AGR Energy Services AS

Reservoir Management Division

Oslo

Reserves Audit 31.12.2023

For Lime Petroleum AS

March 2024

AGR Energy Services Technical Report

Reserves Audit 31.12.2023

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Qualifications

AGR Energy Services AS (Karenslyst allé 4, 0278 Oslo, Norway) is an independent consultancy specialising in, amongst others, petroleum reservoir evaluation, reserves auditing and economic analysis. AGR has conducted evaluations for numerous energy companies and financial institutions. Except for the provision of professional services on a fee basis, AGR does not have any commercial arrangement with any other persons or companies involved in the assets that are the subject of this report.

This Reserves Audit Report (RAR) was managed by Ole Wahl (MSc in Petroleum Engineering), AGR Advisor Reservoir Engineer and member of Society of Petroleum Engineers (SPE). Mr. Wahl has 30+ years of international and Norway experience.

The report was reviewed and signed off by Steinar S. Johansen (MSc Petroleum Engineering, CFA Charter holder (Chartered Financial Analyst), AGR Advisor Reservoir Engineer. Mr. Johansen has Professional Society Affiliation and memberships in Society of Petroleum Engineers (SPE), European Association of Geoscientists and Engineers (EAGE), London Petrophysical Society (LPS) and CFA Institute. Mr. Johansen has 30+ years of international and Norway experience including reserves and resource reporting.

The report was signed and approved by Erik Lorange (MSc in Petroleum Geology), AGR Vice President Reservoir Management. Mr. Lorange, has 35+ years of international and Norway experience.

Evaluation Standard

In this Audit of reserves and contingent resources, AGR has applied the standard petroleum engineering techniques. The Audit is based on the joint definitions of Society of Petroleum Engineers (SPE), World Petroleum Council (WPC), American Association of Petroleum Geologists (AAPG), Society of Petroleum Evaluation Engineers (SPEE), Society of Exploration Geophysicists (SEG), Society of Petrophysicists and Well Log Analysts (SPWLA), European Association of Geoscientists & Engineers (EAGE); Petroleum Resources Management System (PRMS) revised in 2018 and in accordance with the Singapore Exchange Securities Trading Limited Listing Manual.

Basis of Opinion

The evaluation presented in this report reflects our informed judgment based on accepted standards of professional investigation but is subject to generally recognized uncertainties associated with the interpretation of geological, geophysical and subsurface reservoir data. Any evaluation, particularly one involving exploration and future petroleum developments, may be subject to significant variations over short periods of time as new information becomes available.

Disclaimer

This report relates specifically and solely to the subject petroleum licence interests and is conditional upon the assumptions made therein. This report must therefore be read in its entirety. This report was prepared in accordance with standard geological and engineering methods generally accepted by the oil and gas industry, particularly PRMS. Estimates of hydrocarbon reserves and resources should be regarded only as estimates that may change as production history and additional information become available. Not only are reserves and resource estimates based on the information currently available, but they are also subject to uncertainties inherent in the application of judgmental factors in interpreting such information. AGR Petroleum Services AS shall have no liability arising out of, or related to, the use of other than the stated purpose of this report.

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1 Executive Summary

AGR Energy Services AS ("AGR") has conducted an audit of reserves and contingent resources as of 31.12.2023 for Lime Petroleum AS (hereafter shortened to Lime or Lime), in accordance with the Petroleum Resources Management System (PRMS) of SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE, revised in 2018 and the Singapore Exchange Securities Trading Limited Listing Manual.

Lime Petroleum's shareholders are Rex International Investments Pte. Ltd. (at 91.652%, hereafter shortened to Rex), a wholly owned subsidiary of Rex International Holding Limited, and Schroder & Co Banque SA (at 8.348%).

Two assets contain reserves, and the reserves audited by AGR are listed in Table 1.2, Table 1.3 (Yme) and Table 1.4 (Brage) below. These assets also include projects with contingent resources listed in Table 1.5, Table 1.6 (Yme) and Table 1.7 (Brage) below.

Lime Petroleum AS acquired a 10.7212% share in Brasse Field from DNO Norge AS and a 6.2788% share in Brasse Field from OKEA ASA (17.0% total) effective 29.12.2023. The contingent resources on Brasse Field are listed in Table 1.5 and Table 1.8 below.

AGR has performed economic evaluations to determine reserves. The technical production and cost profiles have been provided by Lime and reviewed by AGR. The economic assumptions in Table 1.1 below were provided by Lime, and AGR considers the pricing assumptions to be reasonable and have applied them in the evaluations.

Table 1.1 Price and financial assumptions from Lime

	Units	2024	2025	2026 -> EOFL*
Oil/Condensate Price	USD/bbl (real2024)	85	75	70
Gas Price (40 MJ/Sm3)	NOK/Sm3 (real2024)	4.01	3.36	2.51
NGL Price	USD/boe (real2024)	68	60	56
Exchange rate	NOK/USD	10.0	9.5	9.5
Inflation rate	2% p.a.			
Present value reference date	01.01.2024			
Discount hurdle rate	8% p.a. (nominal)			
Tax	78% (22% corporate tax rate + 56% special tax rate)			

** EOFL - End of Field Life*

Reserves as of 31.12.2023
The audited gross and net reserves as of 31.12.2023 endorsed by AGR, are shown in Table 1.2, Table 1.3 (Yme) and Table 1.4 (Brage) below.

Table 1.2 Gross field, net Lime and net Rex Reserves as of 31.12.2023 according to PRMS

Asset	Lime interest (%)	PRMS project maturity	100% (MMboe)			Lime net (MMboe)			Rex 91.652% interest in Lime (MMboe)		
			1P	2P	3P	1P	2P	3P	1P	2P	3P
Brage	33.8434	On Production / Justified for Development	7.79	11.01	15.01	2.64	3.73	5.08	2.42	3.41	4.66
Yme	10.0000	On Production / Approved for Development	22.65	39.47	41.97	2.27	3.95	4.20	2.08	3.62	3.85
Total			**30.44**	**50.48**	**56.99**	**4.90**	**7.67**	**9.28**	**4.49**	**7.03**	**8.50**

Table 1.3 Yme Field Reserves as of 31.12.2023 (On production / Approved for Development)

Category	Gross Attributable to Licence	Lime interest (10%)	Rex 91.652% interest in Lime	Change from previous update	Risk Factors	Remarks
	Reserves	Reserves	Reserves			
	MMboe	MMboe	MMboe	(%)		
1P	22.65	2.27	2.08	-12.2%	N.A.	N.A.
2P	39.47	3.95	3.62	-27.8%	N.A.	N.A.
3P	41.97	4.20	3.85	-27.7%	N.A.	N.A.

Table 1.4 Brage Field Reserves as of 31.12.2023 (On production / Justified for Development)

Category	Gross Attributable to Licence	Lime interest (34.8434%)	Rex 91.652% interest in Lime	Change from previous update	Risk Factors	Remarks
	Reserves	Reserves	Reserves			
	MMboe	MMboe	MMboe	(%)		
1P	7.79	2.64	2.42	-7.6%	N.A.	N.A.
2P	11.01	3.73	3.41	1.9%	N.A.	N.A.
3P	15.01	5.08	4.66	-6.9%	N.A.	N.A.

Contingent Resources as of 31.12.2023
The audited gross and net contingent resources as of 31.12.2023 endorsed by AGR, are shown in Table 1.5 , Table 1.6 (Yme), Table 1.7 (Brage) and Table 1.8 (Brasse) below.

"Risk Factor" for Contingent Resources means the estimated chance, or probability, that the volumes will commercially extracted. Risk factors proposed by Lime is a volume weighted risk factor for all the contingent resource projects. The risk factors have been reviewed by AGR and found reasonable.

Table 1.5 Contingent Resources as of 31.12.2023 according to PRMS

Asset	Lime interest (%)	PRMS sub-class	100% (MMboe)			Lime net (MMboe)			Rex 91.652% interest in Lime (MMboe)		
			1C	2C	3C	1C	2C	3C	1C	2C	3C
Brage	33.8434	Development Unclarified / Development on hold / Development Pending	6.20	12.64	22.12	2.10	4.28	7.49	1.92	3.92	6.86
Yme	10.0000	Development Unclarified	2.30	8.20	9.55	0.23	0.82	0.95	0.21	0.75	0.87
Brasse	17.0000	Development Pending	19.94	26.14	30.43	3.39	4.44	5.17	3.11	4.07	4.74
Total			**28.44**	**46.98**	**62.10**	**5.72**	**9.54**	**13.61**	**5.24**	**8.74**	**12.48**

Table 1.6 Yme Field Contingent Resources as of 31.12.2023 (Development Unclarified)

Category	Gross Attributable to Licence	Lime interest (10%)	Rex 91.652% interest in Lime	Change from previous update	Risk Factors	Remarks
	Resources	Resources	Resources			
	MMboe	MMboe	MMboe	(%)		
1C	2.30	0.23	0.21	53.4%	0.60	N.A.
2C	8.20	0.82	0.75	173.2%	0.60	N.A.
3C	9.55	0.95	0.87	112.1%	0.60	N.A.

Table 1.7 Brage Field Contingent Resources as of 31.12.2023 (Development Unclarified / Development on Hold / Development Pending)

Category	Gross Attributable to Licence	Lime interest (34.8434%)	Rex 91.652% interest in Lime	Change from previous update	Risk Factors	Remarks
	Resources	Resources	Resources			
	MMboe	MMboe	MMboe	(%)		
1C	6.20	2.10	1.92	-35.7%	0.43	N.A.
2C	12.64	4.28	3.92	-9.7%	0.43	N.A.
3C	22.12	7.49	6.86	21.4%	0.43	N.A.

Table 1.8 Brasse Field Contingent Resources as of 31.12.2023 (Development Pending)

Category	Gross Attributable to Licence	Lime interest (17%)	Rex 91.652% interest in Lime	Change from previous update	Risk Factors	Remarks
	Resources	Resources	Resources			
	MMboe	MMboe	MMboe	(%)		
1C	19.94	3.39	3.11	N.A.	0.85	N.A.
2C	26.14	4.44	4.07	N.A.	0.85	
3C	30.43	5.17	4.74	N.A.	0.85	

Changes in reserves since certification 31.12.2022
Changes in net Lime 2P reserves since 31.12.2022 are listed in Table 1.9 below.

Brage Field:

- The increase in Brage EUR are mainly due to good performance of four new infill wells completed in 2023.
- A-21 A producer and A-40C injector well pair is matured from contingent resources to reserves "Approved for Development".
- Brage Bowmore producer (A-28 C) in Fensfjord is matured from contingent resources to reserves "Justified for Development".
- The upside in 3P is reduced since Audit 31.12.2022 report since much of the upside is captured in the four new 2023 wells which came in better than prognosed.
- In addition, the 3P cut-off is one year earlier compared to Audit 31.12.2022 report.
- The revised downside in 1P is reflecting the limited production history from the four new 2023 wells accounting for 87% of total production towards the end of 2023.

Yme Field

- The production in 2023 gives a negative reserves contribution of all categories.
- The revisions for EUR 1P are positive, but about half of the production in 2023. Hence, the changes in 1P are negative. The main reason for the positive revisions for EUR 1P is a longer historical production supporting a higher EUR 1P estimate.
- The EUR 2P revisions are negative mainly due to poor production performance in 2023. These revisions combined with production in 2023 result in significant reductions of 2P.
- The reasons for 3P reductions are as for 2P.

Table 1.9 Changes in net Lime 2P reserves since 31.12.2022

Asset	Lime interest (%)	Reserves 31.12.2022 (MMboe)	Production (MMboe)	Revisions and other changes (MMboe)	Reserves 31.12.2023 (MMboe)
Brage	33.8434	3.66	1.71	1.78	3.73
Yme	10.0000	5.47	0.67	-0.85	3.95
Total		**9.12**	**2.38**	**0.92**	**7.67**

Changes in contingent resources since certification 31.12.2022
Changes in net Lime 2C contingent resources since 31.12.2022 are listed in Table 1.10 below.

Brage Field

- Two projects matured from contingent resources to "Approved for Development" and "Justified for Development".
- Several new projects identified classified as contingent resources
- The 1C and 3C uncertainty range has increased significantly compared to Audit 31.12.2022 report as two projects has matured from contingent resources into reserves and new projects of less maturity has been added to the list of contingent resources.

Yme Field

- Infill drilling (three wells) on Gamma is matured further, and the resources have increased significantly. Further, explanation for changes are not provided to AGR.

Brasse Field

- 2023 acquisition by Lime Petroleum AS

Table 1.10 Changes in net Lime 2C resources since 31.12.2022

Asset	Lime interest (%)	Contingent resources 31.12.2022 (MMboe)	Revisions and other changes (MMboe)	Contingent resources 31.12.2023 (MMboe)
Brage	33.8434	4.74	-0.46	4.28
Yme	10.0000	0.30	0.52	0.82
Brasse	17.0000	N.A.	N.A.	4.44
Total		**5.04**	**4.50**	**9.54**

2 Introduction and Objectives

AGR has conducted an audit of Lime reserves and contingent resources as of 31.12.2023 in accordance with the Petroleum Resources Management System (PRMS) of SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE and the Singapore Exchange Securities Trading Limited Listing Manual.

This report covers:

- Certification of 1P, 2P and 3P reserves for the following assets (see Fig. 2.1 and Fig. 2.2 for locations):
  - Yme (Repsol is the operator and Lime owns a 10% share)
  - Brage (OKEA is the operator and Lime owns a 33.8434% share)
  - Brasse (OKEA is the operator and Lime owns a 17% share) - First time certification

- Certification of 1C, 2C and 3C contingent resources in:
  - Yme
  - Brage
  - Brasse - First time certification

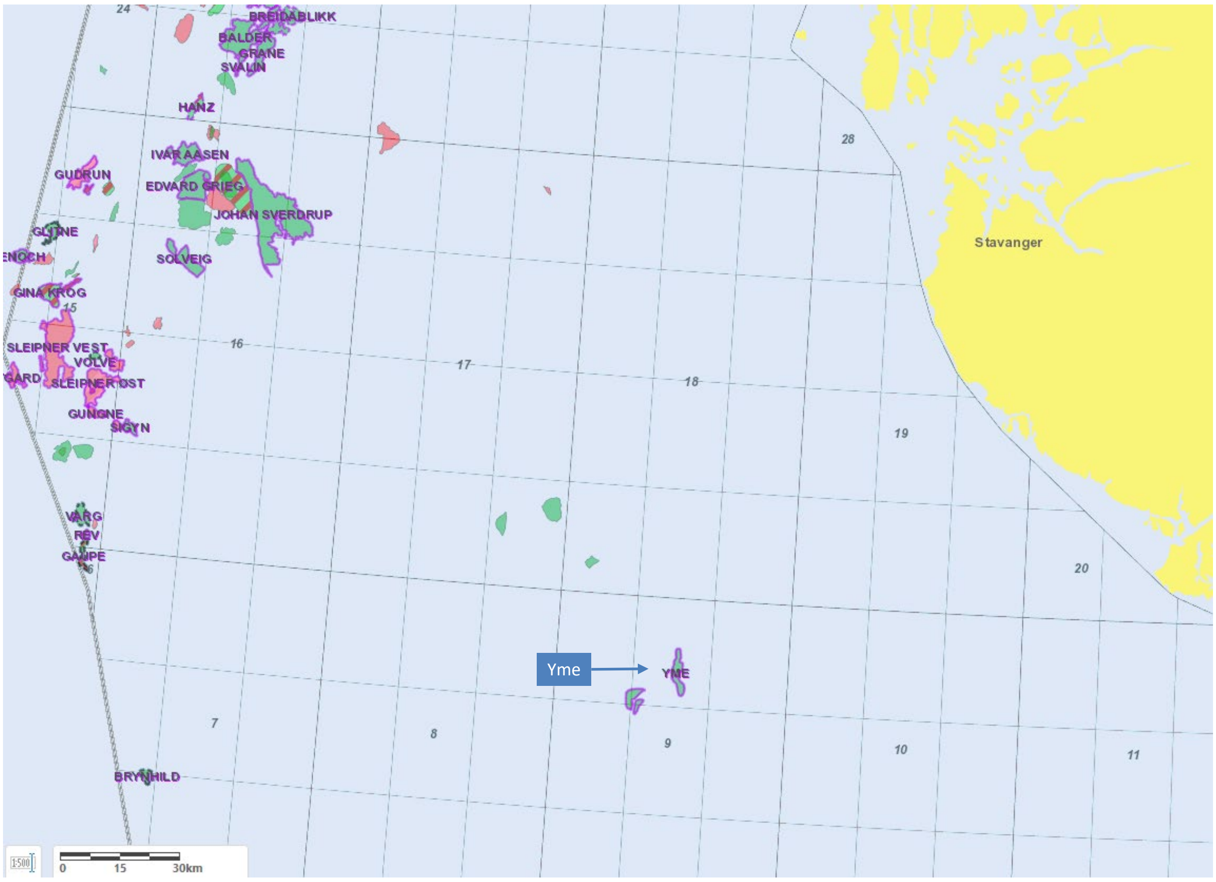

Fig. 2.1 Yme location map
Source: NOD factmaps (www.sodir.no)

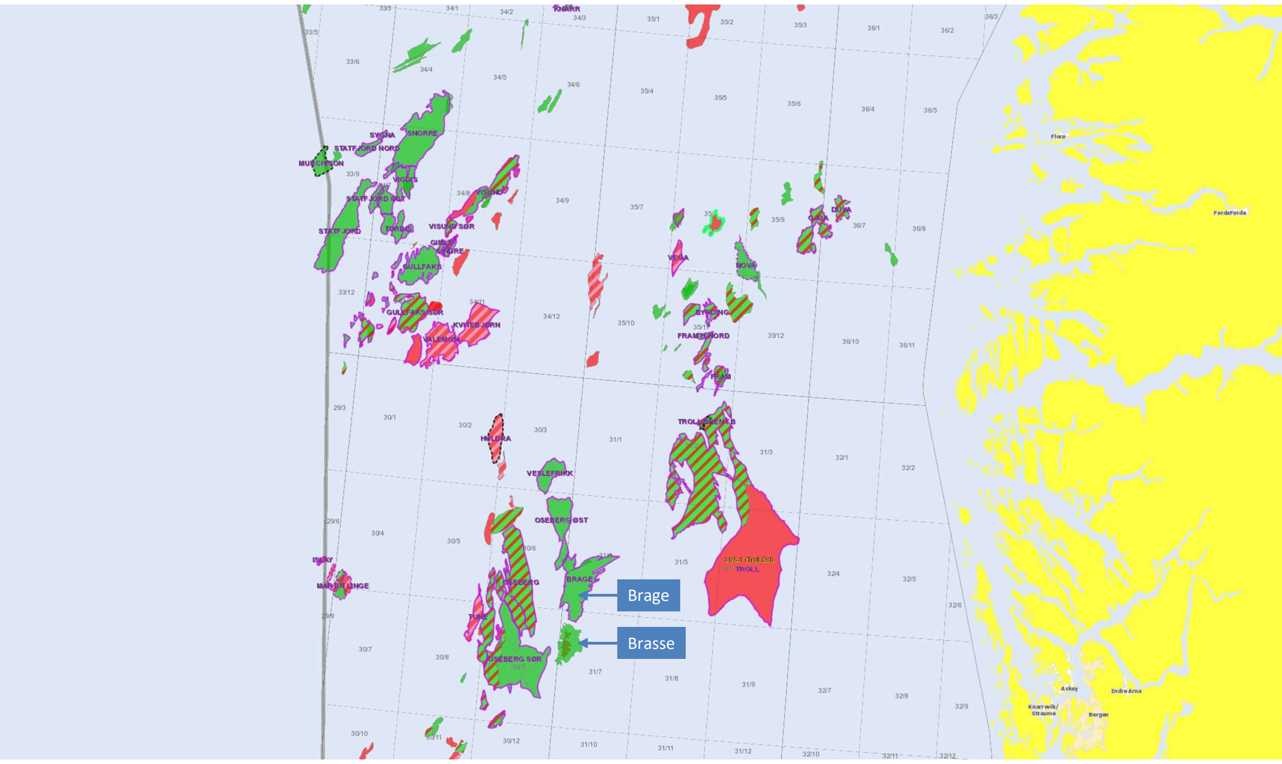

Fig. 2.2 Brage and Brasse location map
Source: NOD Factmaps (www.sodir.no)

Reserves, contingent resources and in-place volumes received from Lime and audited by AGR, are expressed in field units (MMbbl and Bcf). The combined oil equivalent is expressed in MMboe.

