



**Annual Statement of Reserves and
Resources Year End 2024**

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1. Management's Discussion and Analysis (MD&A)

The reported reserves (Developed and Undeveloped) include remaining volumes expected to be recovered based on reasonable assumptions about future technical, economic, fiscal, and financial conditions based on year end 2024 data. The reported contingent resources are potentially recoverable volumes from known accumulations and includes projects that are being matured in the near term.

BlueNord has used same Reserves Evaluator for the Year End 2024 Reserves and Resources estimation as for 2023. The Reserves Evaluator ERC Equipose Ltd ("ERCE") has carried out an independent evaluation of the hydrocarbon Reserves and certain Contingent Resources held by BlueNord Energy Denmark A/S in the DUC Sole Concession area, offshore Denmark. This report has been prepared to support regulatory reporting and for financing purposes. The effective date of this report is 31 December 2024.

ERCE has carried out this work in accordance with the June 2018 SPE/WPC/AAPG/ SPEE/SEG/SPWLA/EAGE Petroleum Resources Management System ("PRMS") as the standard for classification and reporting.

ERCE's forecasts, dated 1 January 2025, of Brent crude oil and National Balancing Point ("NBP") natural gas prices were used for the evaluation, with a long term oil price of US\$/bbl 75.16, and a long term gas price of 29.34 EUR/MWh. These prices are in 2025 real terms and are subject to annual inflation of 2.0% to determine nominal (money of the day) prices.

Though the after tax NPV10 estimates as of 31 December 2024 form an integral part of fair market value estimations, without consideration for other economic criteria they are not to be construed as ERCE's opinion of fair market value. There is no assurance that the forecast production and cost profiles contained in this report will be attained and variances could be material. The recovery and estimates of the company's oil and natural gas resources are estimates only and there is no guarantee that the estimate will be recovered. Actual volumes recovered may be greater than or less than the estimates stated in this report. Further, a significant change in commodity prices may also impact the reserves and lead to reduction or extension of the currently estimated lifetime of the fields.

