



ABL Group Norway AS
Reservoir Management Division
Oslo, Norway



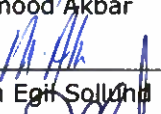
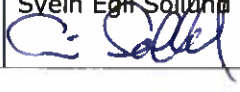
Qualified Person's Report
31.12.2025

For Lime Petroleum Holding AS

March 2026

ABL Group Norway AS

Qualified Person's Report 31.12.2025

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Qualifications

AGR (part of ABL Group Norway AS, Karenslyst allé 4, 0278 Oslo, Norway) is an independent consultancy specialising in, amongst others, petroleum reservoir evaluation, reserves auditing and economic analysis. The company address is Karenslyst allé 4, 0278 Oslo, Norway. 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 Qualified Person's Report (QPR) was managed by Steinar S. Johansen (MEng Petroleum Engineering), AGR Advisor Reservoir Engineer and member of Society of Petroleum Engineers (SPE). Mr. Johansen has 30+ years of international and Norway experience.

The report was reviewed and signed off by Mahmood Akbar (MSc Petroleum Engineering), AGR Advisor Reservoir Engineer, in capacity as Qualified Person. Mr. Akbar is a member of SPE and has 30+ years of international and Norway experience including reserves and resource reporting.

The report was signed and approved by Svein Egil Sollund, ABL Group Norway CEO.

Evaluation Standard

In this Audit of Reserves and Contingent Resources, AGR has applied standard petroleum engineering techniques. This Audit is based on the definitions of the Petroleum Resources Management System (PRMS) revised in 2018 and sponsored by the Society of Petroleum Engineers (SPE), the World Petroleum Council (WPC), the Society of Exploration Geophysicists (SEG), the American Association of Petroleum Geologists (AAPG), the European Association of Geoscientists & Engineers (EAGE) and the Society of Petroleum Evaluation Engineers (SPEE). The requisite disclosures pursuant to Practice Note 6.3 of the Singapore Exchange Securities Trading Limited's Mainboard Listing Rules have been included in this report.

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 herein. 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. ABL Group Norway AS shall have no liability arising out of, or related to, the use of the report.

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1 Executive Summary

This Qualified Person's Report (QPR) is issued for use by Lime Petroleum Holding's (hereafter shortened to Lime) majority shareholder Rex International Holding Ltd (hereafter shortened to Rex). Rex holds an indirect ownership stake in Lime of 89.74%. In 2025 there was a restructuring of ownership in Lime, whereby Rex's share in Lime was increased from 80.14% to the current 89.74%. Rex is listed on the Singapore Stock Exchange.

ABL Group Norway AS (AGR) has carried out an audit of Reserves and Contingent Resources as of 31.12.2025 for Lime, in accordance with the Petroleum Resources Management System (PRMS) of SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE, revised in 2018. This report includes the requisite disclosures pursuant to Practice Note 6.3 of the Singapore Exchange Securities Trading Limited's Mainboard Listing Rules.

The audit encompasses seven assets located in Norway, Germany and Benin. The Lime share of the assets subject to this audit are, according to information received from Lime, held by 100% owned subsidiaries of Lime. Six of the assets contain Reserves, and the Reserves audited by AGR are presented in Table 1.2. Six of the assets include projects with Contingent Resources, listed in Table 1.4.

AGR has carried out economic evaluations to determine the Reserves. The technical production and cost profiles were provided by Lime and reviewed by AGR through an audit approach. The economic assumptions set out in Table 1.1 were provided by Lime, and have been applied in the evaluations by AGR with the addition of oil price differentials specific to each asset.

Table 1.1 Price and financial assumptions from Lime

	Units	2026	2027 -> EOFL ¹⁾
Oil/Condensate Price	USD/bbl (real2026)	65.0	75.0
Gas Price (40 MJ/Sm ³)	NOK/Sm ³ (real2026)	3.60	4.15
NGL Price	USD/boe (real2026)	52.0	60.0
Exchange rate	NOK/USD	10.0	10.0
Exchange rate	EUR/USD	1.20	1.20
Inflation rate	2% p.a.		
Present value reference date	01.01.2026		
Discount hurdle rate	10% p.a. (nominal)		

1) EOFL = End of Field Life

Reserves as of 31.12.2025

The audited gross and net Reserves as of 31.12.2025 endorsed by AGR, are shown in Table 1.2.

