Registration Document

OKEA ASA

Important notice

This Registration Document prepared according to Regulation (EU) 2017/1129, is valid for a period of up to 12 months following its approval by the Financial Supervisory Authority of Norway (the "Norwegian FSA") (Finanstilsynet). This Registration Document was approved by the Norwegian FSA on 07.03.2024. The prospectus for issuance of new bonds or other securities may for a period of up to 12 months from the date of the approval consist of this Registration Document, a securities note and a summary if applicable to each issue and subject to a separate approval.

This Registration Document is based on sources such as annual reports and publicly available information and forward looking information based on current expectations, estimates and projections about global economic conditions, the economic conditions of the regions and industries that are major markets for the Company line of business.

A prospective investor should consider carefully the factors set forth in chapter 1 - *Risk factors* -, and elsewhere in the Prospectus, and should consult his or her own expert advisers as to the suitability of an investment in bonds, including any legal requirements, exchange control regulations and tax consequences within the country of residence and domicile for the acquisition, holding and disposal of bonds relevant to such prospective investor.

The manager and/or affiliated companies and/or officers, directors and employees may be a market maker or hold a position in any instrument or related instrument discussed in this Registration Document and may perform or seek to perform financial advisory or banking services related to such instruments. The managers corporate finance department may act as manager or co-manager for this Company in private and/or public placement and/or resale not publicly available or commonly known. Copies of this Registration Document are not being mailed or otherwise distributed or sent in or into or made available in the United States. Persons receiving this document (including custodians, nominees and trustees) must not distribute or send such documents or any related documents in or into the United States.

Other than in compliance with applicable United States securities laws, no solicitations are being made or will be made, directly or indirectly, in the United States. Securities will not be registered under the United States Securities Act of 1933 and may not be offered or sold in the United States absent registration or an applicable exemption from registration requirements.

The distribution of the Registration Document may be limited by law also in other jurisdictions, for example in Canada, Japan, Australia and in the United Kingdom. Verification and approval of the Registration Document by the Norwegian FSA implies that the Registration Document may be used in any EEA country. No other measures have been taken to obtain authorisation to distribute the Registration Document in any jurisdiction where such action is required, and any information contained herein or in any other sales document relating to bonds does not constitute an offer or solicitation by anyone in any jurisdiction in which such offer or solicitation is not lawful or in which the person making such offer or solicitation is not qualified to do so or to anyone to whom it is unlawful to make such offer or solicitation.

The content of the Prospectus does not constitute legal, financial or tax advice and potential investors should seek legal, financial and/or tax advice.

Unless otherwise stated, the Prospectus is subject to Norwegian law. In the event of any dispute regarding the Prospectus, Norwegian law will apply.

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1. Risk factors

Investing in bonds involves inherent risks, and a number of risk factors may adversely affect the Issuer. Prospective investors should carefully consider, among other things, the risk factors set out in this Registration Document before making an investment decision.

A prospective investor should carefully consider all the risks related to the Issuer and should consult his or her own expert advisors as to the suitability of an investment in the Bonds. An investment in the Bonds entails significant risks and is suitable only for investors who understand the risk factors associated with this type of investment and who can afford a loss of all or part of the investment. Against this background, an investor should thus make a careful assessment of the Issuer, its creditworthiness and its prospects before deciding to invest.

The Issuer believes that the factors described below represent the principal risks inherent in investing in the Bonds, but the Issuer may be unable to pay interest, principal or other amounts on or in connecting with the Bonds for other reasons which may not be considered significant risks by the Issuer based on information currently available to it or which it may not currently be able to anticipate. The risks within each category are listed, in the view of the Issuer, according to the possible negative impact they may have and the probability of their occurrence. The greatest risk within each category is generally mentioned first. It applies for all risk factors that, if materialized, and depending on the circumstances, may have an adverse effect on the Issuer and which may reduce anticipated revenue and profitability, ultimately resulting in a potential insolvency situation.

RISKS RELATED TO THE BUSINESS OF THE ISSUER AND THE INDUSTRY IN WHICH THE ISSUER OPERATES

Highly volatile oil and gas prices

The Issuer's revenues, cash flow, reserve estimates, profitability and rate of growth depend substantially on prevailing international and local prices of oil and gas. Prices for oil and gas are volatile and may fluctuate substantially based on factors beyond the Issuer's control. The recent changes in the geopolitical situation in Europe and Middle East has contributed to increased risk of volatility in oil and gas prices because of changes in demand for oil and gas. In recent history this risk materialised for the industry and the Issuer as a consequence of the international lock-down due to the Covid-19 virus which resulted in a significant drop in oil and gas prices. Consequently, it is impossible to accurately predict future oil and gas price movements. Cash flow and profitability predictions may therefore prove to be lower than expected. Sustained lower oil and gas prices or price declines may in addition lead to a material decrease in the Issuer's net production revenues and may result in material adverse effects for the Issuer, including material impact on the Issuer's financial liquidity as well as on the Issuer's ability to fulfil its obligations, make new investments and raise further financing. Furthermore, sustained lower oil and gas prices may also cause the Issuer to make substantial downward adjustments to its oil and gas reserves. If this occurs, or the Issuer's estimates of production or economic factors change, the Issuer may be required to write-down the carrying value of its proved oil and gas properties for impairments. Further, certain development projects which are or become of substantial importance to the Issuer could become unprofitable as a result of a decline in price and could result in the Issuer having to postpone or cancel a planned project, or if it is not possible to cancel the project, carry out the project with negative economic impact. Additionally, if oil and gas prices remain depressed over time, it could reduce the Issuer's ability to raise new debt or equity financing or to refinance any outstanding loans on terms satisfactory, or at all. The Issuer may from time to time enter into hedging arrangements in the form of derivative financial instruments and fixed price contracts to offset the risk of revenue losses if commodity prices decline. However, such arrangements may be expensive and there can be no assurance that hedging will be available or continue to be available on commercially reasonable terms. In addition, hedging itself carries certain risks, including expenses associated with terminating any hedging agreements.

Reserves and resources are by their nature uncertain in respect of the inferred volume range

At the end of each financial year the Issuer prepares an Annual Statement of Reserves verified by a third-party. Volumes are management estimates based on analysis of available geophysical and well data relevant to the undrilled prospects, combined with regional geological understanding. Further, with respect to contingent resources, the amount of investment needed may make the conversion of resources into reserves not commercially viable. Many of the factors in respect of which assumptions are made when estimating reserves and resources are beyond the Issuer's control and therefore these assumptions may prove to be incorrect over time. Moreover, different geoscientists and reservoir engineers may make different estimates of reserves and cash flows based on the same available data. Actual production, revenues and expenditures with respect to reserves and resources will vary from estimates, and the variances may be material. Also, effects of regulations adopted by governmental agencies, future operating costs, royalties, petroleum tax regulations, development costs and work-over and remedial costs represent further variables and assumptions which will further influence the estimation of reserves and resources. If the assumptions upon which the estimates of the Issuer's oil and gas reserves or resources are based prove to be incorrect, the Issuer may be unable to recover and/or produce the estimated levels or quality of oil or gas. The value of each asset is tested each quarter (or when impairment triggers are present), which may result in impairments in the event of adverse developments in the individual assets' outlooks. Assets held at fair value are particularly sensitive to changes in assumptions/performance. If the Issuer is unable to recover and/or produce the estimated levels or quality of oil or gas, this could have a material adverse effect on the Issuer's business, prospects, financial condition or results of operations.

Production is concentrated in a limited number of offshore fields

Currently, the Issuer's portfolio consists of mid- to late-life assets and the production comes from the Draugen, Brage, Gjøa, Yme, Ivar Aasen, Nova and Statfjord Area fields. If mechanical or technical problems, extreme weather events, shutdowns or other events or problems affect the current or future production on any of these fields, it may have a direct and significant impact on a substantial portion of the Issuer's production or if the actual reserves associated with any one of the Issuer's fields are less than anticipated, this may result in material adverse effects for the Issuer, including on the Issuer's ability to fulfil its obligations, make new investments and raise further financing. In particular, the facilities on the Draugen, Brage, Gjøa and Statfjord Area fields have been producing for several years, increasing the risks related to production and subsequent sensitive cash flow, loosing key wells, infrastructure robustness with regards to corrosion, technical integrity of critical equipment and aging equipment and systems. Upgrades and maintenances to maintain and enhance production may imply increased risks and costs of development or production.

Extending lifetime of producing fields

The Issuer is continuously pursuing the possibility to produce more from its fields. This is likely to extend the producing period beyond the fields' initial contemplated lifetime and may require an extension of term of the relevant Production Licence. Production from the Issuer's fields is contingent upon valid Production Licences. The Production Licences are not automatically extended. There is a risk that the Norwegian state may not approve such extension or impose new conditions or new or amended terms pursuant to the relevant Production Licences. A successful extension of the production may also be subject to the successful implementation of new technical solutions on the fields and their facilities and will be subject to the reservoir having the required features. Extending the lifetime of producing fields will be subject to new and possibly significant investments. These investments will be sanctioned by the relevant Production Licences and based upon economic assumptions at the time of the decision. The Issuer cannot guarantee that the Production Licences will sanction projects that the Issuer is basing its long-term plans on, and thus that such plans will actually be executed. This is in particular relevant for the Draugen field, as the licence period expires in March 2024 and although the Issuer has submitted the application for its extension, there can be no assurance that extension will be approved. Should the extension application not be approved, the Issuer will no longer have a valid Production Licence for the field beyond March 2024, and the field will subsequently be subject to decommissioning. In addition to the above, there can be no assurance

that the Issuer's infill wells and other life extension initiatives will prove successful, and there is therefore an inherent risk that such investments may not be profitable.

Future business dependent on locating, acquiring, developing and producing oil and gas reserves that are economically recoverable

The future success of the Issuer depends, in part, on its ability to find and develop and/or acquire additional reserves that are economically recoverable. Oil and gas exploration and development and production activities are capital intensive and have inherently uncertain outcomes. Significant expenditure is required to establish oil and gas reserves through seismic and other surveys and also exploration and appraisal drilling, and there can be no certainty that further commercial quantities of oil and gas will be discovered or acquired by the Issuer. The Issuer's existing and future oil and gas appraisal and exploration projects may therefore become unprofitable, either from dry wells or from wells that are productive but do not produce sufficient net revenues to return a profit after development, operating and other costs. Not every prospect that is explored will ultimately be developed into producing oil and gas fields. Even if the Issuer discovers or acquires oil and gas resources in the future, there can be no assurance that these will be commercially developed. Completion of a well does not guarantee a profit on the investment or recovery of the costs associated with that well. Developing a discovered hydrocarbon field requires significant investment, which may be made over several years and decades, to build the requisite operating facilities, drilling of production wells along with implementation of advanced technologies for the extraction and exploitation of hydrocarbons with complex properties.

Additionally, the cost of operations and production from successful wells may be materially adversely affected by unusual or unexpected geological conditions or formation pressures, oceanographic conditions, hazardous weather conditions, delays in obtaining governmental approvals or consents, difficulties arising from environmental requirements and other factors. An inability of the Issuer to recover its costs and generate profits from its exploration and production activities may have a material adverse effect on its business, cash flow and financial condition. Producing oil and natural gas reservoirs, particularly in the case of mature fields, are generally characterised by declining production rates that vary depending on reservoir characteristics and other factors. Thus, the Issuer's future oil and natural gas reserves and production, and therefore its cash flow and results of operations, are highly dependent upon the Issuer's ability to predict this decline, to efficiently develop and exploit its current oil and gas assets and find or acquire additional economically attractive recoverable reserves. The Issuer may not be able to develop, find or acquire additional reserves to replace the Issuer's current and future production at acceptable costs. If the Issuer is unable to replace its current and future production its business, financial condition and results of operations will be adversely affected.

Development and exploration projects risk

Exploration and development projects involve complex engineering, procurement, construction work, drilling operations and obtaining of governmental approvals prior to commencement of production. The exploration or development period of an oil and gas asset is commonly associated with high risk, requiring high levels of capital expenditure without a commensurate degree of certainty of a return on the investment. The complexity of offshore development projects also makes them very sensitive to delays and cost increases. Current or future projected target dates for production may be delayed and significant cost overruns may occur. The consequences of a delay could be substantial. For example, it may not be possible to maintain planned drilling schedules, which could result in wells taking considerably longer than forecasted with cost over-runs as a result. The Issuer's estimated exploration and development costs are in general subject to a number of assumptions that may not materialize. Such factors may again impact on the extent to which the fields to be developed are fully funded or remain commercially viable and consequently may result in breach by the Issuer of its obligations and require the Issuer to raise additional debt or equity or result in cancellation of a planned project, or if it is not possible to cancel the project, carry out the project with negative economic impact. The Issuer's hydrocarbon production may be restricted, delayed or terminated due to a number of internal or external factors, among which are malfunctions of hydrocarbon discharge

or production facilities, administrative delays (particularly in the approval of development projects by public authorities), shortages or delays in the availability of drilling and/or production rigs and delivery of equipment and materials, pressure or irregularities in geological formations, equipment failures or accidents or adverse weather conditions or malicious actions. These factors may have a material adverse effect on the Issuer's cash flow as well as on its business, prospects, financial condition or results of operations.

Operations highly dependent on approval in Production Licenses

Operational decisions are made by all the participants in the Production Licences requiring a requisite majority vote. The licensees' decision to drill any scheduled or budgeted wells will depend on a range of factors, many of which are outside the Issuer's control. The Issuer will, as the operator of certain Production Licences, at the relevant time, identify and budget for drilling prospects, it will require the approval of all or a requisite majority of the participants of those Production Licences. Other decisions may also be required to be adopted in order to progress exploration and development, such as e.g. approval of a Plan for Development and Operation, secure continued production or initiate and complete abandonment.

In Production Licences where the Issuer is not the operator of fields in which it has an interest, it has limited control over the management of the assets and mismanagement by the operator or disagreements with the operator as to the most appropriate course of action that may occur. This may result in significant delays, losses or increased costs to the Issuer. There is a risk that partners with interests in the Issuer's Production Licences may not be able to fund or may elect not to participate in, or consent to, certain activities relating to those Production Licences. In these circumstances, it may not be possible for such activities to be undertaken by the Issuer alone or in conjunction with other participants. Decisions by the other partners to engage in certain activities may also be contrary to the Issuer's position not to commence such activities and may require the Issuer to incur its share of costs in relation to those, or the other partners may enforce decisions which will delay or affect the profitability of a project. This is an especially inherent risk in fields under development where the Issuer only holds a minority interest, such as the Draugen power from shore project. Other participants in the Issuer's Production Licences may default on their funding obligations, which may require the Issuer to contribute all or part of such funding shortfall. The Issuer may not have the resources to meet these obligations. Further, the Production Licence partners are jointly and severally responsible to the Norwegian government for financial obligations arising out of petroleum activities pursuant to a Production Licence. If any of the Issuer's partners become insolvent or otherwise unable to pay debts as they fall due, the Production Licence interest awarded to them may be revoked by the relevant government authority who will then reallocate the Production Licence interest. There can be no assurance that the Issuer will be able to continue operations pursuant to these reclaimed Production Licences or that any transition related to the reallocation of the Production Licence would not materially disrupt the Issuer's operations.

