Brønnøysundregistrene

ÅRSREGNSKAPET FOR REGNSKAPSÅRET 2023 - GENERELL INFORMASJON

Enheten

Organisasjonsnummer:	991 317 155
Organisasjonsform:	Aksjeselskap
Foretaksnavn:	ORLEN UPSTREAM NORWAY AS
Forretningsadresse:	Moseidsletta 122 4033 STAVANGER

Regnskapsår

Årsregnskapets periode:	01.01.2023 - 31.12.2023

Konsern

Morselskap i konsern:	Nei

Regnskapsregler

Regler for små foretak benyttet:	Nei
Benyttet ved utarbeidelsen av årsregnskapet til selskapet:	Forenklet IFRS

Årsregnskapet fastsatt av kompetent organ

Bekreftet av representant for selskapet:	Eline J Haugen Pendegraft
Dato for fastsettelse av årsregnskapet:	19.02.2024

Grunnlag for avgivelse

År 2023: Årsregnskapet er elektronisk innlevert
År 2022: Tall er hentet fra elektronisk innlevert årsregnskap fra 2023

Det er ikke krav til at årsregnskapet m.v. som sendes til Regnskapsregisteret er undertegnet. Kontrollen på at dette er utført ligger hos revisor/enhetens øverste organ. Sikkerheten ivaretas ved at innsender har rolle/rettighet for innsending av årsregnskapet via Altinn, og ved at det bekreftes at årsregnskapet er fastsatt av kompetent organ.

Brønnøysundregistrene, 27.06.2025

Resultatregnskap

Beløp i: NOK	Note	2023	2022
RESULTATREGNSKAP			
Inntekter			
Sales income	3, 10	22 132 000 000	43 026 000 000
Other income		8 000 000	10 000 000
Sum inntekter		**22 140 000 000**	**43 036 000 000**
Kostnader			
Exploration expenses	4	676 000 000	633 000 000
Production and sales cost	6, 10	4 151 000 000	2 469 000 000
Employee expenses	5	225 000 000	81 000 000
Depreciation	12	4 691 000 000	4 528 000 000
Depreciation of use to right assets	12	156 000 000	91 000 000
Loss on disposals	12	0	182 000 000
Nedskrivning av varige driftsmidler og immaterielle eiendeler	12		-460 000 000
Other operating expense	7, 10	469 000 000	299 000 000
Sum kostnader		**10 368 000 000**	**7 823 000 000**
Driftsresultat		**11 772 000 000**	**35 213 000 000**
Finansinntekter og finanskostnader			
Renteinntekt fra foretak i samme konsern	18	294 000 000	58 000 000
Other financial income	8	1 404 000 000	1 302 000 000
Sum finansinntekter		**1 698 000 000**	**1 360 000 000**
Rentekostnad til foretak i samme konsern	18	123 000 000	19 000 000
Other financial expenses	9	835 000 000	1 060 000 000
Sum finanskostnader		**958 000 000**	**1 079 000 000**
Netto finans		**740 000 000**	**281 000 000**
Ordinært resultat før skattekostnad		**12 512 000 000**	**35 494 000 000**
Tax on the profit/(loss) for the year	11	9 458 000 000	27 621 000 000
Ordinært resultat etter skattekostnad		**3 054 000 000**	**7 873 000 000**
Årsresultat		**3 054 000 000**	**7 873 000 000**

Balanse

Beløp i: NOK	Note	2023	2022
BALANSE - EIENDELER			
Anleggsmidler			
Immaterielle eiendeler			
Capitalized exploration expenses	12	989 000 000	688 000 000
Goodwill	12	2 803 000 000	2 803 000 000
Sum immaterielle eiendeler		**3 792 000 000**	**3 491 000 000**
Varige driftsmidler			
Assets in production	12	21 664 000 000	15 452 000 000
Assets in development	12	7 909 000 000	7 643 000 000
Right-of-use asset	12	540 000 000	99 000 000
Other fixtures and fittings, tools and	12	8 000 000	7 000 000
Long Term receivable	21	203 000 000	207 000 000
Loan to Group enterpises	18	4 123 000 000	5 296 000 000
Sum varige driftsmidler		**34 447 000 000**	**28 704 000 000**
Sum anleggsmidler		**38 239 000 000**	**32 195 000 000**
Omløpsmidler			
Varer			
Inventory	16	300 000 000	128 000 000
Sum varer		**300 000 000**	**128 000 000**
Fordringer			
Trade receivable		574 000 000	341 000 000
Trade receivables Group enterprises	10	1 344 000 000	3 673 000 000
Other current receivables	14	3 321 000 000	1 877 000 000
Sum fordringer		**5 239 000 000**	**5 891 000 000**
Bankinnskudd, kontanter og lignende			
Cash and cash equivalents	15	2 827 000 000	7 767 000 000
Sum bankinnskudd, kontanter og lignende		**2 827 000 000**	**7 767 000 000**
Sum omløpsmidler		**8 366 000 000**	**13 786 000 000**
SUM EIENDELER		**46 605 000 000**	**45 981 000 000**

Balanse

Beløp i: NOK	Note	2023	2022
BALANSE - EGENKAPITAL OG GJELD			
Egenkapital			
Innskutt egenkapital			
Share capital	17	1 115 000 000	1 115 000 000
Share premuim		1 777 000 000	1 777 000 000
Sum innskutt egenkapital		**2 892 000 000**	**2 892 000 000**
Opptjent egenkapital			
Retained earnings		8 337 000 000	8 645 000 000
Sum opptjent egenkapital		**8 337 000 000**	**8 645 000 000**
Sum egenkapital		**11 229 000 000**	**11 537 000 000**
Gjeld			
Langsiktig gjeld			
Utsatt skatt	11	13 350 000 000	10 431 000 000
Abandonment provision	21, 22	6 578 000 000	3 102 000 000
Sum avsetninger for forpliktelser		**19 928 000 000**	**13 533 000 000**
Annen langsiktig gjeld			
Gjeld til kredittinstitusjoner	19	506 000 000	0
Lease liabilities	13, 22	579 000 000	101 000 000
Sum annen langsiktig gjeld		**1 085 000 000**	**101 000 000**
Sum langsiktig gjeld		**21 013 000 000**	**13 634 000 000**
Kortsiktig gjeld			
Debt to financial institutions payable	19	23 000 000	12 000 000
Leverandørgjeld	10	979 000 000	303 000 000
Taxes payable, not assessed	11	5 268 000 000	18 288 000 000
Employee tax liabilities, duties		62 000 000	28 000 000
Kortsiktig konserngjeld	18, 24		
Other current liabilities	22, 24	2 956 000 000	2 179 000 000
Other liabilities to group enterprises	18, 24	5 072 000 000	0
Interest on debt to group enterprises	18	3 000 000	0
Sum kortsiktig gjeld		**14 363 000 000**	**20 810 000 000**

Balanse

Beløp i: NOK	Note	2023	2022
Sum gjeld		**35 376 000 000**	**34 444 000 000**
SUM EGENKAPITAL OG GJELD		**46 605 000 000**	**45 981 000 000**

Deloitte.

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To the General Meeting of PGNiG Upstream Norway AS

INDEPENDENT AUDITOR'S REPORT

Opinion
We have audited the financial statements of PGNiG Upstream Norway AS (the Company), which comprise the balance sheet as at 31 December 2023, statement of profit and loss, statement of comprehensive income, statement of changes in equity, statement of cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In our opinion

- the financial statements comply with applicable statutory requirements, and
- the financial statements give a true and fair view of the financial position of the Company as at 31 December 2023, and its financial performance and its cash flows for the year then ended in accordance with simplified application of International Accounting Standards according to the Norwegian Accounting Act section 3-9.

Basis for Opinion
We conducted our audit in accordance with International Standards on Auditing (ISAs). Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of our report. We are independent of the Company as required by relevant laws and regulations in Norway and the International Ethics Standards Board for Accountants' International Code of Ethics for Professional Accountants (including International Independence Standards) (IESBA Code), and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Other Information
The Board of Directors and the Managing Director (management) are responsible for the information in the Board of Directors' report. The other information comprises information in the annual report, but does not include the financial statements and our auditor's report thereon. Our opinion on the financial statements does not cover the information in the Board of Directors' report.

In connection with our audit of the financial statements, our responsibility is to read the Board of Directors' report. The purpose is to consider if there is material inconsistency between the Board of Directors' report and the financial statements or our knowledge obtained in the audit, or whether the Board of Directors' report otherwise appears to be materially misstated. We are required to report if there is a material misstatement in the Board of Directors' report. We have nothing to report in this regard.

Based on our knowledge obtained in the audit, it is our opinion that the Board of Directors' report

- is consistent with the financial statements and
- contains the information required by applicable statutory requirements.

Responsibilities of Management for the Financial Statements
The Board of Directors and the Managing Director (management) are responsible for the preparation of financial statements that give a true and fair view in accordance with simplified application of International Accounting Standards according to the Norwegian Accounting Act section 3-9, and for such internal control as management

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determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISAs will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with ISAs, we exercise professional judgment and maintain professional scepticism throughout the audit. We also:

- identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error. We design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- conclude on the appropriateness of management's use of the going concern basis of accounting, and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves a true and fair view.

We communicate with the Board of Directors regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Stavanger, 19 February 2024
Deloitte AS

Bjarte M. Jonassen
State Authorised Public Accountant

PGNIG - Independent auditor's report

Name	Date
Jonassen, Bjarte Munkejord	**2024-02-19**

Identification

bankID Jonassen, Bjarte Munkejord

Skattedirektoratet

Saksbehandler	Deres dato	Vår dato
Torstein Kinden Helleland	19.09.2008	19.03.2009
Telefon	Deres referanse	Vår referanse
22 07 81 39	Gry Merete Mellemstrand	2009/170942

Deloitte AS
Postboks 287 Forus
4066 STAVANGER

Søknad om tillatelse til å utarbeide årsregnskap og årsberetning på engelsk språk for PGNiG Norway AS, org. nr. 991 317 155

Det vises til Deres brev til Finansdepartementet av 19. september 2008 oversendt Skattedirektoratet 13. mars 2009. Det vises videre til e-post av 18. mars 2009 samt telefonsamtale i sakens anledning. De søker på vegne av PGNiG Norway AS om dispensasjon fra kravet til å utarbeide årsregnskap og årsberetning på norsk språk.

I søknaden er det opplyst at selskapet er stiftet og 100 % eid av polske PGNiG SA, som er børsnotert på Warsawa-børsen. Den polske stat eier ca 85 % av aksjene i PGNiG SA. Selskapet er finansiert av morselskapet og har ingen ekstern langsiktig gjeld. Selskapet er etablert som et oljeselskap. Engelsk er i stor grad etablert som forretningsspråk i oljebransjen i Norge. Selskapets regnskap utarbeides etter forenklet IFRS, og innarbeides i konsernregnskapet for det polske konsernet. Konsernregnskapet utarbeides både på polsk og engelsk. Selskapet har norsk regnskapsmedarbeider og polsk økonomisjef. Ca. 1/3 av de ansatte er polske mens resten er norske. Alle styremedlemmene er polske. Da de norske ikke snakker polsk og de polske ikke snakker norsk i særlig grad skjer kommunikasjon internt i selskapet og konsernet, samt mot revisor, i stor grad på engelsk. Avtaler med morselskap utarbeides i hovedsak på engelsk, det samme gjelder styremøtereferater. Selskapet søker på denne bakgrunn om dispensasjon fra Regnskapsloven § 3-4 tredje ledd om at årsregnskap og årsberetning skal være på norsk.

Etter regnskapsloven § 3-4 tredje ledd skal *"årsregnskapet og årsberetningen ... være på norsk. Departementet kan ved ... enkeltvedtak bestemme at årsregnskapet og/eller årsberetningen kan være på et annet språk."*

I Ot. prp. nr. 42 (1997-1998) Om lov om årsregnskap m.v., er det uttalt følgende om regnskapslovens formål, jf. pkt. 1.1:
"Regjeringen har som siktemål at regnskapsloven skal bidra til informative regnskaper for ulike grupper av regnskapsbrukere. Regnskapsbrukerne er dels investorer og kreditorer som tilfører kapital til foretakene, og dels andre grupper som har interesse av å vite hvordan foretaket drives, f.eks. de ansatte og lokalsamfunnet. Informasjonen til kapitalmarkedet skal gi grunnlag for riktig prising av finansielle objekter. Riktig prisdannelse på aksjer er en forutsetning for at ressursbruken i samfunnsøkonomien skal bli best mulig. Gode regnskaper vil også gjøre det vanskeligere for markedsdeltakere å ta ut spekulasjonsgevinster med basis i skjevt fordelt informasjon."

Postadresse
Postboks 9200 Grønland
0134 Oslo
skattedirektoratet@skatteetaten.no

Besøksadresse
Fredrik Selmers vei 4
Org. nr: 974761076

Sentralbord
800 80 000
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22 17 08 60

Det fremgår således at et av hovedformålene med regnskapsloven er å bidra til *"informative regnskaper for ulike grupper av regnskapsbrukere"*. Regnskapsbrukere vil omfatte, jf. uttalelsen i proposisjonen, blant andre investorer, kreditorer, ansatte og lokalsamfunnet. Offentlige myndigheter må også anses som en sentral regnskapsbruker, idet ulike myndigheter, som lignings- og tilsynsmyndigheter, benytter regnskapene som sentrale verktøy i sin kontrollvirksomhet.

Det er etter Skattedirektoratets vurdering derfor avgjørende at spørsmål om dispensasjon fra kravet til å utarbeide årsregnskap og/eller årsberetning på norsk, ikke på vesentlige områder fraviker fra hensynet til brukere av regnskapsinformasjon. Søkeren må dessuten som et utgangspunkt for vurderingen ha en særlig interesse for kun å utarbeide årsregnskap og/eller årsberetning på et annet språk enn norsk.

Som nevnt ovenfor er det særlig hensynet til brukerne av regnskapsinformasjon som skal vurderes ved en dispensasjonssøknad. Selskapet er 100 % eid av polske PGNiG SA som er børsnotert på Warsawa-børsen. Selskapet er finansiert av morselskapet og har ingen ekstern langsiktig gjeld. Konsernregnskapet utarbeides både på polsk og engelsk. Forretningsspråket er i det vesentlige engelsk innen oljebransjen. Arbeidsspråket i selskapet er i stor grad engelsk fordi alle styremedlemmene og mange av de ansatte er polske. Avtaler med morselskap utarbeides i hovedsak på engelsk, det samme gjelder styremøtereferater

Skattedirektoratet gir på bakgrunn av en helhetsvurdering PGNiG Norway AS dispensasjon fra kravet til å utarbeide årsregnskap og årsberetning på norsk språk, jf. regnskapsloven § 3-4 tredje ledd.

Dispensasjonen er gitt under den forutsetning at de ovennevnte opplysninger som vedtaket baserer seg på ikke endres vesentlig.

Med hilsen

Jan Hoelstad
seniorrådgiver
Rettsavdelingen, foretaksskatt
Skattedirektoratet

Torstein Kinden Helleland

PGNiG | UPSTREAM NORWAY
ORLEN GROUP

ANNUAL REPORT 2023

STAVANGER, 19 FEBRUARY 2024

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DIRECTORS' REPORT

PGNiG Upstream Norway AS ("**PGNiG Upstream**" or "**the Company**") was established in May 2007, and its head office is in Stavanger Norway, with a regional office in Tromsø. The objective of the Company is to explore, develop and produce oil and gas.

PGNiG Upstream is a wholly owned subsidiary of ORLEN S.A. ("**ORLEN**"). ORLEN is an integrated, multi-utility corporation primarily active in Central Europe. It supplies energy and fuel to over 100 million Europeans, and its products are sold in over 100 countries across six continents. The main shareholder of ORLEN is the Polish State Treasury.

ORLEN is involved in the upstream and downstream sectors of the oil and gas industry, as well as in power generation and distribution. Central to ORLEN's mission is the commitment to lead the regional energy transition. The company is dedicated to adopting innovative, clean, and sustainable technologies, focusing particularly on low- and zero-emission power generation. This forward-thinking approach is part of ORLEN's strategic goal to achieve emission neutrality by the year 2050.

ORLEN, in its 2030 strategy announced in February 2023 sets ambitious targets for decarbonisation, in which natural gas plays an important role as a transition fuel. Therefore, one of the most important tasks for PGNiG Upstream is to secure stable and reliable gas supplies for ORLEN.

Detailed information about the activities and business profile of ORLEN can be found at the company's internet address: www.orlen.pl/en.

Company overview

PGNiG Upstream is one of the largest gas producers on the Norwegian Continental Shelf ("**NCS**"). During 2023, the Company generated revenues of NOK 22.1 billion, with a production of 26.1 mboe.

The current position is the consequence of the historical investment program. Over the last years PGNiG Upstream has invested more than 40 billion NOK in Norway and participated in the drilling of multiple exploration and production wells. This has led to several discoveries on the NCS, including Ærfugl, Lunde (Shrek), Warka, Newt and Dougal. In addition, the Company has participated in 20 licensing rounds and been awarded 48 production licenses (out of which 11 as operator).

PGNiG Upstream currently owns shares in nineteen producing fields on the NCS (Skarv, Morvin, Vilje, Gina Krog, Ærfugl Nord, Skogul, Kvitebjørn, Valemon, Duva, Alve, Marulk, Ormen Lange, Tommeliten Alpha, Sleipner Vest, Sleipner Øst, Gungne, Utgard, Tambar Øst and Yme) and participates in eight sanctioned development projects (Ormen Lange phase 3, Fenris, Alve Nord, Andvare, Verdande, Tyrving, Yggdrasil and Ørn). Furthermore, there is ongoing evaluation work on recent discoveries. As of 31st of December 2023, the total resources and reserves are expected to be 347 million barrels of oil equivalent (RNB2024 Reserves class 1-5 as defined by NOD - unaudited information).

Field	PUN share	Operator	PUN 2P + 2C 2023 mboe*	PUN prod. 2023 kboe/d
Ærfugl Nord	15.0 %	AkerBP	1,1	2,1
Alve	15.0 %	Equinor	2,2	2,1
Duva	30.0 %	Neptune	9,7	8,6
Gina Krog	11.3 %	Equinor	9,3	6,0
Gungne	15.0 %	Equinor	1,1	0,4
Kvitebjørn	6.5 %	Equinor	8,3	3,5
Marulk	30.0 %	Vår	1,3	2,1
Morvin	6.0 %	Equinor	0,2	0,3
Ormen Lange	14.0 %	Shell	69,8	17,1
Skarv	11.9 %	AkerBP	25,0	17,7
Skogul	35.0 %	AkerBP	2,2	0,7
Sleipner Øst	15.0 %	Equinor	2,5	0,6
Sleipner Vest	15.0 %	Equinor	12,2	3,3
Utgard	17.3 %	Equinor	2,5	0,6
Vale	50.0 %	Sval	0,0	1,3
Valemon	3.2 %	Equinor	0,3	0,3
Vilje	24.2 %	Aker BP	1,3	0,8
Yme	20.0 %	Repsol	7,9	2,7
Tambar Øst	5,44 %	Aker BP	0,4	0,0
Tommeliten Alpha	42.2 %	Conoco	71,1	1,4
Sum of assets producing in 2023			228,3	71,6
Alve Nord	11.9 %	AkerBP	5,0	
Andvare	15.0 %	Equinor	1,4	
Fenris	22.2 %	AkerBP	42,2	
Ørn	40.0 %	AkerBP	21,2	
Tyrving	11.9 %	AkerBP	3,4	
Verdande	0.8 %	AkerBP	0,3	
Yggdrasil	12.3 %	Aker BP	45,6	
Sum of assets in development			119,0	-
Sum PUN asset portfolio			**347,3**	**71,6**

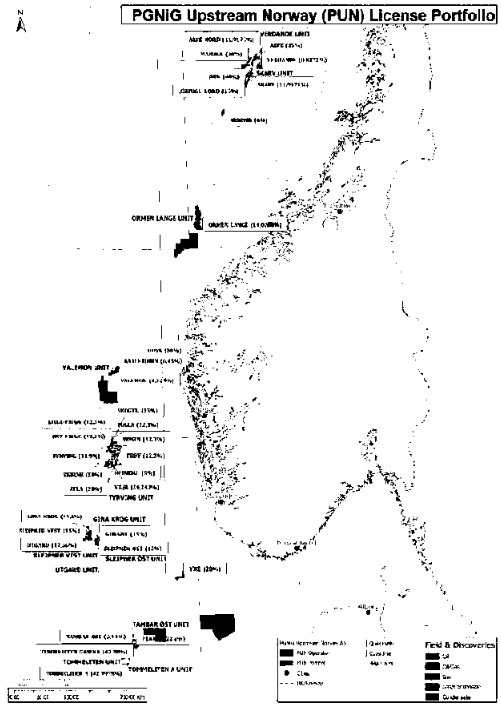
**Source: RNB2024, Note 28*

In addition, the Company holds a considerable exploration portfolio, which is expected to mature into future drill decisions on the NCS.

Together with the assets from its newly acquired subsidiary KUFPEC Norway AS – now rebranded as ORLEN Upstream Norway 2 AS ('OUN2') – the Company consider its portfolio to be well positioned both in respect of near-term production and longer-term development opportunities.

Key developments in 2023

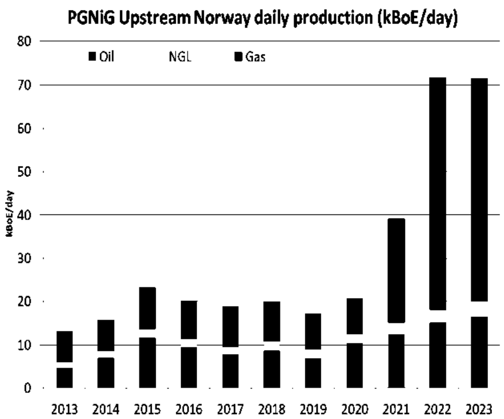
The Company's main objective is to secure stable, reliable and cost-effective gas supplies for the ORLEN Group. This goal is expected to be materialized through diversified hydrocarbon production from the Norwegian Continental Shelf (NCS).