Whenever the term "Technically Recoverable Resources (TRR)" is used with production volumes or profiles, it refers to the estimates before the economic evaluation, i.e. before an economic cut-off has been applied to determine reserves. The cumulative volumes are including sales volumes from 01.01.2024 to end of the profiles.

The reserves and contingent resources audited by AGR, per 31.12.2023, are reported in the "Annual Statement of Reserves and Resources 2023" (ASR) by Lime. In this report these ASR's from Lime are referred to as:

- Lime Expected Reserves 2024 (Summary)[1]
- 00 AGR Statement of Reserves - YME[2]
- 00 AGR Statement of Reserves - Brage_r1[3]
- 00 AGR Statement of Reserves - Brasse[4]

This is the first time the Lime reserves and resources on Brasse are audited by AGR.

No site inspections or visits was conducted as part of this study.

3 Methodology

The methodology applied in this report was (assuming relevant data/information was available):

- Review of the available data, interpretations and resulting models and reports
- Check of the critical parameters in terms of origin of the data, the interpretation and application thereof
- Review of the methodology applied to generate production forecasts and resources estimates
- Review and analysis of the available Petrel™ and Eclipse™ models. No new modelling has been performed except using existing models to enhance understanding and to verify results
- Review of uncertainty evaluations and how key uncertainties impact the project
- Review the subsurface and the overall project risks
- Review of costs and technical lifetime of facilities and wells
- Economic evaluations of the technical profiles to determine reserves as described in appendix A.1 Economics and Technical Profiles.
- For all assets, the Lime Statement of Reserve production profiles are based on and modified RNB2024 submissions. The cost profiles are based on RNB2024. The RNB low case is assumed to represent the P90 case, the base case is assumed to be close to and practically equal to the P50 case and the high case is assumed to represent the P10 case.
- The gas reserves are reported as sales gas at 40 MJ/Sm3.
- Recovery Factor (RF) in this report is defined as the reserves divided by the Petroleum Initially-In-Place (PIIP). Note that with this definition the gas recovery factor may not represent the correct value as gas reserves are reported as dry sales gas and not rich gas at the wellhead.
- The estimated 2023 produced volumes are actuals provided by Lime. These volumes are used for assessment of reserves as of 31.12.2023.
- Classification of the reserves according to the PRMS (SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE)
  - This classification system recommends that no reserves are booked beyond licence expiry date. However, it is a common practice on the Norwegian Continental Shelf that licence period extensions are granted. It is, therefore, assumed that licence periods will be extended and reserves may be recovered beyond the existing licence expiry dates.

Main units and conversion factors
The main units and prefixes as follows:

- bbl = barrels
- Scf = standard cubic feet
- boe = barrels of oil equivalents
- M = prefix; a thousand when used with bbl
- MM = prefix; a million when used with bbl
- B = billion

SI units and prefixes as follows:

- Sm3 = Standard cubic meters
- k = thousand
- M = million
- G = billion
- T = trillion

The following conversion factors are applied in the report:

- Oil and condensate
  - 1 Sm3 = 6.29 bbl (barrel)
  - 1 Sm3 = 1 Sm3 oe = 6.29 boe (oil equivalent)

- Gas
  - 1000 Sm3 gas = 1 Sm3 oe = 6.29 boe
  - 1 Sm3 = 35.315 Scf

- NGL
  - 1 tonne NGL = 1.9 Sm3 oe
  - 1 Sm3 oe = 6.29 boe (barrels of oil equivalents)

4 Recertifications

4.1 Yme

Asset Overview
The Yme Field is located in the Norwegian part of the Norwegian Danish Basin, blocks 9/1, 9/2 and 9/5 in licences PL 316 and PL 316 B, 112 km west-southwest of Egersund, see Fig. 4.1. The water depth is 93 m [5].

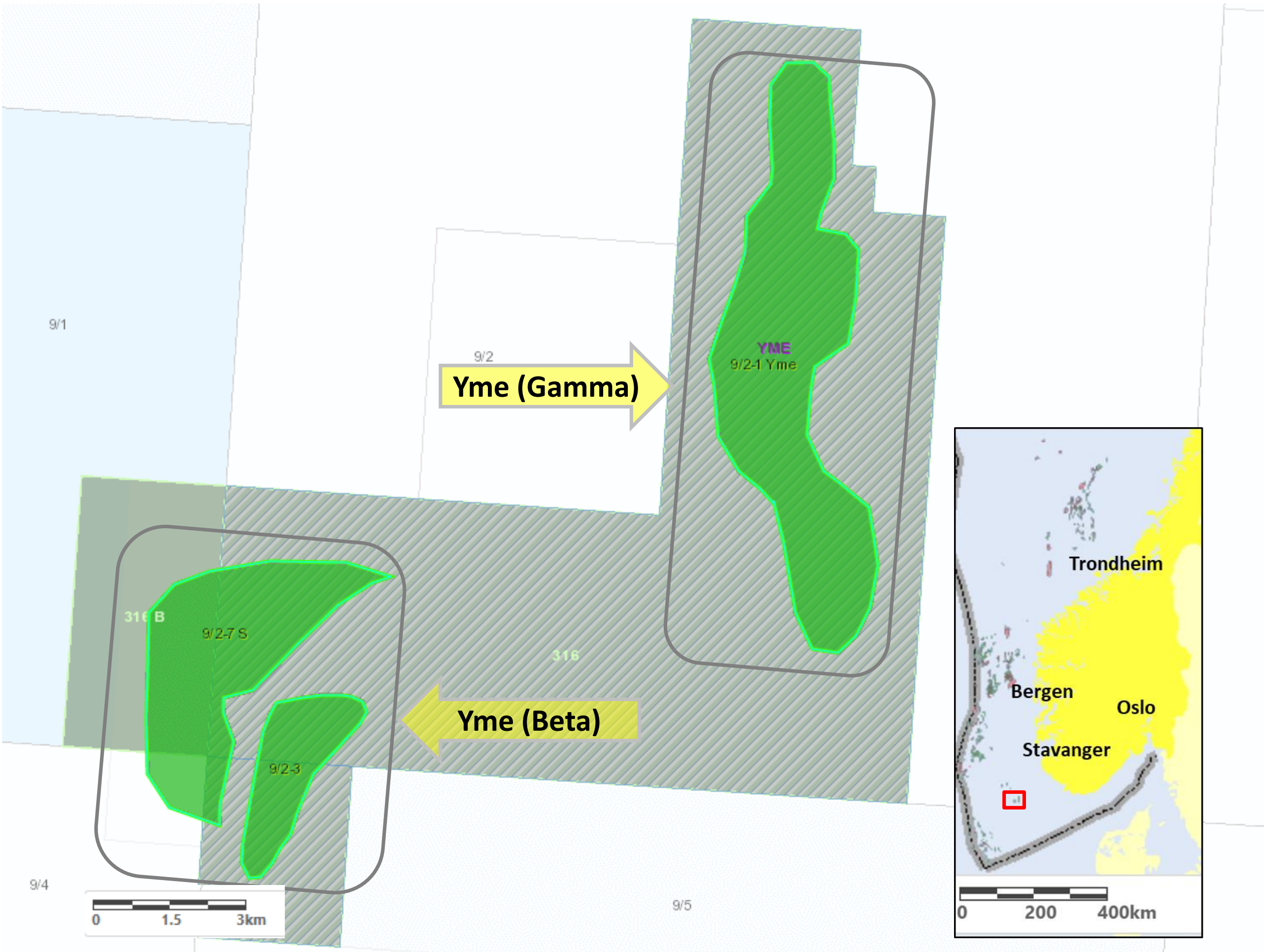

Fig. 4.1 Yme Field Location Map
Source: NOD factmaps (www.sodir.no)

The field was discovered by Equinor (at that time Statoil) in 1987 and was put on production in 1996. Yme ceased production in 2001 after having produced 51 MMboe (8.1 MSm3 oe) as operation was no longer profitable. However, the oil recovery factor was 13% only, hence significant volumes were left in the field. In 2007 a redevelopment plan was submitted by the new operator, Talisman. In 2013, after drilling nine new development wells and two appraisal wells, the redevelopment project was abandoned due to structural deficiencies in the offshore production unit. In 2015 “Yme New Development” was initiated. The new development plan was submitted by the current operator Repsol and the PDO was approved by the authorities in March 2018. The production started in October 2021. PL 316 licence expiry is 18.06.2030.[5]

Licence details summary is shown in Table 4.1. The production licence gives the licensees full rights to explore and produce hydrocarbons at all stratigraphic levels within the licence area.

This audit has been based on the information provided by Lime Petroleum, which included Lime's Statement of Reserves (SoR), the Operator's RNB2024 submission, meeting documents (RC, TC, MC) from

2023, monthly status reports from 2023, work program and budget (WP&B) 2024, DG3 reports, static and dynamic models, production data for the individual wells, as well as Lime's answers to AGR's questions and clarification requests.

Table 4.1 Yme summary table

Asset name/ Country	Lime interest (%)	Rex's interest of Lime (%)	Development Status	Licence expiry date	Licence Area (km2)	Type of mineral, oil or gas deposit	Remarks
PL 316 / 316 B (Yme) / Norway	10	91.652	On production	18.06.2030	140	Oil	-

The licence shares are shown in Table 4.2.

Table 4.2 The licence shares for the Yme Field (%).

Licence	Repsol Norge AS (Op.)	PGNiG Upstream Norway AS	OKEA ASA	Lime Petroleum AS
PL 316 / 316 B (Yme)	55	20	15	10

Discovery
The Yme Field was discovered in 1987 by well 9/2-1 on the Gamma structure[5], containing undersaturated oil at about 3150 m TVD MSL reservoir depth. In 1990, another oil discovery was made by the 9/2-3 well on the Beta structure, 12 km west of the Gamma structure. The discovery was made in reservoir sandstones of Sandnes formation of Late Jurassic age. In the discovery well, OWC was in the transition zone from 3201 to 3210 m TVD MSL.[5]

Reservoir
Yme Field consists of two accumulations Gamma and Beta, which are about 12 km apart. Each is subdivided into three segments separated by faults: Beta East, Beta North, Beta West, Gamma West, Gamma South East and Gamma North East. All segments have 3-way dip closures. All segments, except Beta West, will be redeveloped.

The reservoir in Yme is the Middle to Upper Jurassic Sandnes Formation. The current understanding is that the Sandnes Formation was deposited in a period of transgression with shoreface sediments in a sandy delta. Channel belt complexes associated with this delta correspond to main feeder channel systems and have the best reservoir properties and thickness of 2 to 6 m. Laterally, these sands are relatively continuous. Some coal layers have been observed in cores and in logs, but these are not continuous. The average thickness of the Sandnes Formation is 150 m for Gamma and 115 m for Beta. Vertically, the reservoir is heterogeneous since sediments are deposited from Lower Marine, Estuarine and Upper Marine settings stratigraphical upward. The porosity varies from 8 to 23% and permeability from 1 to 2000 mD [6]. The Estuarine sandstones show high permeability which have already been produced by earlier operators (Statoil/Talisman), whereas Lower Marine sandstones have low permeability and are the main target for the current operator (Repsol). The Gamma East accumulation is communicating with a regional aquifer. Both Gamma and Beta structures are compartmentalized[6].

Development
The Yme New Development is based on reuse from the Talisman operated project and new equipment specifically designed for the Yme New Development project:

<u>Reused facilities on the field:</u>

- Storage tank.
- Caisson with risers and wells.
- Pipelines, umbilicals and subsea facilities at the Beta location.
- Submerged Loading System (SLS).

<u>Changes and new facilities:</u>

- Redeployment and modification of Mærsk Inspirer, a jack-up rig with processing and drilling facilities.
- A new wellhead module (WHM) on top of the existing caisson.
- A new support structure for the caisson.
- Beta North: A new subsea template with three wells tied in to the existing Beta manifold (on stream from Q4 2022).

Reused existing facilities and equipment have been subjected to a verification program. A regular maintenance, functionality and integrity program is implemented to ensure compliance with regulations and safeguard of installations for the entire expected lifetime.

The field will be producing from ten horizontal production wells (six on Gamma and four on Beta) supported by two Water Alternating Gas injectors (WAG) in Gamma and three Water Injectors (WI), one on Gamma and two on Beta. A total 9 out of 15 wells were pre-drilled on Yme Beta and Gamma. These wells were completed during the 2009 - 2010 period (Talisman). All 15 well slots have been drilled as of 31.12.2023.

Produced water re-injection in combination with a regional aquifer will provide reservoir pressure support, and contribute to significant sweep of the reservoir. Artificial lift for the production wells is primarily provided by gas lift, but Gamma East wells utilise Electrical Submersible Pumps (ESP). The oil is exported by tankers and gas is used for power generation, gas-lift and WAG.

Technical lifetime of the wells and facilities

The technical lifetime of the Yme New Development facilities is specified to be 15 years. The current technical lifetime of the Maersk Inspirer is 10 years from installation on the field (January 2021). To extend the lifetime further, a new 5 year classing of the Maersk Inspirer needs to be approved and performed.

Status
The main reference for this section is the Statement of Reserves for Yme[2] and Yme audit presentation[1]. In 2023 the producers C-8 (Gamma North East) and C-9 (Gamma South West) have been drilled and put successfully on production. Well C-3ST (Gamma North West sidetrack) is delayed from 2023 to 2024. The Gamma North East well C-7 is being drilled and is expected to come on water injection early 2024. Currently, gas and water are injected through WAG injectors C-5 and C-6 (both in Gamma West) and water is injected in the Beta East well D-3 and Beta North well E-2. Produced water is treated in the produced water system and discharged to sea. Beta wells D-1 is shut in due to high watercut in April 2023. Hence, currently there three active producers on Beta (D-2H, E-1AH and E-3H). Gamma has six active producers (C-1, C-2, C-3, C-4, C-8A and C-9). C-3 will be sidetracked before the Summer of 2024.

The actual production in 2023 was 37% lower than the Base forecast in the RNB2024 submission. The main reasons for this reduced production are:

- Delayed startup of Gamma wells; C-8A, C-9, C-3ST and C-7
- In addition, C-8A production has been disappointing, partly due to limited availability of Electrical Submersible Pump (ESP)
- Unexpectedly high water cut
- Unplanned shutdowns
- Choking of wells due to operational constraints

Note that licence expiry of Yme is 18.06.2030. It is a common practice on the Norwegian Continental Shelf that licence period extensions are granted. It is therefore assumed that licence periods will be extended and reserves may be recovered beyond the existing licence expiry dates.

PIIP presented by Lime Petroleum
The PIIP estimates as 31.12.2023 is listed in Table 4.3 below.

Table 4.3 Yme PIIP as of 31.12.2023 and 31.12.2022

	PIIP, 31.12.2022			PIIP, 31.12.2023		
Fluids	Low	Base	High	Low	Base	High
Oil/Condensate (MMbbl)	308	345	384	321	362	407
Gas (BScf)	102	116	131	108	122	137

Description of the PIIP

- The PIIP 31.12.2023 estimate is based on the Phase II static model built in 2020, which is updated with post-drill results of Beta infill wells (Infill campaign 2022). The model has been history matched with production data from all the wells except Gamma 2023 infill wells.[2][7]
- The model framework was built from PSDM (Post-Stack Depth Migration) 3D seismic [8]. The model has incorporated new interpreted top and base reservoir, improved faults, new petrophysical interpretation and revised sedimentological concepts[9].
- The subsurface uncertainties incorporated in the static model were Top reservoir structure, FWL in different segments and property modeling. Among these, structure uncertainty was considered to be the most influence on the PIIP volume. In order to address potential influence of structural and depth uncertainty, pore volume multiplier was introduced in the modeling[6].