Risk of non-compliance with obligations under Production Licences, joint operating agreements and field development plans

All Production Licences for the Norwegian Continental Shelf include obligations amongst the parties in the joint venture and obligations between the Production Licence and the authorities. Failure to comply with the obligations under the Production Licences may lead to fines, penalties, restrictions, and ultimately revocation of Production Licences and termination of related agreements. A failure to comply with payment obligations (cash calls) under joint operating agreements (and unitisation agreements) for the Issuer's Production Licences, may lead to loss of voting rights and information within the Production Licence, late payment interest on the defaulted amount, and after 3 months a right for the other licensees to acquire the Issuer's participating interest at book value which may deviate from the real value of the Production Licence. Further, if other licensees default on their payment obligations (cash calls), the Issuer may have to increase its interest level (pro rata) in the relevant field, which in turn will result in a corresponding increase in the Issuer's exposure and investment obligations in the relevant field. Also, the Issuer has been approved as an operator on the Norwegian Continental Shelf. Although future operatorship is performed based on a "no gain, no

loss" principle, the Issuer's Production Licence licensees have audit rights and other rights if the operator has acted with gross negligence or wilful misconduct. All such risks, non-compliance, sanctions or losses could have a material adverse effect on the Issuer and may result in the Issuer not being fully funded to meet such increased exposure and obligations and may consequently result in a breach by the Issuer of its obligations and require the Issuer to raise additional debt or equity.

Infrastructure and transportation risk

The Issuer is dependent on capacity (whether through pipelines, tankers or otherwise) to transport and sell its oil and gas production. The Issuer, or the Production Licence group in which the Issuer holds an interest may need to rely on access to third-party infrastructure to be able to transport produced oil and gas. There can be no assurance that the Issuer will be able to secure access to necessary infrastructure at an economically justifiable cost or access necessary infrastructure at all. Capacity restraints may also follow from downtime due to maintenance work or technical issues which on occasions has led to capacity reductions. The Issuer's assets are mainly mid- to late-life assets, which increases the level of maintenance required, and increases the risk of technical issues. If access to third-party infrastructure and necessary capacity bookings are unavailable or unavailable at an economically justifiable cost, the Issuer's income relating to the sale of oil and gas may be reduced which may have a material adverse effect on the Issuer. Further, constraints in the gas transportation infrastructure used by the Issuer may negatively impact the operation of the Issuer's assets and associated production.

Risks related to decommissioning activities and related costs

There are significant uncertainties relating to the estimated liabilities, costs and time for decommissioning of the current and future facilities and infrastructure on the fields covering the Production Licences in which the Issuer is, has been or will be a participating interest holder. Such liabilities are derived from legislative and regulatory requirements and require the Issuer to make provisions for such liabilities. The Issuer is jointly and severally liable with its Production Licence partners to the Norwegian government for all decommissioning costs and liabilities of each Production Licence in which the Issuer holds an interest. In Norway, there is no obligation or tradition for Production Licence partners to provide security for their respective share of decommissioning liabilities ahead of actual decommissioning. Furthermore, a participating interest holder assigning its interest in a Production Licence remains secondarily liable for decommissioning costs related to facilities existing at the time of assignment. For such secondary liability there is an established practice for providing a decommissioning guarantee or other security. It is therefore difficult to forecast accurately the costs that the Issuer will incur in satisfying decommissioning liabilities. No assurance can be provided that the anticipated cost and timing of removal are correct and any deviation from current estimates or significant increases in decommissioning costs relating to the Issuer's previous, current or future Production Licences may have a material adverse effect on the Issuer.

Limitations to sell or transfer Production Licence

The Issuer's exit in relation to any particular oil and gas interest may be subject to the prior approval from the relevant authorities, pre-emption rights to the state-controlled entity Petoro AS, and the approval of partners and/or third parties under commercial agreements associated with the oil and gas assets. The aforementioned may thus restrict the Issuer's ability to dispose of, sell or transfer a Production Licence interest and make funds available when needed. Future oil and gas interest acquired by the Issuer may also, subject to the specific terms and conditions applicable, be subject to pre-emption rights in favour of the Issuer's partners.

Environmental risk

All phases of oil and gas activities present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions and national regulations as well as applicable health and safety regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills and releases or emissions of various substances. The legislation also requires that wells and facility sites are operated, maintained and abandoned to the

satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and breach may result in the imposition of fines and penalties in addition to loss of reputation. Any pollution may give rise to significant civil liability claims, significant fines as well as criminal sanctions, and may require the Issuer to incur material costs to remedy such discharge. Any changes to, and increases in, current regulation or legal requirements and their enforcement may have a material adverse effect upon the Issuer in terms of additional compliance costs. Unfavourable amendments to current laws, regulations and permits governing operations and activities of development and/or production companies, or more stringent implementation of these, may have a materially adverse impact on the Issuer and no assurance can be provided that current or future environmental laws and regulations will not result in a curtailment or shut down of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Issuer. Any of these circumstances could adversely affect the operation of the Issuer's Production Licences and result in loss of revenues or increased costs and adversely affect the Issuer's profitability.

Political and regulatory risks

The oil and gas industry is subject to extensive government policies, standards, regulations and requirements. No assurance can be given that future political conditions, existing legislation, new interpretation of existing legislation or changes in administrative practice or policies, including in the tax and fiscal regime, will not result in a reduction of income, curtailment of production, delays or a material increase in operating costs and capital expenditure or otherwise adversely affect the Issuer. A failure to comply with applicable legislation, regulations and conditions or orders issued by the regulatory authorities may lead to fines, penalties, restrictions, withdrawal of Production Licences and termination of related agreements. Additionally, the Issuer is dependent on receipt of discretionary government approvals, decisions and permits to develop and produce its assets. Further, the Issuer may be unable to obtain, renew or extend required drilling rights, Production Licences, permits and other authorisations and these may also be suspended, terminated or revoked prior to their expiration. The formal licence period for the Draugen field expires in March 2024 and the Issuer has submitted the application for its extension in line with regulatory requirements and applicable deadlines. The relevant authorities may also stipulate conditions for any such extension or for not revoking any Production Licences or permits. Lack of governmental approvals or permits or delays in receiving such approval may delay the Issuer's operations, increase its costs and liabilities or affect the status of its contractual arrangements or its ability to meet its contractual obligations.

The Issuer's operations related to mid- to late-life production are associated with high emissions of "greenhouse gases" which faces a continuously increase of laws, policies and regulations to mitigate the impact of fossil fuels, and may result in substantial capital, compliance, operational and maintenance costs. Continued political attention to concerns on climate change, the role of human activity in it and potential mitigation through regulation could have a material impact on the Issuer's business.

Insurance risk

The Issuer's offshore oil and gas operations are subject to all the significant risks and hazards typically associated with such operations. The Issuer may not be fully insured against all risks it may face and not all risks are insurable or only insurable at a disproportionately high cost. The nature of the hazards and risks typical for the Issuer's industry is such that liabilities could materially exceed policy limits or not be insured at all, which may result in substantial financial liability or losses. Payment by the Issuer's insurers of any insurance claims may result in increases in the premiums payable by the Issuer for its insurance cover and adversely affect the Issuer's financial performance. In the future, some or all of the Issuer's insurance coverage may become unavailable or prohibitively expensive. Further, any uninsured loss or liabilities, or any loss and liability exceeding the insured limits, may have a material adverse effect on the Issuer.

Labour risk – strikes etc.

The Issuer is exposed to risks related to work stoppages, strikes or other labour disturbances. A large proportion of the Issuer's employees, and those employed by the Issuer's contractors, are represented by labour unions. If a work stoppage or other labour disturbance occurs, the Issuer or its contractors may not be able to negotiate acceptable collective bargaining agreements or future restructuring agreements or may become subject to cost increases or additional work rules imposed by such agreements. As the Issuer's current production is concentrated in a limited number of offshore fields, a work stoppage may affect all or a material part of the Issuer's producing fields, resulting in a significant decrease in the Issuer's revenues. The occurrence of any of the foregoing could materially and adversely affect the Issuer's business, prospects, financial condition and results of operations.

Risks related to cybercrime

Due to its reliance on digital solutions and interfaces, the Issuer is exposed to risk of cybercrime in the form of, for example, Trojan attacks, phishing and denial of service attacks. The Issuer is a potential target for cyber-crime in particular due to the Issuer operating within the energy sector. The nature of cybercrime is continually evolving, in particular as a result of the current geopolitical situation and specifically the conflict between Russia and Ukraine. The Issuer relies in part on commercially available systems, software, tools and monitoring to provide security for processing, transmission and storage of confidential information. Despite the security measures in place, the Issuer's facilities and systems, and those of its third-party service providers, may be vulnerable to cyberattacks, security breaches, acts of vandalism, computer viruses, misplaced or lost data, programming or human errors which exposes the Issuer for cybercrime and/or other similar events. If one or more of such events occur, any one of them could potentially jeopardise confidential and other information related to the Issuer, its customers and its counterparties and may also cause disruption (downtime) in the Issuer's production and cause increased production costs. Any security breach involving the misappropriation, loss or other unauthorised disclosure of confidential information, whether by the Issuer or its vendors, could damage the Issuer's reputation, expose it to risk of litigation, increased capital requirements or sanctions from the Norwegian Financial Supervisory Authority, disrupt its operations or affect the Issuer negatively in other ways, hereunder that the Issuer may also be required to spend significant additional resources to modify its protective measures or to investigate and remediate vulnerabilities or other exposures. This could in turn have a material adverse effect on the Issuer's business, results of operations, financial position and/or prospects.

The Issuer may incur substantial debt in the future

The Issuer may incur substantial indebtedness in the future, either under the bond terms for the Bonds, by increasing the SSRCF, pari passu secured debt, unsecured debt or as subordinated debt. The issuer may, subject to strategic and/or marked conditions, further incur substantial indebtedness in the course of its operation and/or M&A activities, including Deferred Claims. Currently, the Issuer's only outstanding bond is the Bonds, which matures in 2026. Under any circumstance, if the Issuer incurs new debt or other obligations, the related risks that it faces, as listed below, will increase. In addition, the Issuer is currently under and may in the future incur obligations that do not constitute indebtedness as defined under the agreements governing the debt arrangements. As such obligations may not fall within the definition of Total Debt, the Issuer may incur debt or obligations which are not subject to the financial covenants in the bond terms. This entails that the Issuer may, at its discretion, incur substantial liabilities which are not restricted by the financial covenants in the bond terms. Such incurrence of liabilities will influence the degree to which the Issuer is leveraged, which could have important consequences to the Issuer's business and holders of the Bonds, including, but not limited to: (i) making it difficult for the Issuer to satisfy the Issuer's obligations with respect to the Bonds or other indebtedness; (ii) increasing the Issuer's vulnerability to, and reducing its flexibility to respond to, general adverse economic and industry conditions; (iii) requiring the dedication of a substantial portion of the Issuer's cash flow from operations to the repayment of the principal of its indebtedness and interest on such indebtedness, thereby reducing the availability of such cash flow; (iv) limiting the Issuer's ability to obtain additional financing to fund working capital, capital investments, acquisitions, debt service requirements, business ventures, or other general corporate

purposes; (v) limiting the Issuer's flexibility in planning for, or reacting to, changes in its business and the competitive environment and the industry in which the Issuer does business; and (vi) adversely affecting the Issuer's competitive position if its debt burden is higher than that of its competitors.

The Issuer is subject to restrictive debt covenants

The terms of the Bonds will restrict, among other things, the Issuer's ability to: (i) incur additional debt and issue guarantees; (ii) make certain payments, including dividends and other distributions, with respect to outstanding share capital; (iii) repay or redeem subordinated debt or share capital; (iv) create or incur certain liens and security arrangements; (v) make certain investments or loans; (vi) sell, lease or transfer assets; (vii) acquire assets or companies; (viii) expand into unrelated businesses; and (ix) merge or consolidate with other entities.

All of these limitations are subject to significant exceptions and qualifications. The Issuer's compliance with these covenants could reduce its flexibility in conducting its operations, particularly by: (i) affecting the Issuer's ability to react to changes in market conditions, whether by increasing its vulnerability in relation to unfavorable economic conditions or by preventing the Issuer from profiting from an improvement in those conditions; (ii) affecting the Issuer's ability to pursue business opportunities and activities that may be in its interest; (iii) limiting the Issuer's ability to obtain certain additional financing in order to meet its working capital requirements, make investments or acquisitions and carry out refinancings; and (iv) forcing the Issuer to dedicate a significant portion of its cash flows to payment of the sums due for such loans, thus reducing its ability to utilize its cash flows for other purposes.

2. Persons responsible

PERSONS RESPONSIBLE FOR THE INFORMATION

Persons responsible for the information given in the Registration Document are as follows:

OKEA ASA,
Kongens gate 8
7011 Trondheim,
Norway.

DECLARATION BY PERSONS RESPONSIBLE

OKEA ASA confirms that, to the best of its knowledge, the information contained in the Registration Document is in accordance with the facts and that the Registration Document makes no omission likely to affect its import.

07.03.2024

OKEA ASA

COMPETENT AUTHORITY APPROVAL

This Registration Document, drawn up as part of a simplified prospectus in accordance with Article 14 of Regulation (EU) 2017/1129, has been approved by the Financial Supervisory Authority of Norway (the "Norwegian FSA") (Finanstilsynet), as competent authority under Regulation (EU) 2017/1129. The Norwegian FSA only approves this Registration Document as meeting the standards of completeness, comprehensibility and consistency imposed by Regulation (EU) 2017/1129. Such approval should not be considered as an endorsement of the issuer that is the subject of this Registration Document.

3. Definitions

APA	-	Awards in Pre-defined Areas
Boe	-	Barrel of oil equivalent.
Boed	-	Barrels of Oil Equivalent Per Day.
CO_2	-	Carbon dioxide
Company / Issuer / OKEA	-	OKEA ASA, a company existing under the laws of Norway with registration number 915 419 062 and LEI code 549300H385IGBB58CN91.
EEA	-	The European Economic Area
EU	-	European Union
IOR	-	Improved Oil Recovery
Mmboe	-	Million Barrels of Oil Equivalent
M&A	-	Mergers and Acquisitions
NCS	-	Norwegian Continental Shelf
PDO	-	Plan for Development and Operation
PIO	-	Plan for installation and operation
PRMS	-	Petroleum Resources Management System
Production Licence / PL	-	The term "Production Licence" means a Norwegian licence (*Nw.: Utvinningstillatelse*) for the exploration and production of hydrocarbons on the Norwegian Continental Shelf.
Prospectus	-	The Registration Document together with the Securities Note and the Summary.
Registration Document	-	This registration document dated 07.03.2024.
Securities Note	-	Document to be prepared for each new issue of bonds under the Prospectus.
SPE	-	Society of Petroleum Engineer
Summary	-	Document to be prepared for each new issue of bonds under the Prospectus.
UK	-	United Kingdom.
UKCS	-	The UK Continental Shelf.

