Brønnøysundregistrene

ÅRSREGNSKAPET FOR REGNSKAPSÅRET 2020 - GENERELL INFORMASJON

Enheten

Organisasjonsnummer:	991 317 155
Organisasjonsform:	Aksjeselskap
Foretaksnavn:	PGNIG UPSTREAM NORWAY AS
Forretningsadresse:	Vestre Svanholmen 4 4313 SANDNES

Regnskapsår

Årsregnskapets periode:	01.01.2020 - 31.12.2020

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:	08.02.2021

Grunnlag for avgivelse

År 2020: Årsregnskapet er elektronisk innlevert
År 2019: Tall er hentet fra elektronisk innlevert årsregnskap fra 2020

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, 07.07.2022

Resultatregnskap

Beløp i: NOK	Note	2020	2019
RESULTATREGNSKAP			
Inntekter			
Sales income	3	2 180 440 060	2 358 448 707
Other income			
Sum inntekter		**2 180 440 060**	**2 358 448 707**
Kostnader			
Exploration expenses	4	79 969 503	79 436 611
Production and sales costs	6	710 618 191	658 887 098
Employee expenses	5	56 513 498	42 656 346
Depreciation	11	1 364 883 324	774 335 455
Depreciation of use to right assets	11	15 846 097	19 395 976
Nedskrivning av varige driftsmidler og immaterielle eiendeler	11	830 688 186	
Other operating expenses	7	67 078 670	62 354 965
Sum kostnader		**3 125 597 469**	**1 637 066 451**
Driftsresultat		**-945 157 409**	**721 382 256**
Finansinntekter og finanskostnader			
Other financial income	8	175 993 950	74 875 030
Sum finansinntekter		**175 993 950**	**74 875 030**
Rentekostnad til foretak i samme konsern	17	157 078 515	102 783 255
Other financial expenses	9	14 272 557	45 239 804
Sum finanskostnader		**171 351 072**	**148 023 059**
Netto finans		**4 642 878**	**-73 148 029**
Ordinært resultat før skattekostnad		**-940 514 531**	**648 234 227**
Tax on the profit/(loss) for the year	10	-757 550 526	504 940 687
Ordinært resultat etter skattekostnad		**-182 964 005**	**143 293 540**
Årsresultat		**-182 964 005**	**143 293 540**
Overføringer og disponeringer			
Overføringer til/fra annen egenkapital		-182 964 005	143 293 540

Resultatregnskap

Beløp i: NOK	Note	2020	2019
Sum overføringer og disponeringer		**-182 964 005**	**143 293 540**

Balanse

Beløp i: NOK	Note	2020	2019
BALANSE - EIENDELER			
Anleggsmidler			
Immaterielle eiendeler			
Capitalized exploration expenses	11	1 503 127 119	1 055 528 127
Sum immaterielle eiendeler		**1 503 127 119**	**1 055 528 127**
Varige driftsmidler			
Assets in production		7 375 544 635	6 141 751 274
Assets in development		5 168 471 732	4 962 682 867
Right-of-use asset		208 623 897	164 761 188
Other fixtures and fittings, tools and equip.		3 918 688	2 035 254
Sum varige driftsmidler	11	**12 756 558 952**	**11 271 230 583**
Sum anleggsmidler		**14 259 686 071**	**12 326 758 710**
Omløpsmidler			
Varer			
Inventory	15	78 587 723	28 952 598
Sum varer		**78 587 723**	**28 952 598**
Fordringer			
Trade receivables		192 104 010	173 264 737
Trade receivables Group enterprises		129 395 809	42 335 134
Tax Receivable	10	171 805 881	
Other current receivables	13	222 961 040	505 920 383
Sum fordringer		**716 266 740**	**721 520 254**
Bankinnskudd, kontanter og lignende			
Cash and cash equivalents	14	164 237 152	167 014 148
Sum bankinnskudd, kontanter og lignende		**164 237 152**	**167 014 148**
Sum omløpsmidler		**959 091 615**	**917 487 000**
SUM EIENDELER		**15 218 777 686**	**13 244 245 710**

Balanse

Beløp i: NOK	Note	2020	2019
BALANSE - EGENKAPITAL OG GJELD			
Egenkapital			
Innskutt egenkapital			
Share capital	16	1 110 000 000	1 110 000 000
Share premuim		1 282 102 015	1 282 102 015
Sum innskutt egenkapital		**2 392 102 015**	**2 392 102 015**
Opptjent egenkapital			
Udekket tap		680 970 335	498 006 329
Sum opptjent egenkapital		**-680 970 335**	**-498 006 329**
Sum egenkapital		**1 711 131 680**	**1 894 095 686**
Gjeld			
Langsiktig gjeld			
Utsatt skatt	10	3 330 922 368	2 891 730 442
Abandonment provision	20	1 579 688 639	1 005 942 910
Sum avsetninger for forpliktelser		**4 910 611 007**	**3 897 673 352**
Annen langsiktig gjeld			
Gjeld til kredittinstitusjoner	18	3 670 764 854	3 543 340 027
Langsiktig konserngjeld	17	4 253 394 651	2 718 232 051
Lease liabilities	12	147 423 564	148 894 678
Sum annen langsiktig gjeld		**8 071 583 069**	**6 410 466 756**
Sum langsiktig gjeld		**12 982 194 076**	**10 308 140 108**
Kortsiktig gjeld			
Debt to financial institutions payable within 1 year	18	2 339 026	4 562 242
Leverandørgjeld		30 544 885	78 037 704
Taxes payable, not assessed	10	38 357 011	218 089 363
Employee tax liabilities, duties		15 539 653	15 044 813
Kortsiktig konserngjeld	17, 23	36 859 238	31 249 745
Other current liabilities	21, 23	401 812 117	695 026 049
Sum kortsiktig gjeld		**525 451 930**	**1 042 009 916**
Sum gjeld		**13 507 646 006**	**11 350 150 024**

Balanse

Beløp i: NOK	Note	2020	2019
SUM EGENKAPITAL OG GJELD		**15 218 777 686**	**13 244 245 710**

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	Besøksadresse	Sentralbord
Postboks 9200 Grønland	Fredrik Selmers vei 4	800 80 000
0134 Oslo	Org. nr: 974761076	Telefaks
skattedirektoratet@skatteetaten.no		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

ANNUAL REPORT 2020

SANDNES, 8 FEBRUARY 2021

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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 located in Sandnes, Norway with a regional office in Tromsø. The objective of the Company is to carry out exploration and production of oil and gas, as well as other connected activities.

PGNiG Upstream is a subsidiary company in the PGNiG Group. The sole owner of PGNiG Upstream is PGNiG SA ("**PGNiG**"), which is the largest oil and gas exploration and production company in Poland. PGNiG is a leader in the natural gas business in Poland, focusing on trade and distribution, as well as oil and gas exploration, production and gas storage. PGNiG has been listed on the Warsaw Stock Exchange since September 2005, with the Polish State Treasury as the main shareholder. Detailed information about the activities and business profile of PGNiG can be found at the company's internet address: www.en.pgnig.pl.

Company overview

Over the last years PGNiG Upstream has grown and gained significant experience from its operations on the Norwegian Continental Shelf ("**NCS**"). We have built from scratch a company that employs today 38 experienced staff from around the world and has become a successful drilling operator.

Last year our Norwegian operations generated revenue of NOK 2,2 billion, with production in Norway now accounting for 20% of the PGNiG Group's total output.

So far we have invested over NOK 20,7 billion in Norway, and participated in the drilling of more than 50 exploration and production wells. This has led to significant oil and gas discoveries on the NCS, including the Ærfugl, Shrek and Warka fields. In addition, we have taken part in over ten licensing rounds and have been awarded more than twenty production licenses.

PGNiG Upstream currently owns shares in nine producing fields on the NCS (Skarv, Morvin, Vilje, Vale, Gina Krog, Skogul, Ærfugl, Kvitebjørn and Valemon) and shares in seven other projects with development plans (Ærfugl phase 2, Gråsel, Duva, Tommeliten Alpha, King Lear, Alve Nord and Shrek). The total reserves and contingent resources of the Company as of 31st December 2020 amount to 214 million barrels of oil equivalent (unaudited information).

In addition to these assets, the Company's portfolio includes nine exploration licenses on the NCS.

PGNiG Upstream Norway

Board Members

Przemysław Wacławski (Chairman)

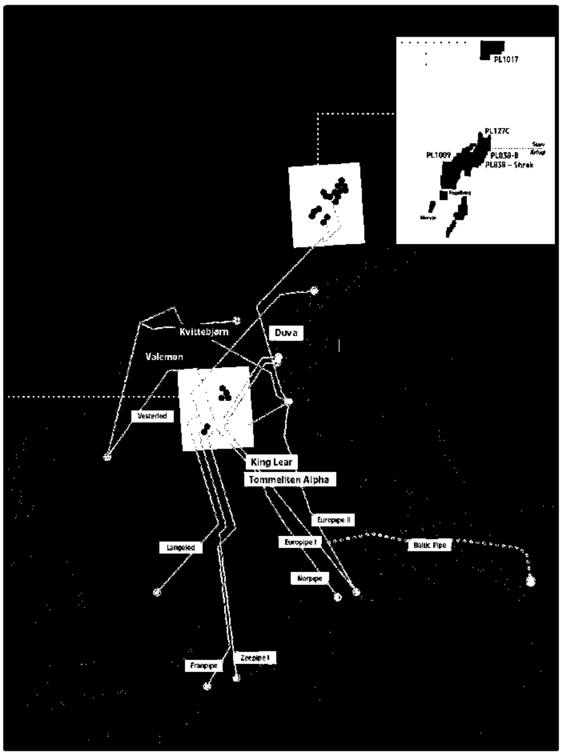
Arkadiusz Sekściński

Jarosław Wróbel

Magdalena Zegarska

Field	PGNiG Share	Operator	Partners	PUN net reserves (31.12.20)* - mmboe	PUN net production (2020) – mboepd
Skarv / Grasel	11,9%	AkerBP (24%)	Equinor (36%), WinDEA (28%)	41,8	10,2
Ærfugl	11,9%				
Ærfugl Nord	15%			4,0	
Alve Nord	11,9%	AkerBP (88%)		5,3	
Morvin	6,0%	Equinor (64%)	Var (30%)	1,8	0,8
Vale	24,2%	Spirit (50%)	Lotos (26%)	0,9	1,6
Vilje	24,2%	AkerBP (47%)	DNO (29%)	3,3	1,6
Gina Krog	11,3%	Equinor (59%)	KUFPEC (30%)	15,1	3,3
Skogul	35,0%	AkerBP (65%)		2,1	3,3
King Lear	22,2%	AkerBP (78%)		35,4	
Duva	30,0%	Neptune (30%)	Idemitsu (30%), SVAL (10%)	27,3	
Tommeliten Alpha	42,4%	Conoco (28%)	Total (20%), Var (9%)	58,5	
Shrek	35%	AkerBP (35%) / PGNiG	Lime (30%)	6,0	
Kvitebjørn	6,5%	Equinor (39,6%)	Petoro (30%), Spirit (19%), Total (5%)	11,6	
Valemon	3,2%	Equinor (66,8%)	Petoro (30%)	1,1	
			PUN assets:	214	20,7

* Except for Duva, reserves are based on the operator's official assumptions as per reported in RNB2021, PGNiG Upstream takes into account the base case (category 1-5), reflecting reserves similar to P50/Mean with the economic cut-off. For Duva, PGNiG uses own estimates. Figures are in mmboe, netto PGNiG



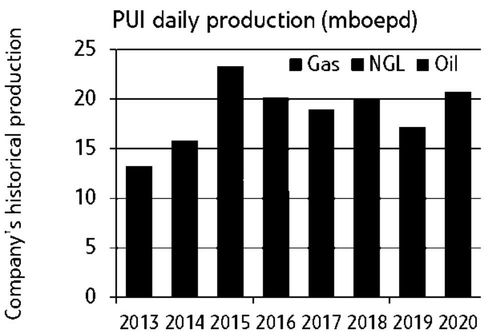
Key developments in 2020

In 2020, the Company continued its activities with the aim to secure uninterrupted gas supplies for the PGNiG Group. We believe that this goal can be achieved through stable and diversified hydrocarbon production from the Norwegian Continental Shelf.

In 2020 the Company delivered revenues of NOK 2,2 billion and an EBITDA of NOK 1,3 billion. These results were possible thanks to the performance of key assets like Skarv and the start-up of Skogul and Ærfugl (phase 1). The total production in 2020 increased by 21% in comparison with the previous year and amounted to 0,48 billion cubic metres of gas, and 615 thousand tonnes of crude oil (including NGL's). This was achieved despite production curtailment implemented by the Norwegian authorities.

The key challenges in 2020 were the decrease of hydrocarbon prices in comparison with previous years and situation with Covid-19. The difficult market conditions led to an impairment of tangible assets with the total value of 831 million NOK. As a consequence, PGNiG Upstream reported a net loss of 183 million NOK in 2020.

With lower results in 2020, the Company focused on increased efficiency and cost reductions. These efforts resulted in a reduction of unit operating expenses in 2020.



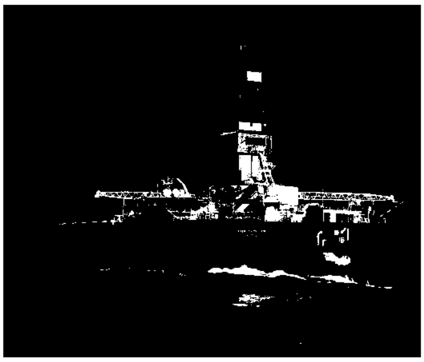
Despite a net loss, the Company managed to maintain a healthy financial situation and stable cash flow in

2020. This was possible thanks to utilization of tax incentives and amendments to financing agreements. The outlook for 2021 is positive with the improved market situation and expected increase in production.

The sections below include an overview of key achievements.

Warka and Alve NE discoveries

In 2020, the Company participated in two exploration wells which resulted in two discoveries (licenses PL1009 and PL127C).