In 2023 the Company delivered strong results, with revenues of NOK 22.1 billion and an EBITDA of NOK 16.6 billion. These results were possible thanks to the performance of key assets like Ormen Lange, Skarv, Duva and Gina Krog, which accounted for approximately 69 % of the total production.

With the total production in 2023 of 3.0 billion cubic metres of gas, and 980 thousand tonnes of crude oil (including NGL's), the Company managed to maintain the record high production level from 2022.

While maintaining production, price levels have come significantly down during 2023, with the realised gas price of 41 EUR/MWh and a realised oil price of 82 USD/boe, explaining the decrease in revenues in comparison with the previous year. The extraordinary increase of gas prices observed during 2021 and 2022 was a consequence of Russia's invasion of Ukraine and curtailment of Russian supplies to Europe. Nevertheless, the geopolitical situation continues to be highly uncertain, which emphasizes importance of the overarching aim of the Company to provide stable gas supplies to ORLEN through the Baltic Pipe



In 2023, the Company exceeded the production target set out in its strategy. Such an increase was possible thanks to significant investments in the previous years and startup of production from Tommeliten Alpha. In addition, PGNiG Upstream continued reduced gas injection on Skarv and Gina Krog to enable more gas export to Baltic Pipe.

The sections below include an overview of the Company's key achievements.

Successful business development activities

During 2023, the Company has made several investments to further strengthen its position on the NCS. On May 2nd, the Company completed acquisition of business from LOTOS Exploration & Production Norge AS ("**LOTOS**") and successfully integrated new assets to its portfolio. This includes interest in the producing fields Sleipner Vest, Sleipner Øst, Gungne, Utgard and Yme, as well as interest in the development projects Yggdrasil and Tyrving. Transaction with LOTOS fulfilled regulatory requirements in Norway and brought significant operational and financial synergies.

In June, the Company completed the acquisition of a 10% interest in the license PL211CS, which includes the Adriana & Sabina discovery, with oil and gas reserves estimated ranging between 38 and 88 million boe gross. The fields are located 20 kilometres southwest of the Skarv field, which is the main centre of the ORLEN Group's operations on the NCS.

On November 17th, the Company signed the agreement to purchase all shares in KUFPEC Norway AS. The transaction was completed on January 5th, 2024.

The acquired subsidiary is now rebranded as ORLEN Upstream Norway 2 AS, and the assets and activities will be consolidated and its organisation integrated with PGNiG Upstream during 2024.

Following this acquisition, the ORLEN Group's natural gas output in Norway will increase by one-third, reaching over 4 billion cubic meters (bcm) in 2024. Post-transaction, PGNiG Upstream's daily production is projected to exceed 100 thousand boe per day, positioning the Company among major oil and gas producers in Norway.

The acquisition KUFPEC Norway AS will expand holdings of PGNIG Upstream in the producing fields of Gina Krog, Sleipner Vest, Sleipner Ost, Gungne and Utgard. In addition, the ORLEN Group will gain 21.8% in the Eirin gas development. Eirin is developed as a subsea tie-back to Gina Krog which ensures attractive profitability and low carbon emissions from production.

On December 27th the Company agreed with Wintershall DEA Norge AS a swap agreement, where PGNiG Upstream transfers a 3.0825 interest in PL 212E (Ærfugl Nord) in exchange for a 11.9175 % interest in PL 159D (Idun Nord) and a further 1.9175 % interest in PL

211CS (Adriana & Sabina). This transaction is expected to complete during first half of 2024. The transaction ensures PGNiG Upstream presence in all licenses in the 'Skarv Satellites' developments, consisting of Alve Nord, Idun Nord and Ørn fields.

Illustration of Skarv Satellite Project, including Ørn, Idun Nord and Alve Nord

The Company passed another important milestone with its announced acquisition of an interest in the Polaris CO_2 storage project in the Barents Sea. The Norwegian Ministry of Energy approved PGNiG Upstream as the operator of this project on January 4th, 2024. This represents a new business area for PGNiG Upstream, and the Company consider its extensive subsurface expertise can be very valuable in the further development of this project. The Polaris Carbon Capture and Storage project is also contributing to the decarbonisation strategy of the ORLEN Group.

Strong development focus

PGNiG Upstream holds a well-diversified portfolio ranging from exploration, development, production and decommissioning. A portfolio that is expected to play an important role in securing gas deliveries to ORLEN.

The Company is currently participating in eight development projects on the NCS (Ormen Lange phase 3, Fenris, Alve North, Verdande, Andvare, Ørn, Yggdrasil and Tyrving). The number of investment projects will further increase in 2024, following acquisition of Eirin and Idun Nord.

The involvement in multiple development projects will enable PGNiG Upstream to increase its hydrocarbon production in future years. As of the balance sheet date, the projects are executed according to schedule.

On October 13th, 2023 an important milestone was achieved when production from the Tommeliten Alpha development commenced. The production started nearly six months ahead of the scheduled date and the filed reserved increased by nearly 21% as a result of successful development.

The hydrocarbons from Tommeliten Alpha will be produced from 11 wells and delivered via a heated pipeline to the Ekofisk facilities for further processing and transportation..

In addition, the Company is working closely with operator Aker BP to evaluate development opportunities for the Lunde (Shrek) discovery. Lunde is a result of the Company's own exploration activities.

Supporting ORLEN strategic ambitions

After the successful merger and integrations of activities of ORLEN, PGNiG and Grupa LOTOS, ORLEN in February 2023 launched its new strategy. At core of this strategy is the ambition to play a leading role in the energy transition in Central Europe towards a target of net zero carbon emissions by 2050.

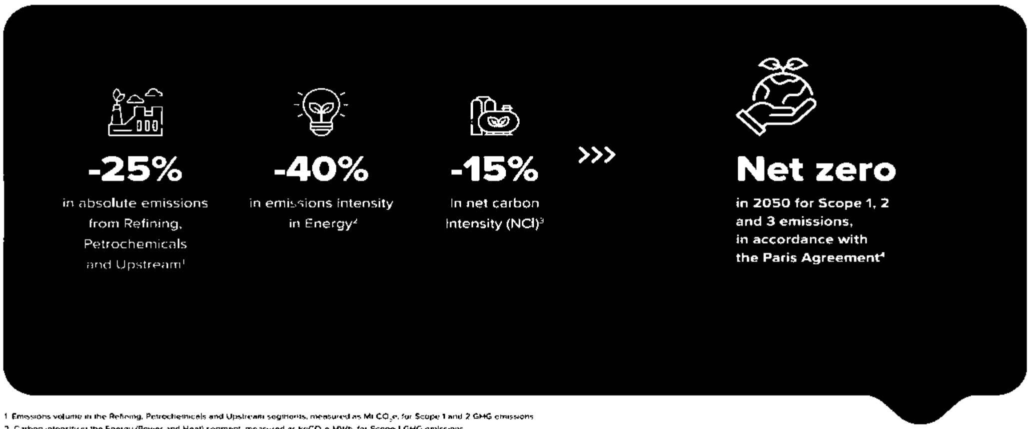
In the ambitious decarbonisation strategy of the ORLEN Group, the use of natural gas as a replacement fuel for coal in Poland's power and heat generation plays a very important role, due to its significantly lower CO_2 emissions. This is why the ORLEN group has set the target to increase production of natural gas from about 8 bcm gas in 2022 to 12 bcm by 2030.

The overview of the decarbonisation targets for the ORLEN Group is included on the following graph.

ORLEN

More ambitious decarbonisation targets confirm our commitment to achieve carbon neutrality in 2050

2030 targets **2050 targets**



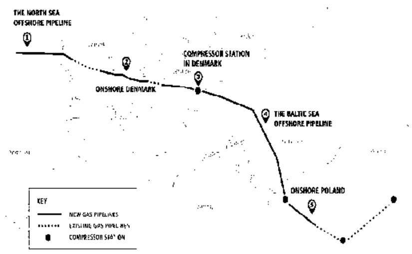
1. Emissions volume in the Refining, Petrochemicals and Upstream segments, measured as Mt CO_2e, for Scope 1 and 2 GHG emissions
2. Carbon intensity in the Energy (Power and Heat) segment, measured as kgCO_2e/MWh, for Scope 1 GHG emissions.
3. Carbon intensity of sold energy products, measured as gCO_2e/MJ, for Scope 1, 2 and 3 GHG emissions
4. Our ambition to reduce emissions is consistent with the goal of limiting climate warming to 1.5 °C by 2050. The achievement of our long-term targets will depend on the technological progress and the regulatory and legal context. Those factors may create more or less favourable conditions for the energy transition and accelerate or reduce the pace of our strategy implementation

A significant portion of the gas production increase is expected to be achieved by PGNiG Upstream on the NCS. The importance of Norway for the ORLEN Group is directly connected with establishment of the Baltic Pipe that enables gas deliveries to Poland and Central Europe.

PGNiG Upstream and the ORLEN group has been heavily involved in the realisation of this infrastructure project that has now been operational since November 2022. For Poland, the Baltic Pipe Project brings the ability to fulfil the following important goals:

- Support green transition with significant reduction in carbon emissions
- Greatly improved air quality
- Increased energy security and control of energy supply
- Stronger integration with Europe
- A more diverse energy mix
- Support increased energy demand while simultaneously reducing the use of coal

Illustration of Baltic Pipe Infrastructure project



By 2030, PGNiG Upstream is expected to increase its supply of natural gas through the Baltic Pipe from approx. 3.1 bcm in 2023 to more than 6 bcm by 2030. The key to delivering on that target will be further investments on the NCS.

Exploration

In 2023, the Company drilled two exploration wells and made two new discoveries.

1. **Fulla & Hugin Exploration, Frigg Øst Beta/Epsilon** PGNiG participated in AkerBP operated exploration drilling resulting in a significant additional reserves to the Yggdrasil development. A combined appraisal and discovery of 8.5-14.3 MSm^{3}oe recoverable oil was made in the Frigg level in the abandoned Øst

Frigg gas field and the adjacent Epsilon prospect. PGNiG holds 12.3%.

2. **Gina Krog Unit Exploration, Dougal:** The 'Dougal' exploration well 15/6-B-20 resulted in a gas/condensate discovery with a recoverable volume range of 0.8-2.6 MSm^3oe. The well was completed for production via the Gina Krog field in January 2024.

Scarabeo 8 drilled Frigg Øst/ Epsilon

Exploration activities are expected to play an important role in enabling PGNiG Upstream to maintain high and stable production in the long-run. The Company remains consistently active in license rounds, and was awarded 10 new licenses in APA 2023, including one new operatorship.

Appraisal drilling on Adriana/Sabina commenced on the 21st December 2023 and results are anticipated in Q1 2024.

Research and development activities

PGNiG Upstream's R&D activities have been focused on tools and methods for exploration, subsurface and production, primarily through its co-operation with universities, ORLEN and external experts.

The total cost of R&D activities amounted to NOK 4.3 million in 2023. The main objective of this expense is to get access to scientific studies that can be used by PGNiG Upstream on its licenses on the NCS.

ORLEN R&D Center

By carrying out these studies, PGNiG Upstream is gaining access to exclusive scientific information and highly qualified personnel. The Company anticipate the benefits from research and development will offset the total costs incurred.

Company development, performance and going concern

In accordance with the Norwegian Accounting Act, the Company's Board of Directors has reviewed the going concern assumption, considering all relevant information available to date. Company accounts are issued and all available information about the future are considered for at least 12 months from the reporting date. The review included the operational outlook and work programs, while maintaining appropriate headroom in respect of liquidity and financial covenant compliance throughout the assessment period.

Following its review, the Board of Directors confirms, pursuant to the Norwegian Accounting Act section 3-3a, that the requirements of the going concern assumption are met, and that these financial statements have been prepared on that basis. The Board is not aware of any matters not covered in this report that could be of significance, when evaluating the Company's position.

Working environment

The Board is pleased to report that the Company has built a highly competent organisation based on experienced employees with varying backgrounds –

both technical and commercial. The average number of employees in 2023 amounted to 98. All employees have been trained in Norwegian regulations.

Company Values

Measures are taken to ensure a safe workplace and continuous improvement of the working environment, among others by maintaining a regular dialogue with elected employee and trade union representatives.

Absence from work due to illness has remained low at 3.60 per cent and there were no work-related injuries nor accidents in 2023. Measures continue to be implemented to maintain these low rates of absence and no work-related injuries.

Equal opportunities

The Company is committed to maintain a working environment with equal opportunities for all based on qualifications, irrespective of gender, leave in connection with childbirth or adoption, care responsibilities, ethnicity, religion, belief, disability or sexual orientation, gender identity or gender expression. PGNiG Upstream does not tolerate any form of discrimination in relation to employees, partners or suppliers.

In December 2023, women held 30% of positions in the Company. At the same time, the Board consisted of five male and two female members. Remuneration is related to job content, competence, and qualification. This ensures that men and women with corresponding positions and equal experience, and who produce equally good results, receive the same pay.

In December 2023, a total of five employees worked voluntary part time, of which three were women and two were men. One female was working in a temporary position. In addition, the Company cooperated with one male consultant. In the course of 2023, the average duration of parental leave was 34 weeks for women, and 14 weeks for men.

External environment

Our aim is to prevent all incidents, accidents or accidental discharges that can cause harm to people, environment, or material assets; we will conduct our business in a safe and environmentally friendly way.

We do not want to cause unnecessary strain to the environment. Our office is in a new energy efficient building, using district heating and cooling, generated by a nearby waste handling plant. PGNiG Upstream operates within an industry where there is risk of pollution of the environment. Therefore, the Company places high focus on the environment in its operated licenses. In addition, PGNiG Upstream closely follows activities of other operators. We perform our duties through audits, verifications, meetings and by reviewing daily, weekly, and monthly reports.

Results, investments

The operational performance in 2023 was very strong, characterized by a stable and high production from the portfolio. Compared to the exceptional pricing environment from 2022, gas prices reduced during 2023 and the Company generated revenues for the year of NOK 22 140 million. PGNiG Upstream has managed the assets safely, reliable and in a cost-effective manner, materializing an EBITDA of NOK 16 619 million.

Accumulated operating costs at the end of 2023 amounted to NOK 10 368 million, of which NOK 4 846 million was classified as depreciation and impairment. The comparative figures for the preceding year were

NOK 7 823 million and NOK 4 160 million, respectively. Personnel costs were NOK 225 million in 2023, compared to NOK 81 million in 2022. The increase was connected with higher number of employees following acquisition of LOTOS as well as lower recharges to operated licenses in 2023.

Net financial income for the period was NOK 740 million, compared NOK 281 million in the previous year. This development is driven by an increased net interest income from financing activities as well as a positive impact from foreign exchange rates.

Fixed assets utilized in production and development are valued at NOK 29 573 million, representing an increase of NOK 6 478 million in comparison with the previous year. This is due to both acquisition of new assets as well as significant development activities in ongoing projects. The Company's cash and cash equivalents position was reduced from NOK 7 767 million to NOK 2 827 million at the end of 2023. The Company's policy in 2023 was based on active cash management.

A detailed overview of the financial performance is included in the relevant sections of the Financial Statements. The Board is not aware of any circumstances of negative significance to the Group's financial position that are not described in the Financial Statements, including notes, neither during the accounting year, nor after the year end closing

A separate country-by-country reporting of payments to authorities for 2023 is provided together with the Annual Report.

The Company will make available a statement in accordance with section 5 of the Norwegian Transparency Act on the Company web-page: www.pgnig.no

In the opinion of the Board of Directors there is no risk associated with financing any further operations of PGNiG Upstream. The Company holds considerable un-

Liquidity and financing

The liquidity of PGNiG Upstream in 2023 has been secured primarily by sales revenues. Based on the EBITDA of NOK 16 619 million, the Company generated a net negative cash flow from operating activities at the level of NOK 1 415 million. In addition, the Company has utilised financing available from affiliated companies, as well as external financing through the RBL Facility as sources of funding for the high investment activity.

The details of the Company's sources of financing are presented in the notes to the Financial Statements.

The Company has an external loan facility of USD 700 million, which include the flexibility of a USD 300 million accordion mechanism on top. This financing arrangement ensures the Company can comfortably meet future commitments and also provide financial flexibility to pursue further development opportunities.

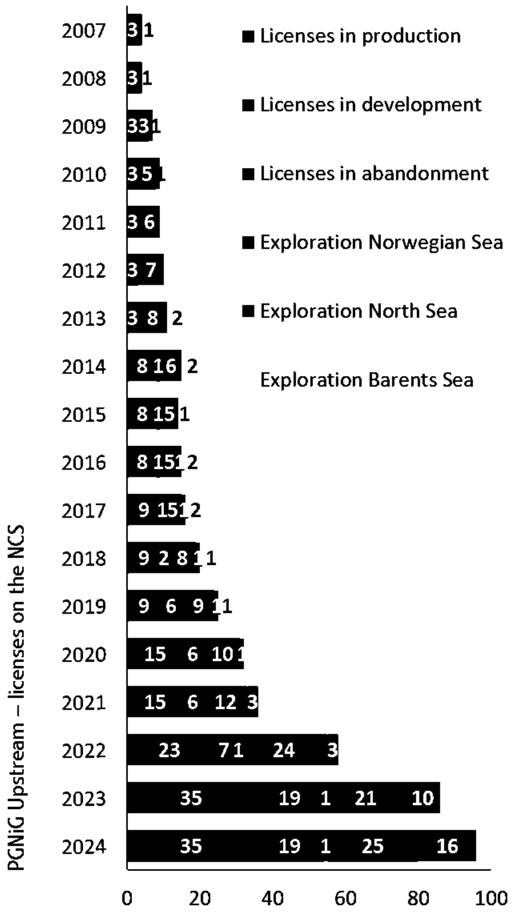
The Company's current liquidity, in the form of cash at hand, existing debt facilities and future operational cash flow supports all current project commitments. The Board confirms that the Company meets the requirements of the Companies Act in ensuring a proper level of equity and liquidity relative to the risk and extent of its business. The Board also confirms that the Company complies with covenants included in its financing agreements.

Skarv FPSO

drawn external credit facilities and cash and cash equivalents, and income from future operational activities look promising.

Risk factors

PGNiG Upstream is operating in a macro environment with high volatility of sales prices, as experienced from price levels and fluctuations experienced in the period from 2020 to 2023. Changes in market conditions (oil and gas prices) and foreign exchange rates may impact future margins.



Another risk factor is related to reserves estimates, which may be inaccurate. The Company is participating in complex projects that are challenging in terms of timing and cost control (for example Yggdrasil, Ørn, Ormen Lange Phase 3, and Fenris). However, the existing portfolio is characterized by relatively low production costs and high margins. Therefore, the risk exposure in the total investment portfolio is considered as acceptable.

PGNiG Upstream has a long-term strategy and uses conservative assumptions in its planning. At the end of the reporting period the Company had no financial hedging instruments or contracts. This policy is supported by the shareholder.

PGNiG Upstream has signed insurance policies for the members of the Board of Directors potential liability towards the Company and third parties. The insurance is policy is renewed on an annual basis.

Outlook

The NCS is recognised as an important area for international upstream activities for ORLEN and has significant exploration potential.

The scale of our Norwegian operations makes Norway the key destination for ORLEN's international expansion, with three main factors determining our choice: diversification of Poland's gas supply sources, strong exploration potential and a stable, transparent regulatory framework.

The expected activities in 2024 include consolidation of the Norwegian operations of PGNiG Upstream and ORLEN Upstream Norway 2 AS ("**OUN2**") within one entity. This will enable materialisation of several synergies and will also fulfil regulatory requirements in Norway. The consolidated operations of the entities is expected to rank among the seventh biggest players on the NCS measured in terms of gas production and reserves.

PGNiG Upstream was founded in 2007 and has since the start been growing at a rapid pace, through organic growth and targeted acquisitions, made possible through the strong support by the parent company, dedicated management and highly competent employees. We have invested more than NOK 30 billion and participated in numerous exploration and production wells, which has led to several discoveries. Altogether, the Company owns shares in eighteen producing fields and eight developments with a total resource and reserves estimate of 347 million boe. In addition, the Company holds a considerable exploration portfolio, which is expected to secure the long-term supply of gas to ORLEN.

Ormen Lange unit

From the perspective of the Board of Directors, PGNiG Upstream will focus on the following main areas:

- securing natural gas supplies for the ORLEN Group,
- developing the exploration & production business, and
- supporting ORLEN Group decarbonisation strategy

It is expected that business development activity will continue in the upcoming years. At the same time PGNiG Upstream plans to develop its operatorship capabilities and, potentially, become an active operator of production and developments in the future. The Company is open for any opportunities and business partnerships that may arise on the NCS, as such. To summarise, increasing production capacity on the NCS and securing new gas supplies for Poland, should enable the Natural Gas business of ORLEN to maintain its leading position in Central Europe. The historical activity by PGNiG Upstream should be seen as an initial step on the growth path of the ORLEN natural gas activities. The next steps will be defined by new projects.

