wells the setting is estimated from general conceptual understanding. (A) Paleogeographic map illustrating a possible scenario from the fluvial coastal plain setting of the upper Are 2.1 Sub-zone. (B) Example of a time-slice from the Are 3.1 Sub zone, showing the first brackish water bay development. The rose diagraph shows paleocurrent directions based on available dip data from the entire Are 3 Zone. (C) Interval within the Are 4 Zone dominated by laterally amalgamated wave-reworked bay deposits. (D) Paleogeographic map from the Are 5.2 Sub-zone. This interval corresponds to the first development of significant tide-influenced facies filling an incised system that drained from the NW towards the SE.
**Figure 21.** A) Fine to medium grained fluvial channel sandstone from Are 1 and 2 fluvial dominated reservoir. B) Peat Swamp coal from Are 1 and 2 fluvial dominated reservoir C) Distributary channel from Are 3-5 Marginal-marine reservoir D) Bay margin shoreface from Are 3-5 Marginal-marine reservoir

**Figure 22.** Sum of negative amplitudes surface attribute map of Are Formation from coal bed to 40 msec above coal bed
Figure 23. RMS surface attribute map (using sweetness volume) of Are Formation 30 msec above coalbed. Potential fluvial/deltaic systems outlined in red.

Figure 24. The petroleum system of Well CK#1.
Figure 25. The proposed location of Well CK#1.

Figure 26. The petroleum system of Well CK#2.
Figure 27. The proposed location of Well CK#2.
Figure 28. Top) Sum of negative amplitudes surface attribute maps of Are formation form coal bed to 40 msec above coal bed. Bottom) Proposed Drilling location of Potential Well #1 in Are Formation
Figure 29. Top) Sum of negative amplitudes surface attribute maps of Are formation form coal bed to 40 msec above coal bed. Bottom) Proposed Drilling location of Potential Well #2 in Are Formation
Figure 30. Top) Sum of negative amplitudes surface attribute maps of Are formation form coal bed to 40 msec above coal bed. Bottom) Proposed Drilling location of Potential Well #3 in Are Formation