Changes in PIIP for Yme Field since Lime_ASR2022

- The PIIP numbers in the Table 4.3 are as presented by Lime in SoR [2], which is consistent to RNB2024[10] submission.
- An overall increase in PIIP is seen which constitutes 4% in GIIP and 5% in STOIIP since 31.12.2022.
- The changes in PIIP are results of dynamic simulation run where history matching of static model were carried out with Beta 2022 infill wells.

Technical profiles, Reserves and Contingent Resources numbers presented by Lime
The technical production and cost profiles used as input for the evaluation of reserves presented by Lime[2], are shown in appendix A.1.1 Yme Technical Production and Cost Profiles.

The Reserves include the following project:

- Yme Base Production

The Contingent Resources include the following project:

- Yme Gamma infill drilling. A feasibility study (DG0) is expected in 2024; after drilling campaign on Gamma is finished.

Description of the production profiles

Reserves
The starting point of Lime's reserves 31.12.2023 is RNB2024[10] with some adjustments:

- 2P is equal to RNB2024 Best case, which is based on Phase II simulation model with some adjustments with respect to the recent well startup times and production efficiency. The production efficiency is assumed to be 73.5% in 2024 and increasing 85.0% in 2027. This value is kept for the following years. The Phase II simulation model is history matched until August 2022[11]. The model has reasonable match for some wells while other wells have poor match or are not matched at all.
- 1P is the RNB2024 Low case adjusted downwards in 2024 and 2025 in order to make a reasonable downside for these two years. The RNB2024 low case is considered unrealistic for the mentioned two years. The basis for the RNB2024 Low case is decline curve analysis assuming av decline exponent, b, of 0.5.
- 3P is as 2P but with 5% higher production efficiency.

Historical and forecasted oil production is shown in Fig. 4.2.

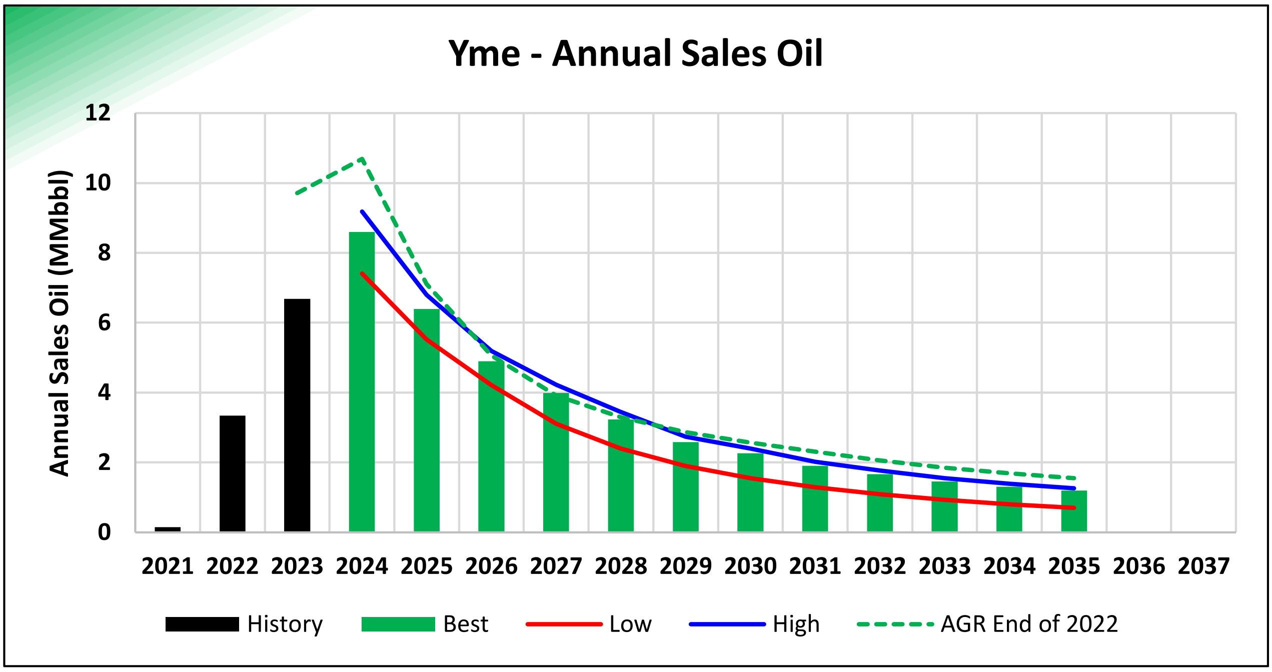

Fig. 4.2 Yme Oil Production
Historical and forecasted oil production, MMbbl/year

The reserves profiles include the following wells:

- Current producers C-1, C-2, C-3, C-4, D-1H, D-2H, E-1, E-3, C-8 and C-9
- Planned side-track of well C-3 (to C-3ST, postponed from 2023 to mid 2024)
- WAG injection wells C-5 and C-6
- Water injection wells E-2, D-3 and C-7 which is to be completed early 2024

The TRR Low estimate is 22% lower, and the High estimate is 6% higher, than the Base estimate.

Contingent resources
The basis for contingent resources is infill drilling of 3 wells[10]. The drillable targets will be defined by summer 2024. A total of 8.2 MMbbl is estimated as 2C contingent resources.

Description of the cost profiles
The OPEX, CAPEX and ABEX profiles in the Lime ASR2023 [2] are based on the RNB2024 [12]. The Yme operations have improved in 2023 compared to 2022 when they experienced several operating upsets. Still, pr October 2023, the achieved production was significantly lower than the budgeted production [13]. To improve the production performance, Yme may experience higher costs than reflected in the current profiles. The OPEX has a steady decline from 2024 onwards. From 2031, the lease contract of the Mærsk Inspirer expires and the rig will be owned by the Yme licence which results in less OPEX. .

Reserves and Contingent Resources audited by AGR

<u>Comments to PIIP</u>

AGR has checked the Phase II static model [8] and supporting document [7] which are used for the PIIP generation. The model includes historical wells (earlier Operators Statoil and Talisman) and infill wells drilled until 2022 with logs and base case model 'PHASE_II_YME_02_WIR2500_BaseCase'. The static model has been updated and history matched. AGR has reviewed RC meeting hand-outs [14][15][16][17] and available documents [18] with following comments -

- The PIIP numbers are consistent those with the RNB2024 submission. [10]

- Uncertainty of the PIIP, related to base case are -11% for low case and +13% for high case, as presented in the Table 4.3 above.
- In AGR's opinion, the ranges are narrow considering the reservoir heterogeneity of the field and structural uncertainty related to Top reservoir interpretation and variable FWL in different segments.
- The PIIP figures presented by Lime have increased by 4% (GIIP) and by 5% (STOIIP) during 31.12.2023. The increase is related to phase II reservoir model which has been updated with 2022 Beta infill post-drilled results-
  - The Beta wells (E-1, and E-3) came ±15 to ±30 m off than prognosed. Well picks updated with new well and using Geosphere information
  - Changed orientation of Estuarine environment (higher permeability) from previous N-S to NW-SE
  - Patchy distribution of coals and extends towards north.
  - Internal baffles 'intra-Estuarine baffle' added between Estuarine and Lower Marine based on pressure measurements in E-2 and Geospere result in E-3. Impact of new baffle will test in the dynamic model.
- Preliminary result of C-8 A well drilled through 4 different segments in Gamma North East compartment shows, segments 1, 2 and 3 are in communication with each other. The 4th segment is not in communication with these three segments, but pressure data indicates a possible depletion. The OWC in well is not determined, data analysis is undergoing. [19]
- AGR considers Phase II static model is not robust for the volume calculation since model does not represent geology in satisfactory way. The low permeability zone which is the current reservoir target, has modelled coarsely. Due to the fact, high permeability layers within low permeability zone are missed.
- The model does not reflect production effect from historical wells which is obvious in the GeoSteering image as water coning and flush zone around historical wells [14]. GeoSteering in the Yme field is working excellent, static model should also have been updated with reservoir thickness, sub-seismic faults, reservoir properties and saturation understanding from the GeoSteering and CPI evaluations.
- The Phase II static model is subject to an extensive re-evaluation to include Gamma 2023 infill wells results. The current zonation and facies modeling approach in modelling may not capture the internal variations. Operator has kicked-off phase III static model which will lead to change in PIIP numbers in next audit. [20][21]
- AGR accepts the PIIP numbers presented by Lime. However, AGR considers the PIIP numbers may be optimistic based on the Phase II static model.

<u>Comments to production profiles</u>

AGR has reviewed the production performance of the wells currently on production. The database is updated to 31.12.2023. AGR checked the dynamic simulation model used as basis for the RNB2024 production profiles. The model is history matched up to end August 2022.

- There is a significant deviation between the simulated and actual water and oil field rates in 2022 and 2023.
  - The simulated oil rates are higher than measured and the simulated water breakthrough comes later in time.
  - Observed water-cut, seem to stabilise at around 60%. The simulated water-cut generally shows a continuos upward trend.
- The estimated ultimate recovery factor of 27% is below the average on the NCS, which is 47%. It should thus be feasible to achieve the planned extractable volumes. However, considering recent and likely future integrity issues, and the high water cut development, active reservoir management will probably be necessary, such as drilling of more wells, recompletions, adjustments to production facilities etc., to achieve the predicted rates.
- There are significant uncertainties related to the future water-cut evolution due to uncertainties in compartmentalization and rock properties.
- Facilities uptime is also very uncertain with the lack of robustness of the production facilities (storage tank, pipelines, tubing, caisson etc.) observed to date.
- The new producers C-8A and C-9 in 2023 are producing with 5000 and 7000 bbl/sd at the end of year 2023, respectively. The watercut is around 10% and increasing.

Comments to contingent resources

Limited information has been available for AGR about the contingent project "Gamma infill drilling". The project is immature, listed as "development unclarified", and is planned matured further towards a possible investment decision after completion of the current drilling campaign on Gamma. The recovery potential for 3 infill wells of 8.2 MMbbl is reasonable, compared with other wells on the Gamma structure.

Comments to facilities and cost profiles

Lime has applied the cost profiles as presented in the Yme RNB 2024 [12], which AGR finds reasonable. AGR has some comments to the RNB profiles provided below.

- There is no CAPEX included for the years 2024 onwards. Cost normally considered as CAPEX may have been defined as OPEX.
- AGR can not find a justification for the steady reduction of the OPEX, especially when considering the need to improve the operating performance and the future classing of the Mærsk Inspirer. The 2024 OPEX budget (item 6) is 1642 MNOK. In 2023 the OPEX budget was 1762 MNOK, however increased by 37% to actual of 2419 MNOK [13].
- Yme has experienced several operating challenges, including facilities performance, since the re-start of production in October 2021. Although improved, operating performance must still be considered a challenge. It is difficult to assess how improving the operating performance may affect the cost profiles.
- The general reduced helicopter availability may potentially affect the operations and cost on Yme, and is reported as a "red risk" in the Yme Risk Register [13].

Economic evaluation and reserves determination

AGR has performed an economic evaluation to determine the reserves with the economic assumptions shown in appendix A.1 Economics and Technical Profiles.

The technical project production and cost profiles shown in appendix A.1.1 Yme Technical Production and Cost Profiles, have been evaluated to ensure project commerciality and the correct economic cut-off. The resulting gross and net reserves are shown in Table 4.4 below.

- For the Base price scenario, the economic cut-off is:
  - 1P: end of 2028, seven years earlier than technical cut-off
  - 2P: end of 2035, same as technical cut-off
  - 3P: end of 2035, same as technical cut-off
- The reserves are classified according to PRMS as follows:
  - "On Production": Yme New Development project
  - "Approved for development": Injectors C7, sidetrack of C-3. All with planned start-up in 2024.

Changes since audit 31.12.2022

The gross Yme balance sheet for reserves is shown in Table 4.6 below and for contingent resources in Table 4.7 below.

Changes to Reserves:

- Revisions (-8.51 MSm3 for EUR 2P):
  - The Operator has honoured the poor production performance in 2023 and has revised the EUR significantly.

Changes to Contingent Resources[12]:

- Infill drilling (three wells) on Gamma is matured further, and the resources have increased significantly. Further, explanation for changes are not provided to AGR.

Comments to recovery factors and reserves ranges

- The recovery factor after the initial development was 13%. In the PDO of 2017 the P50 recovery factor assuming 10 years production was estimated to be 30%.
- The P50 oil recovery factors estimated for this certification are shown in Table 4.8. AGR finds the final recovery factor of 27% to be reasonable taken into account the complexity of the field. However, it is significantly lower than the average of approximately 47% for an oil field on the NCS.
- The oil equivalent 1P is -22% and 3P is +6% versus 2P. The downside is on acceptable, however on the low side. The upside is much smaller than expected. This is mainly due to the methodology applied to generate the upside. In our opinion, given uncertainties in Yme the reserves range is too narrow. The operator is constructing an updated reservoir simulation model which may result in a wider uncertainty range.

Conclusions

- The Yme reserves reported by Lime are generated using RNB2024 as starting point. The Base and High cases are kept unchanged while the Low case is adjusted downwards for the first 2 years. RNB2024 is unrealistic for these years.
- The uncertainty on Yme is very high with respect to future water cut from existing wells, but also possible previous flooding in the new producers' location.
- The Yme New Development had several problems with the performance of the production facilities the first production years 2021 and 2022 . This has improved in 2023, although two shutdowns, one in March and one in July, due to problems with the gas handling facilities. AGR expects that Yme will achieve an acceptable facility regularity in the future.
- The current recovery factor is low, and it should be possible to achieve the planned recoverable volumes.
- AGR hereby endorses the Yme Reserves (Table 4.4) and Contingent Resources (Table 4.5).

Table 4.4 TRR and reserves as of 31.12.2023 - Yme

	TRR (Gross 100 %)			Reserves (Gross 100 %)			Reserves (Lime net 10.0000 %)			Reserves (Rex 91.652% of Lime)		
	Low	**Best**	**High**	**1P**	**2P**	**3P**	**1P**	**2P**	**3P**	**1P**	**2P**	**3P**
1st Production	25 October 2021											
Cut-off (year-end)	2035	2035	2035	2028	2035	2035	2028	2035	2035	2028	2035	2035
Oil/condensate (MMbbl)	30.91	39.47	41.97	22.65	39.47	41.97	2.27	3.95	4.20	2.08	3.62	3.85
Gas (BScf)	-	-	-	-	-	-	-	-	-	-	-	-
NGL, (MMbbl oe)	-	-	-	-	-	-	-	-	-	-	-	-
Total (MMboe)	**30.91**	**39.47**	**41.97**	**22.65**	**39.47**	**41.97**	**2.27**	**3.95**	**4.20**	**2.08**	**3.62**	**3.85**

Table 4.5 Gross and net contingent resources as of 31.12.2023 - Yme

Yme	**Gross (100%)**			**Lime net (10.0000%)**			**Rex 91.652% of Lime**		
Contingent resources (MMboe)	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
Infill Drilling	2.30	8.20	9.55	0.23	0.82	0.95	0.21	0.75	0.87
Total, MMboe	**2.30**	**8.20**	**9.55**	**0.23**	**0.82**	**0.95**	**0.21**	**0.75**	**0.87**

Table 4.6 Balance sheet - Yme Reserves (100%)

Gross reserves balance, 31.12.2022 - 31.12.2023, for Yme (100%)							
Reserves class	**Status 31.12.2022**	**Production (Positive)**	**Revisions**	**Acquisitions or sales**	**IOR**	**Discoveries/ New Projects**	**Status 31.12.2023**
Oil and condensate (MMbbl)							
1P	25.79	6.69	3.55	-	-	-	22.65
2P	54.67	6.69	-8.51	-	-	-	39.47
3P	58.08	6.69	-9.42	-	-	-	41.97
Gas (BScf)							
1P	-	-	-	-	-	-	-
2P	-	-	-	-	-	-	-
3P	-	-	-	-	-	-	-
NGL (MMbbl oe)							
1P	-	-	-	-	-	-	-
2P	-	-	-	-	-	-	-
3P	-	-	-	-	-	-	-
Oil equivalents (MMbbl oe)							
1P	**25.79**	**6.69**	**3.55**	-	-	-	**22.65**
2P	**54.67**	**6.69**	**-8.51**	-	-	-	**39.47**
3P	**58.08**	**6.69**	**-9.42**	-	-	-	**41.97**

Table 4.7 Balance sheet - Yme Contingent Resources (100%)

Gross contingent resource balance, 31.12.2022 - 31.12.2023, for Yme_CR (100%)							
Resource class	**Status 31.12.2022**	**Production (Positive)**	**Revisions**	**Acquisitions or sales**	**IOR**	**Discoveries/ New Projects**	**Status 31.12.2023**
Oil and condensate (MMbbl)							
1C	1.50	-	0.80	-	-	-	2.30
2C	3.00	-	5.20	-	-	-	8.20
3C	4.50	-	5.05	-	-	-	9.55
Gas (BScf)							
1C	-	-	-	-	-	-	-
2C	-	-	-	-	-	-	-
3C	-	-	-	-	-	-	-
NGL (MMbbl oe)							
1C	-	-	-	-	-	-	-
2C	-	-	-	-	-	-	-
3C	-	-	-	-	-	-	-
Oil equivalents (MMbbl oe)							
1C	**1.50**	-	**0.80**	-	-	-	**2.30**
2C	**3.00**	-	**5.20**	-	-	-	**8.20**
3C	**4.50**	-	**5.05**	-	-	-	**9.55**

Table 4.8 Yme P50 Recovery Factors

	Oil 31.12.2023	**Oil at EUR**	**Gas 31.12.2023**	**Gas at EUR**
Produced (MSm3/ GSm3)	59.89	99.36	-	-
Recovery factor	17%	27%	-	-

4.2 Brage

Asset Overview
Brage is an oil field located east of the Oseberg Field and west of the Troll Field in the northern part of the North Sea within production licences 055, 055B, 055D, 055E and 185; and blocks 30/6, 31/4 and 31/7[5]. The field is unitised in the Brage Unit. The water depth varies from 130 to 170 m and the reservoir depth varies between 2000 and 2300 m TVD MSL. See Fig. 4.3[5] for the location map. The field has been on production since 1993[5]. Brage Licence expiry is 06.04.2030.