Warka well drilled by Leiv Eriksson

The first well was drilled 27 kilometres southwest of the Skarv field in the central part of the Norwegian Sea and confirmed discovery of the Warka field. The well was drilled at to a depth of 4,985 m below the sea level and was operated by ConocoPhillips. It encountered a 27-metre gas column in sandstone layers in the Lange Formation. An extensive data acquisition has been carried out which indicated moderate but yet uncertain reservoir quality. The size of the discovery is estimated to be between 8 and 30 bcm of natural gas. Warka is an important success for the Company's exploration team who identified and interpreted this prospect.

The second discovery was made on the Alve Nord East prospect. The well was operated by Aker BP and led to the discovery of recoverable reserves of natural gas, initially estimated at 0,5-1 bcm. In addition, the well confirmed an oil accumulation in the Lower Cretaceous with reserves between 6–17 million barrels.

Both discoveries are important milestones for PGNiG Upstream. PGNiG seek to ensure that the largest possible volumes of our own gas are brought from Norway to Poland via the Baltic Pipe. The new discoveries will help achieving that goal.

Successful business development activities

In 2020, the Company was also heavily involved in business development activities and acquired shares in three producing fields and one discovery on the NCS. In the beginning of the year the Company completed acquisition of 10% shares in Duva from Pandion Energy. The transaction was completed on the 31st January 2020 for accounting purposes.

In February, PGNiG Upstream entered into an agreement to acquire 11,9175% interest in the Alve Nord discovery and increased from 8,0% up to 11,3% its share in the Gina Krog field. The transaction was completed on the 30th April 2020 for accounting purposes. In September, the Company signed an agreement to purchase 6,45% interest in the Kvitebjørn field and 3,225% in the Valemon field from Shell. The transaction was completed on the 31st December 2020 for accounting purposes.

All acquired fields contain predominantly natural gas. Following the transactions, the PGNiG Upstream gas production will increase to 0,9 bcm in 2021, nearly 30% above the previous forecast. This is particularly important for PGNiG, taking into account involvement in the Baltic Pipe project aimed at exporting Norwegian gas to Poland through a new infrastructure connection (**"Baltic Pipe"**).

It is also expected that business development activity will continue in the upcoming years, in order to fulfil by 2022 the strategic goal of increasing equity gas production to 2,5 bcm per year.

Based on fields which are currently owned by PGNiG Upstream, the Company plans to reach 2,2 bcm of gas production in 2026.

Record high development expenses

In order to meet its strategic target, PGNiG Upstream continued investments in the existing asset base. Historical investments resulted in start-up of production from two fields in 2020 (Skogul and Ærfugl phase 1). In addition, Ærfugl phase 2, Ærfugl Nord, Gråsel and Duva are now in the development phase. Another four assets (Tommeliten Alpha, King Lear, Shrek, Alve Nord) are approaching the final investment decision.

In 2020, the operator has brought on stream four production wells in the Ærfugl field. Ærfugl is extremely attractive in terms of profitability. Production from the field is economically viable at oil prices above USD 15 per barrel, as wells are connected to the existing Skarv FPSO, significantly reducing field development costs.

In March, the Company started production from the Skogul field in the North Sea. The project was developed as subsea tie-back to existing infrastructure and offer attractive economic results. In 2020, production from Skogul amounted to 3.300 boe a day net to PGNiG.


Skogul development

Another important investment is connected with the Duva field. PGNiG Upstream joined this project in 2019, following acquisition of the asset. In 2020, majority of offshore installations was completed and the partnership continued to drill production wells. First production from Duva is expected in 2021, with gross production of around 25 000 boe per day.

The current development expenses will translate into a significantly higher production of natural gas, which PGNiG Upstream wants to transport from Norway to Poland through the planned new gas pipeline via Denmark (the Baltic Pipe).

Strong financing position

High involvement in development activities was possible thanks to stable financing provided to PGNiG Upstream by PGNiG as well as external banks.

In 2020, the Company secured additional sources of funding for its ambitious development plans. In April, the Company signed new intercompany loan agreement which secured 1.1 billion NOK of additional funding.

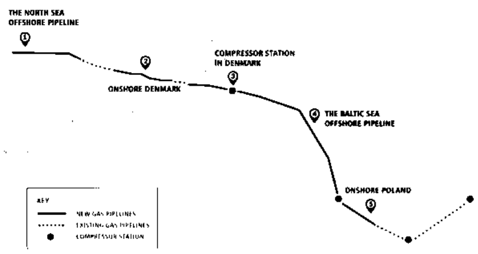
In addition, PGNiG Upstream extended the size of its reserve based loan facility ("**RBL**") to 500 million USD. RBL is a specific type of project finance where the lenders' claims are secured primarily by upstream assets. The financing parties have no recourse to PGNiG and therefore Norwegian operations do not limit any other investment options of the PGNiG Group.

In addition, the company benefited from changes in the upstream tax regime in Norway and received 909 million NOK in the form of negative tax installments from the Norwegian state. These funds, enabled active growth in 2020.

Involvement in the Baltic Pipe Project

Finally, the Company was actively involved in the Baltic Pipe project (**"Baltic Pipe"**) which reached important milestones in 2020.

The Baltic Pipe is a strategic infrastructure project with the goal of creating a new corridor for supply of natural gas from Norway to the Danish and Polish markets, as well as to end-users in neighbouring countries.



The project is implemented in close cooperation between transmission system operators in Norway, Denmark and Poland.

The gas pipeline will have the capacity to transport 10 bcm of natural gas per year to Poland.

PGNiG Upstream plans to utilize capacity in this pipeline to send its own gas production to Poland. Strong commitment to the Baltic Pipe project was confirmed in 2018 with the signing of a long term capacity agreement between PGNiG and the respective transmission system operators.

In addition, the Company has been involved in numerous discussions and consultations regarding the project. PGNiG Upstream took an active role, and closely followed up the development of Baltic Pipe. In 2020, key focus was connected with engineering and procurement. In 2020, all major agreements related to construction have been settled and construction work has started. In addition, the project has obtained construction permits for all sections in all the countries.

The implementation of the Baltic Pipe Project will bring significant socio-economic benefits for Poland, Denmark and other countries of the Baltic Sea region, as well as Central and Eastern Europe. The project is fully consistent with the European Union energy policy guidelines in terms of the provision of secure, affordable and sustainable energy supplies.

BALTIC PIPE PROJECT

Key objectives of the project are:

- Strengthening security of supply in the region by providing access to Norwegian gas for the Danish-Swedish and Polish markets and for the markets in Central and Eastern Europe;
- Further increasing the capacity of Danish gas infrastructure to reduce tariffs for the benefit of the users;
- Increasing competition on regional gas markets and facilitating price convergence between markets, enabling new participants to enter the market;
- Increasing the technical reliability of gas supplies to customers through diversification of sources of gas supplies.

Research and development activities

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

The total costs of R&D activities amounted to NOK 1,1 million in 2020. 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.

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.

Company development, performance and going concern

In the opinion of the Board, the annual accounts document the Company's position as of 31st December 2020. In accordance with Section 3-3a of the Norwegian Accounting Act, the Board confirms that the Company meets the requirements to continue its operations for the foreseeable future, and therefore it continues to adopt the going concern basis in preparing its financial statements. The Board is not aware of any matters not covered in this report that could be of significance, when evaluating the Company's position.

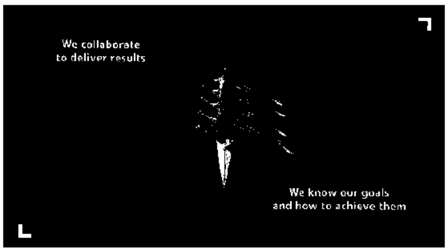
PGNiG Upstream's team at the President Lech Kaczyński LNG Terminal in Świnoujście

Working environment

The Board is pleased to report that the Company has built a very competent organisation based on experienced employees with varying backgrounds – both technical and commercial. The average number of employees in 2020 amounted to 38,3. All employees have been trained in HSE regulations.

In 2020, the Company maintained high focus related to development of Covid-19 and implemented various measures to ensure a safe and comfortable working environment.

Company values



Absence from work due to illness remained low at 1,9 per cent in 2020. There were no work related injuries nor accidents in 2020. Measures continue to be implemented to maintain these low rates of absence.

Equal opportunities

PGNiG Upstream pursues a personnel and recruitment policy that does not discriminate on the basis of gender, age, religion or ethnicity. By the end of 2020, the Company had 28 male and 10 female employees. At the same time, the Board consisted of three male and one female member. The Company will continue to work towards increasing the number of women in the organisation.

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.

External environment

Our aim is to prevent all incidents or accidents that 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 located 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 to 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

In 2020 the Company generated revenues of NOK 2 180 million and EBITDA of NOK 1 266. However, due to high value of impairment charges, PGNiG Upstream generated a net loss of NOK 183 million. At the end of 2020, the Company also showed assets of NOK 15 219 million.

Accumulated operating costs at the end of 2020 amounted to NOK 3 126 million, of which NOK 2 211 million was classified as depreciation and impairment. The comparative figures for the preceding year were NOK 1 637 million and NOK 794 million, respectively. Personnel costs were NOK 57 million in 2020, compared with NOK 43 million in 2019.

Net financial revenues for the period were NOK 5 million, up from costs of NOK 73 million in the previous year. The decrease in net financial expenses is mainly due to lower interest costs and positive exchange rates development.

Skarv and Ærfugl fields

Fixed assets utilized in production and development are valued at NOK 12 757 million. An increase of NOK 1 485 million in comparison with the previous year is due to ongoing investments. The company's cash and cash equivalents remained stable at NOK 164 million at the end of 2020 in comparison with NOK 167 million in 2019. The company's policy in 2020 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 2020 is provided together with the Annual Report.

Skarv FPSO

Liquidity and financing

The liquidity of PGNiG Upstream in 2020 has been secured through sales revenues and supported by both utilization of debt as well as negative tax instalments. Based on the EBITDA of NOK 1 266 million, the Company generated cash flow from operating activities at the level of NOK 1 889 million. The main reason explaining the gap between operating income and EBITDA are tax receivables, following changes in taxation.

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

In the opinion of the Board of Directors there is no risk connected with financing any further operations of PGNiG Upstream. Additional funds will be secured either through revenues, the external credit facility, or from the parent company.

Subsea template (Morvin)

PGNiG Upstream's production in Norway for 2021 is estimated at 633 thousand tonnes of crude oil including NGL's, and 0,9 billion cubic metres of gas. At current oil prices, PGNiG Upstream's revenue in Norway from the current license portfolio is expected to reach NOK 3,5 billion next year.

PGNiG Upstream has a strong owner from the Polish public sector operating in the energy industry. All committed expenses are included in the long term plans for the PGNiG Group. Further funds can be made available for the Company on the basis of loan agreements, or by increasing the share capital.

Risk factors

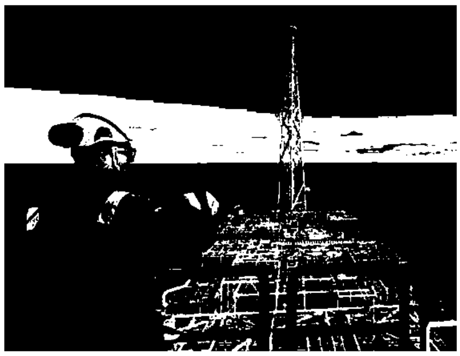
PGNiG Upstream is exposed to risk in various areas. Changes in market conditions (oil and gas prices) and currency exchange rates may affect future margins. The hydrocarbon reserves are estimates, and may be inaccurate. The Company is participating in complex projects that are challenging in terms of timing and cost control (for example Duva and Tommeliten Alpha).

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.

Outlook

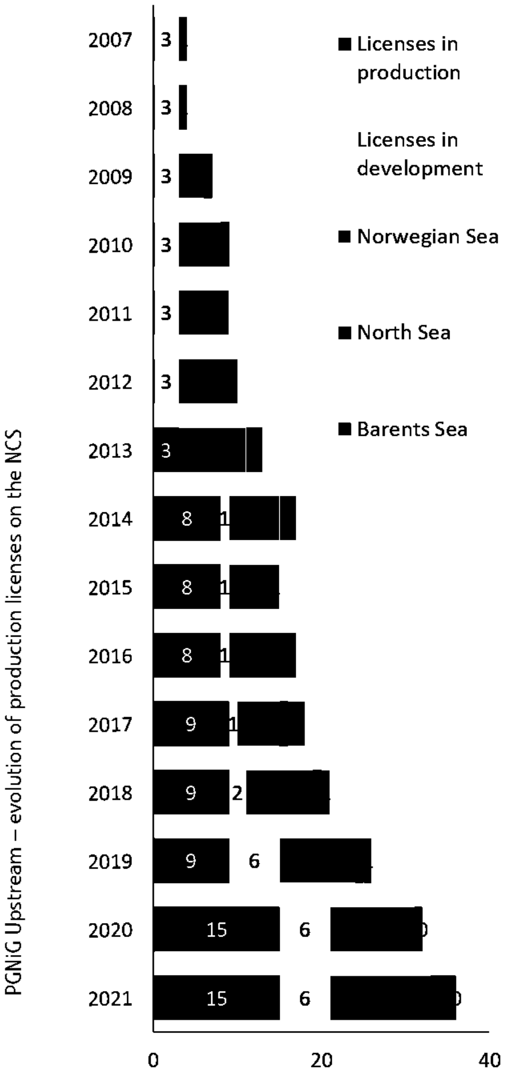
The engagement of the PGNiG Group on the NCS is in line with PGNiG's Development Strategy. The NCS is recognised as an important area for international upstream activities and has significant exploration potential.

The scale of our Norwegian operations makes Norway the key destination for the PGNiG Group'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.



Skarv processing plant

We are committed to scaling up natural gas production in Norway, so that in a few years' time the annual output reaches or exceeds 2,5 bcm. With this in mind, we recently acquired shares in the Kvitebjørn and Valemon fields and we are involved in numerous investment projects. We have also taken steps to acquire interests in new licence areas. Taking into account recent awards from the APA2020, the number of licenses at the beginning of 2021 will increase to a record-high of 36.