17.03.2025



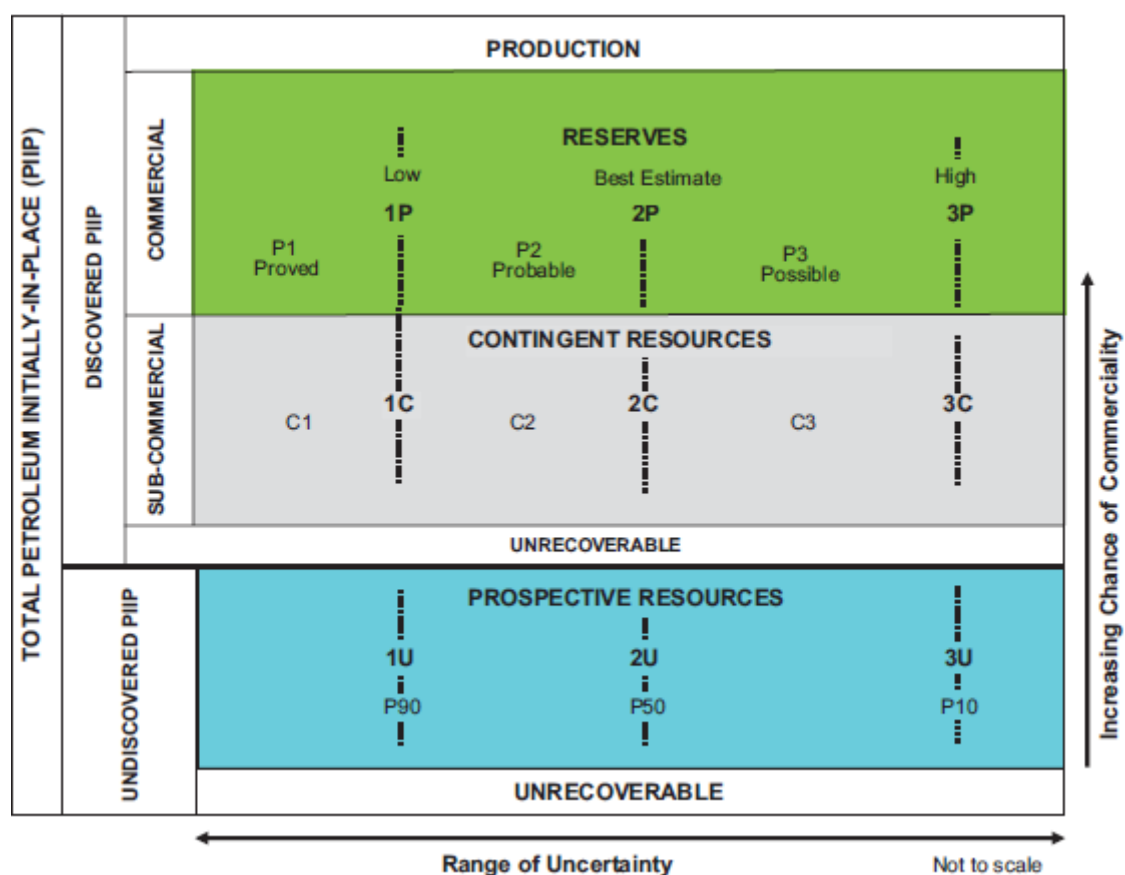
Miriam Jager Lykke

Chief Operating Officer

➤ 2. Reserves and Contingent Resources Classification

ERC Equipoise Ltd ("ERCE") has carried out an independent evaluation of the hydrocarbon Reserves and certain Contingent Resources held by BlueNord Energy Denmark A/S in the Sole Concession area, offshore Denmark. The Reserves are reported on a field gross, Company working interest and Company net entitlement basis as of 31 December 2024. Under PRMS it is the Company net entitlement that should be reported as the entity's Reserves. Both Developed and Undeveloped Reserves are reported for each hub and by product type. Gas Reserves are based on sales volumes and exclude fuel and flare. Oil equivalent Reserves are reported based on an energy equivalent conversion of the gas Reserves using a conversion of 5,200 scf per barrel of oil equivalent ("boe"). ERCE has carried out this work in accordance with the June 2018 SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE Petroleum Resources Management System ("PRMS") as the standard for classification and reporting.

Figure 1–PRMS Resources classification framework



This report provides an overview of Developed Reserves (on production) along with two projects in the sub-class Approved for Development, three projects in the sub-class Justified for Development that have not yet been sanctioned, and six projects in Contingent Resources. The latter are only a subset of the full portfolio of development projects in the Contingent Resource class. No assessment has been made of prospective resources (in accordance with the classification table above).

The Danish Underground Consortium (DUC) is a joint venture with three partners:

TotalEnergies	43.2% equity (Operator)
BlueNord	36.8% equity, except for Lulita where the equity is 28.4%
Nordsøfonden	20.0% equity (State participation, fully paying)

The DUC portfolio of assets comprises four main infrastructure and production hubs, i.e. Dan, Halfdan, Gorm and Tyra, each of which serves as a host platform for several satellite fields. Each hub produces its own power and has at least one accommodation platform. The fields are generally mature, the oldest being the Dan field which came on production in 1972. Dan, Halfdan and Gorm are oil dominated producing assets and the Tyra Hub, including satellites, are gas dominated producing assets.

The DUC license extension was granted on 29 September 2003 by the Danish Minister for Economic and Business Affairs for the period 1st January 2004 and up to 8 July 2042.

The Tyra II project was sanctioned in December 2017 because of seabed subsidence of the Tyra West and Tyra East platforms that posed a risk for the platform integrity under severe weather conditions. Consequently, Tyra and the associated satellite fields were closed-in at the end of Q3 2019. After redevelopment, production from the Tyra II facilities commenced in the first quarter of 2024 marked by first gas from Tyra received at the Danish Nybro facility on 28 March. Incidents with the transformers for the IP and LP compressors impacted the planned ramp-up and production of hydrocarbons from Tyra and the associated satellites. The repaired transformers were in place and installed by late October and on 10 November 2024, full technical capacity on the Tyra II facilities was reached, and production ramp-up commenced. In the interim period, production was enabled from the Harald field. The ramp-up has been impacted by unstable weather conditions and minor operational occurrences resulting in the production ramp up to continue during Q1 2025. By the start-up of production from the Tyra hub, the Tyra hub reserves were matured from the sub-class Under Development in YE2023 to On Production in YE2024.

3. Reserves Estimation

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates as Proved (1P), Proved plus Probable (2P) and Proved plus Probable plus Possible (3P).

The Reserves are reported on a field gross, Company working interest and Company net entitlement basis as of 31 December 2024. Under PRMS it is the Company net entitlement that should be reported as the entity's Reserves. Both Developed and Undeveloped Reserves are reported for each hub and by product type. Gas Reserves are based on sales volumes and exclude fuel and flare. Oil equivalent Reserves are reported based on an energy equivalent conversion of the gas Reserves using a conversion of 5,200 scf per barrel of oil equivalent ("boe").

The ERCE estimates of Developed Reserves in producing fields are based on decline curve analysis ("DCA") and a review of historical performance of recent well interventions and activities. Estimates of Undeveloped Reserves are based on hydrocarbon in place and recovery efficiency estimates, analogue type curves, stochastic historic well performance analysis and/or dynamic modelling.

In accordance with the PRMS guidelines, the Cessation of Production ("CoP") date used to estimate Reserves is defined as (a) the end of the last 12 months period that the maximum cumulative operating cash flow occurs; (b) the end of the technical field life; or (c) the end of the license period, whichever occurs soonest.

4. Reserves

The Developed Reserves include the fields on production from the Dan, Halfdan, Gorm and Tyra hubs. The Undeveloped Reserves includes Reserves from three infill wells (two on Halfdan and one on Valdemar) and three other development projects.