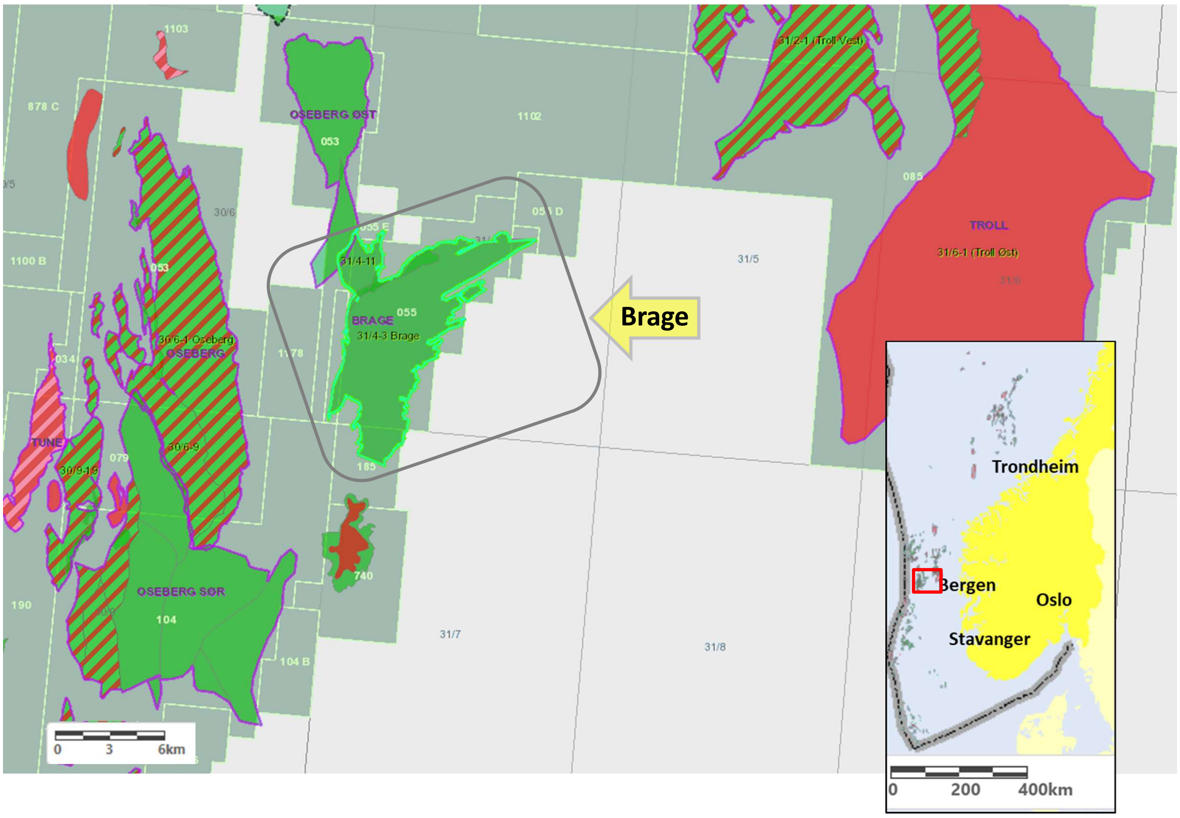

Fig. 4.3 Brage Field Location map
Source: NOD factmaps (www.sodir.no)

In 2023, one change in the licence partnership occured: Petrolia NOCO AS acquired a 12.2575% share in Brage from Vår Energi ASA effective 29.12.2023[5].

This audit of reserves and contingent resources has been based on the information provided by Lime Petroleum, which included Lime's Statement of Reserves (SoR)[3], the Operator's RNB2024 submission[22], meeting documents (RC, TC, MC) from 2023, monthly status reports for 2023, work program and budget (WP&B) 2024, Annual Status Report (ASR) 2023[23], Long Range Plan (LRP) 2023[24], production data for the field, as well as Lime's answers to AGR's questions and clarification requests (Q&A)[25].

Licence details summary is shown in Table 4.9. The production licence give the licencees full rights to explore and produce hydrocarbons at all stratigraphic levels within the licence area.

Table 4.9 Brage summary table

Asset name/ Country	Lime interest (%)	Rex's interest of Lime (%)	Development Status	Licence expiry date	Licence Area (km2)	Type of mineral, oil or gas deposit	Remarks
Brage Unit / Norway	33.8434	91.652	On production	06.04.2030	183.33	Oil and gas	-

The Brage Unit licence shares are listed in Table 4.10.

Table 4.10 Brage Field licence shares (%)

Licence	OKEA ASA (Op)	Lime Petroleum AS	DNO Norge AS	Petrolia NOCO AS	M Vest Energy AS
Brage Unit	35.2000	33.8434	14.2567	12.2575	4.4424

Discovery
Brage was discovered in 1980 by well 31/4-3. Two separate hydrocarbon-bearing sandstone intervals were encountered. The Oxfordian to Kimmeridgian Sognefjord Formation proved oil and gas with the OWC between 2023 - 2029 m TVD MSL. The Callovian Fensfjord Formation was oil bearing with a possible OWC at 2148 m TVD MSL. In 1984 appraisal well 31/4-7 proved oil in Statfjord Fm west of the main field in a horst structure with a higher reservoir pressure[5]. It has since been discovered oil in several fault segments in the Oseberg Formation in the Brent Group north of the Brage horst and also in the Cook Fm on the Brage horst. More recently, well 31/4-A-13 E proven oil and gas in Sognefjord Formation in Kim prospect, being maturated now in DG1 as Sognefjord East.

Reservoir
The Brage Field is part of a series of Middle Jurassic highs located on the Bjørgvin Arch, between the Viking Graben to the West and the Horda Platform to the East. Brage mainly produces oil from sandstones of Late Jurassic Sognefjord Fm and of the Early Jurassic Statfjord Group. Sandstones of Middle Jurassic age in the Brent Group and the Fensfjord Formation also produce oil and gas[5]. The Brage field is a low relief structural trap setting, consisting on a main sector allocated downflank and eastern from a narrow horst structure localized at the west and northwest of the Field. The main sector contains the Fensfjord and the overlying Sognefjord deposits (containing oil and gas in respective Formations). Here, Sognefjord Formation is mainly distributed in the central and Northeast areas of Brage. The northern part of the Brage horst consist of Bowmore, Knockando and Talisker (East and West) deposits/structures: Bowmore contains oil and gas in Fensfjord Formation, Sognefjord Formation and Lower Oseberg Formation, in the Brent Group. Knockando and Talisker segments contain oil and gas in the Lower Oseberg Formation of the Brent Group. The central and southern part of the Brage horst consist on two deposits/structures: the Statfjord and the Cook deposits, both containing oil and gas in respective Formations Fig. 4.4[5][22]. In general, the reservoir quality varies from poor to excellent[5] and there is no communication between the reservoirs and structural elements. More recently, gas has been proven in thin chalk intervals of the Shetland Group, overlying the main sector of Brage.

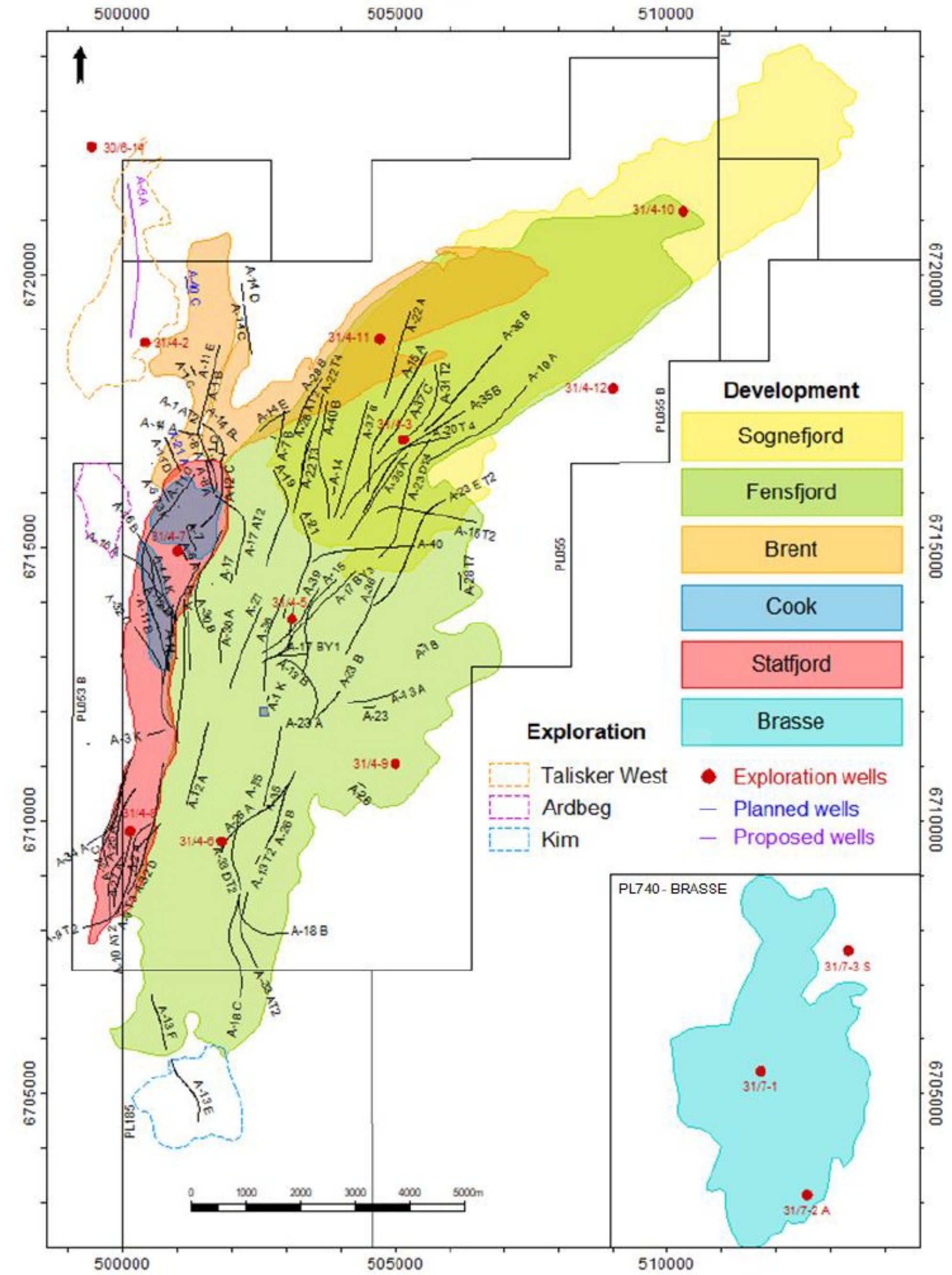

Fig. 4.4 Brage Field development status

Development
The drainage strategy in Sognefjord and Cook is depletion and natural aquifer support; In Statfjord it is Pressure maintenance by water injection and natural aquifer support, in Fensfjord it is occasional water injection, natural aquifer support but mostly depletion drive and in Brent it is partial water injection and natural aquifer support. Older wells were slanted while the newer ones are mostly horizontal. Gas lift is applied to improve recovery.

Brage has been developed with a fixed integrated production, drilling and accommodation facility on a steel jacket with 40 well slots. The oil is transported by pipeline to Oseberg and through the Oseberg Transport System (OTS) pipeline to the Sture terminal in Norway. The gas export pipeline is tied back to Statpipe and transported to the onshore Kårstø gas plant for processing including NGL extraction, and gas export.

<u>Technical lifetime of the wells and facilities</u>

In 2013 the Licence period was extended to 2030. At that time, the facilities were assessed to last at least for such a period, provided proper maintenance. Brage have experienced some technical integrity issues, including corrosion, due to ageing facilities. The current technical lifetime is 2030. The Operator OKEA has an ambition to increase the technical lifetime beyond 2030, and has hence increased both the onshore and the offshore work force with a corresponding impact on the yearly operating cost.

Status
Brage Field is in a mature phase with declining oil production. A continuous drilling and well maintenance program is necessary in order to maintain production due to high water-cut in many of the producers. The field production is currently constrained by gas processing capacity (2.5 MSm3/d), which is shared between gas lift gas and produced gas.

There are currently 30 active wells; 20 oil producers, 2 gas producers, 5 water injectors, 2 Utsira water producer providing injection-water and 1 cutting re-injection well (CRI)[3][24].

There are four new infill wells completed in 2023.

- A-11 E Talisker East Lower Oseberg development oil producer. The well came on stream in May, three months earlier than planned. The performance has been above prognosis, especially for gas.
- A-37 C Sognefjord infill gas producer came on stream in September 2023.
- A-13 F Fensfjord South infill oil producer came on stream 25.10.2023.
- A-30 C Cook infill oil producer (previously Statfjord and Cook). DG3 was sanctioned in July 2023. The well came on stream 05.11.2023.

In addition, there has been a well intervention in A-32 D in 2023 which is completed and included in Base production.

Total production in 2023 was approximately 5.05 MMBoe which was about 28% above the yearly budget (2P forecast). The key contributors to high 2023 production were earlier start-up and better than expected production performance of the four new producers. The four new producers account for 87% of total production towards the end of 2023. Field water cut is currently 93%, and increasing. GOR is currently at 260 Sm3/Sm3, and increasing.

PIIP presented by Lime (as per RNB2024)
The PIIP estimates as of 31.12.2023 and as of 31.12.2022 are listed in Table 4.11 below.

Table 4.11 Brage PIIP as of 31.12.2023

	PIIP, 31.12.2022			PIIP, 31.12.2023		
	Low	Base	High	Low	Base	High
Oil/condensate (MMbbl)	935	1097	1237	935	1097	1237
Free/ Associated gas (BScf)	636	795	932	635	795	930

<u>Description of the PIIP</u>

- PIIP in Table 4.11 is based on ensemble realizations from the full field 3D static and dynamic reservoir model, and it is in line with RNB2024. This PIIP includes those reservoirs that are currently developed, which are the following:
  - Main developed reservoirs (base case): Statfjord (364 MMbbl STOIIP; 109 BScf GIIP), Fensfjord (473 MMbbl STOIIP; 275 BScf GIIP) and Sognefjord (128 MMbbl STOIIP; 222 BScf GIIP)
  - Other developed reservoirs: Bowmore Sognefjord, Bowmore Fensfjord, Bowmore Brent, Talisker East, Brent, Knockando Brent and Cook.
- PIIP uncertainty ranges as for Table 4.11 are -15% and -11% of the base case for oil/condensate and -20% and +15% of the base case for associated/free gas. The ranges are based on combined static and dynamic ensemble realizations.
- PIIP in Table 4.11 excludes the PIIP targeted by the new, undeveloped projects Sognefjord East 31/4-A-13 E (former Kim)[26][27][28][29] and the Shetland 31/4-3 project[30], both classified as RC 7F.

Sognefjord East and Shetland are listed however in PIIP RNB2024, being the PIIP the following:
- Sognefjord East:
  - Base case: 12 MMbbl of oil/condensate; 8 BScf of free/associated gas
  - Low case: 5 MMbbl of oil/condensate; 3 BScf of free/associated gas
  - High case: 25 MMbbl of oil/condensate; 16 BScf of free/associated gas
- Shetland (free gas only):
  - Base case: 71 BScf
  - Low case: 53 BScf
  - High case: 141 BScf

- Sognefjord East PIIP is based on the recent most seismic interpretations and wellbore evaluations from the operator. Shetland PIIP is based on deterministic map-based evaluation from the operator using two different GWC sets depending on the geological concept. Shetland chalk reservoir was perforated by most wells in Brage, but has never been produced. A production test is attempted in 2024 by the perforation of an old well (31/4-A-31 T2).
- The new project Talisker West (RC 7) targets the Lower Oseberg Formation of the Brent Group. However, this may be separated segment from Brage and so, not included in PIIP in Table 4.11.
- Fensfjord 5000 infill project[28] targets remaining reserves contained in NW Fensfjord, as part of Fensfjord reservoir and included in Table 4.11.

Changes in PIIP for Brage field

- No changes in PIIP since 31.12.2022.

The production licence give the licensees full rights to explore and produce hydrocarbons at all stratigraphic levels within the licence area.

Technical profiles, reserves and contingent resources numbers presented by Lime
The technical production and cost profiles are shown in appendix A.1.2 Brage Technical Production and Cost Profiles.

The reserves include the following projects:

- Production from existing wells.
- Talisker East Development including planned A-21 A producer and A-40C injector well pair.
  - The AFE for well pair was approved in Q4 2023.
  - A-21 A is scheduled to be drilled Q1 2024 following completion of A-40C water injector.
- Brage Bowmore producer (A-28C) in Fensfjord (DG2/DG3 Q1 2024).