From the perspective of the Board of Directors, PGNiG Upstream shall in the future focus on two main areas;

- securing natural gas supplies for the PGNiG Group, and
- developing the exploration & production business.

In order to meet its strategic goals, PGNiG Upstream is planning to both increase its future gas production and support infrastructure projects aimed at delivering Norwegian gas to Poland.

PGNiG Upstream will consider further acquisitions, farm-ins and participation in licensing rounds as a mean to increase its documented reserves. The Company wants to be recognised as a serious partner, with a long term investment perspective. At the same time PGNiG Upstream plans to develop its operatorship capabilities and, potentially, be an operator for new exploration wells and development projects. Therefore, the Company is open for any opportunities and business partnerships that may arise on the NCS.

To summarise, increasing production capacity on the NCS and securing new gas supplies for Poland, should allow the PGNiG Group 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 PGNiG Group in Norway. The next steps will be defined by new projects.

Przemysław Wacławski Chairman of the Board	Arkadiusz Sekściński Director of the Board

Jarosław Wróbel Director of the Board	Magdalena Zegarska Director of the Board	Marek Woszczyk General Manager	Sandnes, 8th February 2021

FINANCIAL STATEMENTS

INCOME STATEMENT (NOK)

Note		2020	2019
	Sales income	2 180 440 060	2 358 448 707
3	**Revenue**	**2 180 440 060**	**2 358 448 707**
4	Exploration expenses	(79 969 503)	(79 436 611)
5	Employee expenses	(56 513 498)	(42 656 346)
11	Depreciation	(1 364 883 324)	(774 335 455)
11	Depreciation of use to right assets	(15 846 097)	(19 395 976)
11	Impairment	(830 688 186)	0
6	Production and sales costs	(710 618 191)	(658 887 098)
7	Other operating expenses	(67 078 670)	(62 354 965)
	Total operating expenses	(3 125 597 469)	**(1 637 066 451)**
	Operating income/(loss)	**(945 157 409)**	**721 382 256**
17	Interest expenses to Group enterprises	(157 078 515)	(102 783 255)
8	Other financial income	175 993 950	74 875 030
9	Other financial expenses	(14 272 557)	(45 239 804)
	Net financial items	**4 642 878**	**(73 148 029)**
	Income/(loss) before tax	**(940 514 531)**	**648 234 227**
10	Tax on the profit/(loss) for the year	757 550 525	(504 940 688)
	Net income/(loss)	**(182 964 005)**	**143 293 540**

STATEMENT OF COMPREHENSIVE INCOME

	2020	2019
Net income/(loss)	**(182 964 005)**	**143 293 540**
Total comprehensive income	**(182 964 005)**	**143 293 540**

BALANCE SHEET (NOK)

ASSETS

Note		31/12/2020	31/12/2019
11	Capitalized exploration expenses	1 503 127 119	1 055 528 127
	Intangible assets	**1 503 127 119**	**1 055 528 127**
	Assets in production	7 375 544 635	6 141 751 274
	Assets in development	5 168 471 732	4 962 682 867
	Other fixtures and fittings, tools and equip.	3 918 688	2 035 255
	Right-of-use asset	208 623 897	164 761 188
11	**Tangible fixed assets**	**12 756 558 952**	**11 271 230 583**
	Non-current assets	**14 259 686 071**	**12 326 758 710**
15	Inventory	78 587 723	28 952 598
	Trade receivables	192 104 010	173 264 737
	Trade receivables Group enterprises	129 395 809	42 335 134
13	Other current receivables	222 961 040	505 920 383
10	Tax Receivable	171 805 881	0
	Current receivables	**716 266 740**	721 520 254
14	Cash and cash equivalents	164 237 151	167 014 147
	Current assets	**959 091 615**	**917 486 999**
	Assets	**15 218 777 686**	**13 244 245 710**

EQUITY AND LIABILITIES

Note		31/12/2020	31/12/2019
16	Share capital	1 110 000 000	1 110 000 000
	Share premium	1 282 102 015	1 282 102 015
	Paid-in capital	**2 392 102 015**	**2 392 102 015**
	Retained earnings	(680 970 335)	(498 006 329)
	Equity	**1 711 131 680**	**1 894 095 686**
10	Deferred tax	3 330 922 368	2 891 730 442
20	Abandonment provision	1 579 688 638	1 005 942 910
	Total Provisions	**4 910 611 007**	**3 897 673 352**
17	Debt to Group enterprises	4 253 394 651	2 718 232 051
18	Debt to financial institutions	3 670 764 854	3 543 340 027
12	Lease liabilities	147 423 564	148 894 678
	Long-term liabilities	**8 071 583 069**	**6 410 466 756**
	Trade payables	30 544 885	78 037 704
	Employee tax liabilities, duties	15 539 653	15 044 813
17	Interest on Debt to Group enterprises	35 601 610	30 087 693
23	Other liabilities Group enterprises	1 257 628	1 162 052
18	Debt to financial institutions payable within 1 year	2 339 026	4 562 242
21 | 23	Other current liabilities	401 812 117	695 026 050
10	Taxes payable, not assessed	38 357 011	218 089 363
	Current liabilities	**525 451 930**	**1 042 009 916**
	Liabilities	**13 507 646 006**	**11 350 150 024**
	Equity and liabilities	**15 218 777 686**	**13 244 245 710**

Przemysław Wacławski
Chairman of the Board

Arkadiusz Sekściński
Director of the Board

Jarosław Wróbel
Director of the Board

Magdalena Zegarska
Director of the Board

Marek Woszczyk
General Manager

Sandnes,
8th February 2021

CASH FLOW STATEMENT (NOK)

Note		31/12/2020	31/12/2019
	Cash flows from operating activities		
	Income (loss) before tax	(940 514 531)	648 234 227
11	Depreciation	1 380 729 420	793 731 431
11	Exploration drilling/capitalised seismic expenses	10 489 533	14 817 810
11	Impairment	830 688 186	0
9	Interest expenses	49 486 649	67 995 561
10	Taxes received/(paid)	756 078 219	(812 692 961)
8 | 9	Other financial items without cash effect	(25 759 775)	8 311 042
15	Changes in current assets – Inventory	(49 635 125)	(3 121 446)
	Changes in current receivables	264 120 070	(218 375 076)
	Changes in current receivables from Group enterprises	(86 965 099)	81 274 103
	Changes in current liabilities	(226 889 054)	327 276 618
	Changes in other periodical items	(73 226 433)	25 806 838
	Net cash from operating activities	**1 888 602 061**	**933 258 146**
	Cash flows from investment activities		
11	Purchase of fixed assets	(2 912 549 627)	(2 393 833 658)
11	Purchase of intangible assets	(417 642 303)	(848 245 730)
	Net cash from investment activities	**(3 330 191 930)**	**(3 242 079 388)**
	Cash flows from financing activities		
16	Proceeds from issuance of shares and share premium	0	1 000 000 000
17	Proceeds/(repayment) from long-term debt raised from Group enterprises	1 624 443 200	406 610 000
18	Proceeds/(repayment) from long-term debt raised from financial institutions	109 184 190	1 302 605 070
17	Interests paid to Group enterprises	(151 356 357)	(149 453 513)
9	Interests paid to financial institutions	(86 290 157)	(137 000 830)
12	Lease payments	(57 168 002)	(41 851 436)
	Net cash from financing activities	**1 438 812 874**	**2 380 909 291**
	Change in the balance of net cash	(2 776 996)	72 088 048
	Opening balance of cash and cash equivalents	167 014 147	94 926 099
14	**Closing balance of cash and cash equivalents**	**164 237 151**	**167 014 147**

STATEMENT ON CHANGES IN EQUITY (NOK)

2020

	Share capital	Share premium	Other comprehensive income	Retained earnings	**Total**
Equity at 1st January 2020	1 110 000 000	1 282 102 015	0	(498 006 329)	**1 894 095 686**
Net income/(loss) for the year				(182 964 005)	(182 964 005)
Equity at 31st December 2020	1 110 000 000	1 282 102 015	0	(680 970 335)	**1 711 131 680**

2019

	Share capital	Share premium	Other comprehensive income	Retained earnings	**Total**
Equity at 1st January 2019	1 100 000 000	292 102 015	0	(641 299 868)	**750 802 147**
Share capital increase	10 000 000	990 000 000			1 000 000 000
Net income/(loss) for the year				143 293 540	143 293 540
Equity at 31st December 2019	1 110 000 000	1 282 102 015	0	(498 006 329)	**1 894 095 686**

GENERAL INFORMATION

PGNiG Upstream has its office in Sandnes and is a subsidiary, fully owned by PGNiG, whose head office is in Warsaw.

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

All amounts are in NOK unless otherwise stated.

NOTE 1 SUMMARY OF IFRS ACCOUNTING POLICIES APPLICABLE FOR 2020

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 8th February 2021.

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

The company implemented the amendments to IFRS 3 Business Combinations, on acquisition that are on or after 1 January 2020 in assessing if the company has acquired a business or a group of assets.

There have been no other significant changes to the accounting policies during 2020.

CHANGES TO THE ACCOUNTING POLICY

IFRS 3 Business combination amendments introduce clarification on the definition of a business to help determine whether an acquired set of activities and assets is a business or not.

The amendment to IFRS 3 also introduce an optional fair value concentration test to permit a simplified assessment of whether an acquired set of activities and assets is not a business.

SIGNIFICANT 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 is 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 11.
- 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 20.
- Capitalized exploration expenses which are dependent on existence of commercial oil and gas reserves. For further details refer to Note 11 and 26.

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 DIVESTMENTS

In case of acquisition of an interest in a production license, the Company will evaluate whether the transaction is to be accounted for as an asset acquisition or a business combination, based on the nature and structure of the acquired interest. The acquisition date is the date when effective control is transferred to the acquirer (transaction date). 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.

FOREIGN CURRENCY TRANSLATION AND TRANSACTIONS

The financial statements are presented in 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 on the basis of allocated production. If the accumulated production exceeds accumulated sales (liftings), the Company accounts for an underlift position (asset). If accumulated sales (liftings) exceeds 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.

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, 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 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 particular oil & gas field.

Under the unit-of-production method, annual depreciation rate is calculated based on proved and probable reserves (developed and undeveloped). The basis for depreciation is adjusted with future investments to reflect a reserve basis of proved and probable reserves. The rate of depreciation is equal to the ratio of hydrocarbon production for the period, over the estimated remaining proved reserves and contingent resources expected to be recovered at the beginning of the period.

The future development expenditures necessary to bring those resources into production are included in the basis for depreciation, and are estimated by the management based on nominal price levels. 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.

The Company may also apply the reducing balance method for depreciation of oil & gas fields in special situations if the reducing balance method results in better matching between consumption of economic benefits and depreciation. Such a change from one method to another is applicable only if the reducing balance method better reflects the expected pattern of consumption of the future benefit of particular oil & gas field.

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.

For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash flows. For oil and gas properties this is done on a field by field basis. An impairment loss is the amount by which the carrying amount of the assets exceeds the recoverable amount. 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 fair value and subsequently measured at amortised cost less provision for impairment.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents comprise cash in hand, deposits held at call with banks, and other short term highly liquid investments with original maturities of three months or less. 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 LIBOR 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 LIBOR) 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 using the same depreciation methods as those applied to similar underlying assets. In addition, the right-of-use asset is periodically reduced by impairment losses, if any, and 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.

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 the tax value of any unused tax losses or other tax credits related to its offshore activities to be paid in cash (including interest) from the tax authorities when operations cease. This mechanism, which is described in the Norwegian Petroleum Tax Act section 3c and section 5, reduces the risk related to investing in offshore assets, as the companies will in any case be able to fully recoup the tax value of the investments. 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 expected 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 2020.

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.

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 increased by risk premium and is reviewed at each balance 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

Contingent liabilities are not recognised in the annual accounts. Significant contingent liabilities are disclosed, with the exception of contingent liabilities that are less likely to be incurred.

Contingent assets are not recognised in the annual accounts, but are disclosed if there is a certain probability 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 2020

COMPLETION OF THE DUVA ACQUISITION

In November 2019, the Company bought 10% share in the Duva field from Pandion Energy AS.

The effective date of the transaction for tax purposes was 1st January 2020. The acquisition of Duva was completed on the 31st January 2020 for accounting purposes after fulfilment of the conditions precedent.

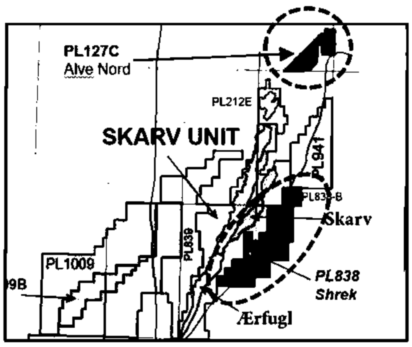
Duva is an oil and gas field discovered in 2016. It is located within the PL636 license area in the North Sea, approx. 140 km north of Bergen. The field is now in development phase with the expected production start-up in 2021.

Detailed information about the Duva field can be found in Note 26.

TRANSACTION WITH AKER BP

In February 2020, PGNiG Upstream has entered into an agreement with Aker BP whereby it acquired 11.9175% interest in the Alve Nord discovery and 3,3% interest in the Gina Krog field. In return, the company transferred a 5% working interest in the licence PL838, and paid a cash consideration to Aker BP.

Licenses around Skarv included in transaction with Aker BP



The Company estimates that the transaction will increase its future gas production by 0,1 bcm a year on an average.

Continuing the successful co-operation between PGNiG Upstream and Aker BP in recent years, it has also been agreed as part of the transaction that the operatorship of PL838 will be transferred from PGNiG Upstream to Aker BP for the development phase. This will optimise the value of the Shrek discovery through Aker BP's vast experience, supply chain and excellent track record of delivering major development projects safely, on schedule and to budget. It is assumed that the Shrek discovery can be developed through a tie-back to the Skarv field. During the next years PGNiG Upstream will continue to take a leading role in exploration on PL838, building on its recent success. It is also the intention that PGNiG will resume operatorship of PL838 once Shrek begins producing.