Table 1 – BlueNord 1P, 2P and 3P Reserves as of 31.12.2024

		1P				2P				3P
		Gross	Gross	Gross	Net	Gross	Gross	Gross	Net	Net
Reserves		Liquids	Gas	boe	boe	Liquids	Gas	boe	boe	boe
as of 31.12.2024	Interest	MMstb	MMboe	MMboe	MMboe	MMstb	MMboe	MMboe	MMboe	MMboe
On Production										
Dan	36.8%	30.9	3.4	34.3	12.6	52.59	8.0	60.6	22.3	30.3
Kraka	36.8%	4.8	0.1	4.9	1.8	7.99	0.2	8.2	3.0	3.8
Dan Hub		35.7	3.5	39.2	14.4	60.6	8.3	68.9	25.3	34.1
Halfdan	36.8%	39.5	17.0	56.5	20.8	68.4	30.4	98.8	36.4	50.1
Halfdan hub		39.5	17.0	56.5	20.8	68.4	30.4	98.8	36.4	50.1
Gorm	36.8%	5.0	0.0	5.0	1.8	9.0	0.1	9.1	3.3	6.1
Skjold	36.8%	9.7	0.1	9.8	3.6	17.1	0.7	17.8	6.5	11.3
Rolf	36.8%	0.8	0.0	0.8	0.3	1.4	0.1	1.5	0.5	1.0
Gorm hub		15.5	0.2	15.7	5.8	27.5	0.8	28.3	10.4	18.4
Tyra	36.8%	17.2	46.0	63.2	23.3	32.2	85.8	118.0	43.4	65.2
Valdemar	36.8%	23.0	10.6	33.6	12.4	37.4	19.3	56.8	20.9	28.8
Roar	36.8%	3.5	7.8	11.3	4.2	6.8	14.7	21.4	7.9	11.4
Lulita	28.4%	1.2	0.7	1.9	0.6	1.8	1.1	3.0	0.8	1.4
Harald	36.8%	6.2	20.1	26.4	9.7	10.7	30.7	41.3	15.2	24.6
Tyra hub		51.2	85.3	136.4	50.0	88.9	151.6	240.5	88.2	131.4
Total		141.8	105.9	247.8	91.0	245.3	191.1	436.5	160.4	234.0
Under Development										
		-	-	-	-	-	-	-	-	-
Total		-	-	-	-	-	-	-	-	-
Approved for Development and Justified for Development										
Halfdan HCA Gas Lift	36.8%	0.2	5.0	5.3	1.9	0.4	7.9	8.3	3.1	2.6
Halfdan Infill (Ekofisk)	36.8%	3.9	1.8	5.8	2.1	5.5	4.8	10.3	3.8	5.7
Halfdan North (Phase 1)	36.8%	10.0	1.5	11.5	4.2	22.3	3.4	25.7	9.5	14.4
Valdemar UC Infill	36.8%	2.1	1.7	3.7	1.4	3.1	3.1	6.1	2.3	2.8
Adda (Phase 1)	36.8%	7.8	11.8	19.5	7.2	17.6	22.4	40.0	14.7	22.0
Total		24.0	21.8	45.8	16.9	48.9	41.6	90.5	33.3	47.5
On Production plus Under Development										
Total		141.8	105.9	247.8	91.0	245.3	191.1	436.5	160.4	234.0
On Production plus Under Development plus Justified for Development										
Total Reserves		165.8	127.8	293.6	107.9	294.3	232.8	527.0	193.7	281.5

Notes:

- Gross Reserves represent 100% of the Reserves to be recovered from the licence.
- Net Reserves are based on the working interest share of the field gross Reserves. As there are no royalties to be deducted, Net Reserves are equal to Net Entitlement Reserves.
- Barrels of oil equivalent are calculated using a conversion of 5,200 scf/boe.
- Gas Reserves are based on sales volumes and exclude fuel and flare. ERCE has assumed each hub provides its own fuel gas and imports fuel gas if it is fuel gas deficient.
- Halfdan Hub Developed Reserves include the Halfdan WROM I/II programme and the recently drilled infill Well HBA-27B.
- Tyra Hub Developed Reserves include future production from existing wells, including the recently drilled Well HEA-04 in the HEMJ accumulation.
- The Halfdan Infill (Ekofisk) includes two wells (HDA-35 + 31), one well Approved for Development and one Justified for Development.

Table 2 – BlueNord 1P, 2P and 3P Developed Reserves as of 31.12.2024

		1P				2P				3P
		Gross Liquids	Gross Gas	Gross boe	Net boe	Gross Liquids	Gross Gas	Gross boe	Net boe	Net boe
Reserves per hub as of 31.12.2024	Interest	MMbbl	MMboe	MMboe	MMboe	MMbbl	MMboe	MMboe	MMboe	MMboe
Dan	36.8%	30.9	3.4	34.3	12.6	52.6	8.0	60.6	22.3	30.3
Kraka	36.8%	4.8	0.1	4.9	1.8	8.0	0.2	8.2	3.0	3.8
Dan Hub		35.7	3.5	39.2	14.4	60.6	8.3	68.9	25.3	34.1
Halfdan	36.8%	39.5	17.0	56.5	20.8	68.4	30.4	98.8	36.4	50.1
Halfdan hub		39.5	17.0	56.5	20.8	68.4	30.4	98.8	36.4	50.1
Gorm	36.8%	5.0	0.0	5.0	1.8	9.0	0.1	9.1	3.3	6.1
Skjold	36.8%	9.7	0.1	9.8	3.6	17.1	0.7	17.8	6.5	11.3
Rolf	36.8%	0.8	0.0	0.8	0.3	1.4	0.1	1.5	0.5	1.0
Gorm hub		15.5	0.2	15.7	5.8	27.5	0.8	28.3	10.4	18.4
Tyra	36.8%	17.2	46.0	63.2	23.3	32.2	85.8	118.0	43.4	65.2
Valdemar	36.8%	23.0	10.6	33.6	12.4	37.4	19.3	56.8	20.9	28.8
Roar	36.8%	3.5	7.8	11.3	4.2	6.8	14.7	21.4	7.9	11.4
Lulita	28.4%	1.2	0.7	1.9	0.6	1.8	1.1	3.0	0.8	1.4
Harald	36.8%	6.2	20.1	26.4	9.7	10.7	30.7	41.3	15.2	24.6
Tyra hub		51.2	85.3	136.4	50.0	88.9	151.6	240.5	88.2	131.4
Total Reserves		141.8	105.9	247.8	91.0	245.3	191.1	436.5	160.4	234.0