Stavanger,
19.02.2024

Robert Dominik Śleszyński *Chairman of the Board*	Marcin Gargas *Director of the Board*	Robert Harasimiuk *Director of the Board*	Urszula Monika Kowalczyk *Director of the Board*
Przemysław Wacławski *Director of the Board*	Iwona Waksmundzka-Olejniczak *Director of the Board*	Maciej Pawel Wyszoczarski *Director of the Board*	Marek Woszczyk *General Manager*

FINANCIAL STATEMENTS

INCOME STATEMENT (NOK million)

Note		2023	2022
3 | 10	Sales income	22 132	43 026
	Other income	9	9
	Revenue	**22 140**	**43 035**
4	Exploration expenses	(676)	(633)
5	Employee expenses	(225)	(81)
12	Depreciation	(4 691)	(4 528)
12	Depreciation of right-of-use assets	(156)	(91)
12	Impairment reversals	0	460
12	Loss on disposals	0	(182)
6 | 10	Production and sales costs	(4 151)	(2 469)
7 | 10	Other operating expenses	(469)	(299)
	Total operating expenses	**(10 368)**	**(7 823)**
	Operating income/(loss)	**11 772**	**35 212**
18	Interest income from Group enterprises	294	58
18	Interest expenses to Group enterprises	(123)	(19)
8	Other financial income	1 404	1 302
9	Other financial expenses	(835)	(1 060)
	Net financial items	**740**	**281**
	Income/(loss) before tax	**12 512**	**35 493**
11	Tax on the profit/(loss) for the year	(9 458)	(27 621)
	Net income/(loss)	**3 054**	**7 873**

STATEMENT OF COMPREHENSIVE INCOME

	2023	2022
Net income/(loss)	**3 054**	**7 873**
Total comprehensive income	**3 054**	**7 873**

BALANCE SHEET (NOK million)

ASSETS

Note		31/12/2023	31/12/2022
12	Goodwill	2 803	2 803
12	Capitalized exploration expenses	989	688
	Intangible assets	**3 792**	**3 491**
12	Assets in production	21 664	15 452
12	Assets in development	7 909	7 643
12	Other fixtures and fittings, tools and equip.	8	7
12	Right-of-use asset	540	99
21	Long term receivable	203	207
18	Loan to Group enterprises	4 123	5 296
	Tangible fixed assets	**34 447**	**28 704**
	Non-current assets	**38 239**	**32 195**
16	Inventory	300	128
	Trade receivables	574	341
10	Trade receivables Group enterprises	1 343	3 673
14	Other current receivables	3 321	1 877
	Current receivables	**5 239**	**5 891**
15	Cash and cash equivalents	2 827	7 767
	Current assets	**8 366**	**13 786**
	Assets	**46 605**	**45 981**

EQUITY AND LIABILITIES

Note		31/12/2023	31/12/2022
17	Share capital	1 115	1 115
	Share premium	1 777	1 777
	Paid-in capital	**2 892**	**2 892**
	Retained earnings	8 337	8 645
	Equity	**11 229**	**11 537**
11	Deferred tax	13 350	10 431
21 | 22	Abandonment provision	6 578	3 102
	Total Provisions	**19 928**	**13 534**
19	Debt to financial institutions	506	0
13 | 22	Lease liabilities	579	101
	Long-term liabilities	**1 085**	**101**
10	Trade payables	979	303
	Employee tax liabilities, duties	62	28
18	Interest on Debt to Group enterprises	3	0
18 | 24	Other liabilities Group enterprises	5 071	0
19	Debt to financial institutions payable within 1 year	23	12
22 | 24	Other current liabilities	2 956	2 179
11	Taxes payable, not assessed	5 268	18 288
	Current liabilities	**14 363**	**20 809**
	Liabilities	**35 376**	**34 444**
	Equity and liabilities	**46 605**	**45 981**

Stavanger,
19.02.2024

Robert Dominik Śleszyński *Chairman of the Board*	Marcin Gargas *Director of the Board*	Robert Harasimiuk *Director of the Board*	Urszula Monika Kowalczyk *Director of the Board*
Przemysław Wacławski *Director of the Board*	Iwona Waksmundzka-Olejniczak *Director of the Board*	Maciej Pawel Wyszoczarski *Director of the Board*	Marek Woszczyk *General Manager*

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CASH FLOW STATEMENT (NOK million)

Note		31/12/2023	31/12/2022
	Cash flows from operating activities		
	Income (loss) before tax	12 512	35 493
12	Depreciation	4 846	4 620
12	Exploration drilling/capitalised seismic expenses	430	392
12	Impairment/reversal of impairments/Disposals	0	(278)
9	Interest expenses	187	81
11	Taxes paid/tax refund	(21 031)	(18 382)
8 | 9	Other financial items without cash effect	(36)	70
16	Changes in current assets – Inventory	29	(9)
	Changes in current receivables	(1 473)	(516)
	Changes in current receivables from Group enterprises	2 401	(883)
	Changes in current liabilities	542	897
	Changes in other periodical items	177	(762)
	Net cash from operating activities	**(1 415)**	**20 723**
	Cash flows from investment activities		
12	Purchase of fixed assets	(6 375)	(4 067)
12	Purchase of intangible assets	(321)	(481)
18	Other investments	(489)	(5 068)
	Net cash from investment activities	**(7 186)**	**(9 616)**
	Cash flows from financing activities		
18	Proceeds/(repayment) from long-term debt raised from Group enterprises	5 000	(1 577)
19	Proceeds/(repayment) from long-term debt raised from financial institutions	506	(4 409)
18	Interests paid to Group enterprises	(119)	(30)
9	Interests paid to financial institutions	(41)	(159)
13	Lease payments	(134)	(35)
17	Dividends paid	(1 551)	(485)
	Net cash from financing activities	**3 661**	**(6 695)**
	Change in the balance of net cash	(4 940)	4 412
	Opening balance of cash and cash equivalents	7 767	3 355
15	**Closing balance of cash and cash equivalents**	**2 827**	**7 767**

STATEMENT ON CHANGES IN EQUITY (NOK million)

2023

	Share capital	Share premium	Retained earnings	Total
Equity at 1st January 2023	1 115	1777	8 645	**11 537**
Dividend			(1 550)	(1 550)
Business combination under common control			(1 811)	(1 811)
Net income/(loss) for the year			3 054	3 054
Equity at 31st December 2023	1 115	1 777	8 337	**11 229**

2022

	Share capital	Share premium	Retained earnings	Total
Equity at 1st January 2022	1 115	1 777	1 257	**4 150**
Dividend			(485)	(485)
Net income/(loss) for the year			7 873	7 873
Equity at 31st December 2022	1 115	1 777	8 645	**11 537**

GENERAL INFORMATION

PGNiG Upstream has its office in Stavanger, Norway and is a subsidiary, fully owned by ORLEN, whose head office is in Płock, Poland.

The financial statements of the Company are consolidated into ORLEN Group statements which can be found at the internet address: www.orlen.pl/en

All amounts are in million NOK unless otherwise stated.

NOTE 1 SUMMARY OF IFRS ACCOUNTING POLICIES APPLICABLE FOR 2023

STATEMENT OF COMPLIANCE

The financial statements have been prepared in line with the simplified application of International Financial Reporting Standards ("**IFRS**") in accordance with the Norwegian Accounting Act § 3-9.

The financial statements were approved for issuance by the Board of Directors and the General Manager on 19th February 2024.

The accounting policies applied in preparing these financial statements are presented below.

BASIS FOR PREPARATION

The financial statement has been prepared on a historical cost basis.

NEW OR AMENDED ACCOUNTING STANDARDS

In these financial statements, the company did not opt to early adapt any standards, interpretations or amendments to the existing standards which have been issued.

CHANGES TO THE ACCOUNTING POLICY

The company adopted Disclosure of Accounting Policies (Amendments to IAS1 and OFRS Practice Statement 2) from January 2023. Although the amendments did not result in any changes to the accounting policies themselves, they impacted the accounting policy information disclosed in the financial statements.

MATERIAL ACCOUNTING ESTIMATES AND ASSUMPTIONS

The preparation of financial statements in conformity with IFRS/simplified IFRS requires management to make judgments, estimates and assumptions that affect the application of policies and reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods.

Accounting estimates are employed in the financial statements to determine reported amounts, including the possibility for realisation of certain assets, income taxes and others. Although these estimates are based on management's best knowledge of historical experience, current events and actions, actual results may differ from these estimates. The estimates and the underlying assumptions are reviewed on an ongoing basis. Changes in estimates will be recognized when there are changes in the underlying assumptions or when new estimates can be determined with certainty.

The key sources of estimation uncertainty relate to:

- Fixed assets whose recoverable amount depends on the future cash flow generated by the assets. For further details refer to Note 12.
- Long term liabilities which are recognized at amortised cost using the effective interest rate method. The key uncertainty relates to the

assumption regarding drawdown and repayment of the long-term loans.
- Provisions which are based either on the expected costs related to decommissioning of facilities or relate to other obligations. For further details refer to Note 21.
- Capitalized exploration expenses which are dependent on existence of commercial oil and gas reserves. For further details refer to Note 12 and 27.

INTERESTS IN JOINT ARRANGEMENTS

A joint arrangement is a contractual arrangement whereby two or more parties undertake an economic activity that is subject to joint control (joint controlled assets). The Company accounts for the joint arrangements by recording its share of the assets, liabilities, and cash flow, which is in line with industry practice in Norway. The Company combines its share of the joint ventures' individual income and expenses, assets and liabilities and cash flows on a line-by-line basis with similar items in the Company's financial statements.

ACQUISITIONS AND TRANSACTION DATE

In order to determine whether a particular transaction should be classified as a business combination in accordance with IFRS 3 (and thus accounted for using the acquisition method), business combination under common control or an asset acquisition in accordance with IAS 16, the reporting entity is often required to apply professional judgement.

The transaction date is when the control is assumed, i.e., the time the related risk and reward in all material respects are transferred to PGNiG. This date is normally dependent on approval from authorities and fulfilment of contractual obligations.

The acquirer's income statement shall incorporate the profits and losses of the acquired interest from the transaction date.

BUSINESS COMBINATIONS UNDER COMMON CONTROL

Combinations involving entities or businesses under common control are excluded from the scope of IFRS 3. There is currently no guidance in IFRS on the accounting treatment for combinations among entities or businesses under common control.

IAS 8 requires management, if there is no specifically applicable standard or interpretation, to develop a policy that is relevant to the decision-making needs of users and that is reliable.

Considering facts and circumstances management could apply a method broadly described as predecessor accounting. PGNiG has concluded that the predecessor accounting method should be applied to the takeover of the LOTOS business.

Principles of predecessor accounting are that assets and liabilities of the acquired entity are stated at predecessor carrying values, which are the carrying values related to the acquired entity. They are selected as the carrying amounts of assets and liabilities of the acquired entity from the consolidated financial statements of the highest entity that has common control for which consolidated financial statements are prepared.

Furthermore, PGNiG has concluded that it will account for the business combination using prospective presentation method from the date of acquisition, i.e., without restating previous periods comparative amounts. Any difference between the consideration given and the aggregate carrying value of the assets and liabilities of the acquired entity at the date of the transaction have been booked to equity.

BUSINESS COMBINATIONS AND GOODWILL

For accounting purpose, the main difference between a business combination and an asset acquisition is that the business combination will result in deferred tax liabilities and goodwill that will not arise if it is an asset acquisition.

In order to consider an acquisition as a business combination (as defined by IFRS 3), the acquired asset or groups of assets must constitute a business. In accordance with IFRS 3, a business is an integrated set of activities and assets that is capable of being conducted and managed for the purpose of providing goods or services to customers, generating investment income (such as dividends or interest), or generating other income from ordinary activities.

In the Exploration and Production segment, projects in the production phase are typically classified as businesses, whereas projects in the exploration phase are regarded as asset acquisitions. Amendments to IFRS 3 effective in January 2020 introduce an optional 'concentration test' which may result in a business combination being accounted for as an asset acquisition if substantially all of the fair value of the assets acquired is concentrated in a single identifiable asset or group of similar identifiable assets.

The valuation is based on currently available information on fair values as of the transaction date (IFRS 13). Fair value is calculated by discounting cash flows from future operations to estimate the net present value. If new information becomes available within 12 months from the acquisition date about facts and circumstances that existed at the time of the acquisition, the company may change the fair value assessment in the purchase price allocation.

If the purchase price at the time of the acquisition exceeds the fair value of the acquired net assets goodwill arises (or vice versa negative goodwill arises).

The main part of the company's goodwill is related to the requirement to recognize deferred tax for the difference between the assigned fair values and the related tax base. Deferred tax positions are booked in accordance with IAS 12 paragraphs 15 and 24. Net deferred tax liabilities related to temporary differences on tangible assets is offset by technical goodwill. Technical goodwill is calculated as the calculated tax (78% for offshore assets in Norway) of differences between fair values of PP&E and other fixed assets and tax values.

There are no specific IFRS guidelines on the allocation of technical goodwill, and the company has therefore applied the general guidelines for allocating goodwill for the purpose of impairment testing. For the purpose of impairment testing, technical goodwill is allocated to the cash-generating units (CGUs). If ordinary goodwill is negative it will be offset against technical goodwill allocated to separate CGUs on a pro rata basis. The company's negative goodwill relates to the increase in expected prices for oil and gas in the future compared to expectations when the consideration was agreed.

Goodwill is not subject for depreciation under IFRS. Furthermore, depreciation of PP&E from the purchase price allocation will reduce recognised deferred tax liabilities. Therefore, the Company expect that goodwill will be subject for impairments if not offset by increase in other assumptions when calculating net present values in the future.

Acquisition-related costs, except costs to issue debt or equity securities, are expensed as incurred (IFRS 3, paragraph 53).

If selling a licence where the company historically has recognized deferred tax and goodwill in a business combination, both goodwill and deferred taxes from the acquisition are included when calculating gain/loss. When recording impairment of such licences as a result of impairment testing, the same assumptions are applied when measuring the impairment. This avoids a gross up of the impairment with tax, in that the impairment charged to the Income statement will not be higher than the original post-tax amount paid in the business combination.

DIVESTMENTS

When an interest in a joint arrangement is divested all assets and liabilities sold are derecognised from the balance sheet. Gain and loss from the sale is included in other income or other operating expenses. Revenues and expenses from the joint arrangement are included in the profit and loss statement until the transaction date.

FOREIGN CURRENCY TRANSLATION AND TRANSACTIONS

The financial statements are presented in million Norwegian kroner (NOK). NOK is the functional currency of the Company.

Transactions, monetary assets, and liabilities

Foreign currency transactions are translated into the functional currency using the exchange rates on the dates of the transactions.

Monetary items in a foreign currency are translated into NOK using the exchange rate applicable on the balance sheet date. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation of monetary assets and liabilities denominated in foreign currencies are recognised as financial items in the income statement.

REVENUE RECOGNITION

Revenues associated with sale and transportation of crude oil, natural gas and other hydrocarbons are recognized when control is passed to the customer. This is typically when title passes at the point of delivery of goods (lifting), but subject to assessment based on the contractual terms of agreements. The company applies the sales method to account for revenues from sale of hydrocarbons.

The company's volume of oil and gas sold (lifted) may differ from the volumes of which the Company is entitled to based on allocated production. If the accumulated production exceeds accumulated sales (liftings), the Company accounts for an underlift position (asset). If accumulated sales (liftings) exceed accumulated production, the Company accounts for an overlift position (liability). The Company values over-/underlift positions at fair value (market value). The periodic change in value of over-/underlift is recognized under Production and sales cost.

NET PROFIT INTEREST

The Gina Krog and Sleipner West field is subject to a net profit interest ("NPI"), as this field was awarded in the second licensing round.

The net profit interest is calculated based on quarterly cash flows. Losses in a quarter can be offset against profits in subsequent quarters. NPI related to abandonment costs incurred after the production has ceased will be refunded by Petoro.

NPI payments are classified as production and sales costs.

EXPLORATION COSTS

The Company employs the successful efforts method to account for exploration and development costs.

All exploration costs, with the exception of acquisition costs of licenses, seismic costs, field evaluation and drilling costs for exploration wells, are charged to expense as incurred.

Seismic costs (including seismic acquisitions and seismic studies), field evaluation and drilling costs for exploration wells are temporarily capitalized, pending the evaluation of potential existence of oil and gas reserves. If reserves are not found, or if discoveries are assessed not to be technically and commercially recoverable, the costs are expensed. The costs for acquiring exploration licenses are capitalized as an intangible asset and assessed for impairment.

Capitalized exploration costs are classified as intangible assets and are re-classified to tangible assets when the development concept is matured.

PROPERTY, PLANT AND EQUIPMENT

Property, plant, and equipment include production facilities, facilities under construction, processing plants, pipelines, machinery and equipment, fixtures, etc. Items of property, plant and equipment are valued at cost, less accumulated depreciation, and any impairment charges. All costs for developing commercial oil and/or gas fields are capitalized as tangible assets. Facilities under construction are not depreciated until the asset is put into operation. The Company also capitalize internal hours charged to development projects and borrowing cost allocated to the development projects.

Ordinary repairs and maintenance costs, defined as day-to-day servicing costs, are charged to the income statement during the financial period in which they are incurred. The cost of major overhauls is included in the asset's carrying amount when it is probable that the Company will derive future economic benefits in excess of the originally assessed standard.

DEPRECIATION OF OIL AND GAS PROPERTIES

Capitalized costs for oil & gas fields in production, processing plants and pipelines are depreciated individually (on a field level) using the unit-of-production method, unless another method can be shown to better reflect the expected pattern of consumption of the future benefit of the particular oil & gas field, processing plant or pipeline.

Under the unit-of-production method, annual depreciation rate is calculated. The annual depreciation rate is based on proved reserves (developed). The rate of depreciation is equal to the ratio of hydrocarbon production for the period, over the proven 1P developed reserves.

Any changes in the resources and cost estimates that affect unit-of-production rates are dealt with prospectively.

The estimated residual value of each field installation is deducted when calculating the asset's depreciable amount.

Processing plants and pipelines are depreciated using the straight-line method over the assets' estimated useful lives.

Depreciation of right-of-use assets are based on the same depreciation methods as those applied to similar underlying assets unless another method can be shown to better reflect the expected pattern of consumption of the future benefit.

IMPAIRMENT OF NON-CURRENT ASSETS

Property, plant and equipment and other non-current assets are subject to impairment testing when there is an indication that the assets may be impaired. At each reporting date the Company assess whether there is any indication that the assets may be impaired. If any indications exist, an impairment test is performed. Goodwill is subject for an annual impairment test regardless of indications and more often if there are impairment triggers.

For the purposes of assessing impairment, assets are grouped at the level of cash-generating units (CGU). CGUs are defined as the oil and gas fields or hub of fields, processing plants and pipelines. An impairment loss is the amount by which the carrying amount of the assets exceeds the recoverable amount of the CGU (including any allocated goodwill). The recoverable amount is the higher of the asset's net fair value less cost to sell and value in use. It is determined by reference to discounted future net cash flows expected to be generated by the asset. Cash flows are discounted using a discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

A previously recognised impairment loss is reversed only if there has been a change in the estimates used to determine the recoverable amount (not however, to a higher amount than if no impairment loss had been recognised). Any reversal is recognised in the income statement. After such a reversal, the depreciation charge is adjusted in future periods to allocate the asset's revised carrying amount, less any residual value, on a systematic basis over its remaining useful life.

TRADE RECEIVABLES

Trade receivables are recognised initially at transaction price and subsequently recognised at nominal value after a deduction for the provision for credit losses. Historically there have been no significant credit losses.

LONG TERM LOANS

Long term loans are initially recognised at fair value plus any directly attributable transaction costs and subsequently measured at amortised cost adjusted for expected credit losses.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents comprise cash in hand, deposits held at call with banks, and cash equivalents. Cash equivalents are short-term (generally with original maturity of three months or less), highly liquid investments that are readily convertible to a known amount of cash and which are subject to an insignificant risk of changes in value. Bank overdrafts are included within borrowings in current liabilities on the balance sheet.

INTEREST-BEARING LIABILITIES

All loans and borrowings are initially recognised at cost, being the fair value of the consideration received net of issuing costs associated with the borrowing.

After initial recognition, interest-bearing loans and borrowings are subsequently measured at amortised cost using the effective interest method.

Effective interest rate reflects an allocation of interest expense, transaction costs and any discount or premium on settlement, over the expected life of the financial instrument.

The measurement of effective interest rate applies to both fixed rate and variable rate instruments. For a fixed rate financial instrument, the effective interest rate is determined as a single constant rate over the life of the financial instrument and does not change as market interest rates change. For a floating rate financial instrument (for example a loan with a margin based on EURIBOR plus a fixed credit spread), the effective interest rate is not a single constant interest rate but is instead calculated through a combination of the spot curve for the benchmark interest rate (for example EURIBOR) and an initial effective spread.

BORROWING COSTS

Borrowing costs are recognised as an expense in the period in which they are incurred, unless they meet criteria as explained below.

Borrowing costs which are directly attributable to the acquisition, construction or production of a qualifying asset, form part of the cost of that asset and therefore are capitalized.

FINANCIAL INSTRUMENTS

The Company may enter financial contracts for instruments related to currencies, commodities, or interests. Such financial instruments may include spot and outright contracts, forward transactions, swap contracts, options etc. The Company does not apply hedge accounting as described in IFRS 9. Financial instruments held by the Company are classified and recognized at fair value at the initial measurement. Subsequent measurement will reflect the classification of the financial instrument. IFRS 9 divides financial assets into two classifications – those measured at amortised cost and those measured at fair value. For assets measured at fair value, gains and losses are recognized entirely in profit or loss. Two measurement categories exist for financial liabilities, fair value through profit and loss ("FVTPL"), and amortized cost. Financial liabilities held for trading are measured at FVTPL, and all other financial liabilities are measured at amortised cost.

LEASES

At the conclusion of the contract, the company assesses whether the contract is a lease or contains a lease.

In the case of contracts that meet the definition of a lease, the company recognises a right-of-use of an asset and lease liability at the lease commencement date. The right-of-use asset is initially measured at cost, which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received. The right-of-use asset is subsequently depreciated, and it is adjusted for certain remeasurements of the lease liability.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted using the incremental borrowing rate as the discount rate. After the commencement date, the company takes into account changes in lease payments by remeasuring the lease liability. The amount of the remeasurement of the lease liability is recognised as an adjustment to the right-of-use asset. However, if the carrying amount of the right-of-use asset is reduced to zero and there is a further reduction in the measurement of the lease liability, any remaining amount of the remeasurement is recognised in profit or loss.

INCOME TAXES

Current income tax assets and liabilities for the current and prior periods are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted or substantively enacted by the balance sheet date.

New regulation

The amendment to IAS 12 – Pillar Two Model Rules is effective from 01.01.2024. The company has assessed that the amendment currently has no impact for the entity.