The effective date of the transaction is 1st January 2020 for tax purposes. The transaction was completed on the 30th April 2020 for the accounting purposes after fulfilment of conditions precedent.

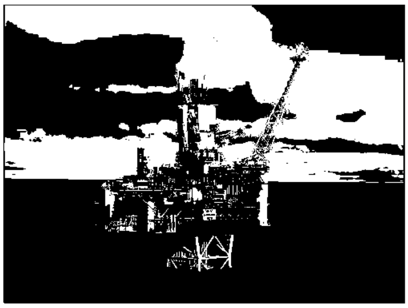
Detailed information about all fields and discoveries can be found in Note 26.

ACQUISITION OF KVITEBJØRN AND VALEMON

In September 2020, PGNiG Upstream signed an agreement with Shell to acquire 6,45% interest in the Kvitebjørn field and 3,225% interest in the Valemon field together with the associated infrastructure.

The acquisition will enable a step increase in the Company's average daily production of hydrocarbons (both oil and gas), of about 30%.

The Kvitebjørn field is located in the northern part of the North Sea, with the water depth of 190 metres. Kvitebjørn was discovered in 1994 and started production in 2004. The field is developed through a fixed platform with fully integrated drilling module.



Kvitebjørn platform (North Sea)

The extracted gas is sent via a subsea pipeline to the Kollsnes terminal, while the condensate is transported via a branch of Troll Oil Pipeline II to the Mongstad terminal.

The Valemon field is located immediately west of Kvitebjørn, with the water depth of 135 metres. Valemon was discovered in 1985 and production commenced in 2015. The field has been developed through a fixed platform with a simplified hydrocarbon separation process, operated remotely from land. Its condensate and gas output are carried via a pipeline to the Kvitebjørn field, and then via a subsea pipeline to the Mongstad processing terminal.

The effective date of the transaction is 1st January 2020 for tax purposes. The transaction was completed on the 31st December 2020 for accounting purposes after fulfilment of conditions precedent.

Detailed information about the acquired fields can be found in Note 26.

All business development transactions mark the next step in the implementation of the PGNiG Group strategy, and will allow for a significant increase in natural gas production outside Poland. Gas produced from the new fields, along with volumes resulting from the previous acquisitions made by PGNiG Upstream between 2017 and 2020, will be sent to Poland through the Baltic Pipe.

INCREASED FINANCING

In 2020, the Company has secured additional financing for further growth.

In April, the company signed new intercompany loan agreement with the committed funding of 1,1 billion NOK (ref Note 17). In July, PGNiG Upstream increased the size of the RBL agreement from USD 450 million to USD 500 million (ref Note 18).

Financing activities in 2020 were aimed at securing necessary funds for ambitious development plans. As of the end of 2020, PGNiG Upstream had 64 million USD and 852 million NOK available for drawing under existing loan agreements. Moreover, latest valuation model performed by the RBL banks indicates that the Company may further increase RBL size to 651 million USD. Financial stability of PGNiG Upstream can be additionally confirmed by a lack of scheduled loan repayments until 2023.

NOTE 3 REVENUE

	2020	2019
Oil sales	1 421 517 385	1 403 582 184
Gas sales	568 858 929	737 356 121
NGL sales	190 063 746	217 510 402
Sales revenue	**2 180 440 060**	**2 358 448 707**

PGNiG Upstream sells its share of crude oil from the Skarv field to Shell under an agreement which was concluded in October 2011. The share of crude oil from Vilje and Vale is sold to Shell under an agreement which was concluded in December 2014. Crude oil from Morvin is sold to Total under an agreement concluded in January 2015. Crude oil from the Gina Krog field is sold to Shell under an agreement concluded 9 January 2018. Gudrun Blend crude from the Gina Krog stream is sold to Shell under an agreement concluded 15 August 2017. Crude oil from Skogul is sold to Shell under an agreement concluded in March 2020.

The Company's gas production is contracted to PGNiG Supply & Trading GmbH, a PGNiG subsidiary based in Munich, Germany. In addition, the company has a contract with Shell to sell gas from Vale, in a case when Vale gas cannot be exported to Germany.

Naphtha from Skarv, Morvin and Gina Krog is sold to Total under an agreement concluded in August 2015.

Ethane from Skarv, Morvin and Gina Krog is sold to Yara Norge under an agreement concluded in March 2016.

LPG from Skarv, Morvin and Gina Krog is sold to Shell under an agreement concluded in January 2016.

NGL-products (naphtha, ethane and LPG, consisting from propane, iso-butane and normal-butane), are sold at the Kårstø terminal. The same applies for Gudrun Blend crude, which is also separated and sold at the Kårstø terminal.

All sales contracts are based on the market prices of the products, and will secure a stable stream of revenues for PGNiG Upstream for years to come.

NOTE 4 EXPLORATION EXPENSES

	2020	2019
Exploration expenses from production licenses	62 852 045	74 120 606
Drilling expenses from production licenses	13 803 074	0
Other exploration expenses	3 314 384	5 316 005
Direct exploration expenses	**79 969 503**	**79 436 611**
Allocated expenses included in:		
- Depreciation	251 038	253 486
- Employee expenses	29 281 520	27 242 854
- Other operating expenses	4 800 537	5 789 131
Allocated exploration expenses	**34 333 095**	**33 285 471**
Total exploration expenses	**114 302 598**	**112 722 082**

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 are connected with participation in, and work on, exploration licenses as further described in Note 26.
- Majority of expenses in 2020 were connected with the licenses PL887, PL838 and exploration activities on the Duva license.
- Drilling cost in 2020 is connected with testing of the Warszawa prospect which was dry (test of Warszawa was designed as a side-track from the successful Warka exploration well).

Other exploration expenses in 2020 are connected with the APA2020 applications, business development activities and purchase of various studies.

Allocated exploration expenses are linked to own exploration activities of PGNiG Upstream. In 2020 they were mostly connected with the follow-up activities on exploration licenses and the participation in the APA2020 Licensing Round, 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 38,3. On 31st December 2020, PGNiG Upstream had 38 employees.

The remuneration for the General Manager for the year amounted to NOK 5 437 659 for wages and NOK 349 992 for other compensations. In addition, contributions to the pension scheme is NOK 646 887 for the period. These amounts are included in employee expenses above. Further, the contract with the General Manager includes a binding period with salary entitlement until 30 September 2022. In addition, PGNiG Upstream has a bonus scheme covering all employees. The bonus amount for the General Manager shall be based on an evaluation of specific "Key Performance Indicators" agreed between the Board of Directors and the General Manager 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 19 for further information.

	2020	2019
Employees*		
Wages, salaries and remuneration	30 325 892	18 435 318
Social security	12 333 672	10 044 986
Pensions (Note 19)	11 857 603	11 146 855
Other staff expenses	1 929 372	1 755 581
Total	**56 446 539**	**41 382 739**

* 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.

	2020	2019
Board of Directors		
Wages, salaries and remuneration	66 959	1 273 607
Total employee expenses**	**56 513 498**	**42 656 346**

** TOTAL EMPLOYEE EXPENSES ABOVE ARE PRESENTED NET OF COST, WHICH WAS RECHARGED TO OPERATED LICENCES, AND NET OF COST FROM INTERNAL HOURS CHARGED TO THE DEVELOPMENT PROJECTS SKOGUL, TOMMELITEN, DUVA, GRÅSEL, ÆRFUGL AND ÆRFUGL NORD. THE TOTAL VALUE OF COST RECHARGED TO OPERATED LICENCES IN 2020 AMOUNTS TO NOK 28,1 MILLION (NOK 50,4 MILLION IN 2019), AND THE TOTAL VALUE OF COST CHARGED TO DEVELOPMENT PROJECTS AMOUNTS TO NOK 14,2 MILLION (NOK 9,5 MILLION IN 2019).

NOTE 6 PRODUCTION AND SALES COSTS

	2020	2019
Operating costs	402 347 709	266 504 090
Gas tariffs and other transportation costs	348 037 088	363 999 369
Over-/(underlift)	(39 766 607)	28 383 640
Total production and sales costs	**710 618 191**	**658 887 098**

Operating costs are reported by the respective Operators on the production licenses: Skarv, Vilje, Vale, Morvin, Gina Krog and Skogul. The operating costs consist of:

- NOK 372 million from the production licenses,
- NOK 23 million related to P&A costs not covered by the abandonment provision, and
- NOK 7 million incurred in relation to sales.

The Company covered gas tariffs in the Gassled network and other transportation costs of NOK 288 million. Other transportation costs included balancing, dispatching, contract handling etc. In addition, the Company incurred NOK 58 million related to cost of sales of dry gas to the affiliated company PGNiG Supply & Trading GmbH, fully owned by PGNiG Group.

In the end of 2020, the Company had a decreased overlift position, which means that accumulated production exceeded the accumulated sales. As a consequence, the Company incurred a reduction of cost related to change in over-/underlift position for 2020. According to accounting policy change in over-/underlift positions is to be adjusted towards production and sales cost. Please refer to note 21 for further information about overlift position.

NOTE 7 OTHER OPERATING EXPENSES

	2020	2019
External fees	12 706 763	16 125 069
Rent premises	1 931 074	1 393 418
Insurance premium	32 742 395	25 693 702
Expensed purchases	10 949 675	8 891 309
Travel costs	622 876	2 189 086
Other	8 125 886	8 062 380
Other operating expenses	**67 078 670**	**62 354 965**
Remuneration to auditor:		
Audit fee (excl. VAT)	375 000	344 780
Other services (excl. VAT)	87 000	613 268
	462 000	**958 048**

Indirect exploration costs presented in note 4 (with the amount of NOK 4,8 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.

External fees were connected with running the Company accounts, legal support and various advisory services.

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 and external experts.

The total costs of R&D activities amounted to NOK 1,1 million in 2020. 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

	2020	2019
Interest received bank	959 457	4 611 169
Interest received customers	0	5 760
Other interest earnings	405 663	2 001 801
Exchange rate differences	174 628 830	68 256 300
Other financial income	**175 993 950**	**74 875 030**

NOTE 9 OTHER FINANCIAL EXPENSES

	2020	2019
Interest costs to financial institutions*	89 829 134	89 005 306
Exchange rate differences	66 373 419	32 931 246
Accretion	47 000 000	34 000 000
Other interest cost	8 491 004	13 096 251
Capitalized borrowing cost	(197 421 000)	(123 793 000)
Other financial expenses	**14 272 557**	**45 239 804**

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

Interest costs are recognised as an expense in the period in which they are incurred. The Company has capitalized the share of borrowing cost allocated to the Skogul, Duva, Gråsel, Tommeliten Alpha, Ærfugl and Ærfugl Nord development projects. The part of borrowing cost capitalized is included under Additions to Assets in development in Note 11.

NOTE 10 TAX ON THE INCOME/(LOSS) FOR THE YEAR

Calculation of taxable income for the year	2020	2019
Net income before taxes	(940 514 531)	648 234 227
Permanent differences	504 687 912	106 814 518
Changes in temporary differences	185 176 229	(494 015 374)
Basis for corporate taxes payable, not assessed	**(250 650 389)**	**261 033 371**
Net financial costs only allowed against CT	230 580 322	192 070 409
Uplift allowable only against SPT	(548 313 283)	(195 290 263)
Expense of capex addition in SPT	(1 263 277 145)	0
Taxable income, special petroleum tax (“SPT”)	**(1 831 660 494)**	**257 813 517**
Covered from loss carry forward SPT	**0**	**0**
Basis for taxes payable, not assessed	**(1 831 660 494)**	**257 813 517**

Tax payable	**2020**	**2019**
Tax payable	0	201 802 911
Other	38 357 011	16 286 452
Tax payable in balance sheet	38 357 011	218 089 363

Tax receivable	**2020**	**2019**
Tax receivable	1 080 872 961	0
Tax refund received in 2020	(909 067 080)	0
Tax receivable in balance sheet	171 805 881	0

Calculation of deferred taxes	**2020**	**2019**
Temporary differences:		
Over-/underlift	(15 030 606)	83 139 592
Long-term liabilities	(193 360 176)	(63 566 473)
ARO provision	1 572 720 726	1 024 000 000
Fixed Assets	(4 432 332 807)	(4 587 662 281)
Intangible Assets	(607 587 261)	(346 294 162)
Lease	(61 200 334)	(15 866 511)
Other	(15 426 095)	11 736 898
Net temporary differences	**(3 752 216 552)**	**(3 894 512 937)**

	2020	**2019**
Losses carried forward:		
Loss carry forward - CT - prior year	0	(16 202 824)
Prior year adjustment	0	16 202 824
Loss carry forward - CT	0	0
Basis for deferred tax - company tax	**0**	**0**

	2020	**2019**
Deferred tax liability on temporary differences	(3 330 922 368)	(2 891 730 442)
Deferred tax asset on loss carry forward CT	0	0
Deferred tax asset/(liability) in the balance sheet	**(3 330 922 368)**	**(2 891 730 442)**

Income taxes charged to income statement consist of:	2020	2019
Changes in deferred taxes	439 191 925	301 168 369
Taxes booked to balance sheet (related to acquisitions)	(89 131 390)	41 816 946
Taxes payable/(receivable), not assessed	(1 080 872 961)	201 802 911
Correction previous year	(26 738 100)	(39 847 538)
Total Tax charge/(credit) to income statement	**(757 550 525)**	**504 940 688**

Effective tax rate reconciliation	2020	2019
Income before taxes	(940 514 531)	648 234 227
Expected tax charge - 78%	(733 601 334)	505 622 697
Permanent differences	267 229 257	131 084 039
Prior year items	(2 817 822)	(45 172 422)
Financial items	904 327	18 781 138
Uplift	(307 055 438)	(109 362 547)
Other	17 790 485	3 987 782
Total Tax charge/(credit)	**757 550 525**	**504 940 688**
Effective tax rate	**81 %**	**78%**

NOTE 11 INTANGIBLE ASSETS AND TANGIBLE FIXED ASSETS

RIGHT OF USE ASSET

2020	FPSO/FSO	Land & buildings	Total
Right-of-use asset at initial recognition 01/01/2020*	171 146 844	13 010 320	184 157 165
Additions	59 708 806	0	59 708 806
Investments at 31/12/20	**230 855 650**	**13 010 320**	**243 865 970**
Accum. depreciation at 1/1/20	(18 404 978)	(990 999)	(19 395 976)
Depreciation in 2020**	(14 801 179)	(1 044 918)	(15 846 097)
Accum. depreciation at 31/12/20	**(33 206 157)**	**(2 035 917)**	**(35 242 073)**
Net book value at 31/12/20	**197 649 494**	**10 974 404**	**208 623 897**
Depreciation method**	unit of production	unit of production	

* Reference is made to note 1 and note 12 for accounting principles used to measure the value of the right-of-use asset.