Table 3 – BlueNord 1P, 2P and 3P Reserves Development from 31.12.2023 to 31.12.2024

Reserves, net Units in mmboe	On production			Under Development			Approved/Justified for Develop.			Total		
	1P	2P	3P	1P	2P	3P	1P	2P	3P	1P	2P	3P
YE2023 Reserves	40.4	79.1	112.0	42.9	75.6	111.9	15.7	30.8	49.3	99.0	185.6	273.2
2024 Production	9.2	9.2	9.2	0	0	0	0	0	0	9.2	9.2	9.2
Acquisitions and disposals												
Revisions	9.0	3.0	1.3				0.4	-0.1	-4.0	9.4	2.9	-2.7
Discovery and Extensions	8.0	11.8	17.9							8.0	11.8	17.9
Additions												
Projects Matured	42.9	75.6	111.9	-42.9	-75.6	-111.9	0.7	2.6	2.3	0.7	2.6	2.3
YE2024 Reserves	91.0	160.4	234.0	0.0	0.0	0.0	16.9	33.3	47.5	107.9	193.7	281.5
Delta (YE2024-YE2023)	50.7	81.2	122.0	-42.9	-75.6	-111.9	1.1	2.5	-1.7	8.9	8.1	8.3

Notes

1. The line 'Production2024' is the BlueNord share of sales volumes (in mmboe).

In 2024 the production from the Base Assets, which include the Dan, Gorm, and Halfdan hubs has been excellent, with an average annual operational efficiency of 91%. In addition to the Operator's focus on maintaining the high operational efficiency, several projects and activities have been undertaken during the year with the objective of maximising the production potential of the assets and minimising the natural production decline. The most significant activities are described below:

- Two newly drilled production wells were brought on stream in 2024. The first new well was the Halfdan Tor NE infill well (HBA-27B), with production start in March 2024. Since production start, the well has had stable production with rates within the expected range. The second new well was the Harald East Middle Jurassic (HEMJ) exploration well. This well was drilled in the second half of the year, and the excellent well results, which exceeded pre-drill expectations, allowed the well to be completed and hooked up to the Harald facilities and put on stream 6th of December 2024. The well is drilled into a gas condensate accumulation situated in the Middle Jurassic sandstone.
- Another highlight of the year was the Gas Acceleration Pilot project on the Skjold field (SGPAP) in which water injection was gradually reduced in parts of the field thereby shifting from water injection to depletion drive to increase the gas and oil production. The project was fully implemented in March 2024, and a positive production response has been observed since May. In addition to the increased production, a benefit of the project is reduced fuel gas consumption as the reduced water injection allows for one of the water injection trains on the Gorm platform to be closed in.
- The production potential and integrity of the individual wells is addressed in the well and reservoir optimisation campaign (WROM) which has been ongoing since mid-2022 by use of the rig Noble Reacher. On Dan interventions on more than 40 wells were carried out in 2022 and 2023. Early 2024 the rig moved to the Halfdan reservoir where a total of 21 well interventions were successfully completed. In Q1 of 2025, the Noble Reacher was moved to the Halfdan NorthEast field to install gas lift on 9 HCA wells to extend the production lifetime of these wells.

As mentioned above, full operational capacity for the redeveloped Tyra II facilities was obtained in November 2024, and ramp-up of Tyra production will continue through Q1 2025.

The YE 2024 2P reserves estimation resulted in a 2P reserves replacement of 189% and consist of both upward and downward revisions.

The key drivers of the revision of Reserves on Production which has an overall increase of 90.4 MMboe are relating to the following:

- Production in 2024
- Maturation of existing Tyra and Harald hub wells from Under Development following the successful restart of the Tyra facility (+75.6 MMboe)
- Discovery of HEMJ in 2024 (+11.8 MMboe)
- Technical revisions to production forecasts based on 2024 production performance and other data available since YE2023 (+3.0 MMboe), including:

- Higher than estimated gas production in the Dan field, related to an increasing gas-oil ratio
- Higher than estimated gas production in the Halfdan NE field, related to a lower level of production decline in Halfdan NE gas wells
- Earlier Gorm Hub CoP (2034 vs 2037) related to removal of Well N-43 from the Gorm production forecasts and changes in emissions related costs with inclusion of Danish green tax
- Later Harald Hub CoP (2035 vs 2028) following the discovery of HEMJ

To keep production high in 2025 and beyond, the operator will maintain the high operational efficiency by keeping focus on reducing unplanned shortfalls, maintain the facilities, and carry out re-active and pro-active workovers on Dan and Halfdan wells. In addition, drilling of two Halfdan Ekofisk infill wells is planned for 2025. The production lifetime as well as the operational efficiency of the Halfdan HCA wells will be improved by installation of HCA GL, and the WROM campaign is expected to continue with WROM III targeting the Gorm wells. The Skjold Gas Acceleration project (SGPAP) will continuously be monitored and optimized. Finally, the HEMJ discovery will extend the Tyra production plateau into 2026.