Table 1.2 Gross field and net Lime and net Rex Reserves as of 31.12.2025

Asset			100% (MMboe)			Lime Petroleum AS net (MMboe)			Rex 89.74% interest in Lime (MMboe) ³⁾		
	Lime interest (%)	PRMS project maturity	1P	2P	3P	1P	2P	3P	1P	2P	3P
Brage	33.8434	On Production / Approved for Development / Justified for Development	11.08	18.91	25.43	3.75	6.40	8.61	3.37	5.74	7.72
Bestla	17.0000	On Production / Approved for Development	19.39	23.93	28.77	3.30	4.07	4.89	2.96	3.65	4.39
Yme	25.0000	On Production	5.89	6.49	10.15	1.47	1.62	2.54	1.32	1.46	2.28
Erfelden	100.0000	On Production / Approved for Development / Justified for Development	2.71	7.12	8.55	2.71	7.12	8.55	2.43	6.39	7.68
Lauben	50.0000	On Production / Approved for Development	0.09	0.13	0.16	0.04	0.07	0.08	0.04	0.06	0.07
Sèmè North	76.0000 ²⁾	Approved for Development	3.20	5.70	6.08	2.35	4.11	4.38	2.11	3.69	3.93
Total¹⁾			42.36	62.28	79.14	13.62	23.38	29.04	12.23	20.99	26.06

1) Total in table may differ slightly from sum of fields due to rounding.

2) Lime working interest in Sèmè North is 76%, but the Reserves net attributable to Lime are based on the Production sharing contract (PSC) where the sum of Cost Oil and Profit oil less 10% royalties for the 2P estimate add up to 72.1% of the gross oil sales.

3) Rex's share in Lime Petroleum has changed from 80.14% to 89.74% in 2025.

Main changes in Reserves since audit 31.12.2024

The changes to the net Rex 2P Reserves are shown in Table 1.3. The revisions are mainly related to:

- Yme: The negative revision for Yme is mainly due to reduced well potential on Beta, overly optimistic DCA in the 31.12.2024 report and one year earlier economic cut-off.
- Brage: For Brage there is a positive revision driven by better than expected well performance for some key wells and two projects matured to Reserves (Talisker Producer and Cook North).
- Bestla: Hydrocarbons in the western segment on Bestla was confirmed resulting in a positive revision.
- Sèmè North: Development project reduced from four to two development wells.
- Erfelden: New geomodel and simulation model resulting in a revised and phased development plan focusing only on the Upper PBS reservoir. Production after licence period ending 31.12.2044 excluded from assessment.

For the Norwegian assets, the Reserves as of 31.12.2024 refer to the previous AGR report[1]. For the German assets, the Reserves per 31.12.2024 refer to the Sproule-ERCE report[2]. For the Benin asset, the Reserves 31.12.2024 refer to the Exceed report[3].

Table 1.3 Changes in net Rex 2P Reserves since 31.12.2024

Asset	Reserves 31.12.2024 ²⁾ (MMboe)	Production (MMboe)	Revisions and other changes (MMboe)	Reserves 31.12.2025 (MMboe)
Brage	3.37	2.01	4.38	5.74
Bestla	2.96	0.00	0.70	3.65
Yme	3.37	1.03	-0.89	1.46
Erfelden	6.82	0.01	-0.42	6.39
Lauben	0.07	0.01	0.00	0.06
Sèmè North	5.80	0.00	-2.11	3.69
Total ¹⁾	22.38	3.05	1.65	20.99

1) Total in table may differ slightly from sum of fields due to rounding

2) For Germany (Erfelden and Lauben) the date of the last resource evaluation by Sproule ERCE was 30.04.2025

Contingent Resources as of 31.12.2025

The audited gross and net Contingent Resources as of 31.12.2025 endorsed by AGR, are shown in Table 1.4.