Deferred tax

Deferred income tax is provided using the balance sheet method on temporary differences at the balance sheet date between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes.

Deferred income tax assets are recognised for all deductible temporary differences, carried forward of unused tax credits and unused tax losses. They are recognised when it is probable that the Company will have a sufficient profit for tax purposes in subsequent periods in order to utilise the tax asset.

Companies operating on the NCS under the petroleum tax regime can claim most of the tax value of any unused tax losses or other tax credits related to its offshore activities to be paid in cash from the tax authorities. Therefore, deferred tax assets that are based on offshore tax losses carried forward are normally recognised in full.

An exception will be where the deferred income tax asset relating to the deductible temporary difference arises from the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss.

The Company recognises previously unrecognised deferred tax assets to the extent it has become probable that the Company can utilise the deferred tax asset. Similarly, the Company will reduce a deferred tax asset to the extent that the Company no longer regards it as probable that it can utilise the deferred tax asset.

Deferred tax, and deferred tax assets, are measured on the basis of the historical and enacted future tax rates applicable to the Company.

Deferred tax, and deferred tax assets, are recognised at their nominal value and classified as non-current intangible assets /long-term liabilities in the balance sheet.

The effect of uplift, a special deduction for petroleum surtax in Norway, is recognised in the current tax calculation.

EMPLOYEE BENEFITS

Pension Obligations

The Company has a defined contribution plan as of 31 December 2023.

For the defined contribution plan, the Company pays contributions to pension insurance plan and charged to the income statement in the period to which the contributions relate. The Company has no legal or constructive obligations to pay further contributions if the fund does not hold sufficient assets to pay all employees the benefits relating to employee service in the current and prior periods. Prepaid contributions are recognised as an asset to the extent that a cash refund or a reduction in the future payments is available.

Bonus Compensation

Employees participate in a bonus compensation arrangement. The expected cost of bonus payments is expensed as salary costs when the employees have rendered the service in exchange of those benefits, and a reliable estimate of the obligation can be made.

PROVISIONS

A provision is recognised when the Company has an obligation (legal or self-imposed) as a result of a past event, it is probable (more likely than not) that a financial settlement will take place as a result of the obligation, and the size of the amount can be measured reliably. Provisions are reviewed at each balance sheet date and adjusted to reflect the current best estimate.

If the effect is considerable, the provision is calculated by discounting estimated future cash flows using a pre-tax discount rate that reflects the market's pricing of the time value of money and, if relevant, risks specifically linked to the obligation.

Assets retirement obligations

According to the license agreements on the NCS, the Company has the obligation to partly or completely remove the offshore facilities at the end of production or when the concession period expires. Consequently, the Company recognizes a provision related to future abandonment and decommissioning of offshore installation. Similarly, the Company has the obligation to participate in the costs of removal of infrastructure used to transport hydrocarbons from the fields.

The Company calculates and records the net present value of the removal liability. The discount rate used when calculating the net present value of the abandonment and decommissioning liability is calculated based on a risk-free interest rate and is reviewed at each balance sheet date.

Related asset retirement costs are capitalised as part of the carrying value of the tangible fixed asset and are depreciated over the useful life of the asset, i.e. unit-of-production method. The liability is accreted for the change in its present value after each reporting period. Accretion expense related to the time value of money is classified as part of financial expense.

SEGMENT REPORTING

The Company's business activities are reported as one segment.

CASH FLOW

The cash flow statement has been prepared using the indirect method.

CONTINGENT ASSETS AND LIABILITIES

A contingent liability is a possible obligation that arises from past events and whose existence will be confirmed only by the occurrence or non-occurrence of one or more uncertain future events not wholly within the control of the entity; or a present obligation that arises from past events but is not recognized because it is not probable that an outflow of resources embodying economic benefits will be required to settle the obligation or the amount of the obligation cannot be measured with sufficient reliability.

Contingent liabilities are not recognised in the annual accounts. Significant contingent liabilities are disclosed, with the exception of contingent liabilities that have a remote possibility to end up in outflow of resources.

Contingent assets are not recognised in the annual accounts but are disclosed if it is probable that a benefit will be added to the Company.

EVENTS AFTER THE BALANCE SHEET DATE

New information on the Company's financial position on the balance sheet, that are present on the balance sheet date and becomes known after the balance sheet date, is recorded in the annual accounts. Events after the balance sheet date that do not affect the Company's financial position on the balance sheet, but which will affect the Company's financial position in the future, are disclosed if significant.

NOTE 2 SIGNIFICANT TRANSACTIONS IN 2023

TRANSACTION WITH LOTOS (MAY 2023)

After ownership changes in Poland in 2022, ORLEN became the ultimate owner of PGNiG Upstream and LOTOS Exploration and Production Norge AS. ORLEN intended to consolidate upstream activities in Norway within one entity.

The decision to integrate the businesses was aimed at achieving operational and financial synergies and bringing the operations into compliance with Norwegian regulatory requirements.

On March 30th, 2023, PGNiG Upstream signed the agreement to purchase the entire business from LOTOS Exploration & Production Norge AS. The agreement was completed on May 2nd 2023 and the effective date for the transaction was agreed as of January 1st, 2023.

The transferred business consisted mainly of assets, data, positions, and rights of LOTOS, as well as obligations and liabilities. This included shares in the producing licenses Sleipner Vest, Sleipner Øst, Gungne, Utgard and Yme. Certain matters were excluded from the transaction, such as Escrow Pledge Agreements, bank accounts, escrow accounts, share capital and defined tax liabilities. Following the transaction, all upstream licenses and employees were transferred from LOTOS to PGNiG Upstream.

The agreed consideration for LOTOS' business was a post-tax amount of NOK 2 344 million (plus interest and effective period settlements).

Consideration	2 344
Interest	40
Settlement adjustments (P&C)	(465)
Total payment to LOTOS	**1 919**

The transaction was accounted for with the use of the Predecessor Accounting method. Before transferring of the balances, the Company identified differences in the accounting policies and aligned the accounting principles between PGNiG Upstream and LOTOS.

The most significant items subject for principle alignment were:

- Depreciation of O&G assets; using different approach on reserves
- Valuation of Over/ Underlift
- Currency conversion for working capital

The purchase of LOTOS business by PGNiG Upstream is a post-tax transaction.

Inception to date balances at the ORLEN Group financial statement level have been booked to the PGNiG Upstream statutory financial statements. Other than that, no tax payable effect has been recorded in the transaction.

LOTOS Norge

The tax values in LOTOS were transferred as part of the transaction. As part of the purchase price allocation for LOTOS performed by group and booked into the ORLEN Group consolidated financial statements the effect on temporary differences between book values and tax values had to be booked accordingly within deferred tax.

The main elements from the transaction and its impact on the balance sheet of PGNiG Upstream are presented in the following table.

data in million NOK	**Assets**		**Liabilities**
Capitalized exploration expenses	456	Retained earnings	(1 811)
Assets in production	2 197	Deferred tax	967
Assets in development	1 315	Abandonment provision	2 573
Other fixtures	0	Lease liabilities	722
Use of right assets	578	Employee liabilities	3
Inventory	200	Other current liabilities	375
Other current receivables	508	Taxes payable	508
Cash and cash receivables	(1 919)		
Total Assets	**3 337**	**Total Liabilities**	**3 337**

TRANSACTION WITH SVAL ENERGI

In June, the Company completed the acquisition of a 10% interest in the license PL211CS, which includes the Adriana & Sabina discovery. The fields are located 20 kilometres southwest of the Skarv field, which is the main centre of the ORLEN Group's operations on the NCS.

The new fields will be tied to the existing production infrastructure in the area through PGNiG Upstream Norway's Ærfugl field, located near Skarv. This will ensure higher profitability of production from the new fields, reduce the time and cost of the development work while also cutting carbon emissions associated with the process.

Adriana is a gas and condensate field, while Sabina contains oil and gas. The fields were discovered in the first quarter of 2021. According to preliminary estimates, their total recoverable reserves could range from 38 to 88 million boe. These volumes can be confirmed after an appraisal well has been drilled, which is planned for the first quarter 2024. The licence partners expect production from the Adriana and Sabina fields to commence in 2029 and 2033, respectively. This will allow PGNiG Upstream Norway to offset the natural decline in production from the existing producing fields.

TRANSACTION WITH KUFPEC

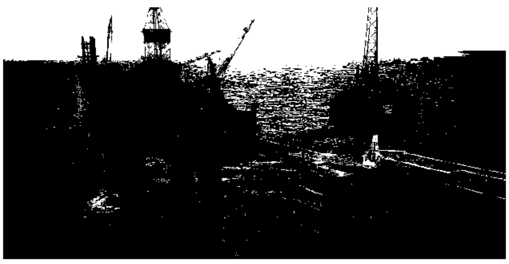
On November 17th, 2023, the Company signed the agreement to purchase all shares in KUFPEC Norway AS. The transaction was completed on January 5th, 2024. The acquired subsidiary is now rebranded as ORLEN Upstream Norway 2 AS, and the assets and activities will be consolidated and integrated with PGNiG Upstream during 2024.

Unlike previous acquisitions in Norway, the agreement covers the acquisition of all shares in KUFPEC Norway AS along with all its assets. The contractual price of the transaction is set at USD 445 million as of 1 January 2023 and includes the value of the acquired fields, as well as the value of the remaining assets of KUFPEC Norway AS, including the significant cash balance. At the time of completion of the transaction, the value of cash in the acquired company exceeded USD 214 million. This enables a quick return on investment, which is estimated at approximately one and a half years from the moment of the settlement of transaction.

KUFPEC NORWAY AS

Following this acquisition, the ORLEN Group's natural gas output in Norway will increase by one-third, reaching over 4 billion cubic meters (bcm) in 2024. Post-transaction, PGNiG Upstream's daily production is projected to exceed 100 thousand boe per day, positioning the Company among major oil and gas producers in Norway.

The newly acquired business encompasses interests in five fields where the ORLEN Group is already active (Gina Krog, Sleipner Vest, Sleipner Ost, Gungne and Utgard). The gas produced from these fields will be transported to Poland via the Baltic Pipe pipeline. In addition, the ORLEN Group will gain 21.8% in the Eirin gas development. Eirin is developed as a subsea tie-back to Gina Krog which ensures attractive profitability and low carbon emissions from production.



The acquisition of KUFPEC Norway is accounted for using the acquisition method in accordance with IFRS 3 Business Combinations.

As at the date of preparation of these financial statements, the accounting settlement of the acquisition has not been completed and the process of measuring the acquired net assets at fair value is at an early stage. Therefore, the Group presented provisional values of identifiable assets and liabilities, which correspond to their book values as of January 5, 2024.

PGNiG Upstream plans to make the final settlement of the acquisition transaction within 12 months from the merger date.

The provisional value of identifiable major items of acquired assets and liabilities as of the acquisition date is presented in the table below.

data in million USD	**Assets**		**Liabilities**
Capitalized exploration expenses	1	Total equity	253
Property, plant and equipment	466	Deferred tax	163
Deposits and prepayments	5	Abandonment provision	207
Inventory	9	Lease liabilities	2
Trade and other receivables	60	Other current liabilities	41
Cash and cash receivables	214	Taxes payable	90
Total Assets	**755**	**Total Liabilities**	**755**

The decrease in net cash balance related to the acquisition of KUFPEC Norway was USD 252 million. The reduction in the cash balance is the difference between the net cash acquired as a part of KUFPEC Norway AS and the paid cash transferred in consideration.

Analysis of the balance sheet positions indicate potential value of goodwill of USD 214 million. PGNiG Upstream expects that this value will decrease as a result of the process of measuring the fair value of property, plant and equipment of KUFPEC Norway AS.

If the acquisition of KUFPEC Norway took place in early 2023 and Kufpec Norway was consolidated with the company, then the company's sales revenue and net profit for the 12 months ended December 31, 2023 would increase by USD 546 million and USD 75 million, respectively.

TRANSACTION WITH WINTERSHALL DEA

On December 27th, 2023 the Company agreed with Wintershall DEA Norge AS a swap agreement, where PGNiG Upstream transfers a 3.0825 % interest in PL 212E (Ærfugl Nord) in exchange for a 11.9175 % interest in PL 159D (Idun Nord) and a further 1.9175 % interest in PL 211CS (Adriana & Sabina). This transaction is expected to complete during first half of 2024.

The transaction is anticipated to optimise the Company's portfolio of licence interests in the Skarv area, translating into improved efficiency and lower overall cost of managing these assets. It will also increase PGNiG Upstream's recoverable reserves of natural gas of by more than 0.4 billion cubic meters.

FINANCING AGREEMENTS

In 2023, the Company signed a loan agreement with LOTOS Exploration and Production Norge AS. In May 2023, the Company purchased business from LOTOS and paid the agreed acquisition price. These funds can be used by LOTOS for further investments or distributions to the owners.

In the interim period (until the final decisions are made), LOTOS signed a loan agreement and made these funds available to PGNiG Upstream in a form of a loan.

NOTE 3 REVENUE

	2023	2022
Oil sales	5 358	4 794
Gas sales	15 528	37 131
NGL sales	639	645
Other (tariff revenue, JV operating income etc.) *	607	456
Sales revenue	**22 132**	**43 026**

* TARIFF REVENUE, JV OPERATING INCOME ETC. WERE PREVIOUSLY REPORTED AS OTHER REVENUE INSTEAD OF SALES REVENUE

All sales contracts are based on the market prices of the products and will secure stable stream of revenues from PGNiG Upstream for years to come. PGNiG Upstream sell gas to their sister company PGNiG Supply & Trading GmbH, the other products are sold to external counterparties.

During 2023 the company amended the majority of oil sales contract and invoicing to customers is now based on lifted quantities at the date of lifting. Previously invoicing to customers was performed monthly in accordance with PQ mechanism which was based on estimated production leading to prepayments from customers.

NOTE 4 EXPLORATION EXPENSES

	2023	2022
Exploration expenses from production licenses	279	293
Drilling expenses from production licenses	303	333
Other exploration expenses	94	7
Direct exploration expenses	**676**	**633**
Allocated expenses included in:		
- Depreciation (note 12)	0.8	0.6
- Employee expenses (note 5)	74.7	48.1
- Other operating expenses (note 6)	17.2	12.2
Allocated exploration expenses	**92.7**	**60.8**
Total exploration expenses	**768.7**	**693.6**

Exploration expenses are presented under different cost categories in the income statement:

(i) **Direct exploration expenses** - reflecting expenditures from the licenses reported by the respective Operators and direct exploration expenses incurred by the Company.

(ii) **Allocated exploration expenses –** being the result of cost allocation.

The costs in **direct exploration expenses** are connected with the following scope of work:

- Exploration expenses from production licenses which relate to participation in exploration licenses. Majority of expenses in 2023 is related to write-off of PL939, PL1009, seismic acquisitions and exploration activities on the other licenses.
- Most of the drilling cost in 2023 related to drilling of the licenses PL939 and PL1009 in previous years assessed to be uneconomic. Discovery was made for the Øst Frigg/ Epsilon well in 2023, due to commercial potential of this discovery, the well costs were capitalized and are included in intangible assets category.

Other exploration expenses in 2023 relate to the APA2023 applications, business development activities and purchase of various studies.

Allocated exploration expenses are linked to own exploration activities of PGNiG Upstream. In 2023 they were mostly connected with the follow-up activities on exploration licenses and the participation in the APA Licensing Rounds, general exploration and follow-up of partner licenses.

The majority of these costs are related to employee expenses. In addition, there are costs of securing access to G&G software and databases which are shared between different activities of PGNiG Upstream. Cost allocations are primarily based on time-writing.

NOTE 5 EMPLOYEE EXPENSES AND BENEFITS

Staff expenses comprise salaries, remuneration, pensions, social security and other expenses.

During the year the average number of employees at the Company was 98. On 31st December 2023, PGNiG Upstream had 107 employees. The increase in number of employees is a consequence of M&A transactions described in Note 2.

The remuneration for the General Manager for the year amounted to NOK 7 393 023 for wages and NOK 34 358 for other compensations. In addition, contributions to the pension scheme of NOK 615 963 have been paid for the period. These amounts are included in employee expenses above. In addition, PGNiG Upstream has a bonus scheme covering all employees.

The bonus amount for the Board Members as well as the General Manager shall be based on an evaluation of specific "Key Performance Indicators" approved by relevant corporate bodies before the start of any calendar year.

PENSIONS

The Company is obliged to have an occupational pension scheme pursuant to the Act relating to Mandatory Occupational Pensions. The Company's pension scheme satisfies the requirements of this act. Ref. Note 20 for further information.

	2023	2022
Employees*		
Wages, salaries and remuneration	140	28
Social security	42	21
Pensions (Note 20)	31	27
Other staff expenses	6	3
Total	**219**	**80**

* Staff expenses attributable to exploration activities are not reclassified to exploration cost in the income statement, but presented as exploration cost in the specification included in note 4.

	2023	2022
Board of Directors		
Wages, salaries and remuneration	7	1
Total employee expenses**	**225**	**81**

** total employee expenses above are presented net of cost, which was recharged to operated licences and business partners, and net of cost from internal hours charged to the development projects, incl. Hugin, Fulla, Fenris, Ormen Lange Phase 3, Alve Nord, Ørn, Andvare, Verdande and Tommeliten until commencement of production. the total value of cost recharged to operated licences in 2023 amounts to nok 47.1 million (nok 81.6 million in 2022), and the total value of cost charged to development projects amounts to nok 37million (nok 33.4 MILLION in 2022).

NOTE 6 PRODUCTION AND SALES COSTS

	2023	2022
Operating costs	2 020	1 269
Gas tariffs and other transportation costs	1 632	1 630
Net Profit (NPI)	246	290
Over-/(underlift)	253	(721)
Total production and sales costs	**4 151**	**2 469**

Operating costs are reported by the respective Operators on the production licenses: Ormen Lange, Skarv, Sleipner East, Sleipner West, Gungne, Utgard, Yme, Vilje, Vale, Morvin, Alve, Marulk, Gina Krog, Skogul, Duva, Ærfugl Nord, Tommeliten Alpha from commencement of production, Nyhamna processing plant, Kvitebjørn oil pipeline, Valemon rich gas pipeline and Yggdrasil oil pipeline, Yggdrasil gas pipeline and Yggdrasil power from shore.

The operating costs consist of:

- NOK 1 800 million from the production licenses,
- NOK 98 million related to changes in the estimated abandonment provision, and
- NOK 121 million incurred in relation to liquid sales.

The Company covered gas tariffs in the Gassled network and other transportation costs of NOK 1 632 million. Other transportation costs included balancing, dispatching, contract handling etc. Reference is made to note 10 for sales costs towards affiliated company PGNiG Supply & Trading GmbH.

In the end of 2023, the Company decreased its underlift position, which means that accumulated sales exceeded the accumulated production. Consequently, the Company incurred an increase in cost related to change in over-/underlift position for 2023. According to accounting policy change in over-/underlift positions is to be adjusted towards production and sales cost. Please refer to note 14 for further information about underlift position.

NOTE 7 OTHER OPERATING EXPENSES

	2023	2022
External fees	299	206
Rent premises	6	5
Insurance premium	99	48
Expensed purchases	24	17
Travel costs	3	1
Other	38	23
Other operating expenses	**469**	**299**

	2023	2022
Remuneration to auditor (thousand NOK):		
Audit fee (excl. VAT)	1 473	800
Other services (excl. VAT)	0	0
	1 473	**800**

Indirect exploration costs presented in note 4 (with the amount of NOK 17.2 million) are not reclassified and are included in different cost categories (for example rent premises etc.)

Other operating expenses comprise external fees, rent premises, insurance, expensed purchases, travel costs etc.

Majority of external fees relate to the support provided to the company by the central upstream unit under the SLA agreement. Thanks to this agreement PGNiG Upstream has direct access to geologists, geophysicists and engineers who are involved in exploration and production activities in Norway.

Remaining part of external fees relate to running the Company accounts, legal support and various advisory services, including M&A advisory. Moreover, the Company incurred costs connected with the maintenance of IT solutions, telephones and internet access.

Other agreements affecting the cost level are those concerning the rental and maintenance of the offices and offshore insurance cost according to legal requirements in Norway.

RESEARCH AND DEVELOPMENT EXPENSES

PGNiG Upstream's R&D activities have been focused on tools and methods for exploration and production, primarily through its co-operation with universities, external experts and joint projects with ORLEN.

The total costs of R&D activities amounted to NOK 4.3 million in 2023. The main objective of this expenses is to get access to scientific studies that can be used by PGNiG Upstream on its licenses on the NCS.

By carrying out these studies, PGNiG Upstream is gaining access to exclusive scientific information and highly qualified personnel. The Company anticipates that the total income from research and development will offset the total costs incurred.

NOTE 8 OTHER FINANCIAL INCOME

	2023	2022
Interest received bank	51	38
Other income from bank deposits	19	9
Other interest earnings	17	21
Exchange rate differences	1 316	1 235
Other financial income	**1 404**	**1 302**

NOTE 9 OTHER FINANCIAL EXPENSES

	2023	2022
Interest costs to financial institutions*	64	113
Exchange rate differences	504	810
Accretion	201	97
Other interest cost	66	91
Capitalized borrowing cost	-	(51)
Other financial expenses	**835**	**1 060**

* Interest costs to financial institutions are presented using the effective interest rate method

NOTE 10 RELATED PARTY ITEMS

Transaction type	P&L line	Counterpart	Relationship	2023	2022
Gas sales	Sales revenue	PGNiG Supply & Trading GmbH	Affiliated company	15 536	37 131
Costs related to gas sales	Production and sales costs	PGNiG Supply & Trading GmbH	Affiliated company	(454)	(370)
Insurance	Other operating expenses	POLSKI GAZ	Affiliated company	(99)	(8)
Technical services (under SLA agreement)	Other operating expenses	ORLEN	Parent company	(242)	(185)
Other services	Other			(18)	(14)
Total (net transfers)				**14 723**	**36 554**

Balance sheet items		Accounts receivables		Accounts payable	
Counterpart	**Relationship**	**2023**	**2022**	**2023**	**2022**
PGNiG Supply & Trading GmbH	Affiliated company	1 343	3 661	0	0
ORLEN	Parent	0	0	(1)	(8)
Total		**1 343**	**3 661**	**(1)**	**(8)**

Related party transactions and associated balance sheet items are displayed in above table. All transactions with related parties in above table are priced on an arm's length basis and are to be settled within two months of the reporting date.