The YE2024 reserves for the **Approved and Justified for Development** has an overall increase of 2.5 MMboe which is driven by the following upward and downward revisions:

- Maturation of the Halfdan North phase 1 development project from Contingent Resources to Justified for Development
- Maturation of the Valdemar UC infill well from Contingent Resources to Justified for Development
- Re-classification of the Valdemar Bo South development as Contingent Resources due to project delay

5. Developed Fields

The DUC assets consist of fourteen developed fields. All fields are situated on the Danish Continental Shelf. The developments consist of four producing hubs: Dan, Gorm, Halfdan and Tyra. Production started from the Dan field in 1972. Oil is exported to shore via an oil pipeline from Gorm and gas is exported both via NOGAT to Netherlands and via Tyra II to shore in Denmark.

5.1 Dan Hub

The Dan hub includes the Dan and Kraka fields.

Dan is an oil field which was discovered in 1971 and brought on production in 1972. The field produces oil and gas from the Ekofisk and Tor chalk reservoir and the production drive mechanisms are gas cap drive/solution gas expansion and waterflooding. Dan is a domal structure, where a major fault separates the NW downthrown A-block from the SE Uptthrown B-block. The West Flank area of the field is located between the Dan A-block and the Halfdan field and was developed at a later stage than the A- and B-blocks.

Initially, the field was developed with vertical and deviated wells and later full field development by horizontal wells. Water injection was tested in 1991 and expanded to full field scale in 1995. A total of approximately 126 wells have been drilled, with currently 40 active oil wells and 31 active water injectors. By end of 2024 the field has produced 764 MMstb of oil and 1,013 Bscf of gas.

Kraka is a tie-back to the Dan field and is an oil field located 8 km to the southeast of the Dan field. The field was brought on production in 1991 and produces oil and gas from the Ekofisk chalk reservoir by a combination of solution gas drive and aquifer support. 10 wells have been drilled and currently 6 oil wells are producing. By end of 2024 the field has produced 42 MMstb of oil and 65 Bscf of gas.

5.2 Halfdan Hub

The Halfdan hub includes the Halfdan Main and the Halfdan North East fields.

Halfdan Main was discovered in 1998 and brought on production in 1999. The field produces oil and gas from the Tor Chalk reservoir by gas cap drive/solution gas expansion and waterflooding. The Halfdan NE field was brought on production in 2000 and produces gas from the Ekofisk Chalk reservoir by depletion drive. The Halfdan Main oil accumulation is contiguous with the Dan accumulation and thins towards SW and NE.

Halfdan Main has been developed in four phases and 71 wells have been drilled, with currently 34 active oil producers and 26 active water injectors. By end of 2024 the field has produced 543 MMstb of oil and 612 Bscf of gas.

Halfdan North East has been developed in three phases and 20 wells have been drilled, with currently 18 active gas producers. By end of 2024 the field has produced 17 MMstb of oil and 822 Bscf of gas.

5.3 Gorm Hub

The Gorm hub includes the Gorm, Skjold and Rolf fields.

The Gorm field was discovered in 1971 and brought on production 1981. The field produces oil and gas from the Ekofisk and Tor Chalk reservoirs. The field is a domal structure divided into a deeper western A-block and the shallower eastern B-block. Ekofisk

is absent across most of the B-block and thickens down flank on the B-block. The production mechanism is dominated by secondary waterflooding. 46 wells have been drilled, with currently 14 active producers and 7 active water injectors. By end of 2024 the field has produced 404 MMstb of oil and 601 Bscf of gas and 305 Bscf gas has been injected (no injection since 2005). Gorm acts further as the oil gathering center and export hub for all DUC fields.

The Skjold field is an oil satellite tie-back to Gorm. It was discovered in 1977 and brought on production in 1982. The field is a dome shaped structure with a relative thin chalk reservoir on the crest, which thickens towards the outer crest and flank areas. The chalk is highly fractured with low matrix permeability and the main drive mechanism is waterflooding. 30 wells have been drilled, with currently 16 active oil producers and 6 active water injectors. By end of 2024 the field has produced 317 MMstb of oil and 163 Bscf of gas.

The Skjold gas acceleration project was implemented in 2024, where water injection has been stopped in part of the field to allow for a partial depletion strategy in the field. To date, the performance of the acceleration project has been in line with expectation, with increased oil and gas production.

Rolf is an oil field, which has been developed as a satellite to Gorm. The field was discovered in 1981 and brought on production in 1985. The field produces from the Ekofisk and Tor Chalk reservoir with intervals of good permeability with fracture connected matrix porosity. The field is four-way dip-closed anticline structure overlying a salt diapir. The production mechanisms are solution gas drive and aquifer support. 3 wells have been drilled, with currently 2 active oil producers. By end of 2024 the field has produced 31 MMstb of oil and 8 Bscf of gas.

5.4 Tyra Hub

The Tyra hub includes the Tyra Main, Tyra South East, Valdemar, Roar, Harald East, Harald West and Lulita fields.