Table 1.4 Gross and net Lime and net Rex Contingent Resources as of 31.12.2025

Asset			100% (MMboe)			Lime net (MMboe)			Rex 89.74% interest in Lime (MMboe) ³⁾		
	Lime interest (%)	PRMS sub-class	1C	2C	3C	1C	2C	3C	1C	2C	3C
Brage	33.8434	Development On Hold / Development Unclassified	30.70	55.27	84.80	10.39	18.71	28.70	9.32	16.79	25.75
Bestla	17.0000	Development On Hold	2.20	4.97	8.29	0.37	0.84	1.41	0.34	0.76	1.27
Yme	25.0000	Development Pending	4.79	7.81	9.71	1.20	1.95	2.43	1.07	1.75	2.18
Lunde	30.0000	Development Unclassified	4.65	7.27	10.28	1.39	2.18	3.08	1.25	1.96	2.77
Sèmè North	76.0000 ²⁾	Development Unclassified	- ⁴⁾	21.67	42.51	0.00	15.63	30.67	- ⁴⁾	14.03	27.52
Erfelden	100.0000	Development Unclassified	0.70	2.30	3.00	0.70	2.30	3.00	0.63	2.06	2.69
Total ¹⁾			43.03	99.29	158.59	14.05	41.62	69.29	12.61	37.35	62.18

1) Total in table may differ slightly from sum of fields due to rounding.

2) Lime working interest in Sèmè North is 76%, but the Reserves net attributable to Lime are based on the Production Sharing Contract (PSC) where the sum of Cost Oil and Profit oil less 10% royalties for the 2P estimate add up to 72.1% of the gross oil sales.

3) Rex's share in Lime Petroleum has changed from 80.14% to 89.74% in 2025.

4) For Sèmè North an economic analysis of Contingent Resources was performed by Tetra Tech RPS and an economic cut-off was applied. For 1C the project was uneconomic, hence no 1C Contingent Resources are reported.

Main changes in Contingent Resources since audit 31.12.2024

The changes to the net Lime 2C Contingent Resources are tabulated in Table 1.5. The revisions are mainly related to:

- Brage: Seven new projects and a positive revision for Brage extended lifetime
- Erfelden: Lower PBS moved from Reserves to Contingent Resources
- Sèmè North: One new project (H6 infill well)

For the Norwegian assets, the Contingent Resources per 31.12.2024 refer to the previous AGR report[1]. For the German assets, the Contingent Resources per 31.12.2024 refer to the Sproule/ERCE report[2]. For the Benin asset the Contingent Resources 31.12.2024 refer to the Tetra Tech report[4].

Table 1.5 Changes in net Rex 2C resources since 31.12.2024

Asset	2C Contingent resources 31.12.2024 (MMboe)	Revisions and other changes ²⁾ (MMboe)	2C Contingent resources 31.12.2025 (MMboe)
Brage	11.36	5.43	16.79
Bestla	0.61	0.15	0.76
Yme	1.68	0.08	1.75
Lunde	1.75	0.21	1.96
Sèmè North ¹⁾	10.20	3.83	14.03
Erfelden	0.00	2.06	2.06
Total ³⁾	25.59	11.76	37.35

1) Lime working interest in Sèmè North is 76%, but a net attributable to Lime of 72.1% has been applied to Contingent Resources (the same as for 2P reserves net entitlement).

2) Rex's share in Lime Petroleum has changed from 80.14% to 89.74% in 2025, this is reflected in the volume change.

3) Total in table may differ slightly from sum of fields due to rounding.

2 Introduction and Methodology

ABL Group (AGR, address Karenlyst alle 4, 0278 Oslo, Norway) has carried out an audit of Lime's Reserves and Contingent Resources as of 31.12.2025 in accordance with the Petroleum Resources Management System (PRMS) of SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE, revised in 2018.

This report includes:

- Audit of 1P, 2P and 3P Reserves for the following assets:
 - Norway: Yme Field (Repsol is the operator and Lime subsidiary Lime Petroleum AS owns a 25% share, see Fig. 2.1 for location)
 - Norway: Brage Field (OKEA is the operator and Lime subsidiary Lime Petroleum AS owns a 33.8434% share, see Fig. 2.2 for location)
 - Norway: Bestla Field (OKEA is the operator and Lime subsidiary Lime Petroleum AS owns a 17% share see Fig. 2.2 for location)
 - Benin: Sèmè North Field (Lime subsidiary Akrake Petroleum Benin SA is the operator and Lime owns a 76% share, see Fig. 2.4 for location)
 - Germany: Erfelden Field (Lime subsidiary Lime Resources Germany GmbH is the operator and owns a 100% share, see Fig. 2.5 for location)
 - Germany: Lauben Field (ONEO is the operator and Lime Subsidiary Lime Resources Germany GmbH owns a 50% share, see Fig. 2.5 for location)
- Audit of 1C, 2C and 3C Contingent Resources for the following assets:
 - Norway: Yme Field
 - Norway: Brage Field
 - Norway: Bestla Field
 - Norway: PL838 Lunde (see Fig. 2.3 for location)
 - Benin: Sèmè North Field
 - Germany: Erfelden Field