No expense has been recognised in the current year or previous years for bad or doubtful debt in respect of amounts owed by related parties.

For information on intercompany loans and guarantees not disclosed in this note reference is made to note 18 and 24.

NOTE 11 TAX ON THE INCOME/(LOSS) FOR THE YEAR

Calculation of taxable income for the year	**2023**	**2022**
Net income before taxes	12 512	35 493
Permanent differences	1 194	683
Changes in temporary differences	1 609	1 226
Basis for corporate taxes payable, not assessed	**15 315**	**37 402**
Tax base corporate tax deductible in special tax	(3 379)	(8 285)
Net financial costs only allowed against CT	(799)	(388)
Net other 22%, only allowed against CT	841	645
Uplift allowable only against SPT	(736)	(538)
Expense of capex addition in SPT	(4 914)	(2 765)
Taxable income, special petroleum tax ("SPT")	**6 328**	**26 071**

Tax payable	**2023**	**2022**
Tax payable	5 064	17 985
Other	204	304
Tax payable in balance sheet	**5 268**	**18 288**

Calculation of deferred taxes	**2023**	**2022**
Temporary differences:		
Over-/underlift	(525)	(646)
Long-term liabilities	(90)	(105)
ARO provision	6 201	2 771
Fixed Assets	(12 599)	(11 127)
Intangible Assets	(561)	(688)
Lease	(440)	2
Other	305	245
Net temporary differences	**(7 709)**	**(9 548)**

	2023	**2022**
Deferred tax asset/(liability) in the balance sheet	**(13 350)**	**(10 431)**

Income taxes charged to income statement consist of:	2023	2022
Changes in deferred taxes	2 919	631
Deferred tax from LOTOS	(967)	0
Taxes booked to balance sheet (related to LOTOS acquisition)	(391)	140
Taxes payable/(receivable), not assessed	7 913	26 947
Correction previous year	(15)	(98)
Total Tax charge/(credit) to income statement	**9 458**	**27 621**

Effective tax rate reconciliation	2023	2022
Income before taxes	12 512	35 493
Expected tax charge - 78%	9 760	27 686
Permanent differences	579	563
Prior year items	(10)	(12)
Financial items	(343)	(231)
Uplift	(529)	(386)
Other	1	1
Total Tax charge/(credit)	**9 458**	**27 621**
Effective tax rate	**76 %**	**78 %**

NOTE 12 INTANGIBLE ASSETS AND TANGIBLE FIXED ASSETS

RIGHT OF USE ASSET

2023	FPSO/FSO	Other	Land & buildings	Total
Right-of-use asset at initial recognition 01/01/2023*	231	-	13	244
Additions	562	34	-	596
Investments at 31/12/23	**793**	**34**	**13**	**840**
Accum. depreciation at 1/1/23	-140	-	-4	-145
Depreciation in 2023	-152	-2	-2	-156
Accum. depreciation at 31/12/23	**-293**	**-2**	**-6**	**-300**
Net book value at 31/12/23	**500**	**32**	**7**	**540**
Depreciation method	**Straight line/UoP**	**UoP**	**Straight line**	
Useful life	Until 2024/-	-	Until 2032	

2022	FPSO/FSO	Land & buildings	Total
Right-of-use asset at initial recognition 01/01/2022*	231	13	244
Additions	0	0	0
Investments at 31/12/22	**231**	**13**	**244**
Accum. depreciation at 1/1/22	(50)	(3)	(53)
Depreciation in 2022	(91)	(1)	(91)
Accum. depreciation at 31/12/22	**(141)**	**(4)**	**(145)**
Net book value at 31/12/22	**90**	**9**	**99**
Depreciation method	Straight line	Straight line	

* Reference is made to note 1 for accounting principles for depreciation and for principle used to measure the value of the right-of-use asset and note 13.

2023	Capitalized exploration expenses	Goodwill	Assets in Development	Assets in Production	Other tools and equipment	Total
Investments at 1/1/23	688	2 804	7 669	29 254	52	40 466
Additions *	780	-	7 008	4 109	6	11 902
Transfer to Assets in development/production**	(49)	-	(6 741)	6 791	-	-
Disposals/expensed previously capitalised cost ****	(430)	-	-	-	-	(430)
Investments at 31/12/23	**989**	**2 804**	**7 935**	**40 153**	**57**	**51 939**
Acc. depreciation 1/1/23	-	-	-	(13 645)	(42)	(13 687)
Acc. impairment 1/1/23	-	(1)	(26)	(157)	(3)	(187)
Accum. depreciation and impairment at 1/1/23	-	(1)	(26)	(13 803)	(45)	(13 874)
Depreciation in 2023***	-	-	-	(4 687)	(5)	(4 692)
Accum. depreciation and impairment at 31/12/23	**-**	**(1)**	**(26)**	**(18 490)**	**(50)**	**(18 566)**
Net book value at 31/12/23	**989**	**2 803**	**7 909**	**21 664**	**8**	**33 372**
Depreciation method***	N/A	N/A	N/A	unit of production	straight line	
Useful life			-	-	3-6 years	

* Additions under "Capitalized exploration expenses" include capitalized acquisition of Hugin and Fulla exploration asset from LOTOS and acquisition of PL211CS Adriana Sabina from Sval Energi. Further addition due to the Øst Frigg/Epsilon oil discovery and Dougal discovery (both drilled in 2023). Other capitalized expenses are related to seismic and field evaluation.

* Additions under "Assets in development" relates to development capex, capitalized hours, seismic and insurance cost on Fenris, Ormen Lange Phase III, Alve Nord, Verdande, Andvare, Ørn, Hugin, Fulla, Yggdrasil Oil Pipeline, Yggdrasil Gas Pipeline, Yggdrasil Power From Shore, Tyrving and Tommeliten Alpha projects.

* Additions under "Assets in Production" includes capex to the producing assets Ormen Lange, Skarv, Gina Krog, Alve, Marulk, Morvin, Vilje, Skogul, Kvitebjørn, Valemon, Duva and Tommeliten which went into production. The amount also includes the acquisition of Yme, Atla, Skirne/Bryggve, Sleipner West, Sleipner East and Utgard from LOTOS. The amount also include change in the estimate of the Asset retirement obligations for the producing assets as at the end of the year of NOK 339 million, which has no cash effect in 2023. For further details refer to Note 21.

** Transfer to Assets in development from Capitalized exploration expenses relates to reclassification of capitalized exploration expenses for Gina Krog Dougal well which went into production in January 2024. Transfer to asset in production from asset in development relates to reclassification of capitalized development capex for Tommeliten Alpha when this started production.

*** Depreciation of Assets in Production is based on the UOP methodology and takes into account consistent assumptions over the whole year. These assumptions were provided by field Operators at the end of 2022. Any changes in estimates will be recognized prospectively from the following year. Reference is made to note 1 for details on accounting principles.

**** Expensed previously capitalized cost under category "Capitalized Exploration Expenses" is substantially related to write-off of drilling cost for PL939 and PL1009 where discovery was assessed uneconomic and seismic cost for other licenses with drop decision.

2022	Capitalized exploration expenses	Goodwill	Assets in Development	Assets in Production	Other tools and equipment	Total
Investments at 1/1/22	909	2 896	3 909	28 144	44	35 903
Additions *	448	0	3 729	1 047	7	5 231
Transfer to Assets in development/production**	(276)	0	213	63	0	0
Disposals/expensed previously capitalised cost *****	(393)	(93)	(182)	0	0	(668)
Investments at 31/12/22	**688**	**2 804**	**7 669**	**29 254**	**52**	**40 466**
Acc. depreciation 1/1/22	0	0	0	(9 120)	(39)	(9 159)
Acc. impairment 1/1/22	0	0	0	(644)	(3)	(647)
Accum. depreciation and impairment at 1/1/22	0	0	0	(9 764)	(42)	(9 806)
Depreciation in 2022***	0	0	0	(4 525)	(3)	(4 528)
Reversal of impairment****	0	0	0	489	0	489
Impairment in 2022	0	(1)	(26)	(2)	0	(29)
Accum. depreciation and impairment at 31/12/22	**0**	**(1)**	**(26)**	**(13 803)**	**(45)**	**(13 874)**
Net book value at 31/12/22	**688**	**2 803**	**7 643**	**15 452**	**7**	**26 592**
Depreciation method***	N/A	N/A	N/A	unit of production	straight line	
Useful life			-	-	3-7 years	

* Additions under "Capitalized exploration expenses" include capitalized exploration well on the licenses PL1064 (Peder), PL1017 (Copernicus) and PL941 (Newt&Balindåsen). Newt was concluded to be geological discovery, possibility of its commercial development. The other did lead to commercial discoveries and were therefore expensed at year end. Other capitalized expenses are related to seismic and field evaluation.

* Additions under "Assets in development" relates to development capex, capitalized hours and capitalized borrowing cost on Tommeliten Alpha, Fenris, Ormen Lange Phase III, Alve Nord, Verdande and Andvare projects.

* Additions under "Assets in Production" includes capex to the producing assets Ormen Lange, Skarv, Gina Krog, Alve, Marulk, Morvin, Vilje, Skogul, Kvitebjørn, Valemon, Duva and Vale. The amount also includes the change in the estimate of the Asset retirement obligations all producing assets as at the end of the year of NOK 311 million, which has no cash effect in 2022. For further details refer to Note 21.

** Transfer to Assets in development from Capitalized exploration expenses relates to reclassification of capitalized exploration expenses for Alve Nord and Verdande. Transfer to asset in production from asset in development relates to reclassification of capitalized development capex for Idun Tunge when this started production.

*** Depreciation of Assets in Production is based on the UOP methodology and takes into account consistent assumptions over the whole year. These assumptions were provided by field Operators at the end of 2021. Any changes in estimates will be recognized prospectively from the following year. Reference is made to note 1 for details on accounting principles.

**** The company has reversed impairment from prior years of NOK 489 million for the Gina Krog field. The reversal was mainly driven by substantial improvement of macroeconomic environment, especially level of gas prices. For further details on impairment testing, please see below.

***** Changes under "Goodwill" category is connected with 2021 acquisition of Ineos E&P Norge AS and adjustment in the measurement within 12 months after the acquisition. In addition, Tyrving (previously Fogelberg) was disposed with value of NOK 182 million under category "Assets in development".

IMPAIRMENT TEST

In the end of 2023, the Company conducted an impairment tests for all its Cash Generating Units (CGUs), which combine assets using the same infrastructure (like the same host platform) or infrastructure assts with fields they are critical to (like Nyhamna in case of Ormen Lange field). Following CGUs have been created: Skarv CGU, Norne CGU, Alvheim CGU, Ormen Lange CGU, Aasgard CGU, Kvitebjørn CGU, Sleipner CGU, Yggdrasil CGU. In case there is lack of commercial/technical basis to combine assets with other assets in PGNiG portfolio (Tommeliten Alpha, Duva, Fenris, Tambar East and Yme), such assets are tested individually. The main aim of these tests was to ensure that all CGUs/assets are carried at no more than its recoverable amount. The recoverable amount was calculated as the asset's fair value, less cost to sell. It was determined by reference to discounted future net cash flows expected to be generated by the asset.

The projected cash flow for assets has been determined based on production and cost profiles provided by respective field Operators. The Company has used its own assumptions regarding tariffs.

As a result of the tests no impairment has been recognized in 2023.

In calculating the net present value, the company applied the oil price scenario based on reports received from parent company (ORLEN). According to assumptions, the average oil price in the next five years accounts for 86.7 USD/bbl (in real terms), and the average gas price in this period accounts for 40.5 EUR/MWh (in real terms).

In addition, variable discount rate was used, with 5 years average at the level of 6.28% (after tax, nominal).

In addition to above calculation stress test was performed with more conservative macroeconomic assumptions (5 years average oil price reduced to 80.5 USD/bbl and 5 yeas gas price reduced to 34.2 EUR/MWh, discount rate increased to 7.88%) Neither base calculation nor the stress test indicated a need for impairment.

A sensitivity analysis has been also carried out in relation to the impairment of all CGUs/Assets owned by the Company. All results of the sensitivity analysis are presented on a net basis (post tax). Gas price, oil price and discount rate have been used in sensitivity analysis.

According to sensitivity analysis, future impairment risk is highest on Duva project. Duva's headroom between carrying amount and recoverable amount is equal to NOK 189 million in the base test and NOK 75 million in the stress test.

It was concluded that Duva field is the most sensitive to gas prices. A 10% gas price decrease would result in a value decrease of NOK 104 million, while a 10%

decrease of oil price would decrease the value by NOK 46 million.

The technical goodwill is included in the carrying value of the CGU/Asset which it was allocated to. Depreciation of PP&E from the acquired assets from INEOS will reduce the deferred tax and it is expected that the goodwill will be subject for impairment if not offset by increase in other assumptions increasing the calculated net present value. As of end 2023 no technical goodwill impairment was required.

IMPAIRMENT TEST FOR CAPITALIZED EXPLORATION EXPENSES

Exploration assets are assessed for impairment when facts and circumstances suggest that the carrying amount of the asset exceeds its recoverable amount.

PGNiG Upstream has assessed capitalized exploration cost for all the exploration licences, and has written off all capitalized cost for licences which are not likely to be the subject of future drilling campaign. In 2023, the Company has written off all capitalized cost related to PL939 and PL1009 following recommendations from respective operators.

NOTE 13 LEASES

	2023	2022
Lease debt 01.01	101	122
New leases	740	0
Payments of lease debt	(110)	(34)
Interest expense on lease debt	25	0
Currency exchange differences	(31)	13
Lease debt 31.12	**725**	**101**

Nominal lease debt maturity breakdown:		
Within one year	148	53
Two to five years	318	47
After five years	275	6
Total	**741**	**106**

The company has used the effective interest rate as the incremental borrowing rate applied in discounting of the nominal lease debt.

The identified leases have no significant impact on the Company's financing or loan covenants.

Out of total lease debt NOK 579 million is classified as long term and NOK 146 million is classified as short term (ref note 22).

NOTE 14 OTHER CURRENT RECEIVABLES

	2023	2022
Accounts receivable, JV	60	24
Prepayments, JV	229	23
Underlift (oil, NGL)	781	839
VAT	36	70
Other current receivables	200	138
Overcall, JV	2 016	782
Other current receivables	**3 321**	**1 877**

PGNiG Upstream have invoice mechanisms under some sales contracts where the invoice values are not directly linked to physical production.

Lifting arrangements for oil and NGL produced in some of PGNiG Upstream's assets are such that each participant may not receive and sell its precise share of the overall production in each period. The resulting imbalance between cumulative entitlement and cumulative production less stock, is underlift or overlift. The Company accounts for fair value of under and overlift position of hydrocarbons based on market prices as per 31.12.2023.

The periodical change to underlift position at the end of 2023 of NOK 58 million is recognized under the Production and sales cost in the Income Statement, see also Note 6.

NOTE 15 CASH AND CASH EQUIVALENTS

	2023	2022
Cash, non-restricted	2 803	5 300
Cash, restricted	24	8
Cash	**2 827**	**5 308**
Cash equivalents	-	2 458
Total cash and cash equivalents	**2 827**	**7 767**

RESTRICTED CASH IS RELATED TO:

* TAXES WITHHELD FROM EMPLOYEES OF NOK 24 MILLION (NOK 8 MILLION IN 2022)

During 2022 PGNiG Upstream entered into short-term bank deposits with an original maturity of three months or less, net of outstanding bank overdrafts. These were settled in 2023.

NOTE 16 INVENTORY

The inventory in 2023 (NOK 300 million) is substantially connected with the spare parts and drilling equipment kept within the joint ventures. The majority of reported spare parts are related to the Sleipner Øst, Yme, Ormen Lange, Skarv and Tyrving. The Company did not account for any hydrocarbons left in inventor.

NOTE 17 EQUITY

The share capital consists of 1 115 000 shares each with a nominal value of NOK 1 000.

In 2023, the Company paid dividend to its shareholders with the value of 1 551 million NOK.

As of the balance sheet date, all the shares are held by the parent company, ORLEN. The parent company represents 100% of votes at the shareholders meeting of PGNiG Upstream. In addition, the parent company produces consolidated statements which include PGNiG Upstream.

All the shares are pledged for the benefit of Societe Generale, London Branch, which acts as the Facility Agent and the Security Agent under the external loan facility (ref Note 19). The execution of the pledge was a pre-condition for PGNiG Upstream raising financing under the reserve-based loan formula. There are certain restrictions on enforcement of this pledge. They are described in the Shareholder Register.

NOTE 18 INTERCOMPANY LOANS (MNOK)

	2023	2022
Principal Loan to Group enterprises	4 046	5 257
Interest receivable from Group enterprises	77	39
Total Loan to Group enterprises	**4 123**	**5 296**
Principal debt to Group enterprises	5 000	0
Interests to Group enterprises	3	0
Total debt to Group enterprises	**5 003**	**0**
Hereof short-term – interest payable within 1 year	5 003	0
Long term liabilities to Group enterprises	**0**	**0**

LOAN TO GROUP ENTERPRISES

The intercompany loan to sole shareholder was signed in June 2022. The available limit under this loan accounts for EUR 500 million. The purpose of the loan is to fund corporate needs.

The loan to shareholder can be disbursed in several tranches. Each tranche shall be disbursed on the basis of a duly prepared Drawdown Request. The tranche is to be paid within 5 working days from receipt of the Drawdown Request. Each tranche can be drawn in NOK, EUR or USD. The availability period for the loan extends to December 2025.

As of 31 December 2023, ORLEN has drawn EUR 360 million under the Loan Agreement. Any outstanding balance under the Loan Agreement bears interest based on the relevant reference rate applicable to the currency drawn, plus margin.

The margin level was based on a benchmarking study and comparable transactions in the oil and gas industry.

The Loan Agreement includes covenants for borrower to disclose information to lender on events that may impact its capacity to repay the loan.

DEBT FROM GROUP ENTERPRISES

As of 31st December 2023 PGNiG Upstream had funding available through three intercompany loans:

- Loan no 3: From 27 August 2010 with the maximum available amount of NOK 4 100 million from shareholder - not utilised as of 31.12.2023
- Loan no 8: From 14 April 2021 with the maximum available amount of NOK 5 000 million from shareholder - not utilised as of 31.12.2023
- Loan no 1/2023: From 25 May 2023 with the maximum available amount of NOK 5 000 million from affiliated entity LOTOS Exploration and Production Norge AS – As of 31.12.2023 PGNiG Upstream has drawn the entire available amount of NOK 5 000 million

The Intercompany Loans can be used to fund corporate needs, including current capital expenditure and exploration-related expenses.

The abovementioned loans can be disbursed in several tranches. Each tranche shall be disbursed based on a duly prepared drawdown request.

In the event of any outstanding balance of shareholder loans, this is to be repaid in 5 equal instalments starting from 31st December 2027, and it bears interest based on 3M NIBOR + margin. The last principal instalment is due on the 31st December 2031.

In the event of an outstanding balance under the loan to affiliate, this is to be repaid within 31st December 2024. It bears interest based on NIBOR + Margin.

The margin levels were based on benchmarking studies and comparable transactions in the oil and gas industry.

The repayment of the shareholder loan number 3 is secured through:

(a) the Norwegian law promissory note; and

(b) the registered pledge over the shares in Production Licenses 212, 212B, 262 on the NCS. The pledge over the Skarv licenses has second priority. The carrying amount of the Company assets pledged as security amounts to NOK 2 324 million. The value of all pledges is limited to the value of PGNiG Upstream's liabilities under this loan.

The repayment of the loan from affiliate is secured through the Norwegian law promissory note.

All intercompany loans are subordinated to the Facility (ref Note 19).

NOTE 19 DEBT TO FINANCIAL INSTITUTIONS

	2023	2022
Principal debt	506	0
Commitment fee	21	12
Effective interest rate amortization	2	0
Debt to financial institutions	**529**	**12**
Hereof short-term - payable within 1 year	23	12
Long term Debt to financial institutions	**506**	**0**

The credit facility ("Facility") was first signed in August 2015 with a group of eight banks. During 2022, PGNiG Upstream signed a six year extension of this loan. As per 31.12.2023, the bank consortium consists of the following banks:

- Société Générale
- ING Belgium NV/SA
- BNP Paribas
- DNB Bank ASA
- SMBC Bank EU AG
- Bank Handlowy w Warszawie S.A.
- Bank Gospodarstwa Krajowego
- Powszechna Kasa Oszczędności Bank Polski S.A.
- Crédit Agricole Corporate and Investment Bank

The Facility provides a revolving credit for seven years and therefore the Facility is classified as a long-term debt. Under this agreement, the Company may select an interest period of one, three or six months. Under the Facility the Company can draw loans in EUR and USD. The Facility is based on the reserve-based loan formula and is governed by English law.

As of 31st December 2023, the available amount under the Facility was limited by overall limit of USD 700 million.

As of 31st December 2023, PGNiG Upstream had utilised the Facility as follows:

- Borrowing of EUR 45 million
- Letter of Credit NOK 1 068 million

The drawing limit will be amortizing over time in accordance with the reduction schedule, starting from 1st July 2025 until 1st September 2028. The Facility is to be repaid in full by 1st September 2028.

The Facility will be one of the key sources of financing for the Company in the years to come. It provides PGNiG Upstream with flexibility in respect of its planned exploration and production activities. The Facility allows the Company to freely acquire further upstream assets on the Norwegian Continental Shelf (without any restrictions imposed by the banks). It also provides for the possibility of including new upstream assets under the RBL. In the balance sheet the loan is presented using the effective interest method.