WI	-	Working Interest

4. Statutory auditors

The Company's independent auditor is PricewaterhouseCoopers AS ("PwC"), with business registration number 987 009 713, and registered address at Dronning Eufemias gate 71, 0194 Oslo, Norway.

PwC is a member of Den Norske Revisorforeningen (The Norwegian Institute of Public Accountants).

PwC has been the Company's auditor since the financial year 2015.

5. Information about the Company

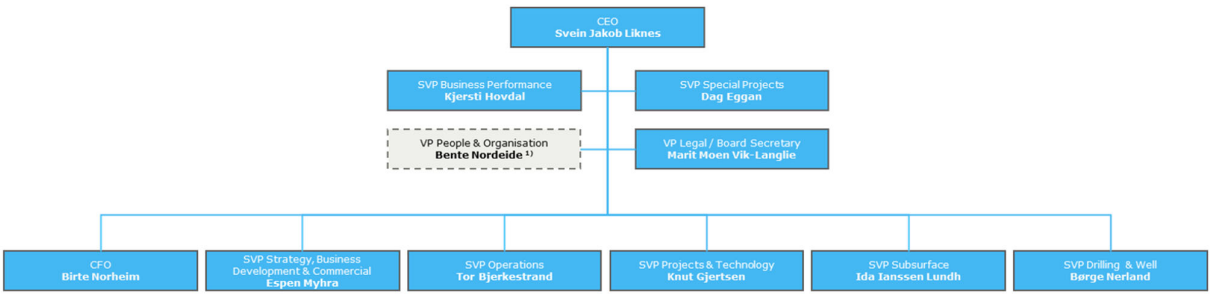
OKEA ASA is a public limited liability company incorporated and domiciled in Norway and existing under the laws of Norway pursuant to the Norwegian Companies Act, the Norwegian Petroleum Act and the Petroleum Taxation Act. The Company was incorporated in Norway on 29 April 2015, and the organisation number in the Norwegian Register of Business Enterprises is 915 419 062 and LEI code 549300H385IGBB58CN91. The Company's registered name is OKEA ASA and the commercial name is OKEA. OKEA's registered office is in the municipality of Trondheim, located at Kongens gate 8, 7011 Trondheim, Norway and the Company's main telephone number at this address is +47 73 52 52 22. Website: www.okea.no[1].

OKEA is a mid to late-life operator on the Norwegian Continental Shelf (NCS). OKEA finds value where others divest and has an ambitious growth strategy built on accretive M&A activities, value creation and capital discipline.

Pursuant to section 3 of the Articles of Association, the objective of the Company "*is petroleum-related activities on the Norwegian continental shelf, including the development and production of oil and gas, and all other business activities as are associated with the above objectives, and share subscription or participation by other means in such operations alone or in cooperation with others*."

The Company does not have any subsidiaries and is not a part of a group at the date of this Registration Document. OKEA has its head office in Trondheim, with major operations centres in Kristiansund and Bergen and offices in Stavanger and Oslo.

As part of the Company's strategy, OKEA targets to maintain a clear, credible, and consistent approach to ESG. ESG concerns are embedded in all business and operational activities, as a key element of the licence to operate. Comprehensive ESG reporting is key to realising and communicating the ESG ambitions, activities, and performance. The Company's 2022 ESG report is available on https://www.okea.no/investor/reports/.



1) Reporting directly to CEO on organizational/cultural matters. Functional reporting to SVP Business Performance.

[1] *Disclaimer - the information on the website does not form part of this Registration Document unless information is incorporated by reference into the Registration Document*

6. The Norwegian Continental Shelf and Regulatory framework

THE NORWEGIAN CONTINENTAL SHELF[2]

The Company's only business segment is development and production of oil and gas on the "NCS. Oil and gas have been produced on the NCS since 1971. Since then oil and gas have been produced from a total of 123 fields on the NCS. At the end of 2023, 92 fields were in production: 67 in the North Sea, 23 in the Norwegian Sea and two in the Barents Sea. Four new field started production in 2023. A further fifteen new fields were under development at the end of the year.

A field is one or several discoveries combined which the licensees have decided to develop, and for which the authorities have approved a plan for development and operation (PDO) or granted a PDO exemption.

Many of the producing fields are ageing, but some of them still have substantial remaining reserves. Moreover, the resource base in these fields increases when small discoveries in the area are tied into existing infrastructure.

A production licence gives a company or a group of companies a monopoly to perform investigations, exploration drilling and recovery of petroleum deposits within the geographical area stated in the licence. The licensees become owners of the petroleum that is produced. A production licence may cover one or more blocks or parts of blocks and regulates the rights and obligations of the participant companies with respect to the authorities.

Production licences are awarded by the Ministry of Energy in numbered licensing rounds, or by yearly awards in predefined areas (APA). Transfer of a production licence or of a share of a production licence must be approved by the Ministry.

A production licence is normally awarded to a group of companies headed by a designated operator. Including several companies in one licence enables less experienced companies to learn from those with more experience, and the different companies can control the operator's activities and together ensure that the best possible decisions are made.

At the end of 2023, a total of approximately 27 companies were active on the NCS, of which around 20 were operators. The diversity of companies of all sizes promotes competition and efficiency. It also ensures interest in different types of projects, and implementation of different kinds of new and cost-effective technologies.

THE PETROLEUM ACT AND THE LICENSING SYSTEM[3]

Norway has established extensive legislation that requires companies to obtain licences and approval from the competent authorities for all phases of petroleum activities.

The Petroleum Act (Act of 29 November 1996 No. 72 relating to petroleum activities) provides the general legal basis for sound resource management, including the licensing system that gives companies rights to engage in petroleum operations. The Act establishes that the Norwegian state has the proprietary right to subsea petroleum deposits on the NCS.

[2] *Source: www.norskpetroleum.no/en/facts*

[3] *https://www.norskpetroleum.no/en/framework/the-petroleum-act-and-the-licensing-system/*

- These sites are operated in cooperation by the Ministry of Energy and the Norwegian Offshore Directorate. Where information has been sourced from a third party the information has been accurately reproduced and that as far as the Company is aware and is able to ascertain from information published by that third party, no facts have been omitted which would render the reproduced information inaccurate or misleading.

Requirements for new players on the Norwegian Continental Shelf[4]
The Norwegian authorities facilitate the establishment of new players on the shelf, since this could contribute to increased value creation.

As a result of this, the general requirement for new players is that they must be able to use their technical petroleum expertise to provide independent contributions to this value creation. At the same time, it is also important that new players possess HSE expertise which helps bolster safety on the shelf.

Players on the Norwegian shelf must have a minimum of expertise in all relevant disciplines in order to be able to analyse, understand and follow up activities in the production licences. The players must have sufficient dedicated capacity and expertise to safeguard their obligations in relation to requirements in the petroleum regulations. An organisation consisting of a minimum of 8-9 people with technical and HSE expertise will therefore be necessary.

Beyond this minimum expertise, players should possess cutting-edge expertise within relevant disciplines in order to contribute to value creation. New players are expected to be able to contribute their own technical assessments which challenge and complement the other licensees.

The player must also be able to document its ability to service financial obligations. Among other things, this means that the player must have a solid foundation of equity, as well as a reasonable ratio between equity and debt. Certain players may also be required to present a plan for financial obligations for their first years of activity on the Norwegian Continental Shelf. Requirements for the player's financial situation must be viewed in relation to the tasks the player has taken upon itself. The financial capacity assessment will be of a more general nature, while at the same time, it may be relevant to set more concrete financial requirements for the player in connection with concrete applications for transfers or awards.

Players seeking an operator role will be subject to more extensive requirements than is the case for other licensees. Operators themselves must have sufficient resources and personnel to manage and implement all activities pursuant to prevailing relevant regulations. In the HSE area, the regulations contain requirements for players seeking to become a licensee, including an operator.

The final evaluation as to whether a pre-qualified player is qualified to be a licensee or operator is made in connection with a concrete application for an ownership interest/operatorship, which will also take into account operational and specific aspects associated with the production licence.

At the date of this Registration Document, OKEA has all necessary concessions and legal, economic and environmental conditions in place.

The life cycle - From area opening procedures to the end of production
Petroleum activities can be divided into several phases. An area must be opened for petroleum activities before any operations are permitted. The first phase is exploration, when any subsea petroleum resources are mapped and proved. If commercially viable discoveries are made, activities enter a new phase with the aim of developing the field and producing from it, at the same time ensuring sound resource management and maximising value creation. When it is no longer possible to produce profitably from a field, operations must be closed down and the installations disposed of (made safe in place or removed).

[4] https://www.sodir.no/en/facts/production-licences/pre-qualification/requirements-for-new-players-on-the-norwegian-continental-shelf/ - *This site is operated by the Norwegian Offshore Directorate. Where information has been sourced from a third party the information has been accurately reproduced and that as far as the Company is aware and is able to ascertain from information published by that third party, no facts have been omitted which would render the reproduced information inaccurate or misleading.*

Opening new areas for petroleum activities
Before licences can be awarded for petroleum activities, the area where activities are planned must have been officially opened. As part of this process, the Ministry of Energy is required to carry out an impact assessment including an evaluation of the possible economic, social and environmental impacts of the activities. During an opening process, the authorities ensure that they have an overview of all relevant arguments for and against petroleum activities in the area in question.

In addition, the general public and the parties affected are given an opportunity to put forward their views. A resource assessment of the area is also made as part of the opening process. Decisions on whether or not to open new areas for petroleum activities are made by Stortinget (Norwegian parliament). Impact assessments and opening of new areas are governed by Chapter 3 of the Petroleum Act and Chapter 2a of the Petroleum Regulations.

Award of production licences
A production licence grants exclusive rights to exploration, exploration drilling and production of petroleum in the area covered by the licence. It also regulates other rights and duties of the licensees vis-à-vis the Norwegian state. Production licences supplement the provisions of the legislation and set out detailed conditions for activities in a particular area. Licensees become the owners of a share of the oil and gas produced proportional to their share of the ownership. An example of a standard production licence with appendices is available on the website of the Ministry of Energy.

Production licences are normally awarded through licensing rounds, in which the Ministry announces that companies can apply for production licences in certain geographical areas (blocks). The announcement procedures, which can apply, the content of applications and application procedures are governed by Chapter 3 of the Petroleum Act and Chapter 3 of the Petroleum Regulations. The Norwegian Offshore Directorate has drawn up detailed guidelines for applications in addition.

On the basis of the applications received, production licences are awarded to groups of companies. Awards are made on the basis of fair, objective and non-discriminatory criteria that are announced in advance.

In each case, the Ministry designates an operator for the joint venture, and this company is responsible for the operational activities authorised by the licence. The licensee group finances the activities jointly. Each licensee is expected to make use of its own particular expertise, and all the licensees have a responsibility for controlling the operator’s activities.

Licensing rounds
Two types of licensing rounds have been established to ensure adequate exploration of both mature and frontier areas of the NCS. All areas that are open and therefore available for petroleum activities may be announced in numbered licensing rounds or through the system of awards in predefined areas (APA). The parts of the NCS to be included in each of the two types of rounds are determined on the basis of expert assessments of the maturity of different areas, particularly in relation to the need for stepwise exploration and utilisation of time-critical resources.

The main differences between numbered licensing rounds and APA rounds are in the stages before licensing rounds are announced; after this stage, the procedures and award process are very similar.

Numbered licensing rounds in frontier areas
Numbered licensing rounds are used for frontier areas, where there is limited knowledge of the geology, greater technical challenges than in mature areas and a lack of infrastructure.

The strategy for licensing rounds in recently opened and frontier areas has generally been based on the principle of step by step or sequential exploration. This means that the results gained from exploration wells drilled in selected blocks in an area should be available before any new blocks are

announced in the same area. In this way, it is possible to map large areas with a relatively small number of wells.

Before a numbered licensing round is announced, there is a nomination process. This starts when all the oil companies on the NCS, both existing licensees and prequalified companies, are asked to nominate blocks for inclusion in the licensing round.

There is a limit on the number of blocks companies can nominate, and they are asked to give grounds for their selections based on their own geological assessments. The Norwegian Offshore Directorate reviews all the nominations it receives and makes its own geological assessment.

Next, the Directorate sends its recommendations for the blocks to be included in the licensing round to the Ministry of Energy. In the 20th licensing round, the Directorate's recommendations were for the first time submitted to public consultation, and this has become normal procedure in subsequent licensing rounds. The Government makes the final decision on which blocks are to be announced, including any special environmental and fisheries-related requirements for petroleum activities.

After the applications have been received, they are assessed in relation to criteria announced in advance and negotiations are held with the companies. The Government decides which licences to award to which companies, and the final awards are formally made by the King in Council.

Numbered licensing rounds have been held since 1965, and are normally announced every other year.

Awards in predefined areas (APA) in mature areas
APA licensing rounds are used for mature areas, where petroleum activities have been in progress for many years. In such areas the geology is well known, there are fewer technical challenges, and there is well developed or planned infrastructure.

As new areas mature, the APA areas can be expanded within the framework for petroleum activities in each sea area. The areas of the NCS where most is known about the geology are included on the basis of expert assessments. No acreage is withdrawn from the APA areas, although exceptions can be made if important new information becomes available.

There is no nomination step in APA rounds. Before a round is announced, the Petroleum Directorate sends its recommendations on the inclusion of any new blocks in the APA areas, based on expert assessments, to the Ministry of Energy. The final proposal for APA areas to be announced in the licensing round is submitted to public consultation.

As in numbered licensing rounds, the Government makes the final decision on which blocks are to be announced, including any special environmental and fisheries-related requirements for petroleum activities. Companies can apply for licences for all acreage in APA areas not already covered by production licences.

After the applications have been received, they are assessed in relation to criteria announced in advance and negotiations are held with the companies. Which licences to be offered is thereafter decided by the Government and the final awards are made by the King in Council.

The APA system was introduced in 2003 to ensure that profitable resources in mature areas are proven and recovered before existing infrastructure is shut down. If this is not done, profitable resources may remain unrecovered because the deposits are too small to justify the building of separate infrastructure. 21 APA licensing rounds have so far been initiated (APA 2003-2023).

APA licensing rounds are announced annually.

OKEA's primary strategy is to participate in relevant APA licencing rounds, in particular in cases where potential in relinquished discoveries or in prospects near existing discoveries or fields are identified. OKEA may from time to time also participate in numbered licencing rounds, if opportunities are considered to have a strategic value and substantial value creation potential.

The exploration phase
Once awarded, a production licence applies for an initial period of up to ten years, which is reserved for exploration activity. To ensure that the area to which the production licence applies is explored properly, the licensee group is obliged under the terms of the licence to carry out a work programme. The obligatory work commitment of the production licence may include geological and/or geophysical activities and exploration drilling. The licence includes deadlines for carrying out the different activities.