Tyra Main is a gas dominated field discovered in 1968 and Tyra SE is an oil dominated field area discovered in 1991. Tyra Main was brought on production in 1984 and Tyra SE in 2002. The Tyra field lies on an inverted structure on the Valdemar-Tyra-Igor low relief ridge. The field produces mainly from the Ekofisk and Tor Chalk reservoirs. The field was developed during 1984 to 1991 with gas plateau production from 1992 to 2007. One horizontal well has been drilled into the Lower Cretaceous Chalk, Tuxen Fm. The gas in the flank area towards Tyra SE was developed during 1998 to 2008. The recovery mechanism is depletion by gas expansion and rock compaction.

The Tyra East and West did comprise of 11 platforms but due to subsidence, the field has been redeveloped referred to as the Tyra II project. Tyra II project started ramping up wells in Q4 2024. The Tyra II project scope included the replacement of the existing accommodation and processing platforms by one single accommodation and one processing platform. The wellhead jackets have been raised, and topsides replaced. A total of 93 wells have been drilled on Tyra Main and SE. In Tyra Main the plan is to reinstate 31 wells and currently 15 wells have been started up. By end of 2024, the field has produced 173 MMstb and 3,775 Bscf of gas and 1,337 Bscf gas has been injected (no injection since 2012). In the Tyra SE field, the plan is to reinstate 16 wells and currently 6 wells have been started up. By end of 2024, the field has produced 35.5 MMstb of oil and 478 Bscf of gas.

Tyra acts further as the gas gathering center and export hub for all DUC fields. During the Tyra II project, Dan has acted as the temporary host for gas export via a by-pass pipeline connecting Dan F to the Tyra-NOGAT pipeline system to the F/3 in the Netherlands. This setup has been made permanent, which means that there are two gas export routes for DUC one to Denmark and one to the Netherlands.

The Valdemar field is an oil and gas field discovered in 1977 and further appraised in 1985 and brought on production in 1993. The Lower Cretaceous chalk, Tuxen Fm has been the primary development target and horizontal wells have been drilled and completed with sand prop fractures. The field is produced by depletion and rock compaction drive under controlled bottom hole pressure constrained mode. 26 wells have been drilled on Valdemar, with a plan to reinstate 21 oil and gas producers. Currently 6 producers from Valdemar B platform have been re-opened. By end of 2024 the field has produced 89 MMstb of oil and 257 Bscf of gas.

Roar is a gas field with an oil rim tie-back to Tyra East. The field was discovered in 1968 and further appraised in 1981. The field was brought on production in 1996. The field produces gas and condensate from the Ekofisk and Tor Chalk reservoir. The gas column thickens towards South, while the oil rim has been encountered by the wells towards the North. 4 gas producer wells have been drilled, with a plan to reinstate all 4 producers in Q1 2025. By end of 2024 the field has produced 589 Bscf of gas and 18 MMstb of condensate.

Harald is a gas/condensate field located in the Northwestern part of the Danish sector. The Harald field comprises of three accumulations; Harald East discovered in 1980, Harald West discovered in 1983, and Harald East Middle Jurassic (HEMJ) discovered in 2024. The fields were brought on production in 1997. The Harald West and HEMJ reservoirs consists of Middle Jurassic sandstones, and Harald East is an elongated dome structure in the Upper Cretaceous Ekofisk and Tor Fm. The production mechanism is depletion drive. The HEMJ accumulation was discovered in October 2024 by an exploration well which was brought on production in December 2024. In total 5 wells have been drilled, 2 on Harald West, 2 on Harald East, and 1 on HEMJ, and currently 3 out of 5 wells, planned to be reinstated, have been re-opened in 2024. By end of 2024 the field has produced 906 Bscf of gas and 52 MMstb of condensate.

Lulita is an oil field with a gas cap discovered in 1991 which were brought on production in 1998. The field is a NE dipping monocline with a main fault boundary in the west and structural dip closure to the SE. The reservoir consists of Middle Jurassic sandstones. The production mechanism is aquifer encroachment, gas cap drive and solution gas expansion. 2 wells have been drilled, however only 1 is planned to be reinstated in 2025. By end of 2024 the field has produced 7.4 MMstb of oil and 28 Bscf of gas. DUC holds a 50% interest in the Lulita field with Ineos (40%) and BlueNord (10%) as partners.

6. Development Projects - Reserves

The development projects include reserves classified as Undeveloped Reserves approved for Development as well as Undeveloped Reserves Justified for Development.

6.1 Halfdan HCA Gas Lift Project

The Halfdan HCA platform hosts ten naturally flowing gas wells. Due to natural depletion, the gas rates are declining, and wells have experienced liquid loading problems. This will be mitigated by making gas lift available to nine of the wells to lift liquids, enabling continued steady production from the wells and reduce their technical rate limits. The HCA gas lift project is approved and is expected to become operational in July 2025. The project will convert an 8-inch condensate export line to import gas-lift gas from the HBB platform with the HCA 16-inch gas export line converted to a multi-phase pipeline. The project is assigned Undeveloped Reserves.