The contingent resources in Lime's Statement of Reserves include the following potential projects:

- Brage infill producer (F5000) in Fensfjord (DG3 Q2/Q3 2024).
- Effect of Brasse tie-in. Contingent on Brasse DG3/PDO approval.
- Climate Response Project (DG3 June 2024).
  - The aim is to reduce fuel gas consumption used for power generation by 30%. (Power from shore via Troll B, wind turbine generator and/or a heat to electricity solution).
- IOR infill wells (Statfjord and Brent Bowmore infill wells, reduced from five to two wells)
- Talisker West (crosses the licence boundary between Brage Unit and Oseberg licence)
- Sognefjord East (new project after the Kim discovery in A-13 E extension drilled in 2023)
- Sognefjord East Prospect (RNB2024, RC 7F). No longer a prospect due to Kim discovery described in Sognefjord East project above.
- Shetland (RNB2024, RC 7F)
- Brage extended lifetime (RNB2024, RC 7A)

Description of the production profiles

The basis for the forecast is a combination of best estimate production profiles generated by Decline curve analysis (DCA) and reservoir simulation models for recent wells with short or no production history (A-11 E, A-13 F, A-30 C, A-37 C, A-21 A). Historical and forecasted oil production and gas sales is shown in Fig. 4.5 and Fig. 4.6 respectively.

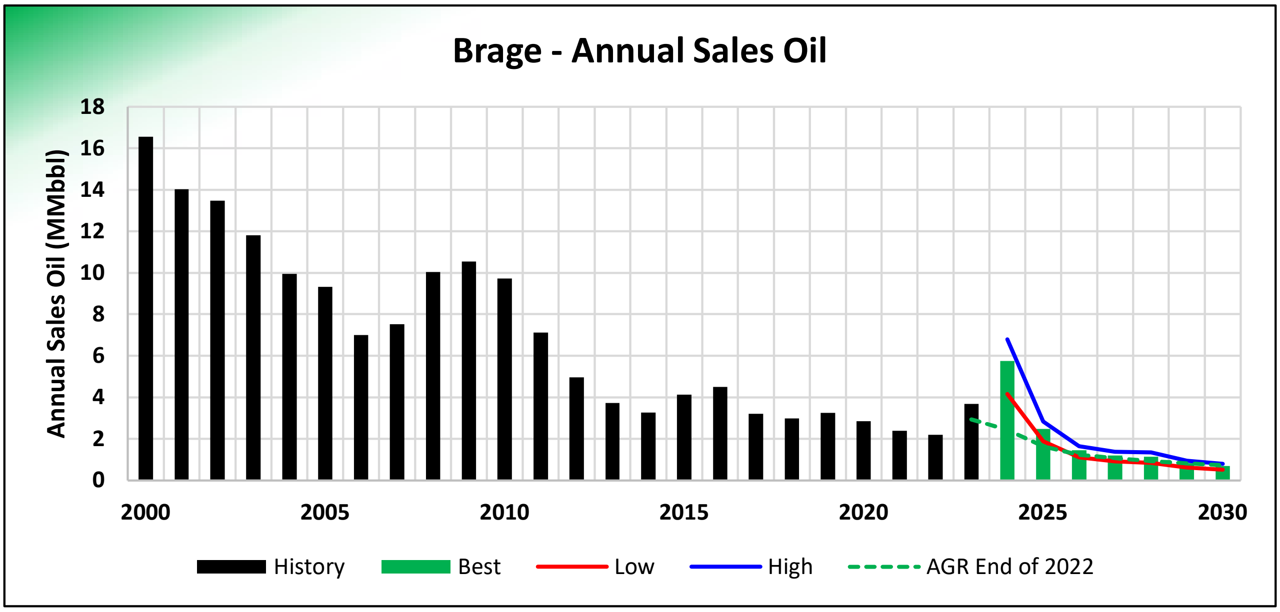

Fig. 4.5 Brage Oil Production
Historical and forecasted oil production, MMbbl/year

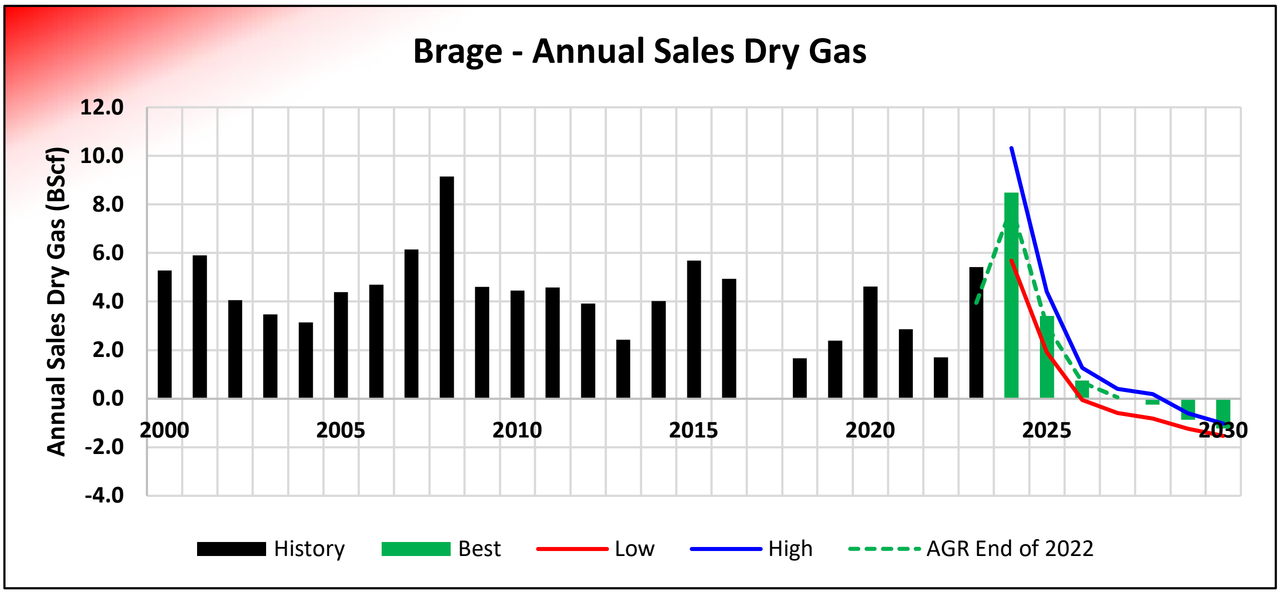

Fig. 4.6 Brage Gas Sales
Historical and forecasted gas sales, BScf/year

- History matched dynamic reservoir simulation models is used for production profiles for the wells planned to be drilled in 2024 (A-21 A).
- A combination of dynamic reservoir simulation model and analogue DCA well performance is used for estimating contingent resources.
- A continuous drilling and well maintenance program is necessary in order to maintain production due to high water-cut and continued decline in production in many of the producers.
- The field production is constrained by gas processing capacity (2.5 MSm3/d) which is shared between gaslift gas and produced gas from reservoir.
- A regularity of 91.0% is assumed for normal years and 83.9% for years with revision stops (next planned in 2026)

Description of the cost profiles

- The cost profiles applied by Lime in Statement of Reserves [3] are in line with the Brage RNB2024 [22] and the WP&B 2024 [31]. The CAPEX and OPEX profiles are based on experienced cost recent years. The OPEX reflects the ambition to extend the technical lifetime beyond 2030.

Reserves and contingent resources audited by AGR

Comments to PIIP

AGR has reviewed the following documents supplied by Lime: Brage RNB2024[22], Lime, Statement of Resources(SoR)[3], Lime's Assets presentation[30] and RC and work meeting handouts[32][33][29][28][27][26]. The evaluation is satisfactory with the following comments:

- Note that neither static nor dynamic models were available and therefore these are not evaluated by AGR.
- The PIIP presented in Table 4.11 excludes that related to the undeveloped Sognefjord East and Shetland deposits. The PIIP has not changed since 31.12.2022, which is as expected in a mature field like Brage.
- AGR has reviewed the available evaluations of the undeveloped Sognefjord East and Shetland reservoirs. The reservoirs are still in early stage and so, AGR believes that PIIP from these may be reducedin next model updates. AGR agrees with the operator's methodology.
- AGR considers that total PIIP uncertainty ranges to be fair for the Brage field. However, AGR observes that PIIP uncertainty ranges are fairly asymmetrical for the following individual reservoirs: Statfjord, Bowmore Brent, Brent and Knockando Brent. The asymmetry in PIIP uncertainty ranges is rare for reservoirs with a long production history. AGR suspects that the skewness of uncertainty may relate to given priority of dynamic ensembles in the selection process of the cases, but the reason for the skewness is not documented to AGR.
- Talisker West project targets the Lower Oseberg Formation of the Brent Group. This segment is separated from Brage and its estimated PIIP is not part of PIIP in Table 4.11 [34][33].
- AGR considers the PIIP figures presented by Lime (Operator's estimates) to be reasonable.

Comments to production profiles

AGR has reviewed Lime's asset presentation[30] and available documentation including licence meeting handouts, RNB2024[22], Lime Statement of Resources (SoR)[3], Annual Status Report (ASR) 2023[23], Long Range Plan (LRP) 2023[24].

- AGR has checked the results of the DCA from the operator for existing wells and found it reasonable [32].
- AGR observes that the Lime forecast for 2024 is about 30% higher than RNB2024. This is considered optimistic, but reasonable considering the performance of the four new 2023 wells.
- Reservoir quality varies from poor to excellent in Fensfjord, Statfjord, Brent and Sognefjord formations facing individual challenges in terms of pressure support, productivity, water cut development and drainage efficiency.
- AGR observes that negative gas sales profile towards the tail end is an indication of gas deficiency in comparison to fuel and flare requirement. This deficiency has no impact on reserves as economic cut-off occurs prior to this event.
- AGR acknowledges that a continuous drilling and well maintenance program is required to maintain production and that the field production is constrained by gas processing capacity.
- Low GOR infill wells are prioritised due to capacity constraint on gas to maximise oil production.
- Apart from 2024, the profiles included and presented by Lime in the Statement of Reserves are similar (with small variations) to the RNB2024 profiles.
  - Lime's oil equivalent technical recoverable resources are approximately 3% higher compared to RNB2024.
- In AGR's opinion, the production profiles presented by Lime are an acceptable basis for reserves determination.

Comments to contingent resources

The contingent resources in NPD Resource Class 5 have limited documentation regarding volumes and target areas for the potential wells. These wells are at an early stage of evaluation and estimates of contingent resources are likely to be revised as these opportunities are matured further. It should also be noted that with the current reserves base, economic cut-off for Brage is at year-end 2025, which leaves a very short time to materialize the contingent resources. If Brasse Development Project is approved (DG3 planned in Q1 2024), this could potentially change the timing of economic cut-off on Brage, i.e. extend Brage lifetime.

The Talisker West potential well is contingent on reaching a commercial agreement with the Oseberg licence since the Talisker West structure crosses the licence boundary between Brage Unit and Oseberg licence with the apex of the structure being well within the Oseberg licence.

Comments to facilities and cost profiles

- The cost profiles applied by Lime are based on the Brage RNB2024 and the WP&B 2024. The WP&B includes the cost of several not yet sanctioned wells.
- AGR has reviewed these costs in light of historical cost on Brage and found the costs presented to be reasonable.
- The technical lifetime of the facilities is expected to be 2030. OKEA has increased the efforts to extend the technical lifetime beyond 2030. The associated cost is reflected in the OPEX.
- The production regularity is currently good, however, Brage has been in production since 1993 and may in the future experience issues due to the ageing facilities which could potentially have an impact on the OPEX and regularity of the facilities.
- AGR expects that the production facilities will be able to handle the planned operations.

Economic evaluation and reserves determination

AGR has performed an economic evaluation to determine the reserves with the economic assumptions shown in appendix A.1 Economics and Technical Profiles.

The technical project production and cost profiles shown in appendix A.1.2 Brage Technical Production and Cost Profiles, have been evaluated to ensure project commerciality and the correct economic cut-off. The resulting gross and net reserves are shown in Table 4.12 below.

- The Brage Bowmore producer (A-28C) project is confirmed commercial.
- For the Base price scenario, the economic cut-off is:
  - 1P: end of 2025, five years earlier than technical cut-off
  - 2P: end of 2025, five years earlier than technical cut-off
  - 3P: end of 2026, four years earlier than technical cut-off
- The reserves are classified according to PRMS as follows:
  - "On Production": Production from existing wells
  - "Approved for Development": A-21 A producer and A-40C injector well pair
  - "Justified for Development": Brage Bowmore producer (A-28C) in Fensfjord.

The economic lifetime of Brage may potentially be extended beyond the current economic cut-off date through further drilling (maturation of contingent resources), optimization of production and operating costs and if Brasse Development Project is approved (DG3 planned in Q1 2024).

Changes since certification 31.12.2022

The gross Brage balance sheet for reserves is shown in Table 4.14 below and for contingent resources in Table 4.15 below.

Changes to Reserves:

- There are four new infill wells completed in 2023.
  - A-11 E Talisker East Lower Oseberg development oil producer (on stream May 2023, three months earlier than planned).
  - A-37 C Sognefjord infill gas producer (on stream September 2023).
  - A-13 F Fensfjord South infill oil producer (on stream October 2023).
  - A-30 C Cook infill oil producer. DG3 was sanctioned in July 2023, i.e. not part of reserves in CPR year-end 2022 report (on stream December 2023).
- Well intervention in A-32 D in 2023 included in Base production.
- A-21 A producer and A-40C injector well pair is matured from contingent resources to reserves "Approved for Development".
- Brage Bowmore producer (A-28 C) in Fensfjord is matured from contingent resources to reserves "Justified for Development"

Changes to Contingent Resources:

- New projects:
  - Brage infill producer (F5000) in Fensfjord. DG3 Q2/Q3 2024.
  - Climate Response Project. DG3 June 2024.
  - Effect of Brasse tie-in. Contingent on Brasse DG3/PDO approval.
  - Sognefjord East (new project after the Kim discovery in A-13 E extension drilled in 2023)
  - Sognefjord East Prospect (RNB2024, RC 7F)
  - Shetland (RNB2024, RC 7F)
  - Brage lifetime extension (RNB2024, RC 7A)

<u>Comments to recovery factors and reserve ranges</u>

- The oil and gas recovery factors are shown in Table 4.16 below. The modest overall recovery factor reflects the variety of reservoir quality from poor to excellent in Fensfjord, Statfjord, Brent and Sognefjord formations with varying degrees of individual drainage efficiency. AGR considers the recovery factors to be reasonable taken into account the complexity of the field. It is, however, significantly lower than the average of approximately 47% for an oil field on the NCS.
- The oil equivalent 1P is -29% and 3P is +36% versus 2P (2025 cut-off). The range is in line with many other mature fields on the NCS and is considered reasonable.

<u>Conclusions</u>

- The PIIP has not changed since 31.12.2022. Total PIIP uncertainty ranges are considered to be fair, however AGR has observed asymmetrical PIIP uncertainty ranges in a few of reservoirs with a long production history.
- The recovery factors are reasonable considering the complexity and multiple reservoir levels of the field, and compared to NCS fields with similar drainage strategies.
- The resource uncertainty range in recoverable oil equivalent volumes is in line with other mature fields on the NCS and is considered reasonable by AGR.
- AGR finds the production profiles and costs figures presented reasonable to be used as a basis for economic analyses of reserves.
- The economic cut-off is at the end of 2025, five years earlier than the end of the technical production profiles.
- The Brage reserves and contingent resources reported by Lime are well documented, based on sound industry practice and are similar (with small variations) to the RNB2024 profiles.
- AGR hereby endorses the Brage reserves (Table 4.12 below) and contingent resources (Table 4.13 below) as reported by Lime.
- If Brasse Development Project is approved (DG3 planned in Q1 2024), this could potentially change the timing of economic cut-off on Brage, i.e. extend Brage lifetime.