Commencement of exploration drilling requires an application for consent prepared by the operator, which must include environmental risk and preparedness assessment, discharge permit as well as baseline surveys. There may also be environmental requirements and/or restrictions for drilling activities during spawning and breeding periods in the relevant drilling area.

If all the licensees agree, they may relinquish the production licence once they have completed the obligatory work. Areas relinquished in this way can later be awarded to new licensee groups. This ensures that mapping of the petroleum resources in different parts of the NCS is steadily improved. As a result, there is now extensive knowledge of the subsea resources in many areas.

The development and operation phase
If the licensees make a discovery and wish to continue work under the licence after they have fulfilled their work obligation, they are entitled to an extension period for the licence. The duration of the extension period is determined by the Ministry of Energy when the licence is awarded, and in most cases is 30 years.

Field development and operation take place during the extension period. If the licensees wish to develop a field, they are obliged to do this in a responsible way. The companies are responsible for planning and implementing development projects, but each project requires prior approval from the Ministry. Major and/or important projects are put before the Storting (norwegian parliament) before the Ministry gives its approval.

The licensees must submit a plan for development and operation (PDO) of a new deposit to the Ministry as a basis for approval. If the project includes pipelines or onshore terminals, a separate plan for installation and operation (PIO) of these must also be submitted and approved.

A PDO/PIO consists of a development plan and an impact assessment. The latter provides an overview of the likely impacts of the project on the environment, fisheries and society otherwise. A PDO/PIO shall include qualitative stress testing against financial climate risk in that the development's break-even price is compared with various scenarios for oil and gas price paths that are compatible with the targets in the Paris Agreement, including the 1.5 degree target.[5] The report on the impact assessment is sent to all those who may be affected by the project so that they have an opportunity to put forward their views. The process ensures that all relevant arguments for and against the project are known before a decision on development is taken, that the field developments approved are responsible, and that their impacts on other public interests are acceptable. In special cases, the Ministry may exempt licensees from the requirement to submit a PDO/PIO.

[5] https://www.sodir.no/globalassets/1-sodir/fakta/utvinningstillatelser/konsesjonsrunder-nor/tfo-2023/miljoe-hms-og-fiskerivilkaar.pdf
- This site is operated by the Norwegian Offshore Directorate. Where information has been sourced from a third party the information has been accurately reproduced and that as far as the Company is aware and is able to ascertain from information pub-lished by that third party, no facts have been omitted which would render the reproduced information inaccurate or misleading.

The Ministry of Energy has together with the Ministry of Labour and Social Inclusion drawn up guidelines for PDOs and PIOs, which explain the legislation further and detail what the authorities expect from developers. The guidelines are also available on the Norwegian Offshore Directorate's website.

The development and operation phase is further regulated by Chapter 4 of the Petroleum Act and Chapter 4 of the Petroleum Regulations.

Cessation of petroleum activities - Requirement to submit a decommissioning plan
The Petroleum Act requires licensees to submit a decommissioning plan to the Ministry between two and five years before the production licence expires or is relinquished, or use of a petroleum installation will be terminated permanently. A decommissioning plan consists of two parts: an impact assessment and plans for disposing of the installations.

The impact assessment must provide an overview of the possible environmental and other impacts of the shut-down process. The disposal part must contain detailed plans for closing down operations and decommissioning installations in the best possible way.

Cessation of petroleum activities and decommissioning are governed by Chapter 5 of the Petroleum Act and Chapter 6 of the Petroleum Regulations. In addition, Norway is bound by international law and guidelines. In this context, Decision 98/3 under the OSPAR Convention is particularly important to the Norwegian authorities. The decision generally prohibits leaving disused offshore installations in place, with limited exceptions.

Health, safety and environment and prevention of pollution
The actors in the Norwegian petroleum industry are highly professional and take a very cautious approach, and there is broad-based tripartite cooperation between employers, trade unions and the state. The Government's ambition is for Norway's petroleum industry to be a world leader in health, safety and environment work. The legislation that has been adopted sets strict requirements as regards the responsibilities of individual enterprises for risk identification, risk reduction, preparedness and response. Management of major accident risk is required to be an integral part of petroleum activities.

The authorities and the parties in the industry have together developed a tool for measuring trends in risk levels in Norwegian petroleum activities, known as RNNP. The Norwegian Offshore Directorate publishes annual reports that give a picture of risk trends in the industry as a whole.

Liability for pollution damage is governed by Chapter 7 of the Petroleum Act, which states that licensees are strictly liable for pollution damage, i.e., they are liable regardless of fault. Chapters 9 and 10 of the Petroleum Act and regulations under the Act govern safety requirements for the industry.

THE PETROLEUM TAX SYSTEM[6]
General
The Norwegian Petroleum Tax system consists of a special petroleum tax and the ordinary corporate tax, with a combined marginal tax rate of 78%. The petroleum tax system was subject to a major revision effective from Jan. 1, 2022, where the special tax was changed to a cash flow type of tax. This was done in order to have more neutral tax system.

The petroleum taxation system is based on the rules set out in the Petroleum Taxation Act (Act of 13 June 1975 No. 35 relating to the taxation of subsea petroleum deposits).

6 https://www.norskpetroleum.no/en/economy/petroleum-tax/ - This site is run in cooperation by the Ministry of Energy and the Norwegian Offshore Directorate. Where information has been sourced from a third party the information has been accurately reproduced and that as far as the Company is aware and is able to ascertain from information published by that third party, no facts have been omitted which would render the reproduced information inaccurate or misleading.

The current special tax rate is 71.8% while the corporate tax rate is 22%. However, under the new cash flow tax system, a calculated corporate tax is deductible for special tax purposes. Thus, the combined marginal tax rate is maintained at a level of 78% (0.22 + (1-0.22) x 0.71,8 = 0.78), as it has been for many years.

As a part of the revision of the petroleum tax system, the previous investment uplift allowance for special tax was abolished. However, there are transitional rules that will give certain qualifying fields continued uplift for investments through the year of planned production start. This will be the situation for fields filed for Government approval before Jan. 1, 2023 and approved by the Government within Jan. 1, 2024. The uplift is currently 12.4% of yearly capex for the relevant fields, and the uplift allowance is deductible for special tax purposes.

Another important element of the revised petroleum tax system is that all tax losses (corporate as well as special tax) per year end 2021, was refunded as a part of the tax assessment for FY 2022 (paid out in December of 2023).

The petroleum tax system is a net income based system, but the tax calculations are different for special tax and corporate tax, as will be covered below.

Norm price
In order to avoid difficult transfer pricing issues, the taxable income from sold crude oil is set by a government body (Norm Price Board) on a daily basis for each field, The price is used as the tax price irrespective of the actual sales price. In order to limit the tax risk most companies use norm price as the contractual sales price. Gas and condensate are not subject to the norm price system.

Tax consolidation between fields
The Norwegian petroleum tax system has no ring fence between different fields and licenses owned by the same legal entity.

License transactions
Direct and indirect license transactions shall be done on an after-tax basis, I.e., the consideration is tax free for the seller and not deductible for the buyer. Various settlements between effective date (normally 1 January in the year of transaction) and completion follow the ordinary petroleum tax rules.

There are relative detailed regulations for tax treatment of license transfers, and in addition the Ministry of Finance is given give authority to deviate from the normal tax rules.

Since a seller will continue to have a secondary liability for decommissioning costs, how to secure seller through buyer guarantees or other methods is often an important part of the transactions and may also raise various tax issues.

Special petroleum tax
As mentioned above the special petroleum tax is a cash flow type of tax where all opex (including such as environmental taxes and a calculated corporate tax) is expensed, and also all capex for offshore facilities are directly expensed. Onshore facilities such as control centres, office buildings, power plants etc., are subject to the ordinary onshore depreciation rules. Decommissioning costs are expense when actually incurred. As mentioned above certain qualifying fields/projects will have a continued uplift.

Special Tax losses will be refunded with its tax value (71.8%), with a payout in December following the income year. Such refunds may also be mortgaged.

Financial type of costs and income are (with some very limited exceptions for some minor financial costs) not subject to special tax.

Corporate tax
Corporate tax (22%) related to the offshore activity will generally follow the GTA rules to set the net taxable income, but with a 6-year straight line depreciation. There are no refunds for corporate tax losses, but an unlimited carry forward without any interest adjustment. Corporate tax losses may not be transferred if the tax loss is the key asset.

A company may also have some income from ordinary onshore activity, and some examples are financial items and gains and losses from price hedging. While losses from financial items may be transferred to the 22% offshore tax basis, only 50% of other losses (such as price hedging) may be transferred to the offshore corporate tax basis.

Calculation of petroleum tax:

Ordinary corporate tax	Special tax
Operating income (norm prices for oil)	Operating income (norm prices for oil)
- Operating expenses	- Operating expenses
- Linear deprecation for investments (6 years)	- Deprecation for investments (100%)
- Exploration expenses, R&D and decom.	- Exploration expenses, R&D and decom.
- Environmental taxes and area fees	- Environmental taxes and area fees
- Net financial costs	- Calculated ordinary tax
- (Loss carry forward)	- Uplift allowance for certain qualifying projects
= Corporation tax base (22%)	**= Special tax base (71.8%)**

Tax payments
Tax payments are made in 6 bi-monthly instalments, starting in August of the income year and until June in the following year. The instalment tax is based on each company's forecast made in June of the income year and may be adjusted for the last 3 instalments when the actual numbers are known. The tax authorities will make the tax assessment around October in the year following the income year, and a balancing settlement will be made in December.

7. Business overview

OKEA is a mid-to late-life operator on the NCS. The Company has a strong asset portfolio including the Draugen and Brage fields, both operated by OKEA, as well as partner positions in Statfjord, Gjøa, Nova, Ivar Aasen and Yme. OKEA also has activities in projects under development, including the Draugen power from shore and continuous drilling of new infill targets at Brage. In addition, OKEA holds interests in discoveries, such as Hamlet, Calypso and Brasse, which are in process of evaluation for development as well as a portfolio of exploration licences with planned and possible activities in the future.

STRATEGY

OKEA has a clear ambition to deliver competitive shareholder returns driven by solid growth, value creation and capital discipline and the strategy is centred around three growth levers:

- actively pursue further value creation in current portfolio,
- pursuing mergers and acquisitions to add new legs to the portfolio, and
- considering organic projects either adjacent to existing hubs or pursuing new hubs, dependent on financial headroom and attractive risk-reward

The strategy also includes a clear capital allocation prioritisation with an overall aim to maximise shareholder return and a target to maintain a clear and credible ESG position. OKEA shall maintain a competent organisation fit for growth with direct management engagement and involvement in key projects and use risk-cost-benefit evaluations in all phases of the Company's business activities.

OVERVIEW OF THE COMPANY'S LICENCES

OKEA holds interests in 41 Production Licences of which 19 are operated.

Producing Licence	Field	OKEA WI	Operator	Status	Phase	Expiry	Next decision
PL 037	Statfjord Unit/Statfjord East/Stafjord Nord/Sygna	28%	Equinor Energy AS	Production	PE	10.08.2026	License extension application sent to authorities
PL 053 B	Brage	35,2%	OKEA ASA	Production	PE	06.04.2030	
PL 055	Brage	35,2%	OKEA ASA	Production	PE	06.04.2030	
PL 055 B	Brage	35,2%	OKEA ASA	Production	PE	06.04.2030	
PL 055 D	NE of Brage	35,2%	OKEA ASA	Production	P	06.04.2030	
PL 055 E	Brage/ 30/6-14	35,2%	OKEA ASA	Production	P	06.04.2030	
PL 093	Draugen	44,56%	OKEA ASA	Production	PE	09.03.2024	License extension application sent to authorities
PL 093 B	Draugen	44,56%	OKEA ASA	Production	P	09.03.2024	License extension application sent to authorities
PL 093 C	Draugen	44,56%	OKEA ASA	Production	P	09.03.2024	License extension application sent to authorities
PL 093 D	Draugen	44,56%	OKEA ASA	Production		09.03.2024	License extension application sent to authorities
PL 153	Gjøa	12%	Neptune Energy Norge AS	Production	PE	08.07.2028	License extension application sent to authorities
PL 153 B	Gjøa	12%	Neptune Energy Norge AS	Production	PE	8.07.2028	

							License extension application sent to authorities
PL 153 C	Gjøa	12%	Neptune Energy Norge AS	Production	PE	08.07.2028	License extension application sent to authorities
PL 158	Draugen	44,56%	OKEA ASA	Production	PE	03.03.2028	License extension application sent to authorities
PL 176	Draugen	44,56%	OKEA ASA	Production	PE	01.03.2028	License extension application sent to authorities
PL 185	Brage	35,2%	OKEA ASA	Production	PE	06.04.2030	
PL 195	35/8-3 (Aurora)/ NE of Nova	65%	OKEA ASA	Production	P	10.09.2030	BoK
PL 195 B	35/8-3 (Aurora)/ NE of Nova	65%	OKEA ASA	Production	P	10.09.2030	BoK
PL 316	Yme	15%	Repsol Norge AS	Production	PE	18.06.2030	
PL 316 B	Yme	15%	Repsol Norge AS	Production	PE	18.06.2030	
PL 338 BS	Ivar Aasen/ 16/1-14 (Apollo)	35%	Aker BP ASA	Production	PE	17.12.2029	
PL 418	Nova	6%	Wintershall Dea Norge AS	Production	PE	16.02.2041	
PL 418 B	Nova	6%	Wintershall Dea Norge AS	Production	PE	16.02.2041	
PL 457 BS	Ivar Aasen	54,707%	Aker BP ASA	Production	PE	31.12.2036	
PL 938	6407/8-8 S (Calypso)/ NW of Draugen	30%	Neptune Energy Norge AS	Planning	I	02.03.2026	BoK
PL 958	East of Draugen	50%	OKEA ASA	Exploration	I	22.06.2025	DoD
PL 1014 B	East of Skuld/ East of Urd	20%	Equinor Energy AS	Exploration	I	01.03.2027	BoK
PL 1014	East of Skuld/ East of Urd	20%	Equinor Energy AS	Exploration	I	01.03.2027	BoK
PL 740	Brasse	39.2788%	OKEA ASA	Planning	IE	07.02.2024	License extension application sent to authorities
PL 1108	West of Gjøa/ 35/9-6 S	30%	DNO Norge AS	Exploration	I	19.02.2028	DoD
PL 1113	West of Draugen	30%	Harbour Energy Norge AS	Exploration	I	19.02.2028	DoD
PL 1115	NW of Draugen	40%	Neptune Energy Norge AS	Exploration	I	19.02.2029	DoD
PL 1117	6407/4-4 (Spirell Sør)/ Nw of Draugen	50%	OKEA ASA	Exploration	I	19.02.2028	DoD
PL 1119	South of Trestakk/ 6406/6-4 S (Tvillingen Sør)	30%	Equinor Energy AS	Exploration	I	19.08.2027	BoK
PL 1150 S	North of Aurora/ North of Nova	30%	Sval Energi AS	Exploration	I	11.03.2029	DoD
PL 1156	SW of Draugen	40%	OKEA ASA	Exploration	I	11.03.2029	DoD
PL 1159	South of Trestakk/ 6406/5-1	50%	OKEA ASA	Exploration	I	11.03.2028	BoK

PL 1161	East of Halten Øst/ North of Draugen	60%	OKEA ASA	Exploration	I	11.03.2029	DoD
PL 1178	West of Brage	50%	OKEA ASA	Exploration	I	17.02.2030	DoD
PL 1180	South of Gjøa	30%	Neptune Energy Norge AS	Exploration	I	17.02.2029	DoD
PL 1186	West of Njord	20%	Equinor Energy AS	Exploration	I	17.02.2030	DoD
PL 1187	North of Draugen	40%	OKEA ASA	Exploration	I	17.02.2030	DoD

Licence phases - I=Initial, IE=Initial Extended, P=Production, PE=Production Extended
Next decision – DoD=Decision to drill or drop, Extension=Decision to enter extension phase, BoK=Decision to concretise

OKEA has an active exploration portfolio in two core areas: The southern part of Norwegian Sea and the northern part of the North Sea. Approximately 50% of these licenses are operated by OKEA, and the Issuer is working towards drill decisions in 2024 in several of these.