SECURITY UNDER FACILITY

The repayment of the Facility is secured through:

(i) the pledge over shares of PGNiG Upstream;
(ii) the registered pledge over loan receivables under a loan agreement between ORLEN and PGNiG Upstream;
(iii) the registered pledge over shares in Production Licenses 029C, 029B, 036, 036D, 044, 122, 134B, 134C, 159B, 193, 193B, 193D, 208, 212, 212B, 249, 250, 262, 460, 636 and the pledge over the

Company's accounts, refund claims, trade receivables and insurance proceeds.

All pledge agreements have been concluded with Societe Generale, which acts as the Facility Agent and the Security Agent under the Facility. The carrying amount of the Company assets pledged as security amounts to NOK 18 961 million.

The effective value of the pledge created under the Pledge Agreements is capped by the value of PGNiG Upstream's liabilities to banks under the Facility.

NOTE 20 PENSION

The company maintains a defined contribution pension scheme in compliance with the Act related to Mandatory Occupational Pensions. The scheme covers pensions for salary amounts both below and above 12G. In addition, the company has signed an agreement with Storebrand which regulates employees' rights connected with transition from the old pension scheme.

The pension scheme covers all employees from the date of employment. By 31st December 2023, the plan had 107 active members. The plan is organised through the insurance company Storebrand Livsforsikring AS. The plan is purely a savings scheme in which the enterprise saves a percentage of the employee's salary in a separate pension account for each employee. The employee's pension is thus determined by the amount saved up during his/her working life and the return added along the way.

NOTE 21 PROVISIONS

ABANDONMENT PROVISION

The Company has recognized provisions for future abandonment for all its oil & gas fields as per year-end 2023. These provisions are related to removal expenditures for the offshore installations.
Decommissioning cost related to Nyhamna processing plant and the pipeline assets (VRGP and KOR) are paid and passed on to the Shippers through the shipper agreement through Gassco/Equinor as operators for the pipelines and processing plant.

The value of abandonment provision is related to the expected costs for plugging of wells and removal of well heads, pipelines and platforms. The abandonment provision covers only installations that existed at the end of 2023. The value of the abandonment costs was based on the study performed by the field operators. The Company has assumed a time of abandonment which is in line with the operator's official data. There is a considerable risk associated with assessing both value and time of abandonment liability. For example, the future development of new reserves like Skarv satellite projects may defer the abandonment date for the Skarv field.

The removal liability is viewed to be a part of the total cost of the relevant property, plant and equipment (ref Note 12).

Provisions recognized in 2023 consist of (numbers presented below are PGNIG share in NOK million):

Field	Abandonment provision	Expected abandonment
Skarv	481	2037-2040
Morvin	57	2038
Vilje	146	2042-2044
Vale	250	2024-2026
Gina Krog	445	2034-2037
Ærfugl	122	2037-2039
Skogul	92	2043-2044
Duva	230	2031-2040
Ærfugl Nord	33	2038-2039
Valemon	140	2028
VRGP	1	2024
Kvitebjørn (incl. KOR)	180	2034
Ormen Lange	606	2044-2050
Alve	122	2028
Marulk	146	2027
Tambar East	11	2029
Gyda	14	2024-2026
Gassled	378	2060
Nyhamna	112	2060
Tommeliten	516	2047-2053
Atla	96	2024-2026
Skirne	256	2024-2026
Heimdal	50	2024-2028
Sleipner West	692	2033-2034
Sleipner East	740	2029-2030
Gungne	22	2034
Utgard	117	2027
Yme	585	2030-2035
Total	**6 639**	

When calculating the net present value of the long-term portion of the liability, PGNiG Upstream used forecasted inflation and discount rates. The company performed an interest rate sensitivity analysis as at 31.12.2023 using the change of +/-0.5 per cent which indicated that the effect on provision would be -6.06% and +6.73% respectively.

The increase in provision from 3 103 million to 6 639 million is caused by acquisition of LOTOS accounted for +2 573 million, new provision related to Tommeliten accounted for +516 million, unwinding of the discount in 2023 accounted for +176 million (ref Note 9) and increase due to change is estimates accounted for 271 million. Out of total decommissioning liability NOK 6 578 million is classified as long term and NOK 61 million is classified as short term (ref note 22).

PGNiG Upstream is also obliged to cover its relative share of removal cost for Gassled installations based on the share of transportation capacity used by the Company relative to the total transportation capacity for the Gassled installations. The Company has received an estimate of expected cost to be covered from PGNiG Upstream for future removal from the Gassled operator. PGNiG Upstream has assumed removal in 2060, resulting in a value of the liability of NOK 378 million at the end of 2023. As such, the Company has accrued for the liability at the end of 2023.

Decommissioning cost related to the Nyhamna processing plant and VRGP pipeline are passed on to the Shippers and a decommissioning receivable of NOK 113 million has been recognized. Decommissioning cost related to the KOR pipeline is paid and passed on to the Shippers, but because it is only the JV license partners themselves that have volumes in this pipeline no decommissioning receivable has been recognized and the company has recognized abandonment removal obligation according to the participating interest.

NOTE 22 OTHER CURRENT LIABILITIES

Other current liabilities consist of accrued costs. In 2022 is also included prepayments from customers of 579 million due to amendments to sales contracts in 2023 there is no prepayments from customers at the end of 2023, reference is made to note 3.

	2023	2022
Working capital, JV	1 552	721
Other current liabilities	222	936
Accruals billings	975	521
ARO provision short term	61	0
IFRS 16 Lease liability short term	146	0
Other current liabilities	**2 956**	**2 179**

NOTE 23 COMMITMENTS AND CONTINGENCIES

PGNiG Upstream has two loan agreements from ORLEN with the value of NOK 9.1 billion. As of 31.12.2023 these were not utilised. In the event of utilisation, the loans are secured by respective promissory notes.

PGNiG Upstream's activities on the NCS are secured by the parent company guarantee issued in 2023.

In addition, PGNiG Upstream has a loan agreement with external lenders, as of 31.12.2023 this loan was utilised through:

- Borrowing of EUR 45 million
- Letter of Credit NOK 1 068 million

The agreement is secured by a comprehensive security package, described in Note 19.

Except for the external borrowing, PGNiG Upstream has not booked any liability connected with the agreements mentioned above. According to the Company accounting policy, liability should be booked in the balance sheet of PGNiG Upstream if it is obliged to make a payment.

At 31st December 2023, PGNiG Upstream is not subject to any legal disputes other than tax dispute with the tax authorities concerning the price (deduction elements) under the intercompany agreement for sales of dry gas and tax dispute with the tax authorities concerning the thin capitalisation for the income years 2010-2016.

EXPECTED LICENSE COMMITMENTS

As a partner in various oil and gas assets, PGNiG Upstream is committed to participate in the expenses within the approved budgets. The budgets for the key assets of the Company are presented below. Inside these amounts there are both expenses which are already committed by the license partners as well as other payments. Commitments listed in the table account for 91% of the total license commitments for 2024.

Field	PGNiG share	Net budget 2024 (NOK million) *
Fenris	22.2%	2,959
Yggdrasil	12.3%	2,766
Ørn	40.0%	966
Tommeliten Alpha	42.2%	662
Ormen Lange	14.0%	514
Yme	20.0%	488
Tyrving	11.9%	464
Sleipner Vest	15.0%	440
Gina Krog	11.3%	397
Skarv	11.9%	386

* Planned license expenses (opex and capex) are based on the approved Business Plan 2024 for PGNiG Upstream

As presented above, the largest commitment relates to the ongoing development projects with the PDO approved in 2023: Fenris, Yggdrasil and Ørn. PGNiG Upstream is committed to execute the investments.

OTHER COMMITMENTS

PGNiG Upstream has also commitments to drill exploration wells in the following licenses or business units:

- PL211CS (operated by Wintershall DEA)
- PL636 (operated by Neptune)
- PL1013 (operated by Eqinor)
- PL1055 (operated by PGNiG Upstream)
- Skarv Unit (operated by AkerBP)
- Tyrving Unit (operated by AkerBP)
- Yggdrasil Unit (operated by AkerBP)

The Company has financial commitments related to bookings in the gas transportation system operated by Gassco. Such commitment in the next two years is secured through the intercompany guarantee with the nominal value of NOK 1500 million. See also Note 21 for information regarding commitment for PGNiG Upstream to share future removal cost related to Gassled transportation system.

PGNiG Upstream is committed to cover the costs from the office rental agreement. The rental agreement is valid until 31st December 2025 and has a yearly value of approximately NOK 6 million.

CONTINGENCIES

The contracts of members of the Board of Directors as well as managers of PGNiG Upstream include a non-competition clause. This clause is applicable for not more than a one-year period, starting at the end of the employment.

The managers will receive a compensation based on their monthly salary (without benefits) in return for the application of the non-competition clause.

LIABILITY FOR DAMAGES/INSURANCE

PGNiG Upstream's operations involve risk for damages, including pollution. Installations and operations are insured through the OEE insurance and drilling Insurance including Third Party Liability.

In addition, PGNiG Upstream holds an insurance policy that covers all risks of physical loss or physical damage to its fields.

NOTE 24 GUARANTEES

PARENT COMPANY GUARANTEES

In 2023, PGNiG Upstream agreed a new parent company guarantee as requested by the Ministry of Energy pursuant to the Norwegian Petroleum Act, as replacement for the parent company guarantee established in 2007.

Pursuant to the provisions of the new Guarantee Agreement, ORLEN has an unlimited valid guarantee to PGNiG Upstream.

The Guarantee Agreement concerns the provision of security by ORLEN regarding the fulfilment of certain obligations of PGNiG Upstream arising under the licenses or by operation of the law with respect to, inter alia, the Norwegian government and certain Norwegian entities. The provision of the guarantee is required under Article 10-7 of the Norwegian Oil Operations Act of 1996. Such a guarantee is a standard document used customarily in production operations in Norway.

The guarantee is secured with a Recourse Note issued by PGNiG Upstream.

***

In 2011, PGNiG Upstream received a parent company guarantee requested by Gassco as operator of the gas transportation system. In 2023, the Company has booked NOK 3 million as a liability connected with this agreement. This value is included in other current liabilities based on invoices received.

***

In 2020, PGNiG Upstream received a parent company guarantee requested by Aker BP in relation of purchase of interest in Gina Krog. The guarantee covers liability of up to NOK 25 million as of 31.12.2023. In 2023, the Company has booked NOK 0.2 million as a liability connected with this agreement.

***

In 2021, PGNiG Upstream received a parent company guarantee requested by INEOS in association with purchase of INEOS E&P Norge AS assets and operations on the NCS. As of 31.12.2023, the Guarantee covers liabilities up to NOK 1000 million.

In 2023 the Company has booked NOK 5 million as liabilities associated with this agreement.

GUARANTEES TO COVER SECONDARY DECOMMISSIONING LIABILITY

The Company secured a Letter of Credit from DNB Bank ASA towards Total E&P Norge AS to cover the decommissioning liabilities transferred from Total E&P Norge AS to the Company as a part of the asset acquisition in 2014.

Similarly, the Company secured a Letter of Credit from DNB Bank ASA towards A/S Norske Shell in relation to purchase of assets in 2020.

PGNiG Upstream secured two separate Letters of Credit from Credit Agricole Corporate and Investment Bank to cover decommissioning liabilities transferred as part of the purchase of assets from LOTOS Exploration and Production Norge AS in 2023 for the benefit of Sval Energi AS and Spirit Energy Norway AS, respectively.

The Company further secured a Letter of Credit from ING Belgium NV/SA under the RBL Credit Facility (ref Note 19) as part of the purchase of assets from LOTOS Exploration and Production Norge AS, for the benefit of ExxonMobil Exploration and Production Norway AS.

As of the balance sheet date, the maximum liability covered under these five guarantees were NOK 1 470.2 million. The Company has accrued for the expected future decommissioning liabilities for the assets as presented in Note 21.

NOTE 25 FINANCIAL RISK MANAGEMENT OBJECTIVES AND POLICIES

PGNiG Upstream has identified the major risks associated with the nature of the Company's business and the appropriate measures to manage those risks have been determined.

As an E&P company, PGNiG Upstream is exposed to a variety of financial risks. These include the following risk categories:

- market risk
- liquidity risk
- credit risk

PGNiG Upstream seeks to minimise the impact of adverse fluctuations in financial markets on its financial performance. Risk management is an integral part of the Company's activities.

The market risk is related to oil and gas commodity price and exchange rate uncertainties. For the time being PGNiG Upstream does not have any derivative forward sales of oil and gas or currencies or other agreements designed to reduce the future risk exposure. The lack of oil price hedging is among other things connected with the adverse tax treatment of crude oil hedging in Norway and the uncertainty regarding production volumes.

PGNiG Upstream minimised exchange rate exposure by utilising loans over several currencies - Norwegian kroner, euro and US dollars.

The debt from financial institutions is denominated in US dollars but allows funds to be drawn under multiple loans in both euro and US dollars. The currency of this loan is a part of the risk management.

The external loan is supposed to be repaid between 2025 and 2028 based on the revenues generated by PGNiG Upstream in these periods. As the revenues are denominated in US dollars and euro, the Company will be able to repay external debt without additional currency risk.

The following was undertaken by PGNiG Upstream to mitigate credit risk:

- cooperation with leading commercial banks;
- cooperation with credible customers;
- conclusion of framework agreements with business partners, that expressly define the rights and obligations of the parties.

The measures undertaken by the ORLEN Group to mitigate the liquidity risk included:

- on-going control of credit/debit operations on bank accounts
- availability of a revolving credit facility agreement
- projections of cash flows at the Company/the ORLEN group level

The main objective of the PGNiG Upstream financial risk management policy is to limit the volatility of cash flows related to the Company's operations to acceptable levels in the short and midterm while building the Company's value in the long term.

In connection with future spending on fields, the Company is able to finance its operations through operating cash flow and external loan (see Note 19). In addition, the potential risk of liquidity loss is covered by available amount under intercompany loan (see Note 18)

NOTE 26 EVENTS AFTER THE BALANCE SHEET DATE

AWARDS IN APA2023

In January 2024, the Norwegian government finally granted shares in more than 62 production licenses to 24 companies. PGNiG applied for shares in ten licenses and succeeded in being awarded ten as a result of the annual licensing round (APA 2023). PGNiG will act as the operator of one of the ten newly awarded licenses.

It should be noted as well that through the purchase of KUFPEC Norway AS, PGNiG will ultimately inherit two additional new license areas around the Sleipner Field.

Four of the newly awarded licenses are located in the Norwegian Sea. PGNiG will act as the operator for one of them. PGNiG will hold 70% shares in PL1220 and act as operator with Equinor as partner with 30 %. The three other license applications from PGNiG concerned areas close to infrastructure in which PGNiG hold shares, and thus extends PGNiG's current footprint in the area. PGNiG will acquire 20% shares in PL1230 where AkerBP will be the operator with 40% equity, 20% in PL1229 where Sval will be the operator with 30% equity and 10% in PL211DS where Wintershall DEA will be the operator with 40%. Several of these licenses are located near the Skarv Field, from which PGNiG's operations in Norway began.

Six of the newly awarded licenses are located in the Norwegian North Sea. Five are located close to development projects in which PGNiG hold shares. PGNiG will acquire 12.3% of shares in PL873B, PL873C and PL1206S, all operated by AkerBP and close to the Yggdrasil development. In addition, PGNiG will acquire 30% and 22.2% of shares in PL1199 and PL1088B respectively, both operated by AkerBP and close to the Fenris development. Finally, PGNiG will acquire 30% shares in PL1101B where OMV will be the operator with 40% equity.

For PL838B, PL1091, PL1193 the operators have completed their voting in preparation to relinquish the license and to notify the authorities. The company did not have any capitalized exploration expenses on these licenses at 31.12.2023.

COMPLETION OF THE KUFPEC ACQUISITION

On 5th January 2024, the Company completed purchase of all shares in KUFPEC Norway AS. The acquired subsidiary was rebranded as ORLEN Upstream Norway 2 AS. It is expected that the assets and activities of ORLEN Upstream Norway 2 AS will be consolidated with PGNiG Upstream during 2024. Reference is made to note 2 for further details.

ACQUSITION OF THE POLARIS CCS LICENSE

In January 2024 the Norwegian Ministry of Energy approved PGNiG Upstream as the operator of the Polaris Carbon Capture and Storage project. This represents a new business area for PGNiG Upstream. PGNiG Upstream Norway and Horisont Energi are partners on the projects and each holds 50% ownership in the license.

NOTE 27 LICENSES

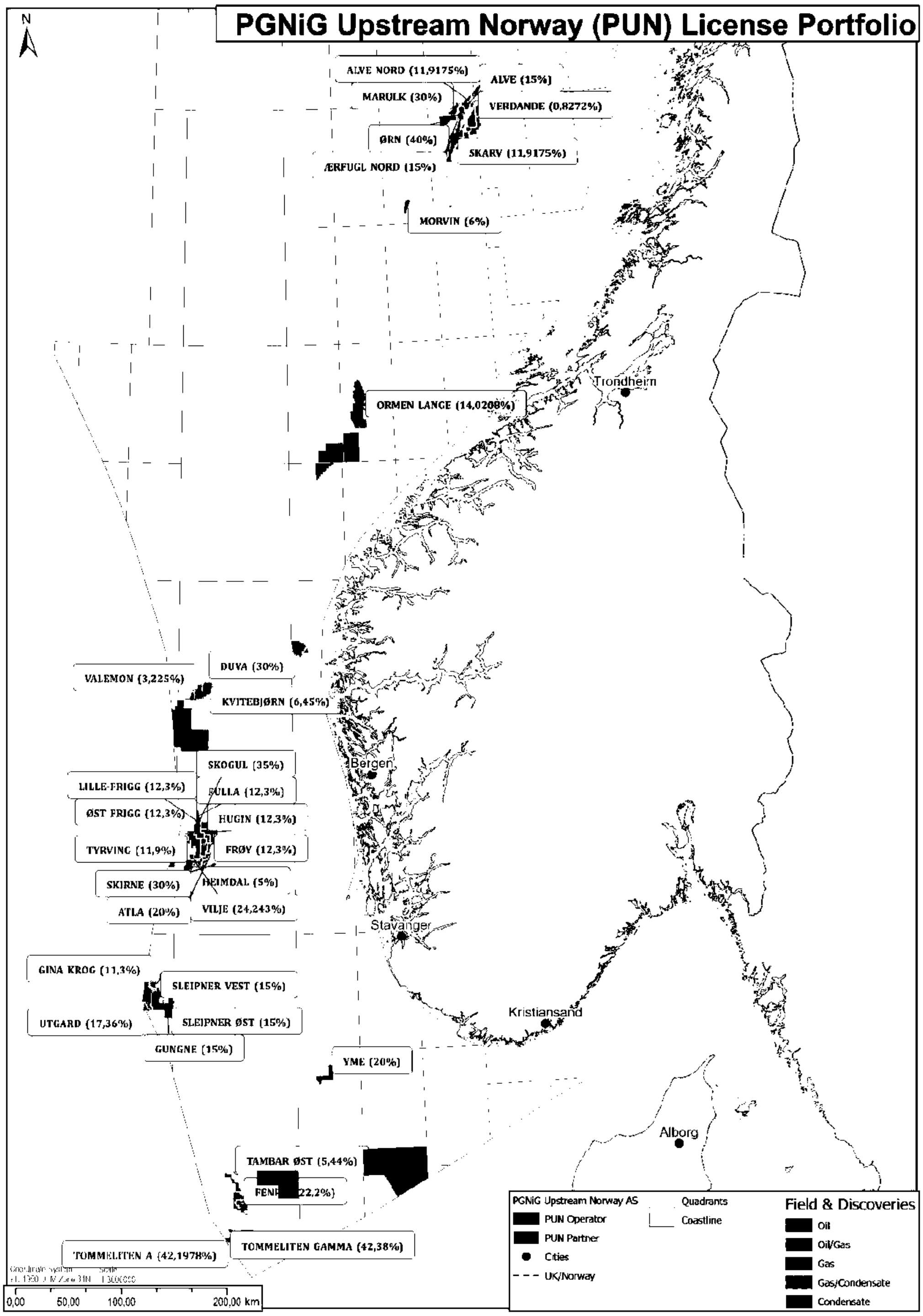
PGNiG Upstream's licenses at 31/12/2023

PL019G	(Gyda/Tambar East)	34%/5.44%
PL026	(Yggdrasil)	12.3%
PL026B	(Yggdrasil)	12.3%
PL029		15%
PL029B	(Gina Krog Unit)	11.3%
PL029C	(Gina Krog Unit)	11.3%
PL036D	(Vilje)	24.243%
PL036BS	(Heimdal)	5%
PL044	(Tommeliten Unit)	42.1978%
PL046	(Sleipner area)	15%
PL046E	(Utgard)	17.36%
PL046F	(Utgard)	17.36%
PL102	(Byggve)	30%
PL102C	(Atla)	20%
PL102D	(Tir)	20%
PL102E	(Skirne)	30%
PL102F	(Tyrving)	11.9%
PL102G	(Tyrving)	11.9%
PL102H	(Tir)	20%
PL122	(Marulk)	30%
PL122B	(Marulk)	30%
PL122C	(Marulk)	30%
PL122D	(Marulk)	30%
PL127C	(Alve N)	11.9175%
PL127DS	(Verdande Unit)	0.827%
PL134B	(Morvin)	6%
PL134C	(Morvin)	6%
PL146	(Fenris)	22.2%
PL146B	(Fenris)	22.2%
PL159B	(Alve/Andvare)	15%
PL159F	(Osprey)	60%
PL159G	(Alve)	15%
PL193	(Kvitebjørn)	6.45%
PL193C	(Kvitebjørn)	6.45%
PL193B	(Valemon)	3.225%
PL193D	(Valemon)	3.225%
PL208	(Ormen Lange Unit)	14.0208%
PL212CS	(Adriana/Sabrina)	10%
PL212	(Skarv Unit)	11.9175%
PL212B	(Skarv Unit)	11.9175%
PL212E	(Ærfugl Nord)	15%
PL250	(Ormen Lange Unit)	14.0208%

If a license is part of a unit, the equity share in the unit is provided in the above table

PL261C	(Skarv Unit)	11.9175%
PL262	(Skarv Unit)	11.9175%
PL316	(Yme)	20%
PL316B	(Yme)	20%
PL333	(Fenris)	22.2%
PL364	(Yggdrasil)	12.3%
PL442	(Yggdrasil)	12.3%
PL442B	(Yggdrasil)	12.3%
PL442C	(Yggdrasil)	12.3%
PL460	(Skogul)	35%
PL636	(Duva)	30%
PL636B	(Duva)	30%
PL636C	(Duva)	30%
PL822S	(Yggrasil)	12.3%
PL838	(Shrek)	35%
PL838B		40%
PL873	(Yggdrasil)	12.3%
PL874		12.3%
PL918S		25%
PL941		20%
PL941B		20%
PL942	(Ørn)	40%
PL1009	(Warka)	35%
PL1009B	(Warka)	35%
PL1013		40%
PL1013B		40%
PL1055		60%
PL1055B		60%
PL1055C		60%
PL1088		22.2%
PL1091		20%
PL1101		30%
PL1123		30%
PL1135		100%
PL1136		50%
PL1142		17.94%
PL1143		17.94%
PL1144		30%
PL1172		30%
PL1175		20%
PL1190		20%
PL1193		20%

PL036E and PL036F is not included in the above table license period for these expired in 2023 and the operator has applied for license extension.