Table 4.12 TRR and reserves as of 31.12.2022 - Brage

	TRR (Gross 100 %)			Reserves (Gross 100 %)			Reserves (Lime net 33.8434 %)			Reserves (Rex 91.652% of Lime)		
	Low	Best	High	1P	2P	3P	1P	2P	3P	1P	2P	3P
1st Production	23 September 1993											
Cut-off (year-end)	2030	2030	2030	2025	2025	2026	2025	2025	2026	2025	2025	2026
Oil/condensate (MMbbl)	10.03	13.52	15.74	6.03	8.23	11.28	2.04	2.78	3.82	1.87	2.55	3.50
Gas (BScf)	3.35	10.30	14.96	7.61	11.90	16.00	2.57	4.03	5.42	2.36	3.69	4.96
NGL (MMbbl oe)	0.11	0.41	0.70	0.40	0.66	0.88	0.14	0.22	0.30	0.12	0.21	0.27
Total (MMboe)	**10.74**	**15.77**	**19.10**	**7.79**	**11.01**	**15.01**	**2.64**	**3.73**	**5.08**	**2.42**	**3.41**	**4.66**

Table 4.13 Gross and net contingent resources as of 31.12.2022 - Brage

Brage	Gross (100%)			Lime net (33.8434%)			Rex 91.652% of Lime		
Contingent resources (MMboe)	1C	2C	3C	1C	2C	3C	1C	2C	3C
Brage infill Fensfjord (F5000)	1.00	2.01	3.01	0.34	0.68	1.02	0.31	0.62	0.93
Brage unit IOR infill wells	1.13	2.16	3.14	0.38	0.73	1.06	0.35	0.67	0.98
Climate Response	0.41	0.41	0.41	0.14	0.14	0.14	0.13	0.13	0.13
Talisker West	1.79	3.33	4.76	0.60	1.13	1.61	0.55	1.03	1.48
Effect of Brasse tie-in	0.36	-1.56	-3.14	0.12	-0.53	-1.06	0.11	-0.48	-0.97
Sognefjord East first producer	1.14	2.24	3.29	0.38	0.76	1.11	0.35	0.69	1.02
Sognefjord East Prospect	0.21	0.43	1.29	0.07	0.15	0.44	0.07	0.13	0.40
Shetland	0.47	0.94	2.52	0.16	0.32	0.85	0.15	0.29	0.78
Brage lifetime extension	-0.32	2.67	6.84	-0.11	0.91	2.32	-0.10	0.83	2.12
Total, MMboe	**6.20**	**12.64**	**22.12**	**2.10**	**4.28**	**7.49**	**1.92**	**3.92**	**6.86**

Table 4.14 Balance sheet - Brage Reserves (100%)

Gross reserves balance, 31.12.2022 - 31.12.2023, for Brage (100%)							
Reserves class	Status 31.12.2022	Production (Positive)	Revisions	Acquisitions or sales	IOR	Discoveries/ New Projects	Status 31.12.2023
Oil and condensate (MMbbl)							
1P	5.88	3.68	3.52	-	-	0.31	6.03
2P	7.02	3.68	4.44	-	-	0.45	8.23
3P	10.72	3.68	3.36	-	-	0.87	11.28
Gas (BScf)							
1P	10.01	5.42	2.54	-	-	0.47	7.61
2P	14.86	5.42	1.78	-	-	0.68	11.90
3P	21.16	5.42	-0.77	-	-	1.03	16.00
NGL (MMboe)							
1P	0.77	0.40	0.01	-	-	0.03	0.40
2P	1.14	0.40	-0.12	-	-	0.04	0.66
3P	1.63	0.40	-0.40	-	-	0.06	0.88
Oil equivalents (MMboe)							
1P	**8.43**	**5.05**	**3.98**	-	-	**0.43**	**7.79**
2P	**10.81**	**5.05**	**4.64**	-	-	**0.61**	**11.01**
3P	**16.12**	**5.05**	**2.82**	-	-	**1.12**	**15.01**

Table 4.15 Balance sheet - Brage Contingent Resources (100%)

Gross contingent resource balance, 31.12.2022 - 31.12.2023, for Brage_CR (100%)							
Resource category	**Status 31.12.2022**	**Production (Positive)**	**Revisions**	**Acquisitions or sales**	**IOR**	**Discoveries/ New Projects**	**Status 31.12.2023**
Oil and condensate (MMbbl)							
1C	5.48	-	-3.65	-	0.64	4.05	6.52
2C	9.73	-	-6.27	-	1.29	5.84	10.58
3C	13.96	-	-8.45	-	1.93	8.48	15.91
Gas (BScf)							
1C	16.20	-	-10.85	-	1.51	-6.83	0.03
2C	16.67	-	-6.57	-	3.03	-2.61	10.52
3C	16.61	-	-1.50	-	4.54	10.30	29.95
NGL (MMboe)							
1C	1.27	-	-0.92	-	0.09	-0.77	-0.33
2C	1.30	-	-0.64	-	0.18	-0.67	0.18
3C	1.30	-	-0.30	-	0.28	-0.39	0.88
Oil equivalents (MMboe)							
1C	**9.63**	-	**-6.50**	-	**1.00**	**2.06**	**6.20**
2C	**14.00**	-	**-8.07**	-	**2.01**	**4.71**	**12.64**
3C	**18.21**	-	**-9.02**	-	**3.01**	**9.92**	**22.12**

Table 4.16 Brage P50 Recovery Factors

	Oil 31.12.2023	**Oil at EUR**	**Gas 31.12.2023**	**Gas at EUR**
Produced (MMbbl/ Bscf)	383.09	391.31	156.11	168.00
Recovery factor	34.9%	35.7%	19.6%	21.1%

5 First Time Certifications

5.1 Brasse

Asset Overview
The Brasse oil and gas discovery is located in production licence 740 approximately 13 km South of the Brage Field and 13 km East of the Oseberg Sør Field in the North Sea. A location map of the field is shown in Fig. 5.1 Fig. 2.2. DG2 concept select was passed in July 2023, and DG3 (PDO) is planned in Q1 2024. Water depth in the area is about 120 m TVD MSL. The depth of the reservoir is near 2200 m TVD MSL. PL740 licence expiry is 07.02.2024.

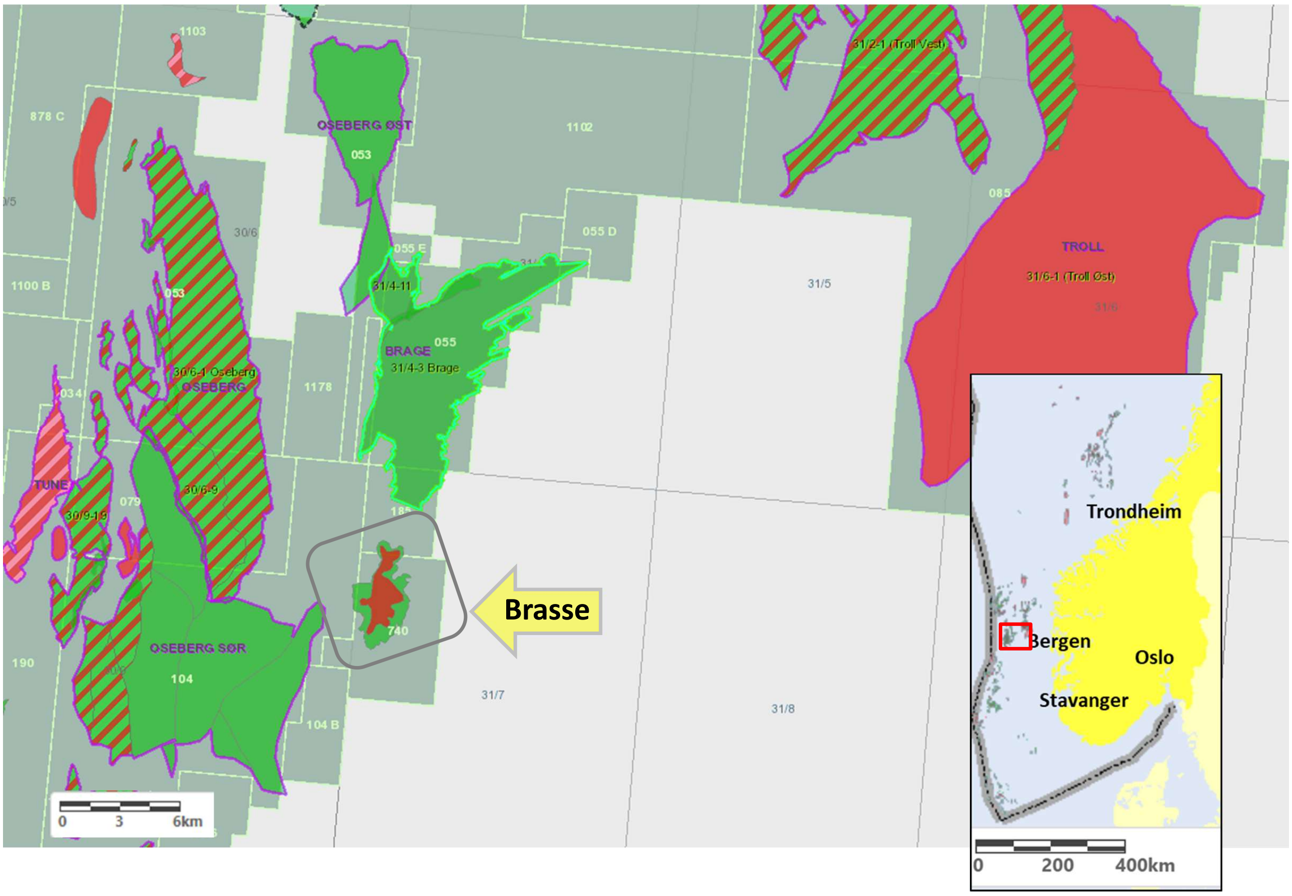

Fig. 5.1 Brasse Field Location map
Source: NOD factmaps (www.sodir.no)

PL 740 License transactions in 2023[5]:

- DNO Norge AS acquired a 50% share in Brasse from Vår Energi ASA effective 07.02.2023, increasing DNO's share in Brasse to 100%.
- OKEA ASA acquired a 50% share in Brasse and operatorship from DNO Norge ASA effective 28.02.2023.
- M Vest Energy AS acquired a 4.4424% share in Brasse from OKEA ASA effective 31.10.2023, reducing OKEA's share in Brasse to 45.5576%.
- Lime Petroleum AS acquired a 10.7212% share in Brasse from DNO Norge AS and a 6.2788% share in Brasse from OKEA ASA (17.0% total) effective 29.12.2023.

The post acquisitions licence shares are reflected in Table 5.2 below.

This audit of reserves and contingent resources has been based on the information provided by Lime Petroleum, which included Lime's Statement of Reserves (SoR), the Operator's RNB2024 submission, meeting documents (RC, TC, MC) from 2023, monthly status reports for 2023, work program and budget (WP&B) 2024, Brasse draft DG3 subsurface support Document[35],Brasse DG3 final Subsurface report[36], as well as Lime's answers to AGR's questions and clarification requests (Q&A)[25].

Licence details summary is shown in Table 5.1. The production licence give the licences full rights to explore and produce hydrocarbons at all stratigraphic levels within the licence area.

Table 5.1 Brasse summary table

Asset name/ Country	***Lime interest (%)***	**Rex's interest of Lime (%)**	***Development Status***	***Licence expiry date***	***Licence Area (km2)***	***Type of mineral, oil or gas deposit***	***Remarks***
PL 740 (Brasse) / Norway	*17.0000*	91.652	*FID Q1 2024*	07.02.2024*	*55*	*Oil and gas*	-

** Lifetime extension will be applied for when DG3/PDO is submitted. Brage (host platform) lifetime is currently 06.04.2030.*

The Brasse licence shares are listed in Table 5.2.

Table 5.2 Brasse licence shares (%)

Licence	**OKEA ASA (Op)**	**DNO Norge AS**	**M Vest Energy AS**	**Lime Petroleum AS**
PL 740 (Brasse)	39.2788	39.2788	4.4424	17.0000

Discovery

Brasse was discovered in 2016 by well 31/7-1. The well confirmed gas and oil in Late Jurassic, Oxfordian to Kimmeridgian/Volgian, sandstones and siltstones of the Sognefjord Formation, Viking Group. The structure has been penetrated, in total, by six wellbores. No wells are drilled in the western segment. The reservoir depth is approximately at 2200 m TVD MSL. An 18 m gas column and 24.4 m oil column were identified and the MDT pressure data proved a OWC at 2172 m TVD MSL, and a general Gas Oil Contact (GOC) at 2148 m TVD MSL. The wellbore was plugged back for sidetracking and abandoned in 2016 as an oil and gas discovery. [35][5]

Reservoir

The Brasse discovery is a 14 km2 low relief, three-way dip closure with a stratigraphic pinchout (north) as result of the north-south oriented fault block rotation and erosion related to the Volgian unconformity. The discovery consists of three segments: Brasse Main, North and West segments. The reservoir rock is the Upper Jurassic, Oxfordian to Kimmeridgian, Sognefjord Formation, being its gross thickness, net reservoir and net pay are variable from excellent in the south to poor in the north of Brasse. The Sognefjord reservoir sands were deposited in marginal to shallow marine environment with several cyclical events in the form of regressive cycles (dominated by deltas front, mouth bars) and transgressive cycles (characterised by tidally influenced lobes and tidal bars). From these cycles, the reservoir rocks named Z1, Z2, Z3, Z4, and Kimmeridgian from deeper to shallower, only Z2 to Kimmeridgian are hydrocarbon filled. The Kimmeridgian reservoir is limited to the north-eastern area only (31/7-3 S). Well 31/7-3 A, drilled in the northern area of Brasse, encountered the Z2 and Z3 reservoir intervals filled with different oils (34 °API) compared to all reservoir levels in the main area to the South (36 °API). These sand intervals have been interpreted as smaller local closures separated from the main area to the South. In general, the reservoir properties vary from excellent in southern area to poor in north, being the average porosity for the zones in the range of 16 - 24% and permeability varies between 50 mD and 5 D (up to 13 D)[37]. Pressure depletion is observed in all six Brasse wells, and are considered to be caused by production from the Troll field, located 35 km northeast of Brasse. The Troll field is connected to Brasse via a regional aquifer.

Development

Brasse is planned to be developed as a 13 km subsea tie back to the Brage host facility. Drainage strategy is depletion with pressure support from gas cap and aquifer support. The development plan comprises two horizontal oil producers, one dual lateral and one single wellbore, in Brasse main segment. The wells will be almost centered in the 24 m oil column (marginally closer to the GOC). Both producers will have inflow control to support well clean-up & HC recovery. Gas lift will be installed for later use after water breakthrough.

No drill stem test was performed in Brasse discovery well 31/7-1. A DST was performed in appraisal well 31/7-2 S (2017) in the Sognefjord reservoir. The well flowed 548 Sm3 oil/day with a GOR of 158 Sm3/Sm3. The oil density was 0.844 g/cm3 and the gas gravity was 0.716 (air = 1) with 0.8% CO_2 and 0.5% H_2S. The maximum flowing temperature was 88.5 °C.

The two satellite wells will produce commingled through a manifold and back to the Brage Field through a 10 inch Pipe in Pipe (PiP) pipeline for processing. From Brage, the oil will be transported by pipeline to Oseberg and through the Oseberg Transport System (OTS) pipeline to the Sture terminal in Norway. The gas export pipeline is tied back to Statpipe.

AGR considers the current Brasse development concept as a reasonable sub-sea tie-back project with a fairly limited topside scope on Brage.

Technical lifetime of the wells and facilities

The design lifes of the Brasse wells and subsea facilities is expected to be sufficient for the current and potentially extended production life of Brage. Current production life is 2030, same as the technical lifetime of Brage. The Brasse lifetime may, however, be extended as a result of the ongoing lifetime extension activities on Brage.

Status
Brasse DG2 was passed in July 2023, and DG3 (PDO) is planned in Q1 2024. Hence, Brasse resources are considered contingent resources until a DG3 is approved. Time is critical as Brasse is planned to come on stream in 2027 and current CoP on Brage (host platform) is 2030, i.e. only four years of production on Brasse. However, Brage is evaluating a liftetime extension option.

The gas processing capacity on Brage (2.5 MSm3/d) is currently fully utilised by Brage. To secure sufficient gas processing capacity for Brasse, a term sheet is in place where Brage is compensated in cash (i.e. no deferral).

The appraisal wells (last one drilled in 2018/2019) have shown that Brasse was depleted by approximately 20 bar (~2 bar/year). This pressure depletion, observed in all six wells drilled in Brasse, is considered to be caused by production from the giant Troll Field, located approximately 35 km North East and connected to Brasse via a massive regional aquifer.

PIIP numbers presented by Lime
The PIIP estimates as of 31.12.2023 are listed in Table 5.3.

Table 5.3 Brasse PIIP 31.12.2023

	PIIP, 31.12.2023		
	Low	**Base**	**High**
Oil/Condensate (MMbbl)	48.1	55.4	65.2
Gas (BScf)	72.9	82.7	98.5

Description of the PIIP

- The PIIP estimates are based on the updated full field reservoir model for DG3 for Sognefjord Formation, performed during 2023. The PIIP in Table 5.3 has been approved in the final version of the DG3[36] by the licence in Q1 2024. This PIIP is lower (<10%) than the PIIP reported in RNB2024.
- The PIIP in Table 5.3 includes the volumes from the Main segment only. The West and North segments (not included in Table 5.3) are uncertain and considered as upsides, presenting the following split in PIIP (base case):
  - North segment: 21 MMbbl of oil/condensate; 18.8 BScf of gas
  - West segment: 10.3 MMbbl of oil/condensate; 8.9 BScf of gas

- The DG3 model is based on the re-evaluation of the CGG23M03 seismic database and interpretations, including the review of well logs, fluid samples, core data, DST, PVT analyses and special core analysis available from all wells. The resulting DG3 reference case, based on the transitional facies change (TFC) depositional model, was used as the basis for a full uncertainty analysis in a combined static and dynamic ensemble workflow. The selected base case resulted in PIIP close to the P50 distribution.
- PIIP uncertainty ranges for Table 5.3 corresponds to -13% and +15% around the PIIP base case for oil/condensate and to -12% and +16% around the PIIP base case for gas. The most influencing static variables on PIIP are oil/water contacts, the structure and facies 3D distribution.
  - Specifically, West segment is uncertain regarding the top structure, reservoir quality, presence and distribution and OWC. Geophysical evaluations concluded that the western fault may not seal towards the south, indicating that the west and main segments connected. In addition, the AVO analysis supports both that the reservoir rock is of quality and the existence of hydrocarbon bearing reservoir in the West segment. The segment is not proven.
  - The PIIP uncertainty for both the North and the West segments are over +/- 25%.

<u>Changes in PIIP since certification 31.12.2022</u>

- Brasse is a first time certification and no PIIP was reported 31.12.2022

The production licence give the licensees full rights to explore and produce hydrocarbons at all stratigraphic levels within the licence area.

Technical profiles and Contingent Resources numbers presented by Lime
The recoverable volumes of Brasse are classified as Contingent Resources according to PRMS, i.e. no technical production profiles are presented in this report.

The Contingent Resources include the following projects:

- Brasse Development Project (DG2 in July 2023, DG3/PDO planned in Q1 2024).

According to the PDO schedule, a DG3 decision is planned Q1 2024. Once the DG3 is approved by the licence, AGR's view is that the Brasse resources will qualify as reserves “Justified for Development” subject to an economic anlysis and cut-off.

<u>Description of the production profiles</u>

- The production profile is based on Operator's full field simulation model.
- The simulation model covers Brasse Main, North and West segments.
- The pressure communication and inflow from North and West segments into main segment is uncertain but assumed to be very limited.
- Brasse is in a hydrodynamically active system:
  - Degree of pressure loss dependent on work program on Troll (i.e. offtake volume).
  - Uncertain movement of GOC and OWC over time which can influence the placement and performance of development wells.
- Brasse is planned to come on stream January 2027 and ends year-end 2030 in alignment with Brage CoP.
  - The technical recoverable resource profile ends year-end 2035.
- According to Lime, there is a term sheet agreement in place where Brage is compensated in cash due to gas processing limitations (i.e. no deferral).

<u>Description of the cost profiles</u>

- The Brasse volumes are not yet classified as reserves, hence the associated development and operating costs have not been reviewed by AGR.