OKEA has an ambition of drilling 3 exploration wells per year. In 2024, OKEA will be partner in the exploration wells in licenses PL1014 (Arkenstone) and PL1119 (Mistral), both operated by Equinor. In addition, the discovery made in Sognefjord East in the Brage Unit will be further appraised in 2024.

OKEA is actively engaging in the annual licensing awards in predefined areas (APA) and was awarded 3 new licenses in APA2023. OKEA is now working actively towards the upcoming APA2024.

SUMMARY OF THE COMPANY'S RESERVES & RESOURCES

OKEA's reserves and contingent resources are classified in accordance with the Petroleum Resources Management System (PRMS) of the Society of Petroleum Engineers (SPE). OKEA reports reserves (1P, 2P, and 3P), as well as contingent resources (1C, 2C and 3C) in the annual statement of reserves (ASR). The ASR EOY 2023 will be published in April 2024, together with the Issuer's annual report for 2023. A high-level summary of the report was published together with Issuer's Q4 results in February 2024.

Reserves
Reserves are defined as the volume of hydrocarbons that are expected to be produced from known accumulations in production, under development or with development committed. Reserves are also classified according to the associated risks and probability that the reserves will actually be produced. Reserves are classified as 1P, 2P or 3P:

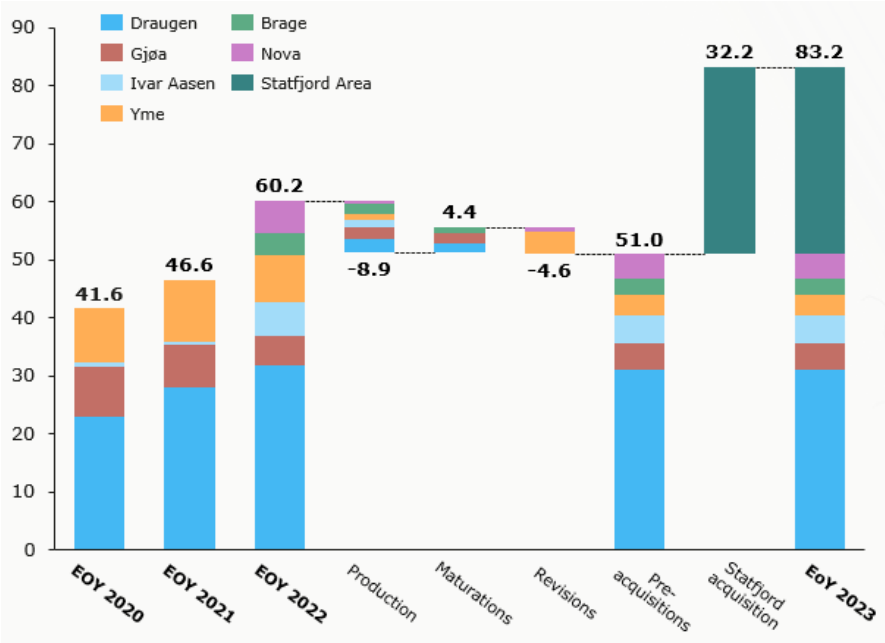
1P – Proven reserves represent volumes that will be recovered with 90% probability.
2P – Proven + Probable represent volumes that will be recovered with 50% probability.
3P – Proven + Probable + Possible volumes that will be recovered with 10% probability.

OKEA has reserves distributed in 10 fields:

Field/Project	OKEA WI	Operator	Project Status Category	Comment
Draugen field	44.56%	OKEA ASA	On production	Includes Hasselmus discovery
Brage unit	35.2%	OKEA ASA	On production	
Gjøa field	12%	Neptune Energy Norge AS	On production	Includes P1 redevelopment and Gjøa Nord (former Hamlet prospect)

Ivar Aasen unit	9.2385%	Aker BP ASA	On production	
Yme field	15%	Repsol Norge AS	On production	
Nova field	6%	Wintershall Dea Norge AS	On production	
Statfjord Unit	23.93123%	Equinor Energy AS	On production	New in OKEA portfolio, and not reported in ASR EoY2022
Statfjord Nord	28.0%	Equinor Energy AS	On production	New in OKEA portfolio, and not reported in ASR EoY2022
Statfjord Øst	14.0%	Equinor Energy AS	On production	New in OKEA portfolio, and not reported in ASR EoY2022
Sygna	15.4%	Equinor Energy AS	On production	New in OKEA portfolio, and not reported in ASR EoY2022

Total net proven plus probable reserves (2P/P50) were estimated at 83.2 million barrels of oil equivalents. The reserves figures account for the effects of production in 2023. The split between individual assets is given in the graph below:



Contingent resources

Contingent resources are potentially recoverable volumes from proven accumulations, which are not currently considered commercially viable. This essentially includes projects that are being matured but that have not passed a Final Investment Decision (FID). OKEA holds contingent resources in several licences, as shown in the table below.

mmboe	Statfjord	Draugen	I. Aasen	Gjøa	Nova	Yme	Brage	Brasse	Aurora	Calypso	YE23
Reserves (2P)	32.2	31.1	4.7	4.6	4.2	3.4	2.9				**83.2**
Resources (2C)	13.1	6.0	1.4	2.6	2.0	1.2	14.5	10.9	8.4	4.5	**64.6**

OVERVIEW OF THE COMPANY'S KEY ASSETS[7]

Draugen (44.56% WI, operator)

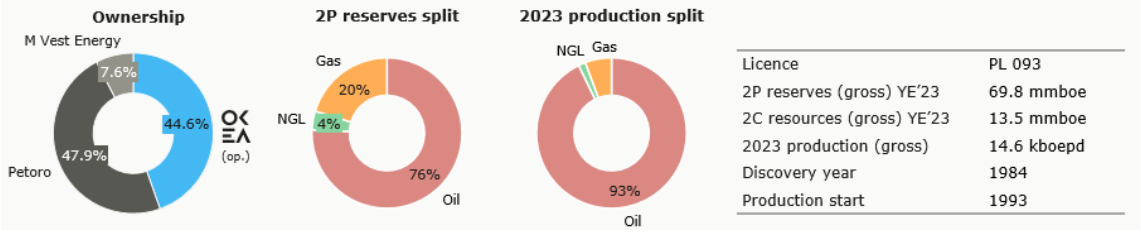
Draugen is an oil field with associated gas in the southern part of the Norwegian sea. Located on the southeast edge of Haltenbanken in the Norwegian Sea, 140 km northwest of Kristiansund, in water depths of 250 metres. Draugen was discovered in 1984 by Shell, the plan for development and operation (PDO) was approved in 1988, and with production start in 1993.

The platform is a concrete gravity-based structure with full oil stabilisation and storage capabilities. Oil is exported by shuttle tankers, gas export/import via Åsgard Transport System. Draugen produces oil from two formations. The main reservoir is in sandstone of Late Jurassic age in the Rogn Formation. The western part of the field also produces from sandstone of Middle Jurassic age in the Garn Formation. The reservoirs lie at a depth of 1,600 metres. The field is produced by pressure maintenance from water injection and natural aquifer support.

The Hasselmus gas discovery is located 7 km northwest of the Draugen platform. A single well (6407/9-9 T2) was drilled on the structure by A/S Norske Shell in 1999, encountering a 16 meters gas column and a 6.8 meters oil column in high quality sands at a depth of 1,700 meters. The discovery was developed as a subsea tie-back to the Draugen platform with one single gas producer. It is expected to recover approximately 1.65 GSm3 of natural gas, and enabled the restart of associated gas and NGL export from Draugen. Production from Hasselmus commenced on 1 October 2023, adding approximately 4,400 boed in gas production at plateau.

OKEA ASA is the operator of the Draugen licence including the Hasselmus discovery. Since taking over as operator in 2018, OKEA has reduced downtime, optimised production and extended field life.

There is a project ongoing to electrify Draugen with power from shore from 2027, this measure will not only reduce emissions, but also result in reduced opex and increase gas export from Draugen. The licence period for PL093, PL093B, PL093C, PL093D, PL158 and PL176 expires 09.03.2024. An application for extension of all these licences to 31.12.2040 has been sent to the authorities.



Licence	PL 093
2P reserves (gross) YE'23	69.8 mmboe
2C resources (gross) YE'23	13.5 mmboe
2023 production (gross)	14.6 kboepd
Discovery year	1984
Production start	1993

Brage (35.20% WI, operator)

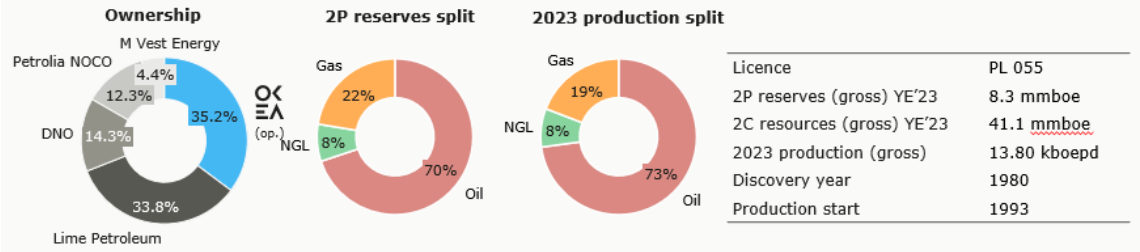
The Brage field is located in the northern North Sea, 125 kilometres west of Bergen at a water depth of 137 metres. Brage was discovered in 1980, and the plan for development and operation (PDO) was approved in 1990. The field has been developed with an integrated production, drilling and accommodation facility with a steel jacket. Production started in 1993.

Brage produces oil from sandstone of the Early Jurassic age in the Statfjord Group, and sandstone of the Middle Jurassic age in the Brent Group and the Fensfjord Formation. The reservoirs lie at a

[7] *The source of the information regarding "Key assets" are extracted from both OKEA ASA and www.norskpetroleum.no - This site is run in cooperation by the Ministry of Energy and the Norwegian Offshore Directorate. Where information has been sourced from a third party the information has been accurately reproduced and that as far as the Company is aware and is able to ascertain from information published by that third party, no facts have been omitted which would render the reproduced information inaccurate or misleading.*

depth of 2,000-2,300 metres. The main drainage strategy is water injection, with gas lift utilised in most wells. Oil is exported via the Oseberg Transport System (OTS) to the Sture terminal. The gas is exported via pipeline to Kårstø. In November 2022, OKEA took over Wintershall Dea's entire share (35.2%) in Brage as well as the operatorship. Production from the Talisker East well commenced in May 2023 and increased production by 60% compared to previous quarter. Additional wells, including a gas producer, a producer in Fensfjord reservoir, and a producer in Cook reservoir were started up in 2023. Production is expected to reach gross yearly average production of approximately 14 kboepd. A PDO for Cook was submitted in Q2 2023 and production started in Q4 2023 through well A-30 C, with rates significantly higher than expected.

Brasse is being assessed for development as a subsea tie-back to Brage. A plan for development and operation (PDO) is currently scheduled to be submitted for approval within first half 2024. PL740 expires 07.02.2024. An application for extension of the license to 06.04.2030, and a proposed condition to submit PDO by 31.12.2025 has been sent to the authorities.



Licence	PL 055
2P reserves (gross) YE'23	8.3 mmboe
2C resources (gross) YE'23	41.1 mmboe
2023 production (gross)	13.80 kboepd
Discovery year	1980
Production start	1993

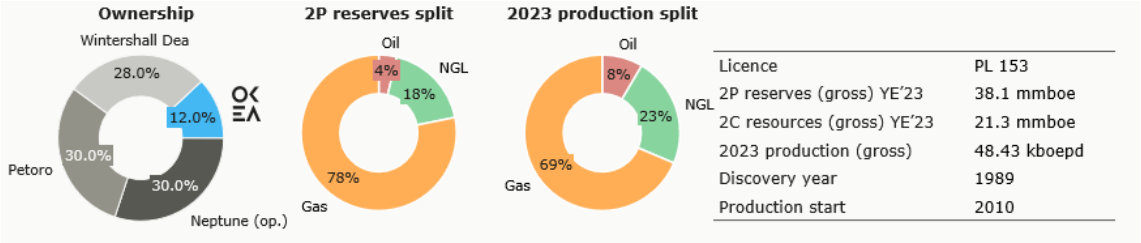
Gjøa (12.00% WI)

Gjøa is an oil and gas field located in the northern part of the North Sea, 50 km northeast of the Troll field, in water depths of 360 metres. Gjøa was discovered in 1989, and the plan for development and operation (PDO) was approved in 2007. The field is developed with thirteen subsea wells connected to five templates and directed back to a semi-submersible unit with full oil stabilisation capacities. The Gjøa facilities are partly supplied with power from shore. The Vega and Vega Sør, Duva and Nova fields are tied-back to Gjøa for processing and further export.

The reservoir contains gas above a relatively thin oil zone in sandstone of Jurassic age in the Dunlin, Brent and Viking Groups. The field comprises several tilted fault segments with partly uncertain communication and variable reservoir quality. The reservoir depth is 2,200 metres. The field is produced by pressure depletion. In the southern segments, oil production was prioritised in the first years. Gas blow-down, production of the gas cap, started in 2015. Low pressure production was implemented in 2017. Stabilised oil is exported by pipeline connected to Troll Oil Pipeline II, for further transport to the Mongstad terminal. Rich gas is exported via the Far North Liquids and Associated Gas System (FLAGS) on the UK continental shelf, for further processing at the St Fergus terminal in the UK.

The Gjøa platform was the first floating platform with power form shore and has been partially electrified since startup, resulting in low associated emissions.

Further maturation of potential development scenarios of the Hamlet discovery is ongoing. Other IOR targets are also evaluated within the PL153/153 C licence utilising new reprocessed seismic data. Options to appraise the Aurora discovery and drill the Selene prospect in PL195 west of Gjøa are under review.