PGNiG Upstream Norway (PUN) License Portfolio
N
ALVE NORD (11,9175%)
ALVE (15%)
MARULK (30%)
VERDANDE (0,8272%)
ØRN (40%)
SKARV (11,9175%)
ÆRFUGL NORD (15%)
MORVIN (6%)
ORMEN LANGE (14,0208%)
Trondheim
DUVA (30%)
VALEMON (3,225%)
KVITEBJØRN (6,45%)
Bergen
SKOGUL (35%)
LILLE-FRIGG (12,3%)
SULLA (12,3%)
ØST FRIGG (12,3%)
HUGIN (12,3%)
TYRVING (11,9%)
FRØY (12,3%)
SKIRNE (30%)
HEIMDAL (5%)
ATLA (20%)
VILJE (24,243%)
Stavanger
GINA KROG (11,3%)
SLEIPNER VEST (15%)
UTGARD (17,36%)
SLEIPNER ØST (15%)
GUNGNE (15%)
Kristiansand
YME (20%)
Alborg
TAMBAR ØST (5,44%)
TOMMELITEN GAMMA (42,38%)
TOMMELITEN A (42,1978%)
0,00 50,00 100,00 200,00 km
PGNiG Upstream Norway AS
PUN Operator
PUN Partner
Cities
UK/Norway
Quadrants
Coastline
Field & Discoveries
Oil
Oil/Gas
Gas
Gas/Condensate
Condensate

THE SKARV FIELD

The licenses PL212, PL212B and PL262 contain the Skarv oil and gas field. Skarv was discovered in 1998 and started production 2013. The Skarv field was developed together with the Idun field located nearby. During 2007 the Skarv and Idun licenses were unitized and both are now only referred to as Skarv Unit.

The Skarv Unit:	
Aker BP (operator)	23.8350%
Equinor	36.1650%
Wintershall DEA	28.0825%
PGNiG Upstream	11.9175%

The Skarv Field is approximately 210 km west of the Norwegian coast in water depths of around 350-450 meters.

The field was developed using a highly advanced FPSO (floating production, storage and offloading vessel), purpose-built for harsh waters and connected to a gas pipeline, allowing the export of natural gas to markets in Europe.

THE ÆRFUGL FIELD

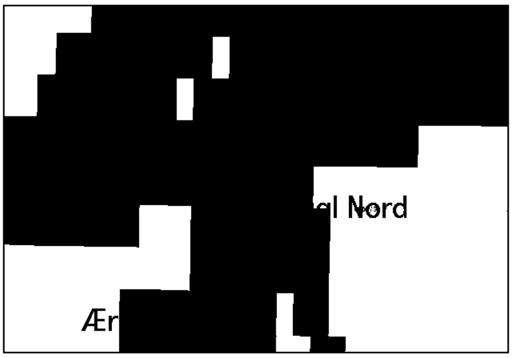
The Ærfugl field is located within the Skarv Unit. Its development plan (PDO) was approved in April 2018.

The PDO covered the full-field development and includes the resources in both the Ærfugl and Ærfugl Nord fields. The reservoir contains gas and condensate in sandstone of Late Cretaceous age in the Lysing Formation. The development concept includes subsea production wells tied-back to the Skarv FPSO. Production started in November 2020.

LICENSE PL212E

PL212E was carved out of the Skarv Unit after the unitization agreement in 2007. The licence is operated by Aker BP (30%), with Equinor (30%), Wintershall DEA (25%) and PGNiG Upstream (15%) as partners.

The license includes the Ærfugl Nord, which lies close to the Ærfugl gas field. Ærfugl Nord was included in the second phase of the Ærfugl development.

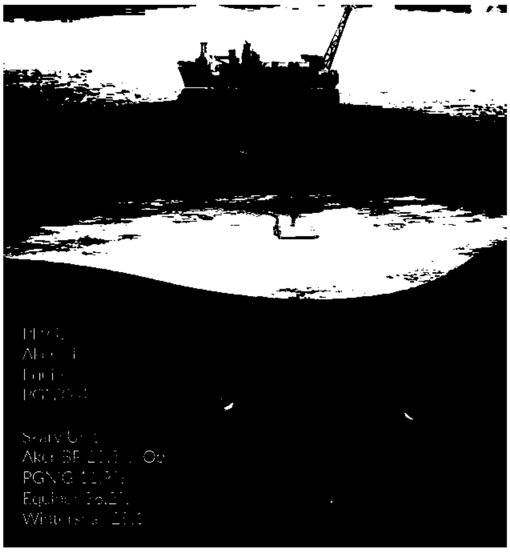


THE ØRN FIELD

The Ørn field is located ca 20 km northwest of Skarv FPSO. Its development plan (PDO) was submitted to the Ministry of Petroleum and Energy (MPE) on 16 December 2022.

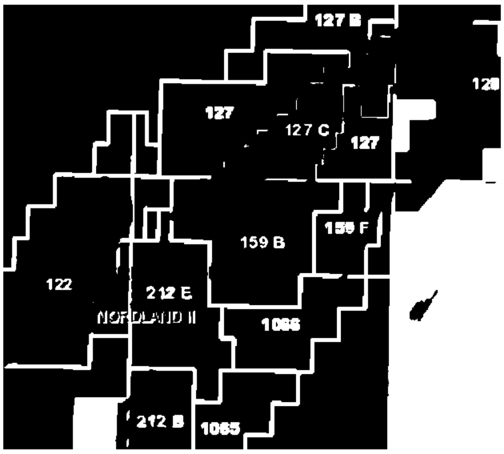
First production is scheduled in 2027, and the field will be developed as a subsea tie-back to Skarv FPSO.

The licence is operated by Aker BP (30%), with Equinor (30%), and PGNiG Upstream (40%) as partners.



THE ALVE NORD FIELD

The Alve Nord field is located ca 30 km north of Skarv FPSO. Its development plan (PDO) was submitted to the Ministry of Petroleum and Energy (MPE) on 16 December 2022. PDO was approved in June 2023, and development of field is ongoing.



First production is scheduled Q2 2027, and the field will be developed as a subsea tie-back to Skarv FPSO.

The licence is operated by Aker BP (68.1%), with Winthershall DEA (20%), and PGNiG Upstream (11.9%) as partners.

THE VERDANDE FIELD

The Verdande field is located ca 5 km northeast of Alve Nord. Its development plan (PDO) was approved by the Ministry of Energy in June 2023

The Verdande Unit:	
Equinor (operator)	59.2682%
Petoro	22.4067%
Vår Energi	10.4979%
Aker BP	7%
PGNiG Upstream	0.8272%

First production is scheduled Q4 2025, and the field will be developed as a subsea tie-back to Norne FPSO with three wells.

THE SLEIPNER FIELD

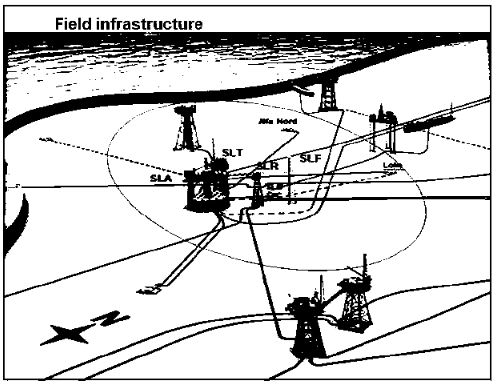
Sleipner is a gas field discovered in 1974 and put on production in 1993. Sleipner consists of three fields; Sleipner East, Sleipner West and Gungne.

The Sleipner West/Sleipner East/Gungne Units:	
Equinor (operator)	58.3494-62%
Vår Energi	13-17.2396%
PGNiG Upstream	15%
ORLEN Upstream Norway 2	9.4112-10%

Sleipner East has been developed with Sleipner A, an integrated processing, drilling and accommodation platform with a concrete base structure. Production from Sleipner East started up in 1993.

Sleipner West has been developed with a normally unmanned wellhead platform (SLB) and a subsea template (Alfa Nord) both tied back to a processing platform (SLT) which is bridge-linked to the Sleipner field centre (SLA). Due to the high CO_2 content in the Sleipner West gas, a CCS plant was included on the SLT platform to meet the sales gas requirements. Production from Sleipner West started up in 1996.

Gungne has been developed with wells drilled from the Sleipner SLA platform. Production from Gungne started up in 1996.



Other fields, i.e. Gudrun, Gina Krog, Sigyn and Utgard have been tied back to the Sleipner.

Sales gas is exported from Sleipner field centre via Gassled (Area D) to the market. Unstable condensate is piped to Kårstø for further processing.

THE GINA KROG FIELD

Gina Krog is an oil and gas discovery located in the Central North Sea, 250 kilometres west of Stavanger and 30 kilometres northwest of Sleipner.

The Gina Krog Unit:	
Equinor (operator)	58.7000%
ORLEN Upstream Norway 2	30.0000%
PGNiG Upstream	11.3000%

The field has been developed with a fixed platform for wells and processing. Oil is exported via a floating storage unit (FSO) that is connected to the platform. Produced gas is transported to Sleipner for further treatment.

Production started in 2017 and Gina Krog currently has 9 wells Gas injection has been the main recovery strategy and gas has been imported for that purpose.

At the end of 2021 import of gas was for gas injection was halted due to a combination of high demand for gas in Europe and very high gas prices. Injection has not been re-started.

A drilling campaign with one in-fill well and one exploration well (B-20/ Dougal) was completed in 2023.

As a part of the CO_2 reduction efforts it was planned to have the platform hooked up to power from shore via the Johan Sverdrup field since September 2023.

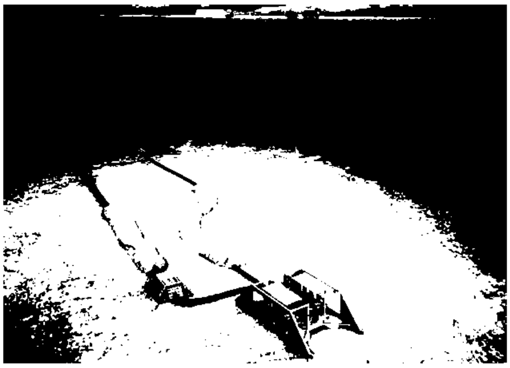
THE UTGARD FIELD

The Utgard field is a gas condensate field that straddles the Norwegian – UK border (62% - 38%) and is located 20 km west of Sleipner. The field was discovered in 1982 and put on production in 2019.

The development concept is a 4-slot subsea template with two wells tied back to the Sleipner SLT platform for processing and reduction of the CO_2 level in the gas. The Utgard gas contains 16 percent CO_2.

The Utgard Unit:	
Equinor (operator)	38.44%
Equinor UK	38.00%
PGNiG Upstream	17.36%
ORLEN Upstream Norway 2	6.20%

The sales gas is exported via Gassled (Area D), and the unstable condensate is transported by pipeline to Kårstø terminal for further processing and export.



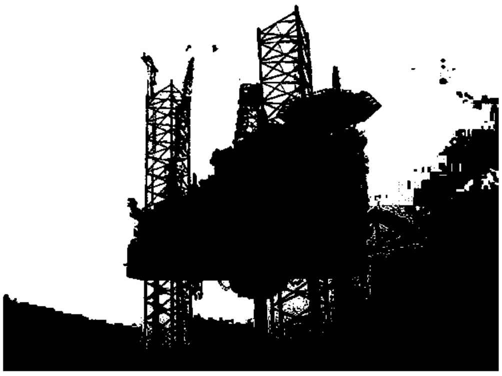
THE YME FIELD

Yme is a field in the southeastern part of the Norwegian sector of the North Sea. The field comprises two separate main structures, Gamma and Beta, which are 12 kilometres part.

The Yme field:	
Repsol Norge AS (operator)	55.00%
PGNIG Upstream	20.00%
OKEA	15.00%
Lime Petroleum	10.00%

Yme was discovered in 1987, and the plan for development and operation (PDO) was approved in 1995. Yme was originally developed with a jack-up drilling and production platform on the Gamma structure and a storage vessel.

The Beta structure was developed with a subsea template. Production started in 1996 with Statoil (Equinor) as the operator, and production was stopped in 2001 because operation of the field was no longer regarded as profitable.



In 2018, an amended PDO for the redevelopment of Yme was approved. The PDO includes a jack-up rig equipped with drilling and production facilities installed on the Gamma structure and a subsea template on the Beta structure. Production from Yme restarted in 2021.

ORMEN LANGE UNIT

The Ormen Lange field is located in the Norwegian Sea, 120 kilometres west-northwest of the Nyhamna processing plant. It was discovered in 1997 in water depth from 800 to more than 1 100 meters. The reservoir lies at a depth of 2 700-2 900 meters below sea level and has excellent quality. The reservoir lies at a depth of 2 700-2 900 meters below sea level and has excellent quality.

The Ormen Lange Unit:	
Shell (operator)	17.8134%
Equinor	25.3452%
Petoro	36.4850%
Vår Energi AS	6.3356%
PGNiG Upstream	14.0208%

The production from the Ormen Lange Field started in 2007 from two 8-slots subsea templates in the central part of the field. Two new templates were installed in 2009 and 2011 in the southern and northers parts of the field. The subsequent phase in the development was the installation of onshore compression with production start in 2017. The current well stock is now 19 producing wells. The Ormen Lange Phase 3 (OLP3) offshore compression is in execution mode with a P50 RFSU in Q4 2025. The field is produced through two 120 km long multiflow pipelines up to the Nyhamna processing plant.

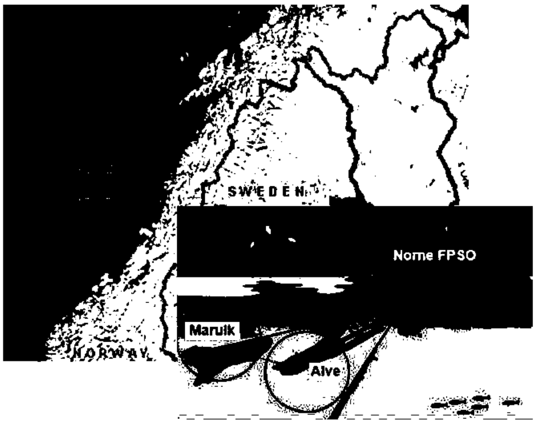
MARULK

The Marulk field is a gas and condensate producer located in PL122 in the Norwegian Sea. It is located some 215 kms offshore with a distance to the production host of c. 25 kms. The Marulk field was discovered in 1992 and it started production in 2012. The water depth in the area is approximately 370 m and the development is completed as a three well subsea tie-back to the Norne FPSO.

Marulk	
Vår Energi AS (operator)	20.00%
Equinor	33.00%
DNO Norge	17.00%
PGNiG Upstream	30.00%

Gas and condensate from the Marulk field was initially produced from two wells draining the Lysing reservoir that was drilled and put on stream in 2012. A third well was drilled in 2019, draining the Lange Formation. Marulk produces gas from Cretaceous sandstone in the Lysing- and Lange Formation. The reservoirs are located at a depth of 2 800 – 2 850 meters.

Marulk is produced via a multiphase pipeline to Norne, with subsequent wet Gas export from Norne via Gassled to Kårstø. Oil and condensate is exported from Norne via Transport tanker.



ALVE

The Alve field is a gas, oil and condensate producer located in PL159B in the Norwegian Sea. It is located some 215 kms offshore with a distance to the production host of c. 16 kms. The Alve field was discovered in 1990 and it started production in 2009. The water depth in the area is approximately 370 m and the development is completed as a four well subsea tie-back to the Norne FPSO.

Alve	
Equinor (operator)	53.00%
DNO Norge	32.00%
PGNiG Upstream	15.00%

The Alve field was initially produced from two wells that was drilled and put on stream in 2009/2010 with a third well drilled in 2016, draining the Ile Formation. During 2022 a fourth well was put on production in the gas zone in the Tilje formation. Alve produces oil and gas from sandstone of Early and Middle Jurassic age in the

Tilje, Not and Garn Formations. The reservoir lies at a depth of 3 600 meters and has moderate to good quality.

Alve is produced via a multiphase pipeline to Norne, with subsequent wet Gas export from Norne via Gassled to Kårstø. Oil and condensate are exported from Norne via Transport tanker.

TAMBAR EAST

Tambar East is a field in the southern part of the Norwegian sector in the North Sea, two kilometres east of the Tambar field, 16 km south of the Ula field and 12 km north of Gyda.

Tambar East Unit	
Aker BP (operator)	46.20%
DNO Norge	37.80%
Repsol	9.76%
ORLEN Upstream Norway 2	0.80%
PGNiG Upstream	5.44%

The Tambar East field was discovered in 2007 (K-5T2). In the same year authorities granted an exemption for the plan for development and operation (PDO) and the field started production. The field was developed with one production well (K-5A) drilled from the unmanned Tambar facility remotely controlled from the Ula field. Production from Tambar East was shut in in 2017 and the well was temporarily plugged in 2019. The well restarted production in 2023.

GYDA

The Gyda field is located in the southern North Sea in PL019B about 280km southwest of Stavanger and between the Ula and Ekofisk fields. The field is operated by Repsol. Production from Gyda ended 29 Feb 2020 after almost 30 years of producing oil and gas. The PL019B license was not extended after its expiration 1 Sept 2020.

The P&A sub project commenced in Jan 2019 and a total of 32 wells have been plugged.

Gyda	
Repsol (operator)	61.00%
ORLEN Upstream Norway 2	5.00%
PGNiG Upstream	34.00%

The Gyda topside, steel jacket, 32 well conductors and the subsea drilling template were removed during summer 2022, utilizing the Allseas Pioneering Spirit heavy lift vessel. Platform demolition is currently ongoing at Aker Stord.

THE VILJE FIELD

The Vilje field is in block 25/4 of the Norwegian North Sea, about 20 kilometres northeast of Alvheim and just north of Heimdal, in 120 metres of water. The Vilje reservoir is Middle to Late Paleocene Heimdal Formation turbidite sandstone, at a depth of approximately 2 100 metres. The Heimdal Formation is a high porosity, high net-to-gross, unconsolidated, high permeability, normally pressured sandstone, with an active water drive.

Vilje is a subsea development with three horizontal subsea wells. The field started production in August 2008. The subsea wells are tied back 19 km via a 12" production flow line, 6" gas lift line and an umbilical to the Alvheim FPSO for processing. The oil is exported from the Alvheim FPSO via tankers.

Vilje	
Aker BP ASA (operator)	46.904%
DNO Norge AS	28.853%
PGNiG Upstream	24.243%

Currently Vilje is being produced through the Vilje VI1 well with intermittent production fromVI2. VI3 is currently shut in.

THE VALE FIELD

The Vale field was discovered in 1991 and started production in 2002. The Vale field was a gas and condensate field located 16 km north of the Heimdal Gas Centre (HGC).

Vale	
Sval Energi AS (operator)	50%
PGNiG Upstream	50%

The licence approved the decommissioning project in 2022. Vale was shut down in September 2023. The license was not extended after its expiration 01.10.2023. According to the formal removal resolution, decommissioning must be completed by the end of 2028.

THE MORVIN FIELD

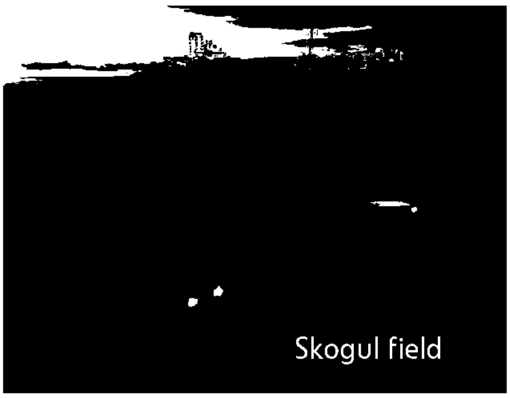
Morvin is located in the Norwegian Sea. The field is classified as a HPHT field, with an initial reservoir pressure of 818 bar and a temperature of 162 degrees Celsius. The field is located close to other projects, approximately 20km north of the existing Kristin field and 15km west of Åsgard B. The reservoir depth is from 4500 – 4800 meters. The water depth in the area is 360 meters.

Morvin	
Equinor (operator)	64,00%
Vår Energi ASA	30,00%
PGNiG Upstream	6,00%

The reservoir contains oil and gas and is developed with four horizontal production wells and two subsea templates tied back to Åsgard B. Åsgard B is a semi-submersible floating production vessel, containing process facilities for treating gas and stabilisation of gas and condensate.

THE SKOGUL FIELD

The Skogul oil field, in PL460, is located approximately 30 km North of Alvheim in blocks 24/3 in the Norwegian sector of the North Sea. The water depth is 107 meters.