Contingent Resources certified by AGR

Comments to PIIP

AGR has reviewed the following documentation: Brasse RNB2024[38], Lime Statement of Reserves[4], Q&A [25], Brasse draft DG3 Subsurface Support Document[35] and Brasse DG3 final document[36] with the following comments:

- Note that neither static nor dynamic models were available and therefore these are not evaluated by AGR.
- The volumes presented in Table 5.3 corresponds to the final DG3 PIIP and is approximately 10% less than PIIP presented in RNB2024.
- While AGR agrees with the main uncertainties described, it is of AGR's opinion that ranges of uncertainty of -13%/+15% for oil/condensate and -12%/+16% for gas of PIIP base case are very narrow given the nature of the static parameters conforming the major uncertainties and for a discovery in a DG3 as Brasse. AGR assumes that this may be the combined result of the following factors:
  - The total amount of variables selected for the uncertainty analysis
  - The analysis may run the variables independently of each other, as interdependency relations may not be defined in the static model.
- In AGR's opinion, the following factors may constitute additional uncertainty:
  - The large, lateral heterogeneity that depositional environments such as the ones forming the reservoir rocks in the upper part of the Sognefjord Formation could reduce the total PIIP by incorporating poorer properties to the average values.
  - The vertical isolation of reservoirs, given the extensive shales that might be deposited at every maximum flooding surface.
  - Oil of type of Brage Sognefjord interval found in 31/7-3 A. AGR suggests that this may be a sign of communication between the northern segment of Brasse and the Brage Field.
- Based on the documentation delivered, AGR suggests that PIIP presented by Lime is satisfactory. However, AGR regards the uncertainty range of PIIP to be narrow given the observations described above.

Comments to TRR

AGR has reviewed Lime's asset presentation[30] and available documentation including licence meeting handouts, Brasse DG3 subsurface report[35], Lime Statement of Resources (SoR)[4] and RNB2024[38].

- The two planned development wells are located in the main segment which is the primary target. The simulation model suggests very limited pressure communication and inflow from North and West segments into Main segment.
- There are several parameters indicating a more complex reservoir that could potentially influence drainage efficiency and the recovery of resources such as:
  - Main segment
    - Reservoir properties are deteriorating from excellent in southern area to poor in the northern area.
    - The formation pressure analysis indicates some degree of vertical baffling between the different reservoir sands. This can be explained by the existence of a total of four maximum flooding surfaces within Sognefjord Formation proven by biostratigraphy analyses indicating the presence of extensive, lateral transgressional shales. These might vertically isolate each reservoir.
  - North segment
    - Reservoir properties are varying from excellent in well 31/7-3 S to poor in well 31/7-3 A.
    - Pressure data in the deeper Z2 and Z3 sand layers (below 2170 m TVD SS) encountered in Well 31/7-3 A in north segment suggests a separation from the shallower layer as well as the main segment. The Z2 and Z3 layers in well 31/7-3 A also have different oil properties (34 °API) compared to the rest of the field (36 °API) suggesting a small local closure.

- West segment
    - Brasse West segment is considered un-proven (i.e. prospective resources) as there are no well penetrations and separated from main segment by a major fault. Hence, the West segment represents an upside potential.
- The pressure depletion induced by the production from Troll (~20 bar) gives rise to a pressure gradient which varies across the field.
- GOC and OWC are not flat surfaces, but vary locally as a function of pressure depletion and reservoir properties.
- Relative permeability is also considered an area with large uncertainty.
- Low relief structure in combination with relative thin oil column (~25 m) with a gas cap may be challenging in terms of effective sweep and oil recovery.
- The short planned production lifetime of four years emphasise the importance of schedule risk in case of a delay. LTE on Brage will reduce this risk.
- A two well development relies on high availability of both wells to secure the TRR volumes.
- The profiles presented by Lime are consistent with the draft DG3 profiles.
- In AGR's opinion the production profiles presented by Lime are reasonable.

<u>Comments to facilities and cost profiles</u>

- The Brasse facilities and costs have not been reviewed in detail by AGR. The facility development solution seems reasonable.

<u>Economic evaluation and reserves determination</u>

The recoverable volumes of Brasse are classified as Contingent Resources according to PRMS and have therefore not been subject to an economic evaluation. The gross and net Contingent Resources are shown in Table 5.4 below.

<u>Changes since certification 31.12.2022</u>

The gross Brasse balance sheet for Contingent Resources is shown in Table 5.5.

- Brasse is a first time certification.

Acquisitions and sales (+26.139 MMboe for 2C gross):

- Lime Petroleum AS acquired a 10.7212% share in Brasse from DNO Norge AS effective 29.12.2023.
- Lime Petroleum AS acquired a 6.2788% share in Brasse from OKEA ASA effective 29.12.2023.

<u>Comments to recovery factors and resource ranges</u>

- The oil and gas recovery factors are shown in Table 5.6 including LTE. The oil recovery factor of 30% is based on STOIIP from Brasse Main segment. The oil recovery factor is considered reasonable, taken into account varying reservoir properties, thin oil column, drainage by depletion with limited pressure support from gas cap and aquifer and pressure depletion from Troll Field.
- The oil equivalent uncertainty range is -24%/+16% versus 2C (Table 5.5). The range is narrow for a project at this maturity level, but considered reasonable given the low overall recovery factor.

<u>Conclusions</u>

- PIIP is based in the DG3 final documentation, approved in February 2024. DG3 PIIP is approximately 10% lower than PIIP in RNB2024 as of 31.12.2023. AGR considers the PIIP related to the Main segment presented by Lime to be acceptable, however its uncertainty range is considered narrow given the nature of variables contributing to it.
- The short planned production lifetime of four years emphasise the importance of schedule risk in case of a delay. LTE on Brage will reduce this risk.
- A two well development relies on high availability of both wells to secure the TRR volumes.

- The Brasse Contingent Resources reported by Lime are well documented, based on sound industry practice and consistent with draft DG3 report[35].
- AGR hereby endorses the Brasse Contingent Resources (Table 5.4), as reported in Lime SoR for Brasse[4].
- Brasse West segment represents an upside potential.
- Once the Brasse DG3 is approved by the licence (planned Q1 2024), AGR's view is that Brasse resources will qualify as reserves "Justified for Development" subject to economic analysis and cut-off.

Table 5.4 Gross and net Contingent Resources as of 31.12.2023 - Brasse

Brasse	**Gross (100%)**			**Lime net (17.0000%)**			**Rex 91.652% of Lime**		
Contingent resources (MMboe)	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
Brasse Development	19.94	26.14	30.43	3.39	4.44	5.17	3.11	4.07	4.74
Total, MMboe	**19.94**	**26.14**	**30.43**	**3.39**	**4.44**	**5.17**	**3.11**	**4.07**	**4.74**

Table 5.5 Balance sheet - Brasse Contingent Resources (100%)

Gross contingent resource balance, 31.12.2022 - 31.12.2023, for Brasse (100%)							
Resource class	**Status 31.12.2022**	**Production (Positive)**	**Revisions**	**Acquisitions or sales**	**IOR**	**Discoveries/ New Projects**	**Status 31.12.2023**
Oil and condensate, MMbbl							
1C	-	-	-	12.91	-	-	12.91
2C	-	-	-	16.49	-	-	16.49
3C	-	-	-	20.39	-	-	20.39
Gas, BScf							
1C	-	-	-	29.42	-	-	29.42
2C	-	-	-	40.36	-	-	40.36
3C	-	-	-	42.01	-	-	42.01
NGL, MMbbl oe							
1C	-	-	-	1.79	-	-	1.79
2C	-	-	-	2.46	-	-	2.46
3C	-	-	-	2.56	-	-	2.56
Oil equivalents, MMbbl oe							
1C	-	-	-	**19.94**	-	-	**19.94**
2C	-	-	-	**26.14**	-	-	**26.14**
3C	-	-	-	**30.43**	-	-	**30.43**

Table 5.6 Brasse P50 Recovery Factors

	Oil RF by 31.12.2023	**Oil RF at EUR**	**Gas RF by 31.12.2023**	**Gas RF at EUR**
Brasse	-	30% *	-	49% *

* Based on STOIIP from Brasse Main segment

6 Appendices

A.1 Economics and Technical Profiles

Economic evaluations have been conducted to determine reserves by using the AGR economic model reflecting the fiscal regime governing the oil and gas industry on the Norwegian Continental Shelf. The price and financial assumptions in Table 6.1 below were provided by Lime and AGR consider these assumptions to be reasonable and have applied them in the economic evaluations.

The technical production and cost profiles used in the economic evaluations have been supplied by Lime and reviewed by AGR. Processing and transportation tariffs reported are 0.5 NOK/Sm3 for oil, 0.5 NOK/Sm3 for Gas and 0.5 NOK/Sm3 oe for NGL - as provided by Lime.

Gas prices and volumes reported assume a calorific value of 40 MJ/Sm3.

The evaluations are forward looking from 01.01.2024, thus any historical costs prior to that date have been ignored. Economic cut-off year is estimated as the year of maximum cumulative net cash-flow. Abandonment costs are shifted to the first year after economic cut-off. When production profiles extend beyond the available cost profiles, it is assumed that the cost level is kept unchanged.

Table 6.1 Price and financial assumptions from Lime

	Units	**2024**	**2025**	**2026 -> EOFL**
Oil/Condensate Price	USD/bbl (real2024)	85	75	70
Gas Price (40 MJ/Sm3)	NOK/Sm3 (real2024)	4.01	3.36	2.51
NGL Price	USD/boe (real2024)	68	60	56
Exchange rate	NOK/USD	10.0	9.5	9.5
Inflation rate	2% p.a.			
Present value reference date	01.01.2024			
Discount hurdle rate	8% p.a. (nominal)			
Tax	78% (22% corporate tax rate + 56% special tax rate)			

A.1.1 Yme Technical Production and Cost Profiles

Yme, P90 case economics input (100%), R.T. MNOK2023

Year	Oil (Volume) MMbbl	Dry Gas (Volume) BScf	NGL (Volume) MMbbl oe	CAPEX MNOK	OPEX MNOK	Other Costs MNOK	Tariff MNOK	Aband. Costs MNOK
2024	7.409	-	-	87	1552	395	-	-
2025	5.518	-	-	-	1214	309	-	-
2026	4.215	-	-	-	1185	294	-	-
2027	3.109	-	-	-	1132	274	-	-
2028	2.399	-	-	-	978	253	-	-
2029	1.901	-	-	-	1107	236	-	-
2030	1.548	-	-	-	1052	217	-	-
2031	1.286	-	-	-	879	197	-	-
2032	1.089	-	-	-	725	188	-	-
2033	0.929	-	-	-	723	184	-	-
2034	0.805	-	-	-	588	180	-	-
2035	0.704	-	-	-	471	175	-	179
2036	-	-	-	-	-	-	-	1710
2037	-	-	-	-	-	-	-	1008
2038	-	-	-	-	-	-	-	167
2039	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	5
2041	-	-	-	-	-	-	-	-
Sum	30.912	-	-	87	11606	2903	-	3070
@COP 2028	22.651	-	-	87	6062	1526	-	-

Yme, P50 case economics input (100%), R.T. MNOK2023

Year	Oil (Volume) MMbbl	Dry Gas (Volume) BScf	NGL (Volume) MMbbl oe	CAPEX MNOK	OPEX MNOK	Other Costs MNOK	Tariff MNOK	Aband. Costs MNOK
2024	8.594	-	-	87	1552	395	-	-
2025	6.391	-	-	-	1214	309	-	-
2026	4.902	-	-	-	1185	294	-	-
2027	3.994	-	-	-	1132	274	-	-
2028	3.228	-	-	-	978	253	-	-
2029	2.578	-	-	-	1107	236	-	-
2030	2.259	-	-	-	1052	217	-	-
2031	1.903	-	-	-	879	197	-	-
2032	1.661	-	-	-	725	188	-	-
2033	1.460	-	-	-	723	184	-	-
2034	1.308	-	-	-	588	180	-	-
2035	1.192	-	-	-	471	175	-	179
2036	-	-	-	-	-	-	-	1710
2037	-	-	-	-	-	-	-	1008
2038	-	-	-	-	-	-	-	167
2039	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	5
2041	-	-	-	-	-	-	-	-
Sum	39.469	-	-	87	11606	2903	-	3070
@COP 2035	39.469	-	-	87	11606	2903	-	179

Yme, P10 case economics input (100%), R.T. MNOK2023

Year	Oil (Volume) MMbbl	Dry Gas (Volume) BScf	NGL (Volume) MMbbl oe	CAPEX MNOK	OPEX MNOK	Other Costs MNOK	Tariff MNOK	Aband. Costs MNOK
2024	9.178	-	-	87	1552	395	-	-
2025	6.798	-	-	-	1214	309	-	-
2026	5.195	-	-	-	1185	294	-	-
2027	4.229	-	-	-	1132	274	-	-
2028	3.448	-	-	-	978	253	-	-
2029	2.742	-	-	-	1107	236	-	-
2030	2.394	-	-	-	1052	217	-	-
2031	2.015	-	-	-	879	197	-	-
2032	1.774	-	-	-	725	188	-	-
2033	1.553	-	-	-	723	184	-	-
2034	1.387	-	-	-	588	180	-	-
2035	1.262	-	-	-	471	175	-	179
2036	-	-	-	-	-	-	-	1710
2037	-	-	-	-	-	-	-	1008
2038	-	-	-	-	-	-	-	167
2039	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	5
2041	-	-	-	-	-	-	-	-
Sum	41.974	-	-	87	11606	2903	-	3070
@COP 2035	41.974	-	-	87	11606	2903	-	179

A.1.2 Brage Technical Production and Cost Profiles

Brage, P90 case economics input (100%), R.T. MNOK2023

Year	Oil (Volume) MMbbl	Dry Gas (Volume) BScf	NGL (Volume) MMbbl oe	CAPEX MNOK	OPEX MNOK	Other Costs MNOK	Tariff MNOK	Aband. Costs MNOK
2024	4.157	5.686	0.316	827	1023	-	81	236
2025	1.876	1.919	0.086	108	1027	-	27	185
2026	1.108	- 0.056	- 0.034	57	1086	-	- 1	42
2027	0.923	- 0.602	- 0.068	11	1022	-	- 8	10
2028	0.837	- 0.825	- 0.081	10	984	-	- 12	371
2029	0.621	- 1.242	- 0.107	10	957	-	- 18	740
2030	0.509	- 1.530	- 0.002	-	312	-	- 22	780
2031	-	-	-	-	-	-	-	1641
2032	-	-	-	-	-	-	-	824
2033	-	-	-	-	-	-	-	807
2034	-	-	-	-	-	-	-	123
2035	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	6
2037	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-
Sum	10.031	3.351	0.111	1023	6412	-	48	5764
@COP 2025	6.033	7.605	0.402	935	2050	-	108	421

Brage, P50 case economics input (100%), R.T. MNOK2023

Year	Oil (Volume) MMbbl	Dry Gas (Volume) BScf	NGL (Volume) MMbbl oe	CAPEX MNOK	OPEX MNOK	Other Costs MNOK	Tariff MNOK	Aband. Costs MNOK
2024	5.748	8.486	0.487	827	1023	-	121	236
2025	2.478	3.411	0.177	108	1027	-	48	185
2026	1.448	0.745	0.015	57	1086	-	11	42
2027	1.203	0.001	- 0.031	11	1022	-	0	10
2028	1.129	- 0.244	- 0.046	10	984	-	- 3	371
2029	0.818	- 0.870	- 0.084	10	957	-	- 12	740
2030	0.696	- 1.230	- 0.106	-	312	-	- 17	780
2031	-	-	-	-	-	-	-	1641
2032	-	-	-	-	-	-	-	824
2033	-	-	-	-	-	-	-	807
2034	-	-	-	-	-	-	-	123
2035	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	6
2037	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-
Sum	13.519	10.299	0.413	1023	6412	-	147	5764
@COP 2025	8.226	11.896	0.664	935	2050	-	169	421

Brage, P10 case economics input (100%), R.T. MNOK2023

Year	Oil (Volume) MMbbl	Dry Gas (Volume) BScf	NGL (Volume) MMbbl oe	CAPEX MNOK	OPEX MNOK	Other Costs MNOK	Tariff MNOK	Aband. Costs MNOK
2024	6.791	10.322	0.599	827	1023	-	147	236
2025	2.839	4.415	0.239	108	1027	-	63	185
2026	1.647	1.266	0.046	57	1086	-	18	42
2027	1.376	0.401	- 0.006	11	1022	-	6	10
2028	1.339	0.189	- 0.019	10	984	-	3	371
2029	0.949	- 0.614	- 0.068	10	957	-	- 9	740
2030	0.797	- 1.023	- 0.093	-	312	-	- 14	780
2031	-	-	-	-	-	-	-	1641
2032	-	-	-	-	-	-	-	824
2033	-	-	-	-	-	-	-	807
2034	-	-	-	-	-	-	-	123
2035	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	6
2037	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-
Sum	15.738	14.956	0.697	1023	6412	-	213	5764
@COP 2026	11.277	16.002	0.884	991	3136	-	228	462

A.2 Summaries of Oil and Gas Reserves and Resources

A.2.1 Yme - Summary of Oil and Gas Reserves and Resources

The Summary of Oil and Gas Reserves and Resources for Yme as of 31.12.2023 is shown in Table 6.2 below.