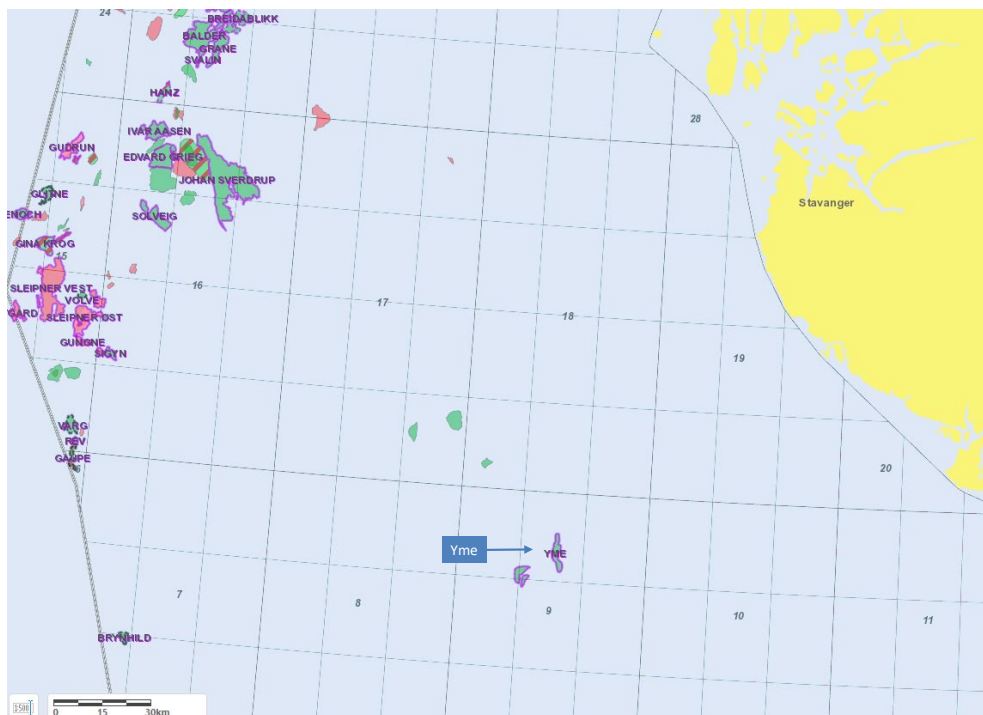


Fig. 2.1 Yme Field location map
Source: www.sodir.no

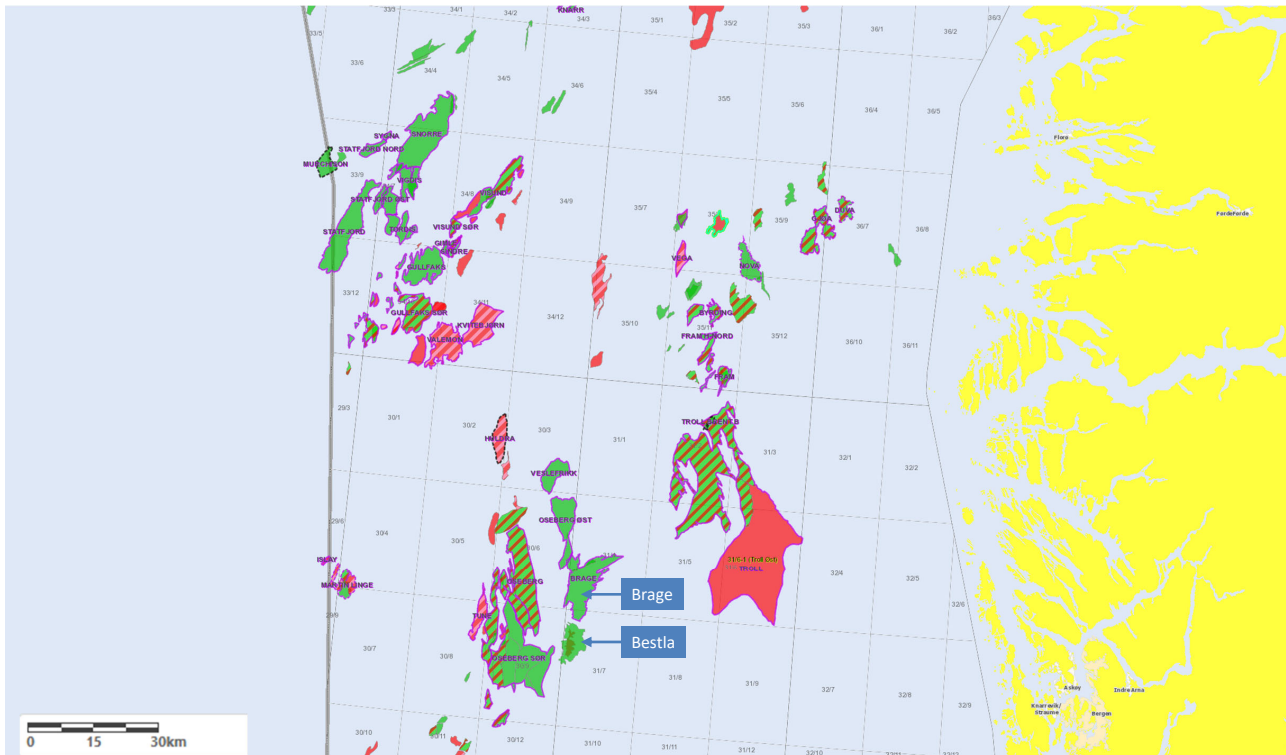


Fig. 2.2 Brage Field and Bestla Field location map