6.2 Halfdan Ekofisk infill wells

The Halfdan Ekofisk Main opportunity targets oil and gas above Halfdan Main Tor development. The Ekofisk Main development potential was confirmed by the drilling of HBB-04 in 2017 and HBB-05 in 2019, respectively. There are plans to drill two Ekofisk infill wells in the Halfdan field starting production in November 2025 and April 2026. The well locations will be optimised based on the results and interpretation of the 2023 4D seismic survey. The two wells are considered firm and have been assigned Undeveloped Reserves. The request for approval covering the first Ekofisk infill wells was provided by the Operator in May 2024 and subsequently approved by the DUC Partners in June. FID for the second Ekofisk infill well has not yet been taken at the date of evaluation.

6.3 Halfdan North Phase 1

The Halfdan North discovery comprises the undeveloped area between the Halfdan Main and Tyra SE fields. An FDP was submitted in 2020 which proposes the discovery is developed with a 12-slot unmanned wellhead platform tied back to the HBD platform in the Halfdan field. A joint call-for-tender ("CFT") was issued in October 2024 for the Tyra North (Adda) and Halfdan North development projects with bids expected to be received in Q1 2025. An FID is currently scheduled in Q2 2025 and first oil in Q1 2028.

The Halfdan North development is planned to be carried out in two phases. Phase 1 comprises three oil producers and two water injectors targeting the central area of the discovery. Phase 2 comprises a further two oil producers and two water injectors targeting the flank areas of the discovery. Based on the maturity of the development, ERCE has classified Phase 1 of the development as Reserves. Phase 2 is contingent on the performance of Phase 1 and as such is classified as Contingent Resources.

6.4 Valdemar UC Infill

An infill well is planned in the Valdemar field targeting the Upper Cretaceous reservoir in an undrilled location between the North Jens and Bo areas. The well will be drilled from an available slot on the VAB platform.

In 2024 the Operator carried out environmental screening, an integrated conceptual study and prepared basis of design documentation, detailed well planning and a site survey (relief well). The FID is expected to take place in Q2 2025 and first oil is scheduled for Q3 2027.

6.5 Tyra North (Adda) Phase 1

The Tyra North (Adda) discovery is located ~12 km northeast of the Tyra East facility. It was discovered in 1977 and appraised by a further five wells between 1981 and 1997. Tyra North is a four-way dip-closed anticline structure created by salt tectonics and has a series of east-west trending faults across the field. Gas is contained in the Tuxen Formation and oil is contained in the overlying Hod Formation. The proposed development project includes a greenfield normally unmanned well head platform with 8 slots and a 4-leg jacket with a fully rated pipeline back to Tyra East E platform. The development includes seven wells drilled and tied back to the platform. The project will have three phases:

- Phase 1: Crest development, 4 Tuxen wells + 1 Hod well;
- Phase 2: Flank development, 2 Tuxen wells;
- Phase 3: Potential for additional Hod well or Tuxen flank well (excluded from ERCE's assessment).

The well design is similar to existing wells in the Valdemar field. The field will be produced under natural depletion (with gaslift) and drawdown limits imposed based on the geomechanical stability of the reservoir rock. The production mechanisms in the Tuxen are compaction and gas expansion, and for the Hod this is compaction drive and solution gas drive.

Four well tests have been carried out in the Tuxen reservoir with gas rates observed between 2.5–20.0 MMscf/d. Well tests and PVT analysis has determined the reservoir pressure to be very close to the dew point pressure of the gas-condensate. Two well tests have been carried out in the Hod reservoir with oil rates observed between 4,100–6,270 stb/d.

A draft FDP was submitted to the DEA in 2021 and the final FDP was submitted in April 2024 and is awaiting approval. The discovery will be developed by a normally unmanned 8-slot wellhead platform tied back to the Tyra East E platform via a 10" multiphase pipeline. Phase 1 of the development includes four horizontal production wells in the Tuxen reservoir and one horizontal production well in the Hod reservoir. The current expectation is for first gas in Q2 2028. Based on the maturity of the development, ERCE has classified Phase 1 of the development as Reserves. Phase 2 is contingent on the performance of Phase 1 and as such is classified as Contingent Resources.

7. Contingent Resources

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorised in accordance with the level of certainty associated with the estimates as 1C, 2C and 3C.

In addition to quantities that are classified by ERCE as Reserves, the assets include quantities that have been classified by ERCE as Contingent Resources. ERCE's estimates of Contingent Resources are based on an independent evaluation of data provided by BlueNord. Estimates are based on decline curve analysis in conjunction with volumetric methods and reviews of reports such as field development plans.

No economic analysis has been performed on the Contingent Resources and, therefore, their economic status is undetermined.

Table 4 – BlueNord 1C, 2C and 3C contingent resources as of 31.12.2024

Contingent Resources as of 31.12.2024		1C				2C				3C
		Gross Liquids MMstb	Gross Gas MMboe	Gross boe MMboe	Net boe MMboe	Gross Liquids MMstb	Gross Gas MMboe	Gross boe MMboe	Net boe MMboe	Net boe MMboe
Gorm WROM III	36.8%	2.0	0.2	2.3	0.8	3.3	0.4	3.6	1.3	2.1
Halfdan Tor NE Infill	36.8%	0.7	0.5	1.2	0.4	1.4	1.0	2.4	0.9	1.3
Halfdan North Phase 2	36.8%	6.4	1.0	7.4	2.7	11.9	1.8	13.7	5.1	7.9
Adda Phase 2	36.8%	1.6	5.7	7.3	2.7	3.4	10.5	14.0	5.1	8.9
Valdemar Bo South	36.8%	10.3	5.5	15.7	5.8	18.5	10.0	28.5	10.5	17.4
Svend Re-development	36.8%	5.3	0.8	6.1	2.2	11.4	1.7	13.1	4.8	7.4
Total		26.3	13.6	39.9	14.7	49.9	25.3	75.3	27.7	45.0