The field was discovered in April 2010 by Det Norske and a PDO was submitted to the authorities in December 2017. The field is developed with one multi-lateral subsea well tied back to the existing Alvheim facilities via the Vilje subsea field. The Skogul development project was completed and production started 14th March 2020.

Skogul	
Aker BP ASA (operator)	65.00%
PGNiG Upstream	35.00%

THE KVITEBJØRN FIELD

Kvitebjørn is an HPHT field in the Tampen area in the northern part of the North Sea, 15 kilometres southeast of the Gullfaks field. The water depth is 190 metres. Kvitebjørn was discovered in 1994, and the plan for development and operations (PDO) was approved in 2000. The field is developed with an integrated accommodation, drilling and processing facility on a steel jacket. Production started in 2004.

Kvitebjørn	
Equinor (operator)	39.55%
Petoro AS	30.00%
Sval Energi AS	19.00%
TotalEnergies	5.00%
PGNiG Upstream	6.45%

Production is routed through first stage separation after which rich gas is transported via Kvitebjørn gas pipeline to Kollsnes. Condensate is transported via Kvitebjørn oil pipeline and TOR 2 pipeline to Mongstad.

Short- term and long-term focus is to continue to mature infill targets and on the planned lifetime extension project for Kvitebjørn to maintain production beyond 2027.

From summer 2023 Kvitebjørn receives all production from Valemon for further processing and export.

THE VALEMON FIELD

Valemon is a HPHT field in the northern part of the North Sea, just west of the Kvitebjørn field. The water depth is 135 metres. Valemon was discovered in 1985, and the plan for development and operation (PDO) was approved in 2011.

The field is developed with a fixed production platform with a simplified process. The facility is the first not normally manned platform on the NCS and is controlled from shore and has temporary living quarters for 40 people. Power is supplied from Kvitebjørn. Drilling is performed by jack-up rig. Production started in 2015.

The full production is from summer 2023 transported by pipeline to the Kvitebjørn field, and via the Kvitebjørn oil-pipeline to Mongstad. The rich gas export to Heimdal was stopped in July 2023. When Heimdal ceased its operation in the summer of 2023 the pipeline was decommissioned.

Valemon	
Equinor (operator)	66.775%
Petoro AS	30.000%
PGNiG Upstream	3.225%

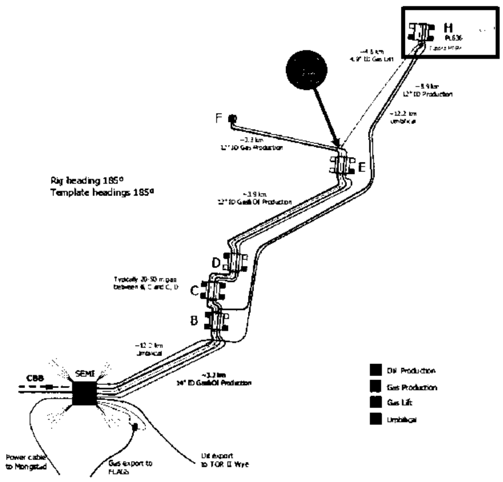
THE DUVA FIELD

Duva is an oil & gas discovery located in PL 636, 636 B & 636 C in the Norwegian sector of the North Sea, approximately 12 km northeast of the Gjøa semi-submersible. Closest distance to shore is only 35 km.

The Duva License partnership is Neptune 30% (Operator), Idemitsu 30%, Sval 10% and PGNiG Upstream 30%.

Duva was developed as a Subsea tieback to Gjøa with 3 oil producers and 1 gas producer. Production commenced in August 2021, And in May 2022 commercial gas export commenced after in-kind re-delivery was finalized.

In 2024 the Cerisa prospect within the license will be tested with an exploration well.



THE TOMMELITEN ALPHA FIELD

The Tommeliten Alpha field is located in PL044, in the Central Graben in the Norwegian North Sea, about 25 km southwest of the Ekofisk field. The discovery was made by Equinor in 1976 with subsequent appraisal wells drilled between 1976-2003. The reservoir is in chalk and there are two main reservoir layers, the Ekofisk Formation and the Tor Formation.

The partnership in the AMI (PL044 unitized with UK license P2220) currently consists of: ConocoPhillips (28.35% and operator), PGNiG Upstream (42.20%), Total (20.29%), Vår Energi (9.09%) and ENI UK (0.07%). Additionally, PGNiG have a 30% share in the PL044 exploration area which lies outside the Sole Risk Area (covering Tommeliten Alpha and Tommeliten Gamma).

The field has been developed as a subsea tie-back to Ekofisk platform and the production started up 13.10.2023 with two well. A total of 11 wells will be drilled, and plateau production is expected to be reached in 2024.

THE FENRIS FIELD (PL146/333)

Fenris is an HP/HT discovery located way south in the Norwegian Sector of the North Sea, 49 km north of Valhall, the Water depth is 67 meters.

Reservoir depth of 5344 meters with pressure above 900 bars and temp. Approx. 165°C, and initial discovery was made in 1988.

A Plan for Development and Operation was submitted to the authorities on 16th December 2022, based on an Unmanned Wellhead Platform with 4 production wells, 50 km tie-back and cost sharing on a new Production and Wellhead Platform on Valhall. Production start-up is expected in 2027.

The partnership in PL146/333 consists of Aker BP (77.8% and operator) and PGNiG Upstream (22.2%).

HEIMDAL

Heimdal is located in the middle part of the North Sea. The water depth is 120 meters. Heimdal was proved in 1972, and the original plan for development and operation (PDO) was approved in 1981.

The field was developed with an integrated drilling, production and housing facility with a steel undercarriage. Production started in 1985. After

Heimdal Gas-center which included a new rises facility- came into operation, Heimdal also became a hub for dry- gas transport from Oseberg, in addition to processing from fields such as Atla, Skirne Vale, Valemon and Huldra.

The fields' own production ceased in 2020. Heimdal was used as a centre for gas processing for associated fields, until 6th September 2023. A closure-plan for Heimdal was delivered in 2020, and according to the disposal decision, the facilities must be removed by the end for 2028.

Heimdal	
Equinor	29.443%
Sval Energi	28.798%
Petoro AS	20.000%
Total Energies EP Norge AS	16.759%
PGNiG Upstream	3.225%

SKIRNE/ BYGGVE

Skirne, including the Byggve deposit, is located in the central part of the North Sea. 20 kilometres east of Heimdal. The water depth is 120 metres. Skirne was discovered in 1990, and the plan for development and operation (PDO) was approved in 2002. The field was development with two subsea frames that were connected to the Heimdal facility. Production started in 2004. Atla was connected to Skirne in 2012.

Skirne/ Byggve was shut down in June 2023 and disposal activities are ongoing. According to the formal removal resolution, decommissioning must be completed by the end of 2028.

Skirne/ Byggve	
TotalEnergies EP Norge AS	40.000%
Petoro AS	30.000%
PGNiG Upstream	20.000%

ATLA (PL102C)

Atla Is located in the central part of the North Sea. 20 kilometres north-east of Heimdal. The water depth is 120 metres. Atla was proved in 2010, and the plan for development and operation (PDO) was approved in 2011. The field was developed with a production well connected to a subsea facility that was connected to Heimdal via Skirne. Production started in 2012.

Atla	
TotalEnergies EP Norge AS	40.000%
Petoro AS	30.000%
Aker BP ASA	10.000%
PGNiG Upstream	20.000%

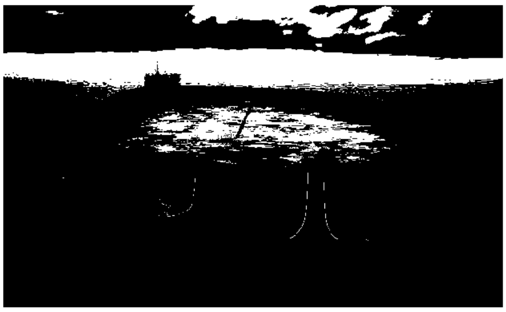
Atla was shut down in June 2023 and disposal activities are ongoing. According to the formal removal resolution, decommissioning must be completed by the end of 2028.

TYRVING

The Trell (102F) and Trine (PL036E) discoveries are located on the Heimdal Terrace and lie east of the producing field Vilje, Heimdal and Alvheim. Trell is a discovery made in production license 102F in 2014, located approximately 10 kilometres east of the Heimdal platform in the North Sea. Trine is a discovery made in 1973 and located in production license 036E. Tre Trine discovery well is located approximately 5 kilometres east of the Heimdal platform. Trell North (PL102G) is currently not penetrated by wells, but seismic and geological evaluations give a high economic chance of success.

Tyrving	
Aker BP	61.260%
Petoro AS	26.840%
PGNiG Upstream	11.900 %

The drainage strategy is pressure depletion. The reservoir properties are of good quality and high well production rates are expected.



Processed gas from Trell and Trine will be transported via the existing export system at Alvheim, which is connected to the SAGE (Scottish Area Gas Evacuation) pipeline system. The oil will be stabilised and stored at the Alvheim FPSO in storage tanks before being transported by tanker to the market. First production is scheduled in 4Q 2024.

YGGDRASIL (HUGIN AND FULLA)

Yggdrasil area development consists of the Hugin, Fulla and Minin license groups. The area is located between Alvheim and Oseberg in the North Sea. Partners in the development are Aker BP (operator) and PGNiG Upstream Norway. Extensive new infrastructure is planned, including three platforms, nine subsea templates and new pipelines for oil and gas export and power from shore. The entire Yggdrasil area will be remotely operated from an integrated operations centre and control room inshore in Stavanger.

Yggdrasil	
Aker BP	87.700%
PGNiG Upstream	12.300%

The Hugin development consist of five oil fields (Frigg, Gamma, Frigg Delta, Langfjellet, Frøy and Rind) and the drainage strategy for the Hugin fields is water injection.

The Hugin fields will be development with a 16-slot integrated production, drilling and quarters (Hugin A) platform on Frigg Gamma Delta field, a twelve-slot NUI wellhead platform on Frøy field, and subsea templates for Rind field and Langfjellet field, all with tiebacks to the Hugin A platform. The Fulla development will be developed with a subsea templated tied back to the Hugin A platform.

The gas will be exported from both Munin UPP and Hugin PdQ via a common new gas export pipeline to Statpipe and then onwards to Kårstø. The oil will be exported from Hugin PdQ via a new oil export pipeline to Sture Terminal via the Grane Oil Pipeline.

The main drilling campaign is planned to commence in 2025 and end in 2028 In the Hugin fields a total of 28 wells are planned, with 20 producers and 8 water injectors. Fulla field is planned develop with 3 production wells. Production start-up is expected in Q1 2027.

The Yggdrasil development will receive power via electrical AC cable from shore, and the connection point to the onshore power grid in Norway will be at Samnanger.

PGNiG Upstream's infrastructure at 31/12/2023	
VRGP (Valemon rich gas pipeline)	3.25%
KOR (Kvitebjørn Oljerør)	6.45%
Nyhamna Processing Plant	8.188%
YGP (Yggdrasil gassrør)	5.16%
YOP (Yggdrasil Oljerør)	7.34%
YPFS (Yggdrasil kraftanlegg)	7.39%

NYHAMNA

Nyhamna	
Petoro	26.138 %
Equinor	30.056 %
CapeOmega	18.209 %
Shell	2.027 %
North Sea Infrastructure	13.700 %
ConocoPhillips	1.681 %
PGNiG Upstream	8.188 %

Nyhamna gas processing plant became operational in 2007. It was originally built to process gas from the Ormen Lange field in the Norwegian Sea. The plant was expanded in 2017 to receive gas through Polarled and became a separate joint venture on 1 October that year. Gassco is the operator with Shell as the Technical Service Provider. A new Mercury Filter became operational in 2023 giving removal capability to the Polarled inlet.

VALEMON RICH GAS PIPELINE (VRGP)

Valemon Rich Gas Pipeline is a 177 km pipeline transporting rich gas from Valemon platform to Heimdal process facilities. The operator is Gassco AS with Equinor as the technical service provider.

The pipeline was decommissioned in the summer of 2023 (see Valemon).

Valemon rich gas pipeline	
Equinor	66.775%
Petoro AS	30.000%
PGNiG Upstream	3.225%

KVITEBJØRN OLJERØR (KOR)

Kvitebjørn oljerør is a 90 km pipeline transporting condensate from Kvitebjørn platform to Mongstad process facilities.

Kvitebjørn oljerør	
Equinor (operator)	39.55%
Petoro AS	30.00%
Sval Energi AS	19.00%
TotalEnergies	5.00%
PGNiG Upstream	6.45%

YGGDRASIL OIL PIPELINE (YOP)

The Yggdrasil Oil Pipeline (YOP) will transport stabilised crude oil from the Hugin A Platform to a new wye-structure at the Grane Oil Pipeline (GOP), for further transport to the Sture Terminal for storage and offloading. Modification will be performed at the Sture terminal in order to transport and handle the crude from the Hugin A platform.

Hugin A processes production from several field and the relative contribution from each field changes over time. The fields involved are Hugin, (Rind, Langfjellet, Frøy, Frigg Gamma Delta), Fulla (Fulla and Lille-Frigg) and Munin (Krafla, Askja and Sentral).

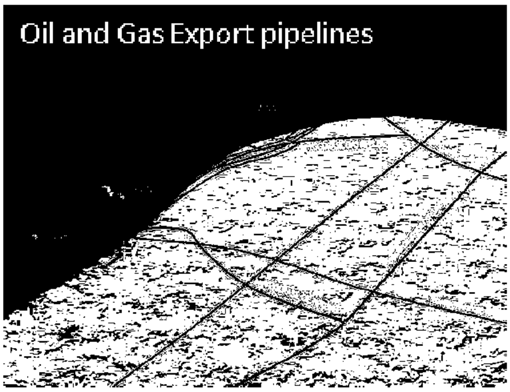
Yggdrasil Oil Pipeline	
Equinor (operator)	21.260%
Aker BP	71.400%
PGNiG Upstream	7.340%

YGGDRASIL GAS PIPELINE (YGP)

The Yggdrasil Gas Pipeline (YGD) will transport rich gas from the Hugin A platform and from Munin UPP platform to the hot tap tee at Statpipe pipeline, and further transport to the Kårstø Plant for further processing to sales gas.

Yggdrasil Gas Pipeline	
Equinor	39.330%
Aker BP	55.510%
PGNiG Upstream	5.160%

The hot tap tee to statpipe will be performed by Gassco as Operator for Statpipe. Equinor is operator in the development phase.



YGGDRASIL POWER FROM SHORE (YPFS)

The power supply to Yggdrasil fields is based on an AC electrical power supply from shore. The development includes a new transformer station at Børdalen in Samnanger, a compensation station in Årskog in Fitjar and a 250-kilometre 145 kV sea cable from Samnanger to the Yggdrasil area in the North Sea

Yggdrasil Power from Shore	
Equinor	25.010%
Aker BP	67.830%
PGNiG Upstream	7.160%

NOTE 28 RESERVES AND CONTINGENT RESOURCES (NOT AUDITED)

For all assets in the table, the Company's reserves and Contingent Resources are based on the operator's official data reported in the Revised National Budget (RNB2024) prepared by field Operators at the end of 2023. PGNiG Upstream follows defend by Operators base cases of proven reserves in Resource Class 1-3 and Contingent Resources in Resource Class 4-5 as per the NPD resource classification. All figures are in million boe and net to PGNiG Upstream*:

* Please note that all data regarding reserves in this Annual Report are unaudited and are based on the information from the respective license Operators.

Field	Oil	Gas	NGL	Total
Skarv & Ærfugl	2.7	18.5	3.8	25.0
Ærfugl Nord	0.1	0.9	0.1	1.1
Morvin	0.1	0.1	0.0	0.2
Gina Krog	1.4	7.6	0.2	9.3
Vilje	1.3	0.0	0.0	1.3
Skogul	2.1	0.1	0.0	2.2
Tommeliten Alpha	19.1	49.5	2.5	71.1
Fenris	15.8	24.2	2.1	42.2
Duva	1.8	6.4	1.5	9.7
Alve Nord	1.2	3.0	0.8	5.0
Kvitebjørn	1.1	6.9	0.3	8.3
Valemon	0.0	0.3	0.0	0.3
Ørn	0.9	19.1	1.3	21.2
Ormen Lange	2.2	67.7	0.0	69.8
Marulk	0.1	1.1	0.1	1.3
Alve	0.2	2.7	0.7	3.6
Tambar Øst	0.3	0.0	0.0	0.4
Verdande	0.2	0.0	0.0	0.3
Gungne	0.1	0.9	0.1	1.1
Sleipner Øst	0.2	2.1	0.2	2.5
Sleipner_Vest	2.2	9.1	0.9	12.2
Tyrving	3.3	0.0	0.0	3.4
Utgard	1.0	1.4	0.1	2.5
Yggdrasil Fulla	4.1	7.2	1.4	12.7
Yggdrasil Hugin	25.8	5.3	1.8	32.9
Yme	7.9	0.0	0.0	7.9
Total	**95.2**	**234.0**	**18.1**	**347.3**

COUNTRY-BY-COUNTRY REPORTING OF PAYMENTS TO AUTHORITIES IN 2023

INFORMATION ON COUNTRY-BY-COUNTRY REPORTING OF PAYMENTS TO AUTHORITIES IN 2023

Background

PGNiG Upstream Norway AS ("**PGNiG Upstream**" or "**the Company**") is subject to the country-by-country reporting of payments to authorities as stated in the Norwegian Accounting Act § 3-3d. The Company is as such obliged to report and publish an annual overview of payments to the authorities for the year. The reporting is based on actual payments done in the year 2023. This report is issued together with the Annual Report for 2023. The report is not subject to external audit.

Country-by-country reporting of payments to authorities

The overview of payments made to the authorities in 2023 consists of profit oil in-kind. taxes and fees. royalty. dividends. bonuses. licencing fees and infrastructure and ownership rights in accordance with the Norwegian Accounting Act § 3-3d and the Regulations to country-by-country reporting §2. As the Company only operates in Norway. all amounts refer to payments to Norwegian authorities. All amounts are presented in Norwegian kroner (unless otherwise stated).

Reporting of other data

In addition. the Company has provided an overview of investments. sales revenues. production. purchase of goods and services and interest costs to associated companies in accordance with the Regulations on country-by-country reporting §3. Information on payments on project level is given where this is available. The amounts included are based on the financial statements for 2023 and to the best extent possible reflect the actual amounts paid in 2023.

COUNTRY-BY-COUNTRY REPORTING OF PAYMENTS TO AUTHORITIES IN 2023

Payments made in 2023	Profit oil in-kind (1)	Taxes and fees (2)	Royalty	Dividends	Bonuses	Licence fees (3)	Infrastruc ture (4)	Ownership rights (5)
Paid. in million NOK	0	21 407	0	0	0	5.4	0	0

(1) Profit oil in-kind: Part of production emitted to authorities.

(1) Taxes and fees: Taxes and fees to the Company's income. production or net result. excluding taxes and fees on consuming goods such as VAT, tax withholding for employees e.g. The amount included for 2023 is related to tax instalments to the Norwegian state of 21 030 967 thousand, payment of net profit interest (NPI) of NOK 375 398 thousand to SDFI (State's Direct Financial Interest) and net custom tariffs paid (+)/refunded (-) to Skatteetaten for CO2 fuel and flare and NOx of NOK 854 thousand. VOC is not included, as the payment is done to a third party (Altera Norway). For further details, please refer to the Annual Report.

(2) Bonuses related to signatures. discoveries and production.

(3) Fees related to licences. access to licences. concessions e.g. typically this includes area fee in Norway. As area fee is paid by the operators. the Company will only include area fees paid from operated licences for the year, during 2023 area fee was paid for PL159F of NOK 2 715 thousand. Reported amounts in 2023 include NOK 86 thousand for the sector fees from Petroleum Safety Authority in Norway and 123 thousand for fees related to the APA2023 licensing round.

(4) Contributions to improved infrastructure. Ordinary tariff cost from the Gassled transportation system paid to Gassco is not included.

(5) Distribution of shares or other ownership interests in the Company to the authorities.

REPORTING OF ADDITIONAL DATA

The Company is also obliged to provide certain additional data under the regulations on country-by-country reporting § 3. Such data is presented in the table below. For further details to these numbers. please refer to the financial statement and notes to the Annual Report.

Other information	Investments (1)	Revenues (2)	Production (3) million boe	Purchase of goods and services (4)	Interest to/from associated companies (5)
Million NOK (except production)	7 186	43 035	26,1	4 121	(137)

(1) Investments include the purchase of assets from LOTOS, it also includes changes in loan to parent company. In addition, it includes purchase of Adriana Sabina, investments on Ormen Lange Phase 3, Tommeliten Alpha, Fenris, King Lear, Alve North, Verdande Yggdrasil, Tyrving and Andvare development projects, investments on the producing fields and investments on exploration licences and investment in onshore assets (office machines e.g.). For further details, please refer to the Annual Report.

(2) Total revenues for the year 2023 from sales of hydrocarbons and other income. For further details, please refer to the Annual Report.

(3) Production of hydrocarbons in million boe for the year from all the producing fields presented in million barrels of oil equivalent. For further details, please refer to the Annual Report.

(4) Purchase of goods and services in relation to operating activities. Includes also operating cost from joint ventures.

(5) Net of Interest cost/income paid to (+) /received from (-) associated companies (loan from/to parent Company). For further details, please refer to the Annual Report.

Stavanger,
19.02.2024

Robert Dominik Śleszyński *Chairman of the Board*	Marcin Gargas *Director of the Board*	Robert Harasimiuk *Director of the Board*	Urszula Monika Kowalczyk *Director of the Board*
Przemysław Wacławski *Director of the Board*	Iwona Waksmundzka-Olejniczak *Director of the Board*	Maciej Pawel Wyszoczarski *Director of the Board*	Marek Woszczyk *General Manager*