Source: www.sodir.no

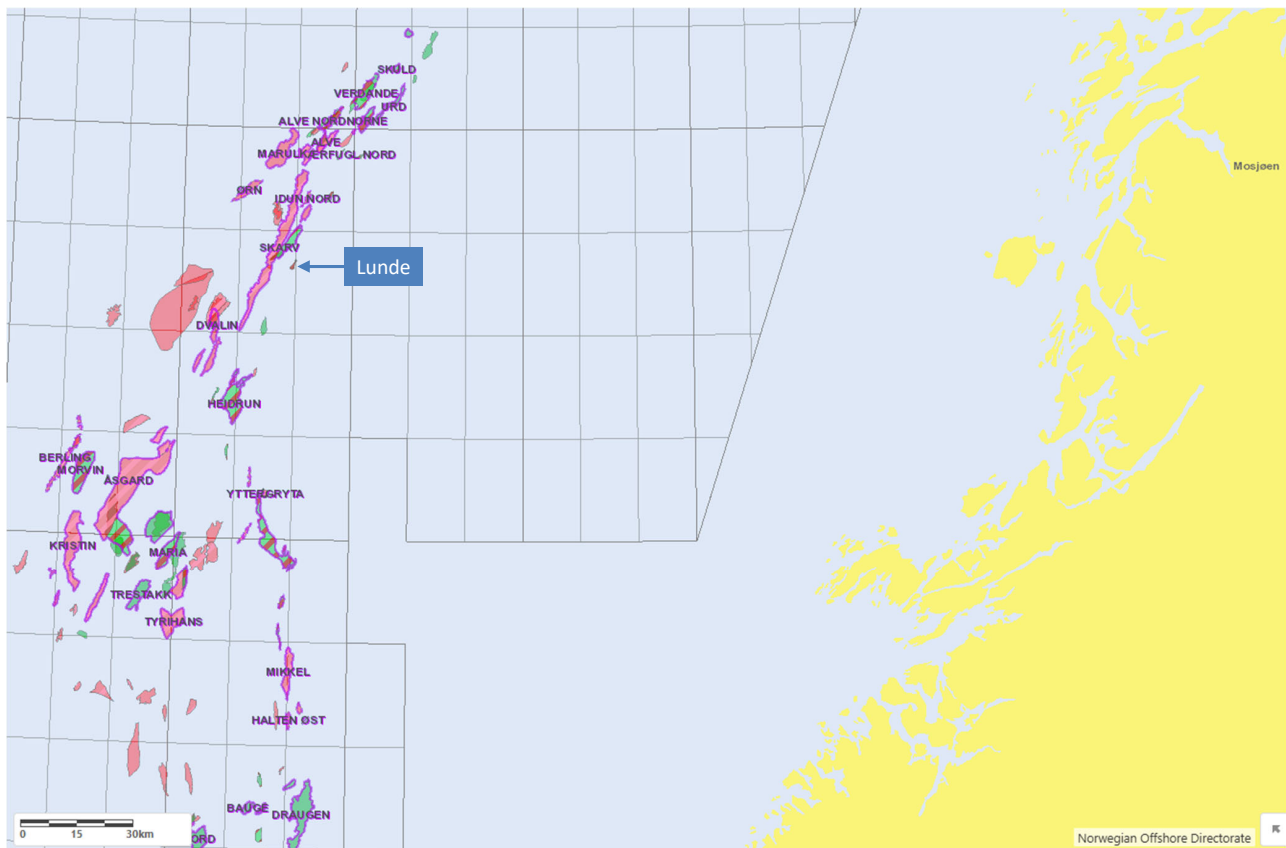


Fig. 2.3 Lunde Discovery location map
Source: www.sodir.no

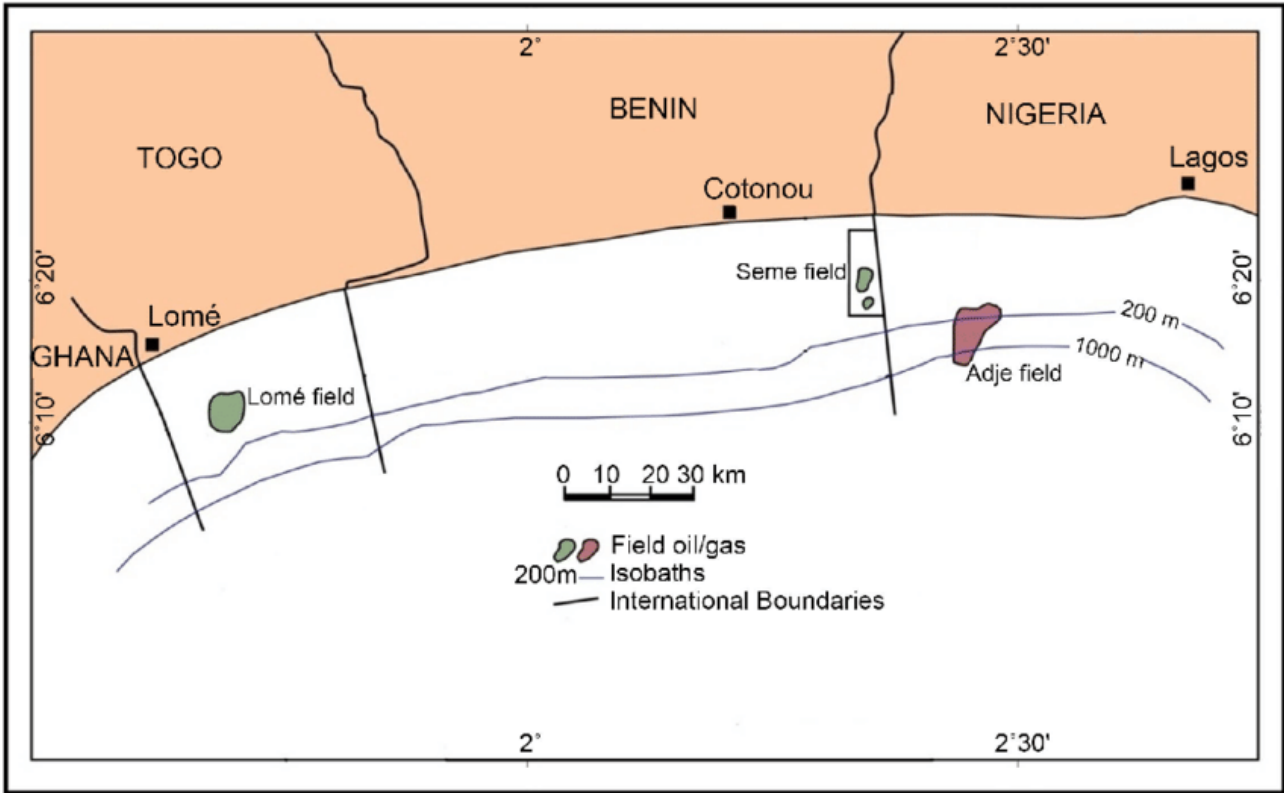


Fig. 2.4 Sèmè Field location map
Source: D'Almeida et al: Structural Modeling of the Top Turonian Reservoir in the Northern Seme Oilfield (Benin, West-Africa) (2021)