Notes:

1. Gross Contingent Resources represent 100% of the Contingent Resources of the project.
2. Net Contingent Resources are based on BlueNord's working interest share (36.80%) of the Gross Contingent Resources.
3. Contingent Resources are based on wellhead volumes prior to any shrinkage or additional recovery of liquids during processing.
4. These are unrisks Contingent Resources that have not been risked for chance of development.
5. There is no certainty that it will be economically viable to produce some, or any, of the Contingent Resources.
6. The total Contingent Resources presented are based on aggregating individual projects with different levels of risk and as such should be used with caution.

The six projects: Gorm WROM III, Halfdan Tor NE Infill, Halfdan North Phase 2, Tyra North (Adda), Valdemar Bo South and Svend Reinstatement are classified by ERCE as Contingent Resources. These projects are expected to be the next projects to be matured as reserves and are only a subset of the full portfolio of projects in DUC.

8. Projects – Contingent Resources

8.1 Gorm WROM III

A WROM campaign (“WROM III”) in the Gorm field has been included in the 2025 budget, although a FID is pending. The main goal of the campaign will be to reinstate production from a number of closed in wells by clean out, perforation and straddle installations.

ERCE has reviewed the information provided regarding 13 notional targets presented by the Operator in November 2024. The activities include: reinstatement of seven oil producers, optimisations in four oil producers, and optimisations in two water injectors. The Gorm WROM III has been assigned Contingent Resources and sub-classified as Development Pending.

8.2 Halfdan Tor North East infill wells

Within the Halfdan field an infill well (Well HBA-27B) was drilled during 2023 targeting the Tor reservoir. Original plans were to immediately follow this with a second infill well (Well HBA-15B). However, due to the poorer than expected results of Well HBA-27B, the resource estimates and commerciality of the second well are now being reassessed and the well is contingent on the performance of Well HBA-27B and evaluation of the 4D seismic acquired in 2023 in the Dan-Halfdan area. The well is classified as Contingent Resources in the sub-class Development Pending.

8.3 Halfdan North Phase 2

The Halfdan North Phase 2 consists of four additional wells (2 producers and 2 water injectors) targeting the flank area of Halfdan North.

The Contingent Resources are sub-classified as Development On Hold based on the timeframe to potential development. Production from Phase 1 of the Halfdan North development is scheduled in Q2 2028, meaning any Phase 2 development would likely occur in late 2028 or 2029.

8.4 Tyra North (Adda) Phase 2

The Tyra North (Adda) Phase 2 project consists of two additional horizontal gas production wells located in the north/northeastern area of the Tuxen reservoir in the Adda discovery. The wells are contingent on the results of Phase 1 of the Tyra North development but are also located in a more structurally and stratigraphically complex area of the discovery which poses drilling risks.

The Contingent Resources are sub-classified as Development On Hold based on the timeframe to potential development. Production from Phase 1 of the development is scheduled in Q2 2028, meaning any Phase 2 development would likely occur in late 2028 or 2029.

8.5 Valdemar Bo South

The Valdemar Bo South (VBS) development targets oil from the Tuxen reservoir in the undeveloped area located south of the Valdemar BA platform. The Tuxen reservoir is part of the Lower Cretaceous (LC) hydrocarbon pool of the greater Valdemar Field. The reservoir in the development area is appraised by wells JUDE-1X, the distal part of VBA-06E and BO-3X. All wells confirmed oil-bearing Tuxen Fm reservoir.

The Valdemar Bo South FDP was submitted in 2020 and the proposed development includes five horizontal production wells drilled from a normally unmanned 6-slot wellhead platform. The platform will be tied back to the existing VCA platform via a 2.5 km 12” multiphase pipeline.

In connection with the unplugging of the Tyra and satellite wells during 2024, new information became available including long pressure build-up from the closed in Valdemar wells, which had been closed in since 2019. The depletion in the Valdemar Bo area, requires further investigations which is planned to be included in the final update of the Field Development Plan.

After finalising the FEED covering Tyra North in the third quarter of 2024, prioritization was given to combine the Tyra North with the Halfdan North Development, instead of the Valdemar Bo South project. Therefore, the Valdemar Bo South Project has been reclassified to contingent resources, sub-class, Development On Hold.

8.6 Svend Re-development

The Svend field is located 20 km south of the Harald field and was on production from 1996 to 2015, when it was shut-in due to well integrity issues. The wells have been abandoned, and the unmanned wellhead platform has been left in "lighthouse mode" ahead of a potential re-development of the field with two new infill wells.

The Svend re-development project involves drilling two infill wells (one in the north and one in the south) and upgrading the facilities to reinstate production. A solution to address flow assurance issues by the conceptual studies will be defined following the results of the successful discovery of the Harald East Mid-Jurassic..

The Contingent Resources are sub-classified as Development Unclassified based on the need for further conceptual studies.

9. Prospective Resources

No prospective resources have been included in this report.