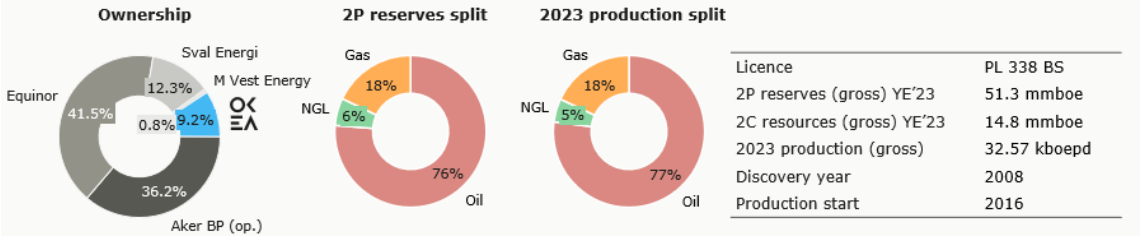
Licence	PL 153
2P reserves (gross) YE'23	38.1 mmboe
2C resources (gross) YE'23	21.3 mmboe
2023 production (gross)	48.43 kboepd
Discovery year	1989
Production start	2010

Ivar Aasen (9.2385% WI)

Ivar Aasen is a field in the northern part of the North Sea, 30 kilometres south of the Grane and Balder fields. The water depth is 110 metres. Ivar Aasen was discovered in 2008, and the plan for development and operation (PDO) was approved in 2013. The development comprises a production, drilling and quarters (PDQ) platform with a steel jacket and a separate jack-up rig for drilling and completion. Production started in 2016. The platform is equipped for tie-in of a subsea template planned for the development of the Hanz field, and for possible development of other nearby discoveries. First stage processing is carried out on the Ivar Aasen platform, and the partly processed fluids are transported to the Edvard Grieg platform for final processing and export. Edvard Grieg also provides the Ivar Aasen platform with gas lift and electricity.

Ivar Aasen produces oil from sandstone reservoirs. The field consists of the discoveries 16/1-9 Ivar Aasen and 16/1-7 (West Cable). The 16/1-9 Ivar Aasen reservoir consists of fluvial sandstone of Late Triassic to Middle Jurassic age in the Skagerrak and Sleipner Formations and shallow marine sandstone in the Middle Jurassic Hugin Formation. The reservoir lies at a depth of 2,400 metres. It is compartmentalised and has moderate to good quality. Parts of the reservoir have an overlying gas cap. The reservoir in 16/1-7 (West Cable) is in fluvial sandstone in the Middle Jurassic Sleipner Formation. It lies at a depth of 2,950 metres and has moderate quality. 16/1-9 Ivar Aasen is produced by pressure support from water injection. 16/1-7 (West Cable) is produced by pressure support from an aquifer. Oil and gas are transported to the Edvard Grieg platform for final processing. The oil is exported by pipeline to the Grane Oil Pipeline, which is connected to the Sture terminal. The gas is exported in a separate pipeline to the Scottish Area Gas Evacuation (SAGE) system in the UK for further processing at the St Fergus terminal.

The Ivar Aasen platform was supplied with power from shore from 2023 as part of the wider Utsira High electrification project, resulting in lower associated emissions. Plans for an IOR 2026 campaign are initiated. In addition, well intervention campaigns are executed approx. three times per year.



Licence	PL 338 BS
2P reserves (gross) YE'23	51.3 mmboe
2C resources (gross) YE'23	14.8 mmboe
2023 production (gross)	32.57 kboepd
Discovery year	2008
Production start	2016

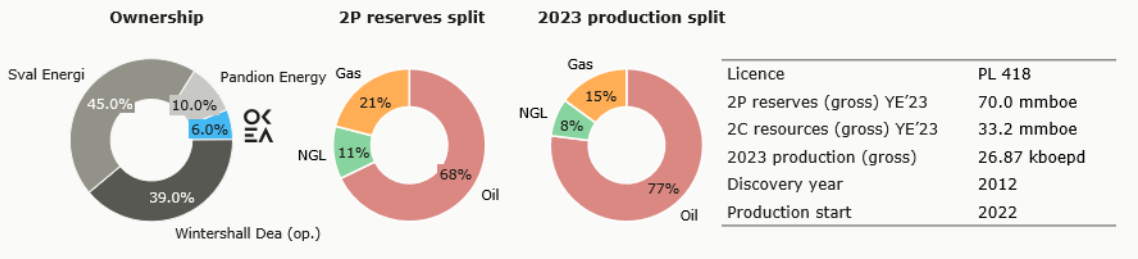
Nova (6.00% WI)

Nova is a crude oil and associated gas field located 120 kilometres northwest of Bergen and 17 kilometres southwest of Gjøa. The water depth is roughly 370 metres. Nova was discovered in 2012, and the plan for development and operation (PDO) was approved in 2018. The production started in 2022. The field consists of two subsea templates, one with three oil producers and one with three

water injectors, tied back to Neptune-operated Gjøa platform. Power for the Nova field comes via the Gjøa platform from shore.

The reservoir contains oil with a gas cap in sandstone of Late Jurassic age in the Heather Formation in the Viking Group, at a depth of 2,500 metres. The reservoir quality is good. The field is produced by pressure support from water injection and with gas lift. Oil from Nova is transported via Gjøa through the Troll Oil Pipeline II to Mongstad in Norway, associated gas is exported via the Far North Liquids and Associated Gas System (FLAGS) pipeline to St Fergus in the UK, supplying the European energy market.

In November 2022, production was significantly reduced due to issues with the water injection wells. Some of the issues were resolved rapidly by well interventions in December 2022. A side-track drilling operation of one of the injector wells was successfully completed in 2023. Although production has improved during 2023, it is still constrained by reduced effectiveness of water injection. A rig has been secured to drill a fourth water injector in 2024.



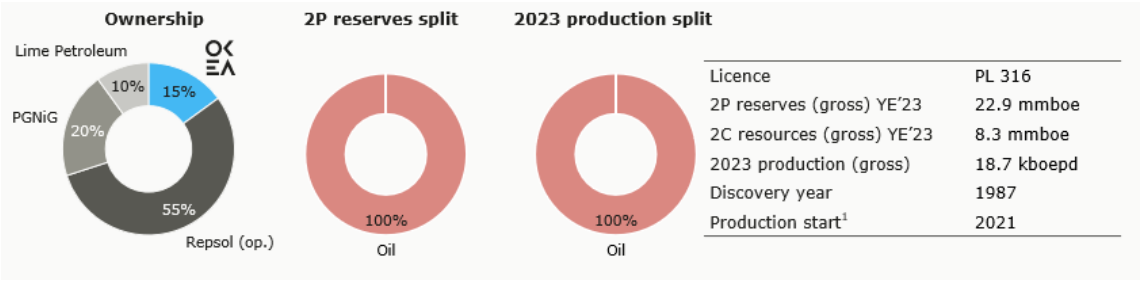
Licence	PL 418
2P reserves (gross) YE'23	70.0 mmboe
2C resources (gross) YE'23	33.2 mmboe
2023 production (gross)	26.87 kboepd
Discovery year	2012
Production start	2022

Yme (15.00% WI)

Yme is a field in the southeastern part of the Norwegian sector of the North Sea, 130 kilometres northeast of the Ula field, in water depths of 100 metres. Yme was discovered by Equinor in 1987 and originally started producing in 1996. Low oil prices led to the abandonment of the field in 2001. Yme was the first field on the NCS to be considered for redevelopment after being shut down. OKEA acquired an ownership interest in 2016 and started preparing a new PDO. In March 2018, an amended PDO for the redevelopment was approved, with Repsol as operator, based on a leased jack-up production unit. The production started in October 2021.

The water depth is 77-93 metres. The field comprises two separate main structures, Gamma and Beta, which are 12 kilometres apart. The reservoirs are in sandstones of Middle Jurassic age in the Sandnes Formation, at a depth of 3,150 metres. They are heterogeneous and have variable reservoir properties. The field is produced by pressure support from partial water injection and water alternating gas (WAG) injection. The oil is transported with tankers and the associated gas is used for power consumption or reinjected.

In recent quarters, water-cut from the producing wells has been higher than initially anticipated, resulting in recued expectations for production and recoverable reserves. This has resulted in impairments at Yme for several consecutive quarters. Two producer wells have been drilled in the Yme Gamma campaign and have contributed to lift plateau production to ~3.6 kboepd net to OKEA by Q4 2023. One more water injector and one producer is planned to be put on injection/production within H1 2024. Further infill well opportunities are being evaluated.



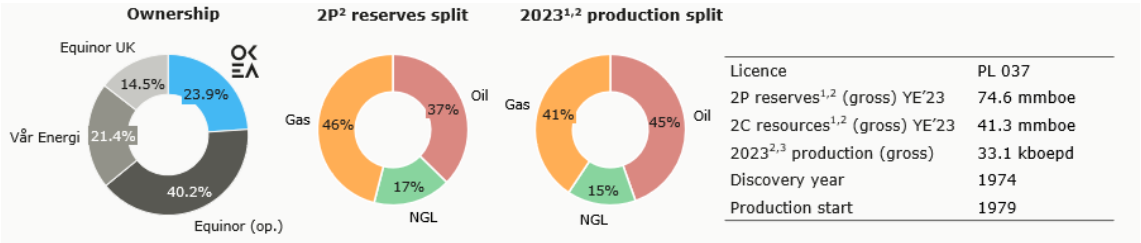
Licence	PL 316
2P reserves (gross) YE'23	22.9 mmboe
2C resources (gross) YE'23	8.3 mmboe
2023 production (gross)	18.7 kboepd
Discovery year	1987
Production start[1]	2021

[1] *For Yme New Development*

Statfjord (23.93123% WI)

Statfjord is a field in the Tampen area in the northern part of the North Sea, on the border between the Norwegian and UK sectors. The Norwegian share of the field is 85.47 per cent. The water depth is 150 metres. Statfjord was discovered in 1974, and the plan for development and operation (PDO) was approved in 1976. The field has been developed with three fully integrated concrete facilities: Statfjord A, Statfjord B and Statfjord C. Statfjord A, centrally located on the field, came on stream in 1979. Statfjord B, in the southern part of the field, in 1982, and Statfjord C, in the northern part, in 1985. The satellite fields Statfjord Øst, Statfjord Nord and Sygna have a dedicated inlet separator on Statfjord C. A PDO for Statfjord Late Life was approved in 2005. Equinor's Field Life eXtension (FLX) organisation now operates the asset, and work is ongoing to further extend the lifetime of the field. The FLX unit has an ambition to deliver a 200% increase in reserves, 25% cost reduction and 50% CO_2 reduction in the Statfjord Area by 2030 vs a 2020 base. Statfjord A is planned to be decommissioned in 2027, whereas Statfjord B and C and satellites are expected to produce until the late 2030s.

Statfjord produces oil and associated gas from Jurassic sandstones in the Brent and Statfjord Groups, and in the Cook Formation. The Brent and Statfjord Groups have excellent reservoir quality. The reservoirs lie at a depth of 2,500-3,000 metres in a large fault block tilted towards the west, and in several smaller blocks along the eastern flank. The field was originally produced by pressure support from water alternating gas injection (WAG), water injection and partially gas injection. Statfjord Late Life entails that all injection now has ceased. To release the solution gas from the remaining oil, depressurisation of the reservoirs started in 2007. Stabilised oil is stored in storage cells at each facility. Oil is loaded onto tankers from one of the two oil-loading systems on the field. Since 2007, gas is exported through Tampen Link, and routed via the Far North Liquids and Gas System (FLAGS) pipeline to the UK. Gas is routed through the FLAGS pipeline from Statfjord B to St Fergus in the UK.

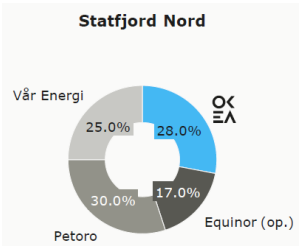


Licence	PL 037
2P reserves[1,2] (gross) YE'23	74.6 mmboe
2C resources[1,2] (gross) YE'23	41.3 mmboe
2023[2,3] production (gross)	33.1 kboepd
Discovery year	1974
Production start	1979

[1]*Corresponds to 28% in the Norwegian section of the field* [2] *Norwegian share*

Statfjord Satellites

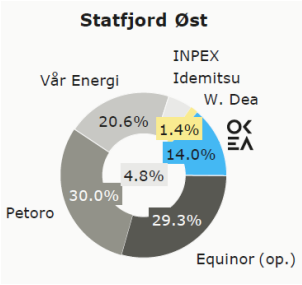
Statfjord Nord (28.0% WI)



Statfjord Nord is a field in the Tampen area in the northern part of the North Sea, 17 kilometres north of the Statfjord field. The water depth is 250-290 metres. Statfjord Nord was discovered in 1977, and the plan for development and operation (PDO) was approved in 1990. The field has been developed with two production templates and one water injection template tied-back to the Statfjord C facility. Production started in 1995.

Statfjord Nord produces oil from Middle Jurassic sandstone in the Brent Group and Upper Jurassic sandstone in the Munin Formation. The reservoirs lie at a depth of 2,600 metres and are of good quality. The field is produced with pressure maintenance from water injection. The well stream is transported in two pipelines to the Statfjord C facility for processing, storage and export.

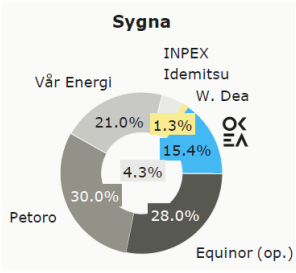
Statfjord Øst (14.0% WI)



Statfjord Øst is a field in the Tampen area in the North Sea, seven kilometres northeast of the Statfjord field. The water depth is 150-190 metres. Statfjord Øst was discovered in 1976, and the plan for development and operation (PDO) was approved in 1990. The field has been developed with two subsea production templates and one water injection template, tied-back to the Statfjord C platform. In addition, two production wells have been drilled from Statfjord C. Production started in 1994.

Statfjord Øst produces oil from Middle Jurassic sandstones in the Brent Group. The reservoir has good quality and lies at 2,400 metres depth. The field was originally produced with water injection but is now produced by pressure depletion. The well stream is transported in two pipelines to the Statfjord C facility for processing, storage and export. 5 new wells have been sanctioned as part of the SFØ gas lift project. Four out of five are already drilled. The last one is currently being drilled. One is on production and the four last ones are expected to be on production in Q1 2024.

Sygna (15.4% WI)

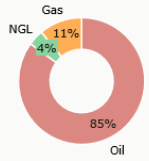


Sygna is a field in the Tampen area in the northern North Sea, just northeast of the Statfjord Nord field. The water depth is 300 metres. Sygna was discovered in 1996, and the plan for development and operation (PDO) was approved in 1999. The field has been developed with one subsea template with four well slots, connected to the Statfjord C facility. Three production wells have been drilled from the template. A long-reach water injection well was drilled from the Statfjord Nord template. Production started in 2000.