Fig. 2.5 Erfelden Field and Lauben Field location map
Source: Lime

Petroleum Initially-In-Place (PIIP), Reserves, and Contingent Resource estimates received from Lime and audited by AGR are expressed in field units (MMbbl and BScf). The combined oil equivalent volume 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 01.01.2026 to end of the profiles.

The reserves and Contingent Resources audited by AGR, per 31.12.2025, are reported in the "Annual Statement of Reserves" (ASR) by Lime. These included production and cost forecasts for Low, Best and High cases. In this report these ASRs from Lime are referred to as:

- 00 AGR Statement of Reserves - Yme[5]
- 00 AGR Statement of Reserves - Brage2025[6]
- 00 AGR Statement of Reserves - Bestla2025[7]
- 00 AGR Statement of Reserves 31 Dec 2025- Lunde[8]
- SoR2026 - Benin[9]
- 00 AGR Statement of Reserves - Erfelden YE2025[10]
- 00 AGR Statement of Reserves - Lauben YE2025[11]

This is the first time the Lime assets and associated resources on Lauben, Erfelden and Sèmè North are audited by AGR.

No site inspections nor visits was conducted as part of this study.

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 Summaries of Oil and Gas Reserves and Resources.
- Contingent Resources presented are technically recoverable volumes not constrained by economic cut-off, except for Benin Contingent Resources where an economic evaluation and economic cut-off has been applied.
- For the assets on the Norwegian Continental Shelf (NCS), the Lime profiles are either based on RNB2026 submissions or based on internal work and analysis by Lime.
- For the assets in Germany and Benin, the Lime profiles are based on internal work and analysis by Lime.
- The gas reserves are reported as sales gas at 40 MJ/Sm³.
- Recovery Factor (RF) in this report is defined as the sales volumes divided by the Petroleum Initially-In-Place (PIIP). Note that with this definition the gas recovery factor may not represent the correct value since
 - gas is reported as dry sales gas and not rich gas at the wellhead
 - not all produced gas may be sold due to fuel and flare
- The estimated 2025 produced volumes are actuals provided by Lime. These volumes are used for assessment of reserves as of 31.12.2025.

- 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.
- With respect to titles (ownership) to the assets as well as company and ownership structures, AGR has relied upon information received from Lime and has not performed independent verification of these particulars.

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, 1 000
- M = million, 1 000 000
- G = billion, 1 000 000 000
- T = trillion, 1 000 000 000 000

The following conversion factors are applied in the report:

- Oil and condensate
 - 1 Sm³ = 6.29 bbl
 - 1 Sm³ = 1 Sm³ oe = 6.29 boe
- 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

3 Asset Descriptions (AGR Recertifications)

This section covers the four asset in Norway which AGR has previously audited as of 31.12.2024[1]. The sections contain brief asset descriptions and an overview of the resources as of 31.12.2025 for these assets with some commentary on methodology and changes since the estimates reported 31.12.2024. The resource estimates presented in the sections below are gross and net to Lime. In order to convert those numbers to estimates net attributable to Rex, the estimates should be multiplied by Rex's 89.74% share in Lime. The resource estimates net attributable to Rex are found in section 1 Executive Summary as well as in A.1 Summaries of Oil and Gas Reserves and Resources.

3.1 Norway - 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, 140 km southwest of Stavanger, see Fig. 3.1. The water depth is 92 m (Gamma Template).