** Depreciation of right-of-use assets is based on the UOP methodology using the same depreciation methods as those applied to similar underlying assets

2019	FPSO/FSO	Land & buildings	Total
Right-of-use asset at initial recognition 01/01/2019*	171 146 844	13 010 320	184 157 165
Additions	0	0	0
Investments at 31/12/19	**171 146 844**	**13 010 320**	**184 157 165**
Depreciation in 2019	(18 404 978)	(990 999)	(19 395 976)
Accum. depreciation and impairment at 31/12/19	**(18 404 978)**	**(990 999)**	**(19 395 976)**
Net book value at 31/12/19	**152 741 867**	**12 019 322**	**164 761 188**
Depreciation method**	unit of production	unit of production	

* Reference is made to note 1 and note 12 for accounting principles used to measure the value of the right-of-use asset at initial recognition.

** Depreciation of right-of-use assets is based on the UOP methodology using the same depreciation methods as those applied to similar underlying assets.

2020	Capitalized exploration expenses	Assets in Development	Assets in Production	Other tools and equipment	Total
Investments at 1/1/20	1 055 528 127	4 962 682 867	12 372 716 722	39 217 323	18 430 145 038
Additions *	479 323 618	2 024 557 428	1 587 172 165	4 072 485	4 095 125 696
Transfer to Assets in development/production**	(21 235 092)	(1 664 107 629)	1 685 342 721	0	0
Expensed previously capitalised exploration	(10 489 533)	0	0	0	(10 489 533)
Investments at 31/12/20	**1 503 127 119**	**5 323 132 666**	**15 645 231 608**	**43 289 808**	**22 514 781 201**
Acc. depreciation 1/1/20	0	0	(6 111 976 469)	(34 243 971)	(6 146 220 441)
Acc. impairment 1/1/20	0	0	(118 988 979)	(2 938 097)	(121 927 076)
Accum. depreciation and impairment at 1/1/20	0	0	(6 230 965 448)	(37 182 068)	(6 268 147 517)
Depreciation in 2020***	0	0	(1 362 694 271)	(2 189 052)	(1 364 883 324)
Reversal of impairment****	0	0	32 549 298	0	32 549 298
Impairment in 2020 ****	0	(154 660 934)	(708 576 551)	0	(863 237 485)
Accum. depreciation and impairment at 31/12/20	**0**	**(154 660 934)**	**(8 269 686 973)**	**(39 371 121)**	**(8 463 719 028)**
Net book value at 31/12/20	**1 503 127 119**	**5 168 471 732**	**7 375 544 635**	**3 918 688**	**14 051 062 175**
Depreciation method***	N/A	N/A	unit of production	straight line	
Useful life		-	-	3-6 years	

* Additions under "Capitalized exploration expenses" include the acquired Alve Nord field (PL127C), capitalized exploration well on the license and capitalized drilling expenses on the Warka prospect drilled in 2020 on the PL1009 license in the Norwegian Sea resulting in significant gas discovery. Other capitalized expenses are related to seismic and field evaluation.

* Additions under "Assets in development" relates to the acquisition of the Duva field. In addition there was development capex, capitalized hours and capitalized borrowing cost on the Skogul (before skogul started production), Ærfugl, Ærfugl Nord, Tommeliten Alpha, Gråsel and Duva projects. The amount also includes the change in the estimate of the Asset retirement obligations related to Ærfugl, Ærfugl Nord and Duva fields in the amount of NOK 72 million, which has no cash effect in 2020. For further details refer to Note 20.

* Additions under "Assets in Production" relates to the acquisition of additional 3,3% in the Gina Krog field and the acquired interest in Kvitebjørn and Valemon fields. In addition it include capex to the producing assets Skarv, Gina Krog, Morvin, Vilje, Skogul and Vale. The amount also includes the recognized abandonment removal obligation acquired with Kvitebjørn and Valemon and the change in the estimate of the Asset retirement obligations related to Skarv, Gina Krog, Morvin, Vilje, Skogul and Vale in the amount of NOK 276 million, which has no cash effect in 2020. For further details refer to Note 20.

** Transfer to Assets in development from Capitalized exploration expenses relates to reclassification of capitalized exploration expenses for Gråsel prospect within Skarv license. Transfer to asset in production from asset in development relates to reclassification of capitalized development capex for Skogul and Ærfugl phase 1 when these 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 2019. Any changes in estimates will be recognized prospectively from the following year. The Company may in special cases also apply the reducing balance method of depreciation in accordance with accounting principles, refer note 1. The Vilje field was depreciated under the reducing balance method from 2016.

**** The company has recognised impairment of NOK 709 million for the Gina Krog field and NOK 155 million for the Duva field in 2020. The impairment is based on a lower recoverable amount calculated compared to the actual book value prior to impairment. For further details on impairment testing, please see below. In contrast, the company has reversed parts of impairment from prior years related to the Morvin and Vale field, in gross NOK 32,5 million.

2019	Capitalized exploration expenses	Assets in Development	Assets in Production	Other tools and equipment	Total
Investments at 1/1/19	280 556 593	2 505 131 780	12 112 010 077	37 564 686	14 935 263 136
Additions *	839 687 010	2 407 653 420	260 706 645	1 652 637	3 509 699 712
Transfer to Assets in development**	(49 897 667)	49 897 667	0	0	0
Expensed wells/seismic previously capitalised	(14 817 810)	0	0	0	(14 817 810)
Investments at 31/12/19	**1 055 528 127**	**4 962 682 867**	**12 372 716 722**	**39 217 323**	**18 430 145 038**
Acc. depreciation 1/1/19	0	0	(5 338 851 655)	(33 033 331)	(5 371 884 986)
Acc. impairment 1/1/19	0	0	(118 988 979)	(2 938 097)	(121 927 076)
Accum. depreciation and impairment at 1/1/19	0	0	(5 457 840 634)	(35 971 428)	(5 493 812 062)
Depreciation in 2019***	0	0	(773 124 814)	(1 210 640)	(774 335 455)
Reversal of impairment****	0	0	0	0	0
Impairment in 2019 ****	0	0	0	0	0
Accum. depreciation and impairment at 31/12/19	**0**	**0**	**(6 230 965 448)**	**(37 182 068)**	**(6 268 147 517)**
Net book value at 31/12/19	**1 055 528 127**	**4 962 682 867**	**6 141 751 274**	**2 035 255**	**12 161 997 522**
Depreciation method**	N/A	N/A	unit of production*****	straight line	
Useful life		-	-	3-7 years	

* Additions under "Capitalized exploration expenses" include the acquired King Lear field (PL146/333) and capitalized drilling expenses on the first operated exploration well 6506/5-9 on the PL838 license in the Norwegian Sea resulting in the Shrek discovery. Other capitalized expenses are related to seismic and field evaluation. Investments in seismic and drilling were made in the PGNiG Upstream licenses King Lear, PL838, PL887 and PL1017.

* Additions under "Assets in development" relates to the acquisition of the Duva field as well as development capex, capitalized hours and capitalized borrowing cost on the Skogul, Ærfugl, Ærfugl Nord, Tommeliten Alpha and Duva fields. The amount also includes the change in the estimate of the Asset retirement obligations related to Skogul, Ærfugl and Duva fields in the amount of NOK 171 million, which has no cash effect in 2019. For further details refer to Note 20.

* ADDITIONS UNDER "ASSETS IN PRODUCTION" INCLUDE CAPEX TO THE PRODUCING ASSETS SKARV, GINA KROG, MORVIN, VILJE AND VALE. THE MAJORITY RELATES TO THE DRILLING CAMPAIGN FOR PRODUCTION WELLS ON GINA KROG. IN ADDITION, THE AMOUNT INCLUDES THE CHANGE IN THE ESTIMATE OF THE ASSET RETIREMENT OBLIGATIONS RELATED TO SKARV, GINA KROG, MORVIN, VILJE AND VALE IN THE AMOUNT OF NOK 13 MILLION, WHICH HAS NO CASH EFFECT IN 2019. FOR FURTHER DETAILS REFER TO NOTE 20.

** TRANSFER TO ASSETS IN DEVELOPMENT FROM CAPITALIZED EXPLORATION EXPENSES RELATES TO RECLASSIFICATION OF CAPITALIZED EXPLORATION EXPENSES FOR LICENSE PL212E ÆRFUGL NORD. ÆRFUGL NORD IS INCLUDED IN THE SECOND PHASE OF THE ÆRFUGL DEVELOPMENT.

*** 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 2018. ANY CHANGES IN ESTIMATES WILL BE RECOGNIZED PROSPECTIVELY FROM THE FOLLOWING YEAR. THE COMPANY MAY IN SPECIAL CASES ALSO APPLY THE REDUCING BALANCE METHOD OF DEPRECIATION IN ACCORDANCE WITH ACCOUNTING PRINCIPLES, REFER NOTE 1. THE VILJE FIELD WAS DEPRECIATED UNDER THE REDUCING BALANCE METHOD FROM 2016.

**** THE COMPANY DID NOT RECOGNIZE ANY IMPAIRMENT OR REVERSAL OF IMPAIRMENT IN 2019. FOR FURTHER DETAILS ON IMPAIRMENT TESTING PLEASE SEE BELOW.

IMPAIRMENT TEST

In the end of 2020, the Company conducted an impairment tests for all its fields (including Skarv Unit, Morvin, Vilje, Vale, Gina Krog, Skogul, Tommeliten Alpha, Duva and Ærfugl Nord) with exception of newly acquired assets (Valemon and Kvitebjørn). The main aim of these tests was to ensure that all assets are carried at no more than its recoverable amount. The recoverable amount was calculated as the asset's net 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, with exception of Duva and Gina Krog projects, for which PGNiG Upstream's own estimated production profile was used. The Company has used its own assumptions regarding gas tariffs.

As a result of impairment test, impairment write offs have been done for Gina Krog and Duva, while impairment reversal was done on Morvin and Vale projects.

The impairment test for Skarv included also the Ærfugl development. The reason for combining these tests is the fact that the Ærfugl development is located within the Skarv Unit and will be developed as a part of the Skarv project.

PGNiG Upstream performed separate impairment test for Ærfugl Nord (previously Snadd Outer) where the Company holds different equity share than in Ærfugl and Ærfugl Nord will also pay processing tariff to the Skarv Unit.

In calculating the net present value, the company applied the oil price scenario based on the latest reports received from mother company (PGNiG SA), which are based on WoodMackenzie and Pöyry forecasts. According to assumptions, the average oil price in the next five years accounts for 459 NOK/bbl (in real terms), and the average gas price in this period accounts for 1,89 NOK/Sm^3 (in real terms).

In addition, a discount rate was used (7,22% after tax, nominal) that reflects current market assessments of the time value of money and the specific risks.

A sensitivity analysis has been carried out in relation to the impairment of all fields 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 Gina Krog and Duva projects. In both projects the carrying amount is equal to the recoverable amount.

It was concluded that Gina Krog field is the most sensitive to oil prices. A 10% oil price decrease would result in a value decrease of NOK 57,6 million, while a 10% decrease of gas price would decrease the value of NOK 46,7 million NOK.

For the Duva project, the highest sensitivity was observed on oil price as well. A 10% oil price decrease would result in decrease of field's value of NOK 103,5 million, while a 10% decrease of gas price would decrease value of NOK 83,9 million NOK.

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 campaigns

NOTE 12 LEASES

	2020
Lease debt 01.01.2020	148 894 678
New leases	59 708 806
Payments of lease debt	(57 168 002)
Interest expense on lease debt	4 780 591
Currency exchange differences	(8 792 508)
Lease debt 31.12.2020	**147 423 564**

Nominal lease debt maturity breakdown (NOK):	
Within one year	38 357 779
Two to five years	109 708 485
After five years	7 555 897
Total	**155 622 161**

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.

NOTE 13 OTHER CURRENT RECEIVABLES

	2020	2019
Accounts receivable, JV	15 139 927	26 325 212
Prepayments, JV	63 760 940	52 680 667
VAT	2 061 927	3 960 723
Other current receivables	96 512 344	284 322 470
Overcall, JV	45 485 902	138 631 311
Other current receivables	**222 961 040**	**505 920 383**

PGNiG Upstream have invoice mechanisms under some sales contracts where the invoice values are not directly linked to physical liftings. Other current receivables include the value of revenue which is incurred on the basis of liftings, but not invoiced, of NOK 83 million at the end of 2020.

NOTE 14 CASH AND CASH EQUIVALENTS

	2020	2019
Cash and cash equivalents, non-restricted	158 174 547	161 041 756
Cash and cash equivalents, restricted	6 062 604	5 972 392
Total cash and cash equivalents *	**164 237 151**	**167 014 147**

Restricted cash is related to:

* taxes withheld from employees of NOK 6,1 million (NOK 6 million in 2019)

NOTE 15 INVENTORY

The inventory in 2020 (NOK 78,6 million) is solely connected with the spare parts and drilling equipment kept within the joint ventures. The reported spare parts are related to the Skarv Unit, Gina Krog Unit, Morvin, Vilje, Vale, Skogul, Kvitebjørn and Valemon. The Company did not account for any hydrocarbons left in inventor

NOTE 16 EQUITY

The share capital consists of 1 110 000 shares each with a nominal value of NOK 1 000.