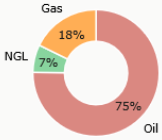
Sygna produces oil from Middle Jurassic sandstones in the Brent Group. The reservoir lies at a depth of 2,650 metres and has good quality. The field is produced by pressure maintenance from water injection. The well stream is transported by pipeline to the Statfjord C facility for processing, storage and export.

The fields Statfjord Nord, Statfjord Øst and Sygna all have a shared process module on Statfjord C. Oil is loaded onto tankers and gas is exported through Tampen Link and the Far North Liquids and Gas System (FLAGS) pipeline to the UK.

2P reserves split (Combined)



2023 production split (Combined)



	Statfjord Nord	Statfjord Øst	Sygna
Licence	PL 037	PL 037	PL 037
2P reserves (gross) YE'23	25.4 mmboe	27.5 mmboe	2.3 mmboe
2C resources (gross) YE'23	5.6 mmboe	0.0 mmboe	0.0 mmboe
2023 production (gross)	7.6 kboepd	4.6 kboepd	0.7 kboepd
Discovery year	1977	1976	1996
Production start	1995	1994	2000

8. Administrative, management and supervisory bodies

Board of Directors:

Name	Position
Chaiwat Kovavisarach	Chairman of the board
Mike Fischer	Vice chair
Rune Olav Pedersen	Board member
Nicola Gordon	Board member
Finn Haugan	Board member
Jon Arnt Jacobsen	Board member
Phatpuree Chinkulkitnivat	Board member
Elizabeth (Liz) Williamson	Board member
Sverre Nes	Board member (employee elected)
Ragnhild Aas	Board member (employee elected)
Per Magne Bjellvåg	Board member (employee elected)

Set out below are brief biographies of the members of the Board of Director:

Chaiwat Kovavisarach – Chairman
Non-executive.
Chaiwat Kovavisarach (born 1966) has been the President and Group CEO of Bangchak Corporation Public Company Limited since 2015. He also serves on the board of several listed and non-listed companies and is the chairman of Thai-Europe Business Council, vice chairman of the Federation of Thai industries, the executive chairman of the Board of Trustees of the Asian Institute of Technology, a Director of the Government Pension Fund, director of Bank of Thailand's Credit Information Protection Committee and Board of trustee of KMITL. He holds a Master of Engineering from the Asian Institute of Technology (AIT), an MBA from Thammasat University and a Bachelor of Engineering from King Mongkut's Institute of Technology Ladkrabang (KMITL).

Mike Fischer - Vice chair
Non-executive.
Member of the people and organisation committee and member of sustainability and technical risk committee.
Mike Fischer (born 1958) has nearly 40 years' experience in the oil and gas industry. He is currently an Executive Advisor to the Natural Resources business unit of Bangchak. Dr. Fischer has previously held senior management positions at Ophir Energy, OMV, Woodside Energy and BP. He holds a PhD from the University of Wales and a BSc from the University of Leeds.

Rune Olav Pedersen - Board member
Independent, non-executive.
Chair of the audit committee.
Rune Olav Pedersen (born 1970) has been President & CEO of PGS ASA since 2017. Mr. Pedersen has previously held the position of executive vice president & general counsel at the company. Prior to joining PGS he was partner in the oil and gas department of the law firm Arntzen de Besche. He has a law degree from the University of Oslo, a post-graduate diploma in European competition law from Kings College London and an Executive MBA from London Business School.

Nicola Gordon - Board member
Independent, non-executive.
Chair of the sustainability and technical risk committee.
Nicola Gordon (born 1957) has many years of experience from the energy industry. Ms. Gordon holds several board positions, among others as Chair of the audit & risk committee at the Scottish Envi-

ronment Protection Agency and trustee at the Scottish Ensemble and the Royal High School Preservation Trust. Gordon's experience at the Royal Dutch Shell Group includes vice president for Shell International, asset manager and board director at A/S Norske Shell and managing director at Shell Denmark. She is a Chartered Engineer and Fellow of the Energy Institute and holds an MSc in Petroleum Engineering from Heriot-Watt University and a BSc in Chemical Engineering from University of Newcastle upon Tyne.

Finn Haugan - Board member

Independent, non-executive.

Chair of people and organisational committee and member of audit committee.

Finn Haugan (born 1953) was from 1991 to May 2019 the CEO of SpareBank 1 SMN, before that deputy CEO of Fokus Bank (Danske Bank). Mr Haugan now holds positions as chairperson for the listed companies Norbit ASA and SpareBank 1 Sørøst-Norge. Furtheron he holds the position as chairperson for the non-listed companies Sinkaberg Hansen AS, Elekt AS, Folkeinvest AS, Borg Forvaltning AS and Solon Eiendom AS and as deputy chairperson for LL Holding AS. Mr Haugan holds a master's degree in business administration (MBA).

Jon Arnt Jacobsen - Board member

Independent, non-executive.

Jon Arnt Jacobsen (born 1957) has extensive experience from the energy industry. Mr Jacobsen has 24 years of executive management experience from Equinor ASA within corporate finance, refining marketing and trading, procurement as well as internal audit and corporate security. Prior to Equinor, Mr Jacobsen worked in DnB ASA for 12 years in various management positions within corporate banking both for the oil & gas industry and Norwegian corporates. Mr Jacobsen has also been General manager for DnB´s Singapore branch. Mr Jacobsen has previous experience as board member in Mesta AS, Storebrand ASA and Statoil Fuel & Retail ASA. Mr Jacobsen has various business degrees from Norway and a MBA from University of Wisconsin-Madison.

Phatpuree Chinkulkitnivat - Board member

Non-executive.

Phatpuree Chinkulkitnivat (born 1974) is currently a Group Chief Financial Officer at Bangchak Corporation Public Company Limited, a leading energy company in Thailand. She had more than 20 years experience in banking industry prior to joining Bangchak and held the position of Chief Financial Officer at BCPG Public Company Limited, a flagship in the power generation business of Bangchak Group. Phatpuree holds a Master of Business Administration (High Distinction) from the University of Michigan, USA, and a Bachelor of Economics (First Class Honors) from Chulalongkorn University.

Elizabeth (Liz) Williamson - Board member

Independent, non-executive.

Liz Williamson (born 1984) is the Head of Energy for Rand Merchant Bank and is responsible for M&A transactions in the renewable and oil & gas space across Africa. She has led the growth of the bank's international energy strategy since 2018. Originally from Texas but now based in London, Liz started her career in private equity focused on US upstream transactions. Thereafter she joined GMP Securities and Canaccord where she advised international E&P companies on capital markets and M&A. Liz holds an Honours degree from Davidson (North Carolina, USA) and a Masters in Energy Finance from the City University London, Bayes Business School.

Sverre Nes - Board member

Employee elected.

Sverre Nes (born 1971) holds the position of Discipline Responsible – Process in OKEA. He was employed in Hydro from 1991 to 2012. He was trained as process technician and worked there in various departments in addition to being stationed in Qatar as supervisor between 2009-2010. Sverre joined Wintershall in 2013 and currently works for Brage as Discipline Responsible for Process.

Ragnhild Aas - Board member
Employee elected.
Ragnhild Aas (born 1973) holds the position of VP Technical Services in OKEA. She has worked in OKEA since 2016 and has previously also held the position of VP Operations. Prior to joining OKEA she worked in Altera for 16 years where her last position was FPSO Operations Manager. Ragnhild holds an MSc in Process Engineering from Norges Teknisk-Naturvitenskapelige Universitet (NTNU) and a BSc in Chemical Engineering from Trondheim Ingeniørhøgskole.

Per Magne Bjellvåg - Board member
Employee elected.
Per Magne Bjellvåg (born 1969) holds the position of Lead Process Engineer in OKEA. He has been with OKEA since 2018 and prior to this he has worked in Norske Shell and FieldTalk Solutions. With more than 28 years of experience in the oil and gas industry he has held various positions, mainly in operations and maintenance of onshore and offshore process plants as well as underwater installations. Per Magne holds a BSc in Process Engineering from Høgskolen Stord Haugesund.

Management:

Name	Current position
Svein J. Liknes	CEO
Birte Norheim	CFO
Børge Nerland	SVP Drilling & Wells
Knut Gjertsen	SVP Projects and Technology
Ida Ianssen Lundh	SVP Subsurface
Espen Myhra	SVP Business Development & Commercial
Tor Bjerkestrand	SVP Operations
Kjersti Hovdal	SVP Business Performance
Dag Eggan	SVP Special Projects
Marit Moen Vik-Langlie	VP Legal

Set out below are brief biographies of the members of the Management:

Svein J. Liknes - CEO
Svein J. Liknes has more than 25 years' experience from the oil and offshore industry. He served in Aker Energy both as acting CEO and Head of Operations. Liknes also has experience as SVP Operations & Asset Development in Aker BP. Mr. Liknes has background from the Norwegian Armed Forces and studied Nautical Science at the University of Stavanger and Haugesund.

Birte Norheim - CFO
Birte Norheim has more than 15 years' experience from the oil and gas sector. Prior to joining OKEA, she has held various managerial and financial positions within the sector, including as CEO for Njord Gas Infrastructure AS and Vice President Finance for Sevan Marine ASA. Birte holds a Master of Applied Finance from Queensland University of Technology.

Børge Nerland - SVP Drilling & Wells
Børge Nerland spent more than a decade working at BP, gaining international experience from several parts of the world including the UK, Azerbaijan, Egypt, Trinidad, Algeria and Alaska. He has experience in onshore and offshore drilling and field developments. He joined Wintershall Norge in 2010, later becoming Vice President Production for Wintershall Dea. He has an MSc in Petroleum Engineering from the Norwegian Institute of Technology (NTNU) in Trondheim.

Knut Gjertsen - SVP Projects and Technology
Knut Gjertsen has thirty-five years' experience from Multiconsult, Norwegian Contractors, Aker, Kværner and Statoil/Equinor. Last positions in Equinor was Head of the Snøhvit/Hammerfest LNG operations and the Johan Castberg Project. He holds a master degree in engineering.

Ida Ianssen Lundh - SVP Subsurface
Ida Ianssen Lundh has more than 11 years of experience within the oil and gas sector from Det norske oljeselskap and national and international positions within Shell, before joining OKEA in 2015. In OKEA she has held the positions VP Drilling & Wells and VP Business Development, working within the merger and acquisition space. She holds a Master of Science in Petroleum Engineering from NTNU and Colorado School of Mines.

Espen Myhra - SVP Business Development & Commercial
Espen Myhra has close to 20 years' experience within the oil and gas sector. Before joining OKEA in 2015 Espen held the position as Deputy Director General and Head of the Exploration Section in the Norwegian Ministry of Petroleum and Energy. Espen has also been Energy counselor at the Norwegian Embassy in Washington DC and Ottawa. In OKEA Espen has experience as VP Business Development and VP Commercial.

Tor Bjerkestrand - SVP Operations
Tor Bjerkestrand has thirty years' experience at Aker Engineering, Phillips Petroleum, Kværner Oil & Gas, Petroleum Development Oman and Shell. Experienced Manager with a demonstrated history of working in the oil & gas industry both nationally and internationally. Holds a Master of Science in Engineering.

Kjersti Hovdal - SVP Business Performance
Kjersti Hovdal has around 20 years' experience from various leadership positions within finance in OKEA, Aker BP/Det norske oljeselskap/Pertra. She started her career working as an auditor and advisor for Ernst & Young. She holds a bachelor's degree in accounting and auditing.

Dag Eggan - SVP Special Projects
Dag Eggan has more than 25 years' experience from the oil and offshore industry. He was co-founder and partner of PIER Offshore Management Services, and has experience from several senior management positions, including Quality Risk Manager in the Mobile Newbuilds Group in Statoil and VP QSHE in Ocean Rig, Sevan Drilling and Skeie Drilling & Production. Holds a Master of Science in Environmental & Resource Engineering.

Marit Moen Vik-Langlie - VP Legal
Marit Moen Vik-Langlie has 10+ years of experience with commercial and contracts law, and holds a Master of Law from the University of Oslo. She came to OKEA in 2016 from Advokatfirmaet Steenstrup Stordrange DA (Sands).

Nomination Committee:
The nomination committee's main purpose is to propose candidates for election to the Board and remuneration of the Board. The committee shall consist of three members. The members of the nomination committee should be selected to take into account the interests of the Company's shareholders in general. The majority of the nomination committee should be independent of the Board and the senior management. The nomination committee shall not include the CEO or any other members of the senior management.
The nomination committee should justify why it is proposing each candidate separately.

The Nomination Committee currently consists of Sverre Strandenes and Reidar Stokke.

Audit Committee:
The function of the Audit Committee is to prepare matters to be considered by the board and to support the board in the exercise of its management and supervisory responsibilities relating to financial reporting, statutory audit, internal control and collaboration with the Financial Supervisory Authorities. Furthermore, the Audit Committee shall perform a separate financial review of contract

commitments exceeding NOK 100 million (gross amount for operated licences and not for non-operated licences) as part of the internal control of major commitments.

The Audit Committee currently consists of Rune Olav Pedersen (Chair), Finn Haugan, Jon Arnt Jacobsen, Phatpuree Chinkulkitnivat and Ragnhild Aas.

Sustainability and Technical Risk committee ("STR committee")

The STR committee shall follow up the Company's management of ESG related matters, review main risks for exploration, reserves and resources, projects and investments, and monitor overall risk management and internal control. The STR committee shall further contribute to the board's review of the Company's most important areas of exposure to risk and its internal control arrangements. Furthermore, the STR committee reviews opportunities related to business development and M&A and is authorised to:

- Approve relinquishment of exploration licenses
- Approve sale and purchase of exploration licenses within approved budgets
- Approve sale and purchase of assets up to NOK 300 million after tax for projects that are in line with OKEA's strategy and certain other criteria.

The STR Committee currently consists of Nicola Gordon (Chair), Mike Fischer, Elizabeth Williamson and Sverre Nes.

People and Organisation committee (P&O committee)

The P&O committee shall evaluate and propose the compensation of the Company's CEO, administer the Company's bonus incentive program and advice the board on general compensation and organisation related matters as well as on the annual report on the compensation of the senior management team and other leading persons, pursuant to applicable rules and regulations. The P&O committee shall also advise the CEO on matters relating to other material employment issues in respect of the senior management. The P&O committee shall endorse the overall limits for the annual salary adjustments for employees, within the budget set by the board.

The P&O Committee currently consists of Finn Haugan (Chair), Mike Fischer, Jon Arnt Jacobsen and Per Magne Bjellvåg.

OKEA can from time to time acquire seismic data or services from Petroleum Geo-Services ASA, in which the Board member Rune Olav Pedersen is the CEO and President. Other than this, there are currently no potential conflicts of interests between any duties to the Company of the persons referred to in this section – chapter 8 - and their private interests or other duties. The Board of Directors and the Company continuously monitor potential for conflicts of interests in accordance with applicable legislation and regulations, including the Norwegian Code of Practice for Corporate Governance. The Company also have established a Code of Conduct which includes regulations on procedures on business ethic matters, applicable also for its Board members.