Table 6.2 Yme - Summary of Oil and Gas Reserves and Resources

Category	Gross Attributable to Licence (MMbbl / Bcf)	Net Attributable (10.00% Lime share) (MMbbl / Bcf)	Net Attributable (91.652% Rex Int.. Share of Lime) (MMbbl / Bcf)	Change[1] from previous update (%)	Risk Factors[2]	Remarks
Reserves						
Oil Reserves						
1P	22.65	2.27	2.08	-12.2%	N.A.	-
2P	39.47	3.95	3.62	-27.8%	N.A.	-
3P	41.97	4.20	3.85	-27.7%	N.A.	-
Natural Gas Reserves						
1P	-	-	-	-	-	-
2P	-	-	-	-	-	-
3P	-	-	-	-	-	-
Natural Gas Liquids Reserves						
1P	-	-	-	-	-	-
2P	-	-	-	-	-	-
3P	-	-	-	-	-	-
Contingent Resources						
Oil						
1C	2.30	0.23	0.21	53.4%	0.60	Immature project
2C	8.20	0.82	0.75	173.2%	0.60	Immature project
3C	9.55	0.95	0.87	112.1%	0.60	Immature project
Natural Gas						
1C	-	-	-	-	-	-
2C	-	-	-	-	-	-
3C	-	-	-	-	-	-
Natural Gas Liquids						
1C	-	-	-	-	-	-
2C	-	-	-	-	-	-
3C	-	-	-	-	-	-

- *1P: Proved*
- *2P: Proved + Probable*
- *3P: Proved + Probable + Possible*
- *MMbbl: Millions of barrels*
- *Bcf: Billions of cubic feet*

Name of Qualified Person: Steinar S. Johansen

Date: 13. March 2024

Professional Society Affiliation / Membership:

- Society of Petroleum Engineers (SPE)
- European Association of Geoscientists and Engineers (EAGE)
- London Petrophysical Society (LPS)
- CFA Institute

Notes:

1) Net Attributable to Issuer means the Company's effective working interest share under the respective production licence. The Company is entitled to a full share of these volumes. Lime Petroleum's shareholders are Rex International Investments Pte. Ltd. (at 91.652%), a wholly owned subsidiary of Rex International Holding Limited, and Schroder & Co Banque SA (at 8.348%).

2) Applicable to Resources. "Risk Factor" for Contingent Resources means the estimated chance, or probability, that the volumes will be commercially extracted.

A.2.2 Brage - Summary of Oil and Gas Reserves and Resources

The Summary of Oil and Gas Reserves and Resources for Brage as of 31.12.2023 is shown in Table 6.3 below.

Table 6.3 Brage - Summary of Oil and Gas Reserves and Resources

Category	Gross Attributable to Licence (MMbbl / Bcf)	Net Attributable (33.8434% Lime share) (MMbbl / Bcf)	Net Attributable (91.652% Rex Int.. Share of Lime) (MMbbl / Bcf)	Change[1] from previous update (%)	Risk Factors[2]	Remarks
Reserves						
Oil Reserves						
1P	6.03	2.04	1.87	2.6%	N.A.	-
2P	8.23	2.78	2.55	17.2%	N.A.	-
3P	11.28	3.82	3.50	5.2%	N.A.	-
Natural Gas Reserves						
1P	7.61	2.57	2.36	-24.0%	N.A.	-
2P	11.90	4.03	3.69	-19.9%	N.A.	-
3P	16.00	5.42	4.96	-24.4%	N.A.	-
Natural Gas Liquids Reserves						
1P	0.40	0.14	0.12	-47.7%	N.A.	-
2P	0.66	0.22	0.21	-41.7%	N.A.	-
3P	0.88	0.30	0.27	-45.8%	N.A.	-
Contingent Resources						
Oil						
1C	6.52	2.21	2.02	18.9%	0.43	Weighted average of 9 projects
2C	10.58	3.58	3.28	8.8%	0.43	
3C	15.91	5.38	4.93	14.0%	0.43	
Natural Gas						
1C	0.03	0.01	0.01	-99.8%	0.43	-
2C	10.52	3.56	3.26	-36.9%	0.43	-
3C	29.95	10.14	9.29	80.3%	0.43	-
Natural Gas Liquids						
1C	- 0.33	- 0.11	- 0.10	-125.9%	0.43	-
2C	0.18	0.06	0.06	-85.9%	0.43	-
3C	0.88	0.30	0.27	-32.5%	0.43	-

- *1P: Proved*
- *2P: Proved + Probable*
- *3P: Proved + Probable + Possible*
- *MMbbl: Millions of barrels*
- *Bcf: Billions of cubic feet*

Name of Qualified Person: Steinar S. Johansen

Date: 13. March 2024

Professional Society Affiliation / Membership:

- Society of Petroleum Engineers (SPE)
- European Association of Geoscientists and Engineers (EAGE)
- London Petrophysical Society (LPS)
- CFA Institute

Notes:

1) Net Attributable to Issuer means the Company's effective working interest share under the respective production licence. The Company is entitled to a full share of these volumes. Lime Petroleum's shareholders are Rex International Investments Pte. Ltd. (at 91.652%), a wholly owned subsidiary of Rex International Holding Limited, and Schroder & Co Banque SA (at 8.348%).

2) Applicable to Resources. "Risk Factor" for Contingent Resources means the estimated chance, or probability, that the volumes will be commercially extracted.

A.2.3 Brasse - Summary of Oil and Gas Reserves and Resources

The Summary of Oil and Gas Reserves and Resources for Brasse as of 31.12.2023 is shown in Table 6.4 below.

Table 6.4 Brasse - Summary of Oil and Gas Reserves and Resources

Category	Gross Attributable to Licence (MMbbl / Bcf)	Net Attributable (17.00% Lime share) (MMbbl / Bcf)	Net Attributable (91.652% Rex Int.. Share of Lime) (MMbbl / Bcf)	Change[1] from previous update (%)	Risk Factors[2]	Remarks
Reserves						
Oil Reserves						
1P	-	-	-	-	-	-
2P	-	-	-	-	-	-
3P	-	-	-	-	-	-
Natural Gas Reserves						
1P	-	-	-	-	-	-
2P	-	-	-	-	-	-
3P	-	-	-	-	-	-
Natural Gas Liquids Reserves						
1P	-	-	-	-	-	-
2P	-	-	-	-	-	-
3P	-	-	-	-	-	-
Contingent Resources						
Oil						
1C	12.91	2.19	2.01	100%	0.85	New acquisition
2C	16.49	2.80	2.57	100%	0.85	
3C	20.39	3.47	3.18	100%	0.85	
Natural Gas						
1C	29.42	5.00	4.58	100%	0.85	New acquisition
2C	40.36	6.86	6.29	100%	0.85	
3C	42.01	7.14	6.54	100%	0.85	
Natural Gas Liquids						
1C	1.79	0.31	0.28	100%	0.85	New acquisition
2C	2.46	0.42	0.38	100%	0.85	
3C	2.56	0.44	0.40	100%	0.85	

- *1P: Proved*
- *2P: Proved + Probable*
- *3P: Proved + Probable + Possible*
- *MMbbl: Millions of barrels*
- *Bcf: Billions of cubic feet*

Name of Qualified Person: Steinar S. Johansen

Date: 13. March 2024

Professional Society Affiliation / Membership:

- Society of Petroleum Engineers (SPE)
- European Association of Geoscientists and Engineers (EAGE)
- London Petrophysical Society (LPS)
- CFA Institute

Notes:

1) Net Attributable to Issuer means the Company's effective working interest share under the respective production licence. The Company is entitled to a full share of these volumes. Lime Petroleum's shareholders are Rex International Investments Pte. Ltd. (at 91.652%), a wholly owned subsidiary of Rex International Holding Limited, and Schroder & Co Banque SA (at 8.348%).

2) Applicable to Resources. "Risk Factor" for Contingent Resources means the estimated chance, or probability, that the volumes will be commercially extracted.

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A.3 Abbreviations and definitions

Abbreviation	Definition
1C	Low estimate scenario for Contingent Resources.
1P	Proved Reserves; denotes low estimate scenario for Reserves
2C	Best estimate scenario for Contingent Resources.
2P	Proved plus Probable Reserves; denotes best estimate scenario for Reserves
3C	High estimate scenario for Contingent Resources.
3P	Proved plus Probable plus Possible Reserves; denotes high estimate scenario for Reserves
4D	Four Dimensional (time lapse seismic)
AAPG	American Association of Petroleum Geologists
ABEX	ABandonment EXpenditures
AVO	Amplitude Versus Offsets
bbl	Volume unit, 1 barrel = 42 US gallons ≈ 159 L
BHP	Bottom Hole Pressure
Bo	Formation volume factor for oil
BOK	"Beslutning Om Konkretisering". Feasibility decision gate.
BOV	"Beslutning Om Videreføring". Concept selection gate
BRV	Bulk Rock Volume
CAPEX	CAPital EXpenditures
CBM	Controlled Beam Migration
CCA	Conventional Core Analysis, identical to RCA
CGR	Condensate Gas Ratio
CoS	Chance of success
CPI	Computer Processed Interpretation
D	Darcy
DCA	Decline Curve Analysis
DG1	Decision Gate 1; At least one technical concept is demonstrated economical
DG2	Decision Gate 2; Concept selection
DG3	Decision Gate 3; Project sanction; deliver PDO
DST	Drill Stem Test
EAGE	European Association of Geoscientists and Engineers
EC	Engineering Committee
EOFL	End of Field Life
EOS	Equation Of State
EOY	End Of Year
ESP	Electrical Submersible Pump
EUR	Estimated Ultimate Recovery; the sum of reserves and historic production
FFM	Full Field Model
FLAGS	Far North Liquids and Associated Gas System
Fm	Formation
FMT	Formation Multi-Tester™ (Weatherford); formation pressure data, also MDT, RCI, RFT
FOL	Free Oil Level
FPSO	Floating Production Storage and Offloading vessel
FWL	Free Water Level
GBS	Gravity Base Structure
GCV	Gross Calorific Value
GDT	Gas Down To
GIIP	Gas Initially In Place
GOC	Gas-Oil Contact
Gp	Group

Abbreviation	Definition
G	billion (Giga) SI unit multiplier = 109
GWC	Gas-Water Contact
HCPV	Hydrocarbon Pore Volume
HM	History Match
ICD	Inflow Control Device
IOR	Increased Oil Recovery
km	Kilometre
LPA	Lime Petroleum AS
LQ	Living Quarters
LWD	Logging While Drilling
m	meter, milli
mm	million; oilfield unit multiplier
mmbbl	million barrels of stock tank oil
mmboe	million barrels of oil equivalent
mmbtu	million British thermal units
mD	millidarcy, permeability unit
M	million (Mega) SI unit multiplier = 106
MBAL	Material Balance (software)
MC	Management Committee
MD	Measured Depth
MDT	Modular Formation Dynamics Tester™ (Schlumberger); formation pressure data, also FMT, RCI, RFT
MJ	megajoule (million joules)
MNOK	Million NOrwegian Kroner
MOD	Money Of the Day
MOPU	Mobile Offshore Production Unit
MODPU	Mobile Offshore Drilling and Production Unit
MSL	Mean Sea Level
Mt	Million tonnes
MUSD	Million US Dollars
MWD	Measurement While Drilling
NCS	Norwegian Contintental Shelf
NGL	Natural Gas Liquids
NOD	Norwegian Offshore Directorate
NOK	Norwegian Kroner
NPD	Norwegian Petroleum Directorate
NPV	Net Present Value
oe	Oil Equivalent. 1 Sm3 oe = 1 Sm3 oil =1000 Sm3 gas
OED	Olje og Energi Departementet (Ministry of oil and energy)
ODT	Oil Down To
OPEX	OPerating EXpenditures
OTS	Oseberg Transport System
OWC	Oil-Water Contact, identical to WOC
PDO	Plan for Development and Operations
PDQ	Processing Drilling and Quarter
PIIP	Petroleum Initially In Place
PLT	Production Logging Tool
PRMS	Petroleum Resources Management System
PSA / PTIL	Petroleum Safety Authority of Norway
PSDM	Pre-Stack Depth Migration

Abbreviation	Definition
PVT	Pressure Volume Temperature; fluid properties
PV	Present Value
QC	Quality Control (Quality Check)
RC	Resources category (in the NPD's resources classification system), Reservoir Committee
RCA	Routine Core Analysis, identical to CCA
RCI	Reservoir Characterization Instrument™ (Baker Hughes); formation pressure data, also FMT, MDT, RFT
RF	Recovery Factor
RFT	Repeat Formation Tester™ (Schlumberger); formation pressure data, also FMT, MDT, RCI
RKB	Rotary Kelly Bushing
RMP	Reservoir Management Plan
rm3	Reservoir cubic metre
RNB	Revised National Budget; sheets/forms (NPD)
RT	Real Terms
Scf	Square foot
Sm3, Sm3	Standard cubic meter
Sw	Water Saturation
SWAG	Simultaneous Water And Gas injection
SCAL	Special Core Analysis
SEG	Society of Exploration Geophysicists
SLS	Submerged Loading System
Sodir	Sokkeldirektoratet
SoR	Statement of Reserves
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
SPWLA	Society of Petrophysicists and Well Log Analysts
SSIV	Subsea Isolation Valve
SSPU	Subsea Pump Upgrade
STOIIP	Stock Tank Oil Initially In Place (at the discovery time)
STOIP	Stock Tank Oil In Place at a specified time after the discovery
SWE	Effective Water Saturation
T	Trillion, SI unit multiplier = 1012
TAR	Turnaround. Planned maintenance shutdowns.
THP	Tubing Head Pressure
Technical	Used with volumes. Refers to values calculated without economic cut-off
TRR	Technically Recoverable Resources. Quantities producible using currently available technology and industry practices, regardless of commercial considerations.
TVD	True Vertical Depth
VSH	Volume of Shale
UK	United Kingdom
USD	US Dollar
WAG	Water Alternating Gas
WCT	Water Cut
WHM	Well Head Module
WI	Water Injector
WOC	Water-Oil Contact, identical to OWC
WPC	World Petroleum Congress
WUT	Water Up To
ÅTS	Åsgård Transport System

A.4 Summary of 2018 SPE Petroleum Resources Classification

The following table has paragraphs that are quoted from the 2018 Petroleum Resources Management System and summarise the key resources classes and categories, while the figure below shows the recommended sub-classes based on project maturity.

Table 6.5 Summary of 2018 Petroleum Resources Management System

Class/Sub-class	Definition
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.
On Production	The development project is currently producing and selling petroleum to market.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.
Development Unclarified	A discovered accumulation where project activities are under assessment and where justification as a commercial development is unknown based on available information.
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.

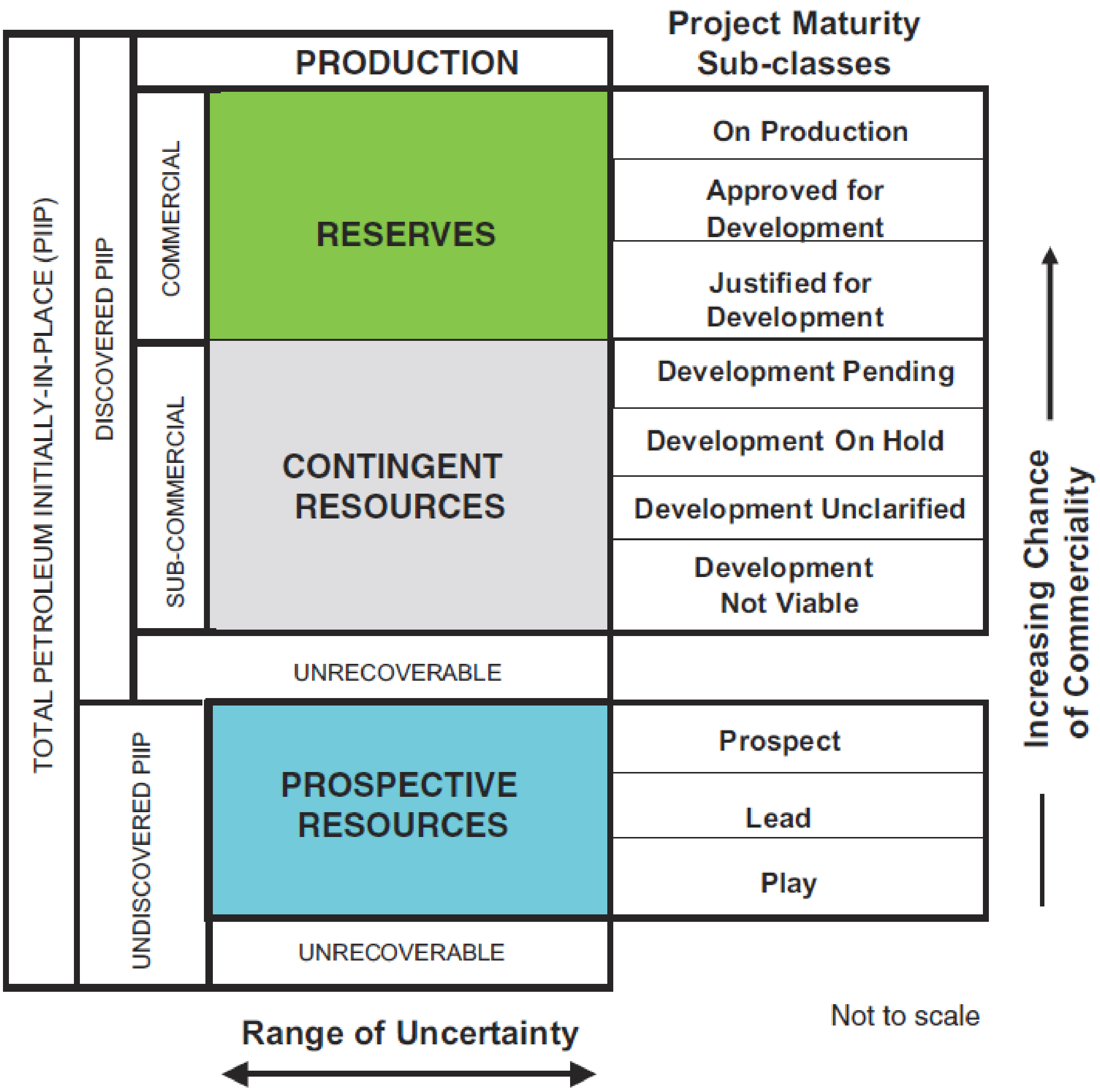

Fig. 6.1 Illustration of the SPE's reserves classification system
Source: www.spe.org

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