All the shares are held by the parent company, PGNiG, with its office in Warsaw. 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 18). 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 17 DEBT TO GROUP ENTERPRISES

	2020	2019
Principal debt to Group enterprises	4 253 394 651	2 718 232 051
Interests to Group enterprises	35 601 610	30 087 693
Total debt to Group enterprises	**4 288 996 261**	**2 748 319 744**
Hereof short-term - payable within 1 year	0	0
Hereof short-term – interest payable within 1 year	35 601 610	30 087 693
Long term liabilities to Group enterprises	**4 253 394 651**	**2 718 232 051**

As of 31 December 2020 PGNiG Upstream was funded through two intercompany loans:

- Loan no 3: From 27 August 2010 with the maximum available amount of NOK 4 100 000 000 (out of which the Company has drawn NOK 3 818 232 051).
- Loan no 8: From 30 April 2020 with the maximum available amount of NOK 1 100 000 000 (out of which the Company has drawn USD 51.000.000).

The Intercompany Loan 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 on the basis of a duly prepared Drawdown Request at least 7 days prior to the requested date of disbursement. Each tranche can be drawn in NOK, EUR or USD.

During 2020, PGNiG Upstream paid interest related to intercompany loans for previous periods in the total amount of NOK 144.243.332,83 for loan no 3 and USD 754.167,03 for loan no 8.

The outstanding balance of both loan number 3 (NOK 3,8 billion) and loan number 8 (USD 51 million) 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.

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

The repayment of the Loan 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 4 046 783 276. The value of all pledges is limited to the value of PGNiG Upstream's liabilities under this loan.

Intercompany loan is subordinated to the Facility (ref Note 18). Additionally, loan receivables under this loan are secured for the benefit of Societe Generale, London Branch, as a part of the security package under the Facility

NOTE 18 DEBT TO FINANCIAL INSTITUTIONS

	2020	2019
Principal debt	3 730 211 250	3 606 906 500
Arrangement fees paid	(57 761 198)	(61 892 164)
Effective interest rate amortization	653 828	754 165
Debt to financial institutions	**3 673 103 880**	**3 545 768 501**
Hereof short-term - payable within 1 year	2 339 026	2 428 474
Long term Debt to financial institutions	**3 670 764 854**	**3 543 340 027**

The credit facility (**"Facility"**) was initially signed in August 2015 with eight banks. As per 31.12.2020, the bank consortium consists of the following banks (BNP Paribas, Societe Generale, ING, SEB, HSBC, Citibank, BGK S.A, PKB S.A, SMBC and Bank Handlowy w Warszawie S.A). During 2020, Facility amount was increased from USD 450 million, to USD 500 million.

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 is able to draw loans in EUR and USD. The Facility is based on the reserve based loan formula and is governed by English law.

As of 31.12.2020 the available amount under the Facility was limited by overall limit of USD 500 million (including utilization of accordion). This limit was only partially utilized, as the Company borrowed USD 436 million under the Facility at 31.12.2020.

The drawing limit will be amortizing over time in accordance with the reduction schedule, starting from 1st July 2023 until 1st July 2026. The Facility is to be repaid in full by 1st July 2026.

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 with respect to its planned exploration and production activities. The Facility allows the Company to freely acquire further upstream assets in the area of 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 PGNiG and PGNiG Upstream;
(iii) the registered pledge over shares in Production Licenses 029C, 029B, 036, 036D, 134B, 134C, 212, 212B, 249, 262, 460, 044 TA, 044, 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, London Branch, 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 12 352 213 982.

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, i.e. USD 436 million.

NOTE 19 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 2020, the plan had 38 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 20 PROVISIONS

ABANDONMENT PROVISION

Provisions recognized in 2020 consist of (numbers presented below are PGNIG Upstream share in NOK million):

Field	Abandonment provision	Expected abandonment
Skarv	359	2033-2036
Morvin	46	2032
Vilje	107	2037-2039
Vale	90	2021-2024
Gina Krog	381	2033-2035
Ærfugl	72	2033-2036
Skogul	72	2036
Duva	160	2032
Ærfugl Nord	4	2035
Valemon (incl. VRGP)	112	2029
Kvitebjørn (incl. KOR)	170	2035
Total	1573	

The Company has recognized provisions for future abandonment for all its oil & gas fields as per year-end 2020. These provisions are related to removal expenditures for the offshore installations.
Decommissioning cost related to 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.

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 2020. The value of the abandonment costs was based on the study performed by the field operators and verified through comparison to the other development projects. 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 Ærfugl 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 11).

When calculating the net present value of the long term portion of the liability, PGNiG Upstream used an inflation rate of 2 per cent and a nominal discount rate of 3,82 per cent.

An increase of abandonment removal obligation was observed on Gina Krog (+137 million) and Duva (+117 million) following higher participant interest, Vale (+14 million), Vilje (+9 million), Skogul (+8 million) and Ærfugl (+8 million) following subsea installation campaign. A decrease was observed on Skarv (-46 million) and no change on Morvin . In addition, the Company accounted for abandonment removal obligation on Ærfugl Nord (+4 million), Valemon (+112 million) and Kvitebjørn (+170 million). Unwinding of the discount in 2020 accounted for NOK +47 million (ref Note 9).

As a shipper in the Gassled system, 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. This estimate was inflated using a rate of 2 per cent and discounted at the rate of 3,82 per cent. PGNiG Upstream has assumed removal in 2050, resulting in a value of the liability of NOK 7 million at the end of 2020. As such, the Company has accrued for the liability at the end of 2020.

Decommissioning cost related to the pipepline assets (VRGP and KOR) are paid and passed on to the Shippers because it is only the JV license partners themselves that have volumes in these pipelines no decommissioning receivable has been recognized and the company has recognized abandonment removal obligation according to participant interest.

NOTE 21 OTHER CURRENT LIABILITIES

	2020	2019
Working capital, JV	216 269 782	559 638 457
Overlift (oil, NGL)	51 801 629	118 025 018
Other current liabilities	132 839 905	17 362 574
Undercall, JV	900 802	0
Other current liabilities	**401 812 117**	**695 026 050**

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 overlift position of hydrocarbons based on market prices as per 31.12.2020.

The periodical change in overlift position at the end of 2020 was NOK (66,2) million. This periodical change is recognized under the Production and sales cost in the Income Statement, see also Note 6.

NOTE 22 COMMITMENTS AND CONTINGENCIES

PGNiG Upstream has a loan agreement from PGNiG with the value of NOK 5,2 billion, out of which a total of NOK 4,3 billion is drawn by the end of 2020 (NOK 3,8 billion and USD 51 million). The loan is secured by respective promissory notes. By the end of 2020, the outstanding value of promissory notes amounted to NOK 3,8 billion and USD 51 million.

PGNiG Upstream's activities on the NCS are secured by the mother company guarantee issued on 22nd October 2007 (see Note 23). In return, PGNiG Upstream issued a Recourse Note which covers the whole principal sum of the mother company guarantee (EUR 627 555 648,36).

In addition, PGNiG Upstream has a loan agreement with external lenders with the outstanding liability of USD 212 million and EUR 183,5 million. This agreement is secured by a comprehensive security package, described in Note 18.

For the time being 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 2020, 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. In the previous years the tax authorities have also issued a draft notice of potential reassessment for 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 all assets and the Company's shares are presented below. Inside these amounts there are both expenses which are already committed by the license partners as well as other payments.

Field	PGNiG share	Budget 2021 (NOK million)*
Skarv	11,92 %	568,64
Tommeliten Alpha	42,38 %	613,78
Duva	30,00 %	566,69
Gina Krog	11,30 %	287,13
Ærfugl Nord	15,00 %	159,00
Kvitebjørn	6,45 %	118,08
King Lear	22,20 %	113,55
Skogul	35,00 %	77,89
Vale	24,24 %	74,36
Valemon	3,23 %	65,68
Vilje	24,24 %	45,60
Morvin	6,00 %	9,18
Shrek	35,00 %	6,22
Alve Nord	11,92 %	2,73

* Planned license expenses (opex and capex) are based on the approved Business Plan 2021 for PGNiG Upstream

As presented above, the largest commitment is connected with development projects: Tommeliten Alpha, Duva, Ærfugl, Ærfugl Nord. PGNiG Upstream is committed to execute the investments.

OTHER COMMITMENTS

PGNiG Upstream has also the following commitments connected with participation in exploration licenses:

- PL939 - the partners have decided to drill an exploration well in the license in 2021 The net costs of this well are budgeted at the level of NOK 198 million (net to PGNiG Upstream);
- PL1064 - the partners have decided to drill an exploration well in the license in 2022.

The Company has financial commitments related to bookings in the gas transportation system operated by Gassco. The estimated value of such commitments in

2021 amounts to approximately NOK 315 million. See also Note 20 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 with Seabrokers Group.

The rental agreement is valid until 31st December 2026 and has a yearly value of approximately NOK 1 million. The total value of the remaining commitment under this rental agreement amounts to NOK 6 million.

CONTINGENCIES

The contracts of top 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 23 GUARANTEES

MOTHER COMPANY GUARANTEES

In 2007, PGNiG Upstream received a mother company guarantee as requested by the Ministry of Petroleum and Energy pursuant to the Norwegian Petroleum Act.

Pursuant to the provisions of the Guarantee Agreement, PGNiG has issued a guarantee to PGNiG Upstream to the amount of EUR 627 555 648,36. The guarantee is effective until 1st January 2050.

The Guarantee Agreement concerns the provision of security by PGNiG with regard to 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 mother company guarantee requested by Gassco as operator of the gas transportation system. In 2020, the Company has booked NOK 1 046 193 as a liability connected with this agreement. This value is included in other current liabilities on the basis of invoices received.

***

In 2020, PGNiG Upstream received another mother 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 31.12.2020. In 2020, the Company has booked NOK 119 583 as a liability connected with this agreement.

OTHER GUARANTEES

The Company secured a Letter of Credit from SEB (Svenska Enskilda Banken) 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 The Letter of Credit secured a Letter of Credit from SEB (Svenska Enskilda Banken) towards A/S Norske Shell which was issued December 2020 in relation to purchase of assets on 31.12.2020. As of the balance sheet date, the maximum liability covered under these two guarantees were NOK 121,7 million. The Company has accrued for the expected future decommissioning liabilities for the assets as presented in Note 20.

NOTE 24 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 the oil price and exchange rate uncertainties. For the time being PGNiG Upstream does not have any derivative forward sales of oil 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 using loans both in 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 2023 and 2026 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. Further to that, in 2015 the Company has entered into a Market Risk Management Services Framework Agreement in PGNiG (Centralized Model), which is a master agreement setting general rules for future operational and strategic risk management.

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 PGNiG 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 PGNiG Group;

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 18). In addition, the potential risk of liquidity loss is covered by available amount under intercompany loan (see Note 17)

NOTE 25 EVENTS AFTER THE BALANCE SHEET DATE

AWARDS IN APA2020

In January 2020, PGNiG Upstream was awarded four new exploration licenses as a result of the APA2020 licensing round.

Two of the new licenses (PL 1123 and PL 1124) are located near the Skarv field in the Norwegian Sea, whereas the PL 1088 and PL 146B licenses lie in close roximity to the King Lear field in the North Sea.

The operator of the two new licensees in the North Sea is Aker BP, with a 77,8% interest in each of them. PGNiG Upstream is a partner on the licenses, holding a 22,2% interest in each of them. The company has also acquired a 30% interest in the PL 1123 license in the Norwegian Sea, with Aker BP and ConocoPhillips (operator) as the other partners. It also received an 11,9175% interest in PL 1124, with the other partners being Aker BP (operator), Equinor and Wintershall DEA.

NOTE 26 LICENSES

PGNiG Upstream's licenses at 31/12/2020

PL029B	(Gina Krog Unit)	11,3%
PL029C	(Gina Krog Unit)	11,3%
PL036D	(Vilje)	24,243%
PL036	(Vale)	24,243%
PL249	(Vale)	24,243%
PL044	(Tommeliten Unit)	42,38%
PL127C	(Alve N)	11,9175%
PL134B	(Morvin)	6%
PL134C	(Morvin)	6%
PL146	(King Lear)	22.2%
PL193	(Kvitebjørn)	6,45%
PL193C	(Kvitebjørn)	6,45%
PL193B	(Valemon)	3,25%
PL193D	(Valemon)	3,25%
PL212	(Skarv Unit)	11,9175%
PL212B	(Skarv Unit)	11,9175%
PL212E	(Ærfugl Nord)	15%
PL262	(Skarv Unit)	11,9175%
PL333	(King Lear)	22,2%
PL433	(Fogelberg)	20%
PL460	(Skogul)	35%
PL636	(Duva)	30%
PL636B	(Duva)	30%
PL636C	(Duva)	30%
PL838	(Shrek)	35%
PL838B		40%
PL939		30%
PL941		20%
PL1009	(Warka)	35%
PL1009B	(Warka)	35%
PL1017		50%
PL1064		30%

THE SKARV FIELD

The licenses PL212, PL212B and PL262 contain the Skarv oil and gas field. The Skarv Field was discovered in 1998, and it has taken 13 years to mature the field to its current stage. 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.

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 Plan for Development and Operation (PDO) was submitted to the Ministry of Petroleum and Energy (MPE) on behalf of the Skarv Unit and PL212 E partnerships on 15 December 2017. The PDO was approved in April 2018.