The Company's registered business address, Kongens gate 8, 7011 Trondheim, Norway, serves as c/o address for all the persons referred to in this section – chapter 8 in their capacities as Directors and Management of the Company.

9. Major shareholders

OKEA's share capital is as of the date of this Registration Document NOK 10,391,035.00, divided on 103,910,350 shares, each with a par value of NOK 0.1. - fully paid. There is only one class of shares and there are no differences in voting rights between the shares. The shares are registered in VPS under ISIN NO0010816895.

OKEA has been listed on the Oslo Børs since 18th June 2019 under the ticker "OKEA".

The 20 largest shareholders in OKEA, as per 29 January 2024:

Investor	Shares	% of top 20	% of total
BCPR PTE. LTD.	47,218,098	71.64%	45.44%
CLEARSTREAM BANKING S.A.	3,369,847	5.11%	3.24%
SALT VALUE AS	2,660,710	4.04%	2.56%
STATE STREET BANK AND TRUST COMP	1,422,257	2.16%	1.37%
MORGAN STANLEY & CO. LLC	1,209,798	1.84%	1.16%
SJÆKERHATTEN AS	1,093,000	1.66%	1.05%
SKANDINAVISKA ENSKILDA BANKEN AB	985,736	1.50%	0.95%
CITIBANK, N.A.	933,165	1.42%	0.90%
KØRVEN AS	789,285	1.20%	0.76%
SKJEFSTAD VESTRE AS	780,617	1.18%	0.75%
NORDNET LIVSFORSIKRING AS	733,751	1.11%	0.71%
SILVERCOIN INDUSTRIES AS	733,395	1.11%	0.71%
INTERACTIVE BROKERS LLC	613,316	0.93%	0.59%
WAATVIKA AS	562,489	0.85%	0.54%
THE BANK OF NEW YORK MELLON	538,020	0.82%	0.52%
THE BANK OF NEW YORK MELLON	514,697	0.78%	0.50%
NIMA INVEST AS	479,517	0.73%	0.46%
ESPEDAL & CO AS	425,908	0.65%	0.41%
NORDNET BANK AB	429,225	0.65%	0.41%
PERSHING LLC	420,062	0.64%	0.40%
Total number owned by top 20	**65,912,893**		**63.43%**
Total number of shares	**103,910,350**		**100.00%**

No single shareholder has direct or indirect control over OKEA as of the date of this Registration Document. BCPR PTE. LTD. (BCPR) owns 45.44% of OKEA. BPCR is a wholly owned subsidiary within Bangchak Corporation Plc. Group (BCP). BCPR PTE. LTD. is indirectly controlled by Bangchak Corporation Public Company Limited. No single shareholder has direct or indirect control over Bangchak Corporation Public Company Limited.

The Company is not aware of any arrangements which may at a subsequent date result in a change of control of the Company. Minority shareholders are protected against abuse by relevant regulations in inter alia the Norwegian Public Limited Companies Act and the Norwegian Securities Act.

For information regarding related party transactions reference is made to note 35 in the annual report 2022. Please see the cross-reference list in section 12 in this Registration Document.

10. Financial information

The financial statements for the year ended 31 December 2022 have been prepared in accordance with IFRS Accounting Standards (IFRS) as adopted by the European Union (EU) and in accordance with the additional requirements following the Norwegian Accounting Act. The interim financial statements for the 12-month period ended 31 December 2023 have been prepared in accordance with IAS 34 Interim Financial Reporting.

The 2022 Financial Statements have been audited by PricewaterhouseCoopers AS, as set forth in their auditor's report [incorporated by reference herein]. The Interim Financial Statements have not been audited. PricewaterhouseCoopers AS has not audited, reviewed, or produced any report on any other information provided in this Prospectus, other than related to the 2022 Financial Statements.

The 2022 annual report, H1 2023 report and third and fourth quarter 2023 report of OKEA ASA is incorporated by reference. Please see the cross-reference list in section 12 in this Registration Document:

OKEA ASA

	2022 *audited*	**H1 2023** *unaudited*	**Q3 2023** *unaudited*	**Q4 2023** *unaudited*
Statement of comprehensive income	Page 57	Page 16	Page 15	Page 16
Statement of Financial position	Page 58 - 59	Page 17	Page 16	Page 17
Statement of changes in equity	Page 60	Page 18	Page 17	Page 18
Statement of cash flows	Page 61	Page 19	Page 18	Page 19
Notes to the (Interim) financial statements	Page 62 - 111	Page 20 - 35	Page 19 - 34	Page 20 - 35
Independent Auditor's report	Page 115 - 122	-	-	-

2022: https://www.okea.no/wp-content/uploads/2023/04/okea-annual-report-2022.pdf

H1 2023: https://www.okea.no/wp-content/uploads/2023/07/okea-q2-2023-quarterly-report.pdf

Q3 2023: https://www.okea.no/wp-content/uploads/2023/07/okea-q3-2023-quarterly-report.pdf

Q4 2023: https://www.okea.no/wp-content/uploads/2024/02/okea-q4-2023-quarterly-report.pdf

The historical financial information for 2022 has been audited, the interim financial statements are unaudited.

OTHER STATEMENTS FOR THE COMPANY

Financial statements and trend information
In March, OKEA entered into an SPA with Equinor to acquire 28% WI in PL037 (Statfjord Area) with effective date 1 January 2023. The transaction was closed on 29 December 2023. The acquired portfolio comprises 23.93123% WI in Statfjord Unit, 28% WI in Statfjord Nord, 14% WI in Statfjord Øst Unit and 15.4% WI in Sygna Unit. The Statfjord assets provide a significant increase in total production and reserves to OKEA and enhances diversification and portfolio robustness. Net production to OKEA from Statfjord area was 10,862 boepd in the fourth quarter of 2023. RNB 2024 indicated a 10-15% reduction in volumes over the lifetime of the acquired assets in addition to an increase in costs compared to RNB 2023. The decrease in volumes was most significant in the near-term. Equinor, as operator, has initiated a project focused on increasing production reliability, maturing well targets and drilling performance, and revisiting the drainage strategy to increase liquid offtake and maximise recoverable reserves. On completion of the transaction all identifiable assets and liabilities were recognised in the financial statements at fair value at completion date. The excess of consideration above the fair value of assets less liabilities was recognised as ordinary goodwill which was impaired at day one. The goodwill impairment was mainly a result of the reduction in production and reserves estimates from RNB 2023 to RNB 2024.

Following from the purchase price allocation, technical goodwill was recognised as an offset to deferred tax on oil and gas properties and will be tested for impairment at each balance sheet date. Any impairment of technical goodwill may not be reversed. The technical goodwill recognized from the transaction was just above NOK 1 billion. Technical goodwill arises as an offset to deferred tax liabilities recognised in business combinations after IFRS 3. Technical goodwill will be impaired over the lifetime of the asset as the remaining recoverable amount from the assets gradually reduces below the book value of the fixed asset recognised as an oil & gas property. Further information is to be found in the fourth quarter quarterly report.

There are no significant changes in the financial position of the Company which may have occurred since the end of the last financial period for which either audited financial statements or interim financial statements have been published. And there has been no material adverse change in the prospects of the Company since the date of its last published audited financial statements or any significant change in the financial performance of the company since the end of the last financial period for which financial information has been published to the date of the Registration Document.

There are no known trends, uncertainties, demands, commitments or events that are reasonably likely to have a material effect on the Company's prospects for at least the current financial year.

Legal and arbitration proceedings
There are no governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened of which the Company is aware), during a period covering at least the previous 12 months which may have, or have had in the recent past significant effects on the Company and/or Group's financial position or profitability.

SUMMARY OF DISCLOSED INFORMATION

All of OKEA ASA's stock exchange announcements are available on the Company's website: https://www.okea.no/investor/investor-news/
The below table is a summary of the information disclosed by the Company under Regulation (EU) No 596/2014 over the last 12 months which is relevant as at the date of the Registration Document.

ADDITIONAL REGULATED INFORMATION REQUIRED TO BE DISCLOSED UNDER THE LAWS OF A MEMBER STATE	
Date	*Description*
01.02.2024	OKEA fourth quarter 2023 trading update
29.12.2023	Transaction between OKEA ASA and Equinor Energy AS completed
11.12.2023	Financial calendar for OKEA ASA
26.10.2023	Key information relating to the cash dividend to be paid for OKEA ASA
26.10.2023	OKEA ASA - NOK 1.00 dividend payment payable on or about 15 December
19.10.2023	OKEA third quarter 2023 trading update
01.11.2022	The transaction between OKEA ASA and Wintershall Dea was completed today. OKEA becomes operator of the Brage field with effect from 1 November 2022
06.09.2023	OKEA ASA - Exercise of call option
30.08.2023	OKEA ASA: Successful Placement of Senior Secured Bond Issue
13.07.2023	OKEA ASA - NOK 1.00 dividend payment payable on or about 15 September
13.07.2023	Key information relating to the cash dividend to be paid for OKEA ASA
06.07.2023	OKEA second quarter 2023 trading update
11.05.2023	OKEA ASA - Minutes of annual general meeting
04.05.2023	Key information relating to the cash dividend to be paid for OKEA ASA
04.05.2023	OKEA ASA - NOK 1.00 dividend payment payable on or about 15 June
27.04.2023	OKEA first quarter 2023 trading update
17.04.2023	OKEA ASA - Notice of annual general meeting
17.04.2023	OKEA ASA - Notice of annual general meeting

ANNUAL FINANCIAL AND AUDIT REPORTS	
Date	*Description*
03.04.2023	Publication of annual reports for 2022
03.04.2023	Publication of annual reports for 2022
03.04.2023	Publication of annual reports for 2022
03.04.2023	Publication of annual reports for 2022

HALF YEARLY FINANCIAL REPORTS AND AUDIT REPORTS/LIMITED REVIEWS	
Date	*Description*
08.02.2024	OKEA ASA - Fourth quarter 2023 financial results
26.10.2023	OKEA ASA - Third quarter 2023 financial results
13.07.2023	OKEA ASA - Second quarter 2023 financial results
04.05.2023	OKEA ASA - First quarter 2023 financial results

MANDATORY NOTIFICATION OF TRADE PRIMARY INSIDERS	
Date	*Description*
05.03.2024	OKEA ASA - Mandatory notification of trade
27.02.2024	Correction of previous press release on completion of purchases under share-based bonus program and mandatory notification of trade
23.02.2024	Completed purchases under share-based bonus program and mandatory notification of trade
31.10.2023	MANDATORY NOTIFICATION OF TRADE PRIMARY INSIDERS
14.09.2023	OKEA ASA - Mandatory notifications of trades by primary insiders
13.09.2023	Completed purchases under long-term incentive plan and board compensation package and mandatory notification of trade
04.05.2023	MANDATORY NOTIFICATION OF TRADE PRIMARY INSIDERS
29.03.2023	Completed purchases under share-based bonus program and mandatory notification of trade

NON-REGULATORY PRESS RELEASES	
Date	*Description*
22.02.2024	OKEA ASA - Purchases under share-based bonus program
21.02.2024	OKEA ASA - Purchases under share-based bonus program
20.02.2024	OKEA ASA - Purchases under share-based bonus program
19.02.2024	OKEA ASA - Purchases under share-based bonus program
16.02.2024	OKEA ASA - Purchases under share-based bonus program
15.02.2024	OKEA ASA - Purchases under share-based bonus program
14.02.2024	OKEA ASA - Purchases under share-based bonus program
13.02.2024	OKEA ASA - Purchases under share-based bonus program
13.02.2024	Initiation of share acquisitions by employees in OKEA ASA
07.02.2024	OKEA webcast Q4 2023
31.01.2024	Invitation to OKEA fourth quarter 2023 conference call
16.01.2024	Three licences awarded to OKEA in APA 2023
25.10.2023	OKEA webcast Q3 2023
18.10.2023	Invitation to OKEA third quarter 2023 conference call
03.10.2023	First gas from Hasselmus
09.08.2023	The Brasse project continues with OKEA as operator
05.07.2023	Invitation to OKEA second quarter 2023 conference call
26.04.2023	Invitation to OKEA first quarter 2023 conference call
28.03.2023	OKEA ASA - Purchases under share-based bonus program
27.03.2023	OKEA ASA - Purchases under share-based bonus program
24.03.2023	OKEA ASA - Purchases under share-based bonus program
23.03.2023	OKEA ASA - Purchases under share-based bonus program
22.03.2023	OKEA ASA - Purchases under share-based bonus program
22.03.2023	Initiation of share acquisitions by employees in OKEA ASA

INSIDE INFORMATION	
Date	*Description*
30.11.2023	Statfjord transaction update

04.10.2023	Revision in reserves at the Yme field
24.08.2023	OKEA ASA: Fixed Income Investor Meetings for Contemplated Senior Secured Bond and Commitment for Revolving Credit Facility
20.03.2023	OKEA acquires 28% working interest in PL037 (Statfjord Area) from Equinor

EX DATE	
Date	*Description*
01.12.2023	OKEA - Trading ex. dividend NOK 1.00 today
01.09.2023	OKEA - Trading ex. dividend NOK 1.00 today
02.06.2023	OKEA - Trading ex. dividend NOK 1.00 today
02.03.2023	OKEA - Trading ex. dividend NOK 1.00 today

MAJOR SHAREHOLDING NOTIFICATIONS	
Date	Description
11.04.2023	Disclosure of Major Shareholding on OKEA ASA for Jungfrau SICAV SIF
11.04.2023	Disclosure of Major Shareholding on OKEA ASA for Banque Pictet & Cie SA

11. Documents on display

For the term of the Registration Document the following documents (or copies thereof), where applicable, may be inspected:

- the up to date memorandum and articles of association of the Company;
- all reports, letters, and other documents, valuations and statements prepared by any expert at the Company's request any part of which is included or referred to in the Registration Document.

The documents may be inspected at the Company's website: http://www.okea.no

12. Cross reference list

In section 9 of this Registration Document information regarding related party transactions is incorporated by reference to note 35 in the annual report 2022.

In section 10 of this Registration Document, the financial information is incorporated by reference to the following:

- Information concerning the Company's Q4 2023 financial figures is incorporated by reference from the Company's Q4 2023 report.
- Information concerning the Company's Q3 2023 financial figures is incorporated by reference from the Company's Q3 2023 report.
- Information concerning the Company's H1 2023 financial figures is incorporated by reference from the Company's H1 2023 report.
- Information concerning the Company's 2022 financial figures is incorporated by reference from the Company's Annual Report 2022.

The Company's financial reports are available at:

Q4 2023: https://www.okea.no/wp-content/uploads/2024/02/okea-q4-2023-quarterly-report.pdf
Q3 2023: https://www.okea.no/wp-content/uploads/2023/07/okea-q3-2023-quarterly-report.pdf
H1 2023: https://www.okea.no/wp-content/uploads/2023/07/okea-q2-2023-quarterly-report.pdf
2022: https://www.okea.no/wp-content/uploads/2023/04/okea-annual-report-2022.pdf