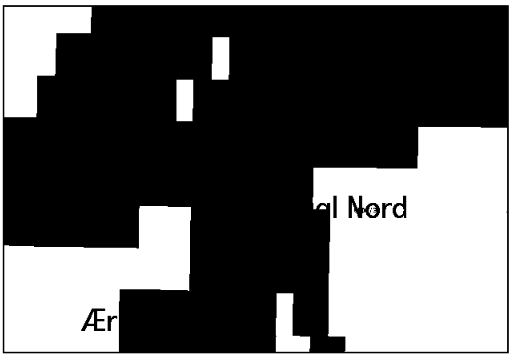
The PDO covers the full-field development and includes the resources in both the Ærfugl and Ærfugl Nord (previously Snadd Outer) fields. The PDO outlines a two-phased development. Phase 1 started production in November 2020. Phase 2 started production from first well in April 2020, and target is to have the 2 remaining wells onstream in November 2021.

As part of the PDO approval test production from A-1H well was granted as permanent production. After having test-produced this well for 5 years, the key conclusions is that the test well is connected to a large reservoir volume with excellent production characteristics. On the basis of these results, the partners have matured the development concept for the Ærfugl field.

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 will be included in the second phase of the Ærfugl development.



THE GINA KROG FIELD

Gina Krog, previously known as Dagny, was first discovered by Esso in 1974. It 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 %
KUFPEC	30,0000 %
PGNiG Upstream	11,3000 %

It has been developed through a new build oil processing platform and attendant FSO. It includes 20 well slots and full oil processing for up to 10000 Sm3/d, gas injection/export of 9 mmSm^3/d and produced water treatment of 4000 Sm^3/d. The platform was installed on location in 2016 and the field started production in June 2017.

The Gina Krog field started production in 2017 and is now in stable operation, with 9 oil producers, 4 gas injectors and two gas producers on stream. The primary drilling campaign was finalized July 2019, having drilled and completed 15 wells and one additional top hole, compared to 14 wells planned in the PDO.

Gina Krog Oil production is constrained by the 9 MSm^3/d gas processing capacity. The oil processing capacity is not fully utilized and a second drilling campaign is being planned for 2022.

In the long term phase (2020+), it is important to develop Gina Krog further in accordance with the Sleipner Region 2040 ambitions. This includes infill IOR drilling, evaluating an alternative oil export solution and establish a basis for low pressure production. Possible third-party tie-ins will also still be an option. Cost efficiency is important to maximize the tail end production period.

Produced gas is transported to the Sleipner hub centre where the gas is processed and routed into the Gassled pipeline. The produced condensate is routed via Sleipner to Kårstø in an existing condensate pipeline.

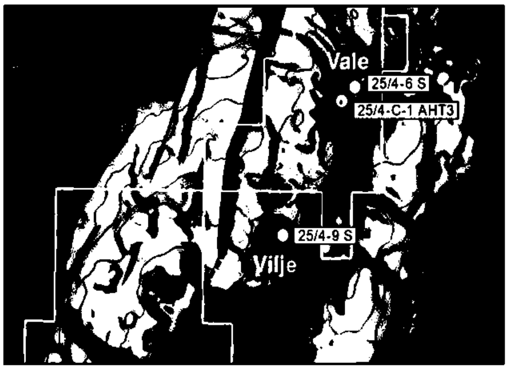
Oil export is organized through Atea shuttle tankers. Oil recovery is increased by gas injection.

THE VILJE FIELD

The Vilje field is located 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 connected to the Alvheim FPSO. The plan for development and operation (PDO) was approved by the authorities in December 2004, production wells were drilled in 2007, and 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.

Since the start-up of production the field has consistently delivered production above the annual plans. Currently Vilje is being produced through the Vilje VI1 well, VI2 and VI3 is shut in. At the end of 2020, the water cut increase is flattening out, at around 74% and oil rate around 690 Sm3/d. The Vilje production is partially held back to allow the new Skogul filed preference.



THE VALE FIELD

The Vale field is a gas and condensate producer located 16 km north of the Heimdal Gas Centre (HGC). The Vale field was discovered in 1991 and started production in 2002. The water depth in the area is approximately 114-120 metres.

The development concept is a single well subsea tie-back via 8" flowline to the Heimdal platform. No pressure support is employed for the field. The base model for field life is therefore natural depletion. There is a regional aquifer to the south and west of the field, which provides the drive necessary for production. The production limitations in 2019 was resolved in 2020 by installation of a new coalescer on Heimdal to the very high produced water salt content. MethylEthyleneGlycol injection was also installed to prevent hydrate plugging in the pipeline when produced water production is expected to increase. The License has approved to extend gas processing at Heimdal and to continue production beyond 24th October 2021.

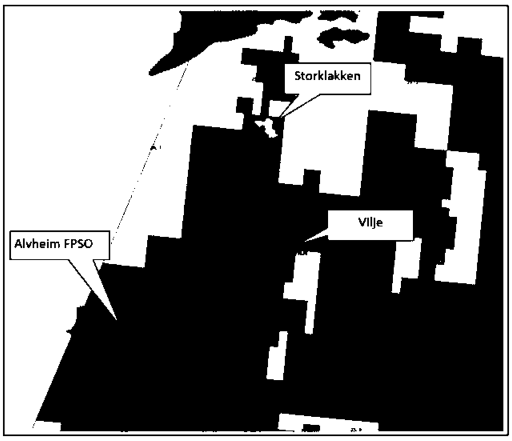
THE MORVIN FIELD

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.

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. Three infill drilling targets and three coiled tubing well clean out operations is planned for execution by 2025 to extend and maintain production. An ultralow pressure production modification on Åsgard with indicative positive economics is also proposed for the later field life.

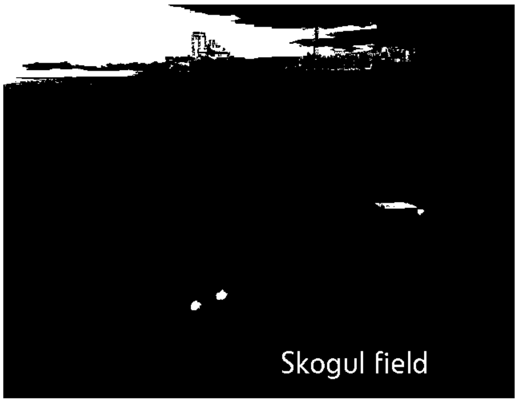
THE SKOGUL FIELD

The Skogul oil field, in PL460, is located approximately 40 km North of Alvheim in blocks 24/3, 25/1 and 25/2 in the Norwegian sector of the North Sea. The water depth is 107 meters. An area map and overview is shown below.



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 as a one multi-lateral subsea well tied back to the existing Alvheim facilities via the Vilje subsea flowbase. The Vilje subsea flowbase is located approximately 16 km from Skogul.

The Skogul development project was completed and production started 14th March 2020.



Skogul field

THE KVITEBJØRN FIELD

Kvitebjørn

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 with a steel jacket. Production started in 2004.

Production is routed through first stage separation facilities where rich gas is transported via Kvitebjørn gas pipeline to Kollsnes. Condensate is transported via Kvitebjørn oljerør and TOR 2 pipeline to Mongstad.

The license partners are Equinor (operator), Petoro, Spirit Energy and Total. PGNiG purchased license share from Shell in 2020 and officially became partner from 31.12.2020.

There is an ongoing infill drilling campaign that will extend into 2021 and most likely beyond 2022. Short term and long term focus is therefore to continue to mature infill targets and on various aspects related to lifetime extension for Kvitebjørn in order to maintain production beyond 2027

THE VALEMON UNIT

Valemon

Valemon is an 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 separation process design. The facility is the first Not Normally Manned platform on the NCS and is controlled from shore. Power is supplied from Kvitebjørn. Temporary living quarters for 40 people. Drilling is performed by jack-up rig. Production started in 2015.

The condensate is transported by pipeline to the Kvitebjørn field, and via the Kvitebjørn oljerør to Mongstad. The rich gas is exported via the previous

Huldra pipeline to Heimdal for further export to the UK or continental Europe. Valemon has the possibility of rerouting rich gas production to Kvitebjørn if Heimdal is unavailable.

The PDO drilling program for Valemon consisted of 11 producers and 2 injector for water/waste. 3 additional wells have since been drilled. 13 producers are currently in operation, some in on/off mode due to low reservoir pressure. There are 20 well slots in total.

The license partners are Equinor (operator) and Petoro. PGNiG purchased license share from Shell in 2020 and officially became partner from 31.12.2020.

THE DUVA DEVELOPMENT

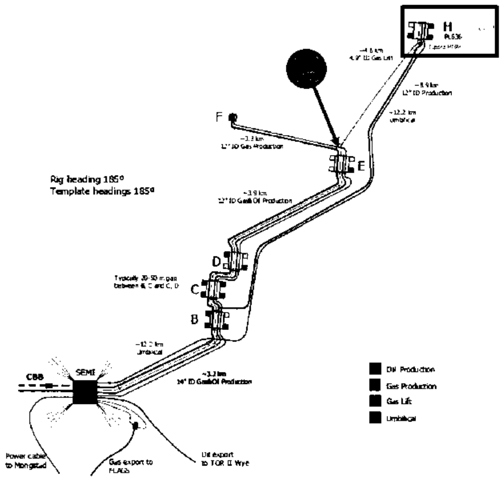
Duva is an oil & gas discovery located in PL 636, 636 B & 636 C in the Norwegian sector of the North Sea, approximately 12 km northeast of the Gjøa semi-submersible. Closest distance to shore is only 35 km.

As of the end of 2020, the Duva License partnership included: Neptune 30% (Operator), Idemitsu 30%, SVAL 10% and PGNiG Upstream 30%.

The Duva discovery was made in well 36/7-4 in August 2016. The Water depth in the Duva area ranges from 345 to 361 meters. Expected lifetime for Duva is 13 years. Duva will be developed as a Subsea tieback to Gjøa. Initial 2 years, production profile is limited by available oil and gas processing capacity at host, Gjøa. Duva is planned with 3 oil producers and 1 gas producer. Production is scheduled to start in 2H 2021.

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 PL044 currently consists of: ConocoPhilips (28,26% and operator), PGNiG Upstream (42,38%), Total (20,23%) and Vår Energi (9,13%).

The field is located in the direct vicinity of large, already developed fields, including the giant Ekofisk field.

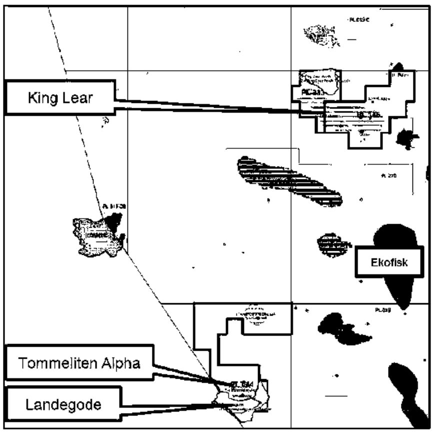
According to current plans, production is expected to commence in 2024, and the development concept assumes tie-back to the existing infrastructure on Ekofisk. This will allow for a cost-effective development, further decrease of future production cost, and will accelerate the field's start-up.

THE KING LEAR FIELD (PL146/333)

King Lear is an HP/HT discovery located way south in the Norwegian Sector of the North Sea, 19 km north of Ekofisk and the Water depth is 67 meters.

Reservoir depth of 5344 meters with pressure above 900 bars and temp. Approx. 165oC. A total of 8 wildcats have been drilled, and initial discovery was made in 1988. Exploration well in 2012 proved 48 m gas/condensate column, and 70m in sidestep.

The partnership in PL146/333 currently consists of Aker BP (78,8% and operator) and PGNiG Upstream (22,2%).



THE FOGELBERG DISCOVERY (PL433)

Fogelberg is located in blocks 6506/9 and 6506/12 in the Haltenbanken area of the Norwegian Sea.

The partnership in PL433 currently consists of: Spirit Energy (51,7% and Operator), PGNiG Upstream (20%), DNO (15%) and ONE-DYAS Norge (13,3%).

Gas/condensate was found in the Garn and Ile formations in 2010. The discovery is located 17 km north of Åsgard and 30 km south west of Heidrun.

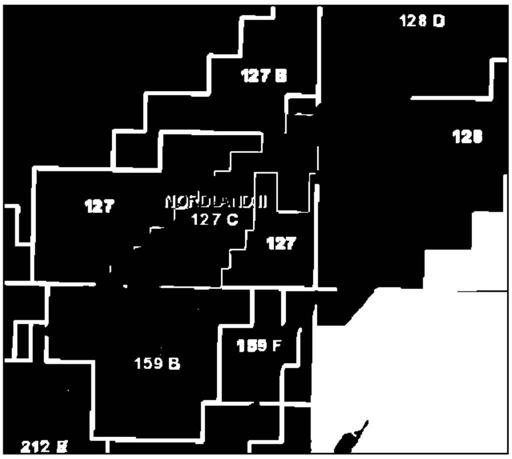
An appraisal well was drilled H1 2018 to reduce volume uncertainty, verify reservoir quality and well productivity in Garn and Ile, and collect representative fluid samples.

Following the appraisal well campaign the definition of the in place volume range has been improved. Recoverable volumes and associated profiles are currently being evaluated. The reserve estimate related to Fogelberg may be changed as a result of further evaluation of the discovery.

LICENSE PL 127C

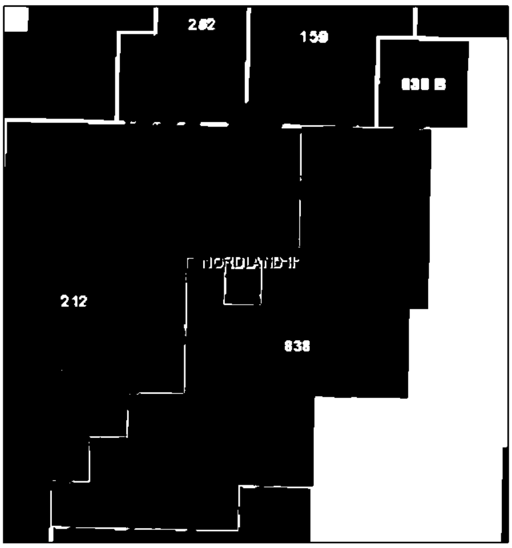
On 30th April 2020 PGNiG entered the PL127C Alve Nord licence after purchasing 11.9175% from Operator Aker BP. The partnership is currently Aker BP (operator 88,0825%) and PGNiG. The licence contains the Alve NE gas & oil discovery from 2011.

In Q3 2020 the AlveNE exploration well was drilled and demonstrated an extension of Equinor's Cape Vulture discovery from the neighbouring licence PL128D westward into PL127C.



LICENSE PL 838/838B

In January 2016, PGNiG Upstream was awarded operatorship and 40% shares in PL838 in the Norwegian Sea as part of the APA2015 licensing round. PL838 is situated directly south east of the Skarv field. PGNiG transferred a 5% share and the operatorship role to Aker BP on the 30th April 2020. The partnership is now Aker BP (35% & operator), PGNiG 35% and Lime (30%).

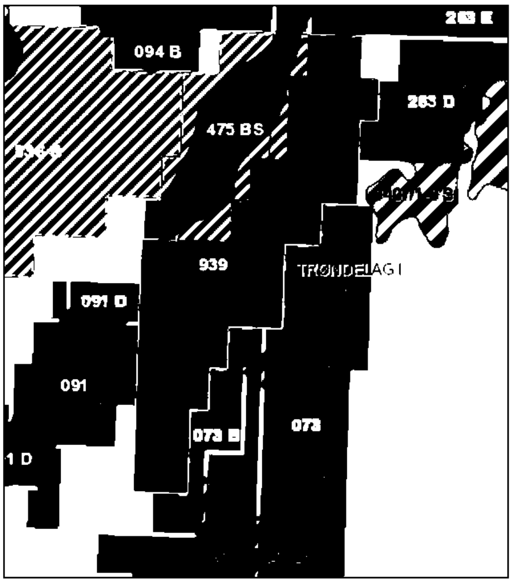


An exploration well was completed in October 2019, resulting in the Shrek discovery (3-6 MSm^3 oe rec.). Shrek was the first operated well for PGNiG UN. The next milestone in PL838 is the DG1 decision scheduled for August 2021. An extension licence, PL838B, was awarded in APA2018 with a drill or drop deadline in March 2021.

LICENSE PL939

In January 2018, PGNiG Upstream was awarded 30% shares in PL939 in the Haltenbanken area of the Norwegian Sea. PL939 is situated directly south east of the Maria field. The operator is Equinor (70%).

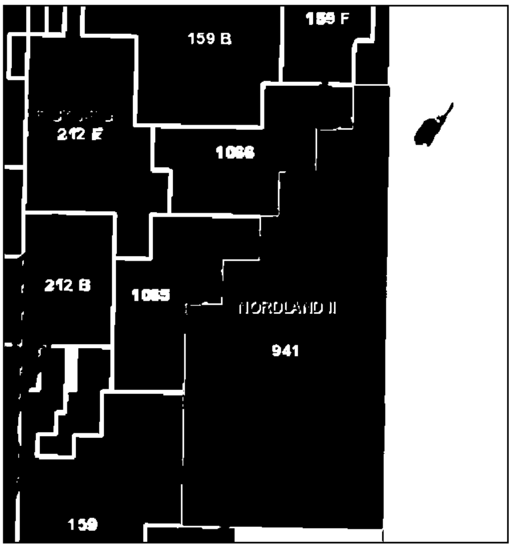
The work program is reprocessing of 3D seismic data and has been completed. A drill or drop decision is due by 2nd March 2021. Drill decision was taken ahead of this deadline. The well is planned to be drilled in 2021.



LICENSE PL941

In January 2018, PGNiG Upstream was awarded 20% shares in PL941 in the Haltenbanken area of the Norwegian Sea. PL941 is situated north east of the Skarv field. The other partner is operator Aker BP (80%).

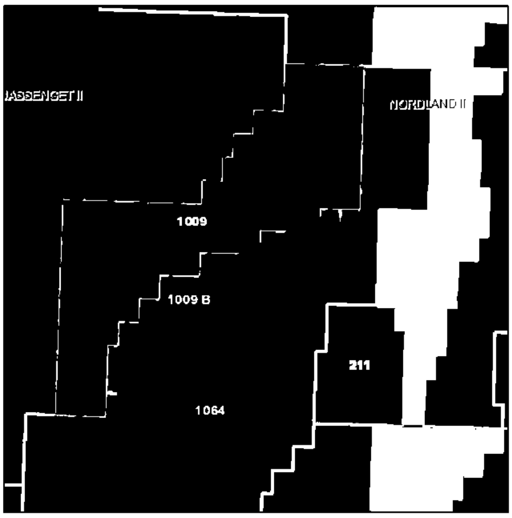
The work program is reprocessing of 3D seismic data. A drill or drop decision is due 2nd March 2021.



LICENSE PL1009/1009B

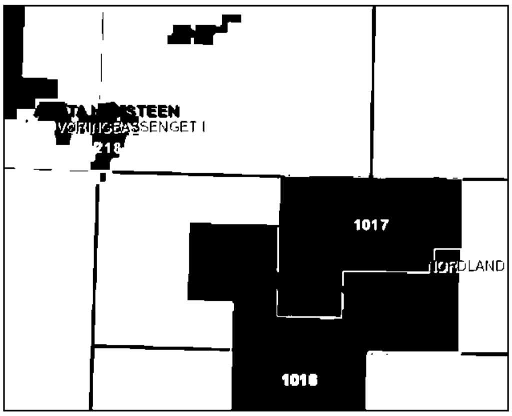
In January 2019, PGNiG Upstream was awarded 35% shares in PL1009 in the Haltenbanken area of the Norwegian Sea. PL1009 is situated north west of the Victoria discovery. The other partner is operator ConocoPhillips (65%). The work program in PL1009 was one firm well. In January 2020, PGNiG Upstream was awarded 35% shares in PL1009B, as additional acreage to PL1009. The other partner is operator ConocoPhillips (65%). The work program is as PL1009.

The Warka prospect was drilled in Q3 2020 resulting in a significant gas discovery with preliminary recoverable volumes estimated between 8 to 30 MSm^3 oe. The next milestone is the decision to concretize (BoK) due 1st March 2022. Currently appraisal well is planned to be drilled on the license.



LICENSE PL 1017

In January 2019, PGNiG Upstream was awarded operatorship and 50% shares in PL1017 in the Norwegian Sea. PL1017 is situated south east of the Aasta Hansteen field. The other partner is Equinor (50%).

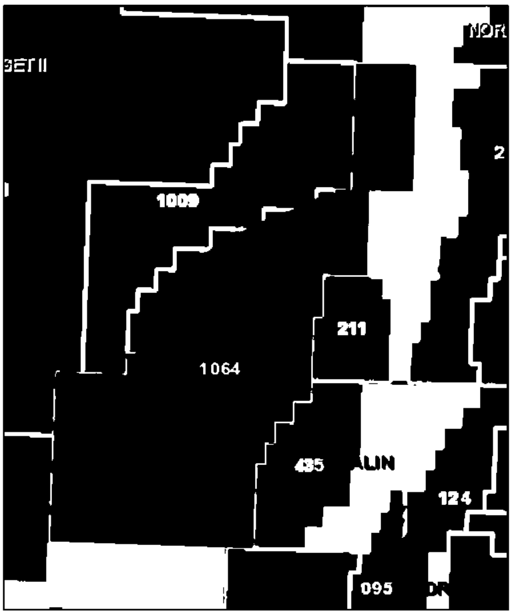


The work program is reprocessing of 3D seismic data and an electromagnetic feasibility study.

LICENSE 1064

In January 2020, PGNiG Upstream was awarded 30% shares in PL1064 in the Haltenbanken area of the Norwegian Sea. PL1064 is situated southeast of PL1009 and PL1009B. The other partners are operator ConocoPhillips (40%) and Aker BP (30%).

The work program is one firm exploration well which should be drilled within two years. The next milestone is the decision to concretize (BoK) due 14th Feb 2022.



PGNiG Upstream's pipelines at 31/12/2020		
KOR	(Kvitebjørn Oljerør)	6,45%
VRGP	(Valemon rich gas pipeline)	3,25%

KVITEBJØRN OLJERØR (KOR)

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

The operator is Equinor, holding 39.55% share. Petoro AS has 30%, Spirit Energy Norway AS has 19% and Total E&P Norge AS has 5%. PGNiG Upstream purchased 6,45% of the license shares from Shell in 2020.

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. Equinor, holding 39.55% share is the Technical Service Provider (TSP). Petoro AS has 30% share. PGNiG Upstream purchased 3,225% of the license shares from Shell in 2020.

NOTE 27 RESERVES AND CONTINGENT RESOURCES (NOT AUDITED)

For all assets except for Duva, the Company's reserves and Contingent Resources are based on the operator's official data reported in the Revised National Budget (RNB) for 2020. PGNiG Upstream reports the Mean value of proven reserves in Resource Class 1-3 and Contingent Resources in Resource Class 4-5 as per the NPD resource classification. For Duva, PGNIG Upstream used own estimates. 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	6,60	28,75	6,43	41,78
Ærfugl Nord	0,28	3,03	0,68	3,99
Morvin	0,81	0,65	0,29	1,75
Gina Krog	4,64	8,71	1,75	15,10
Vilje	3,34	0,00	0,00	3,34
Vale	0,32	0,56	0,00	0,88
Skogul	1,94	0,17	0,00	2,12
Tommeliten				
Alpha	15,36	40,70	2,38	58,44
King Lear	13,47	14,81	7,10	35,38
Duva	8,32	15,38	3,57	27,27
Alve Nord	1,02	3,47	0,78	5,27
Shrek	3,25	2,22	0,49	5,96
Kvitebjørn	1,73	9,41	0,44	11,58
Valemon	0,14	0,95	0,01	1,11
TOTAL	**61,24**	**128,80**	**23,92**	**213,96**

COUNTRY-BY-COUNTRY REPORTING OF PAYMENTS TO AUTHORITIES IN 2020

INFORMATION ON COUNTRY-BY-COUNTRY REPORTING OF PAYMENTS TO AUTHORITIES IN 2020

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 2020. This report is issued together with the Annual Report for 2020. 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 2020 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 2020 and, to the best extent possible, reflect the actual amounts paid in 2020.

COUNTRY-BY-COUNTRY REPORTING OF PAYMENTS TO AUTHORITIES IN 2020

Payments made in 2020	Profit oil in-kind (1)	Taxes and fees (2)	Royalty	Dividends	Bonuses (3)	Licence fees (4)	Infrastruc ture (5)	Ownership rights (6)
Paid, in thousand NOK	0	(756 139)	0	0	0	69	0	0

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

(2) 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 2020 is related to negative tax instalments from the Norwegian state of -756 078 thousand, and net custom tariffs refunded from Skatteetaten for CO2 fuel and flare and NOx of NOK -60 thousand million. VOC is not included, as the payment is done to a third party (Teekay).

(3) Bonuses related to signatures, discoveries and production.

(4) 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 (NOK 123 000 in 2019). Reported amounts in 2020 include NOK 69 000 for the sector fees from Petroleum Safety Authority in Norway.

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

(6) 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 cost to associated companies (5)
Million NOK (except production)	3 330	2 180	7,6	817	151

(1) Investments include the acquisition of Kvitebjørn, Valemon, Alve Nord and additional interest in Gina Krog and Duva. It also includes the Ærfugl phase 2 (incl Ærfugl Nord), Tommeliten Alpha, Duva and Gråsel development projects, the producing fields Skarv, Gina Krog, Vilje, Skogul, Vale and Morvin, 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 2020 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 Skarv, Vilje, Skogul, Vale, Morvin and Gina Krog fields presented in million barrels of oil equivalent.

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

(5) Interest cost paid to associated companies (loan from parent Company).

Przemysław Wacławski
Chairman of the Board

Arkadiusz Sekściński
Director of the Board

Jarosław Wróbel
Director of the Board

Magdalena Zegarska
Director of the Board

Marek Woszczyk
General Manager

Sandnes,
8th February 2021

KPMG

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To the General Meeting of PGNiG Upstream Norway AS

Independent auditor's report

Report on the Audit of the Financial Statements

Opinion

We have audited the financial statements of PGNiG Upstream Norway AS, which comprise the balance sheet as at 31 December 2020, the income statement, statement of comprehensive income, statement of changes in equity and 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 accompanying financial statements are prepared in accordance with law and regulations and give a true and fair view of the financial position of the Company as at 31 December 2020, and its financial performance and its cash flows for the year then ended in accordance with simplified application of international accounting standards according to section 3-9 of the Norwegian Accounting Act.

Basis for Opinion

We conducted our audit in accordance with laws, regulations, and auditing standards and practices generally accepted in Norway, including 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 laws and regulations, 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

Management is responsible for the other information. The other information comprises information in the annual report, except the financial statements and our auditor's report thereon.

Our opinion on the financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of the Board of Directors and the Managing Director for the Financial Statements

The Board of Directors and the Managing Director (management) are responsible for the preparation and a true and fair view of the financial statements 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 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 laws, regulations, and auditing standards and practices generally accepted in Norway, including 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 laws, regulations, and auditing standards and practices generally accepted in Norway, including 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.

KPMG

PGNiG Upstream Norway AS

Report on Other Legal and Regulatory Requirements

Opinion on the Board of Directors' report

Based on our audit of the financial statements as described above, it is our opinion that the information presented in the Board of Directors' report concerning the financial statements and the going concern assumption is consistent with the financial statements and complies with the law and regulations.

Opinion on Registration and Documentation

Based on our audit of the financial statements as described above, and control procedures we have considered necessary in accordance with the International Standard on Assurance Engagements *(ISAE) 3000, Assurance Engagements Other than Audits or Reviews of Historical Financial Information*, it is our opinion that management has fulfilled its duty to produce a proper and clearly set out registration and documentation of the Company's accounting information in accordance with the law and bookkeeping standards and practices generally accepted in Norway.

Stavanger, 8 February 2021
KPMG AS

Mads Hermansen
State Authorised Public Accountant