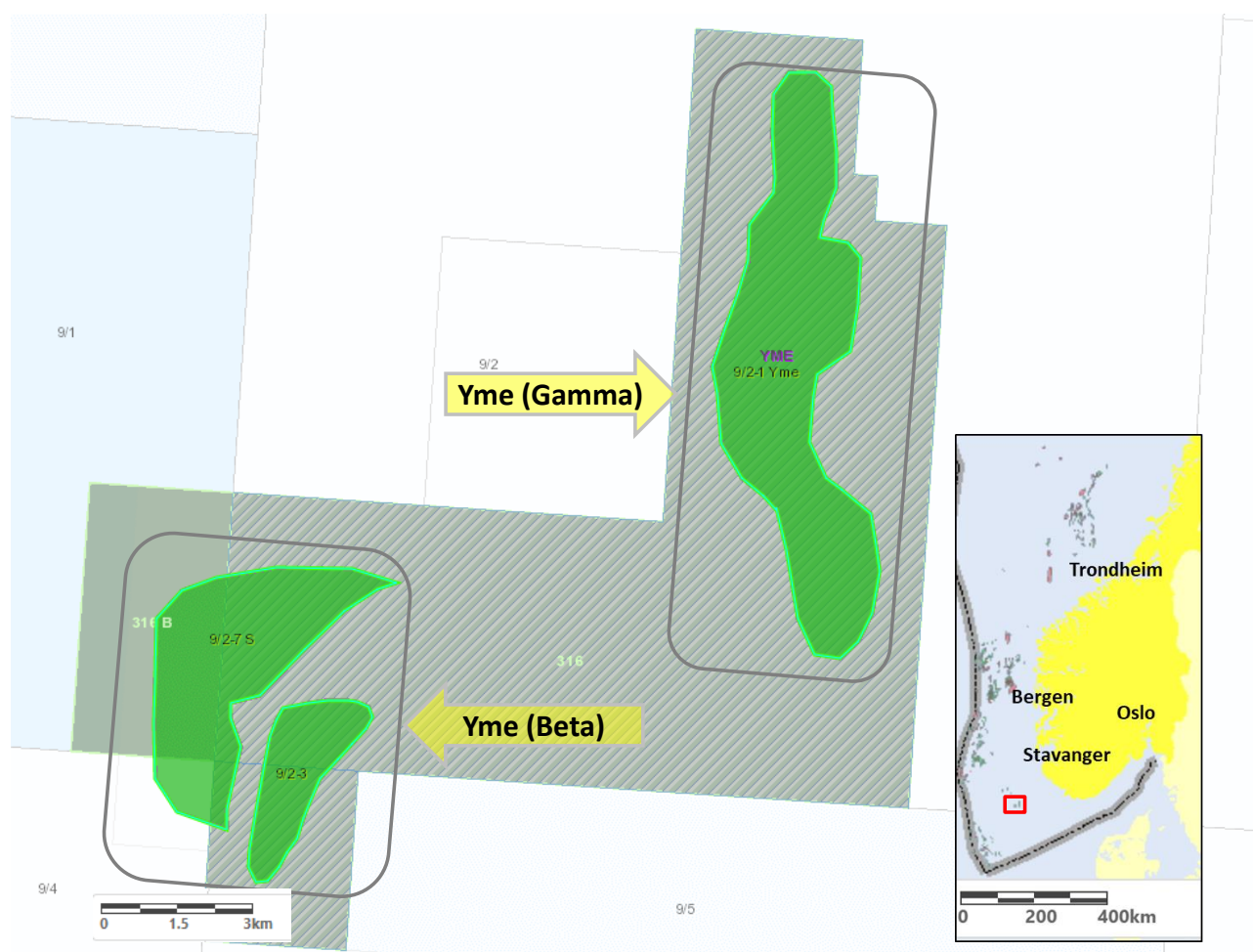


Fig. 3.1 Yme Field location map

Source: NOD factmaps (www.sodir.no)

The field was discovered by Statoil in 1987 and came on production in 1996. Yme ceased production in 2001 after having produced 51 MMbbl of oil, as the operation was no longer profitable in a low oil price environment at the time. The oil recovery factor was only 14%, hence significant volumes were left in the field at the time of abandonment. In 2007, a re-development plan was submitted by the new operator Talisman. In 2013, after drilling nine new development wells and two appraisal wells, the re-development project was abandoned due to structural deficiencies in the offshore production unit. In 2015 a new project

“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.

Licence details summary is shown in Table 3.1 and the licence shares are shown in Table 3.2. 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, which included Lime's Statement of Reserves (SoR), the operator's submission to the Norwegian Revised National Budget for 2026 (RNB2026), meeting documents (RC, TC, MC) from 2025, Annual Status Report, work program and budget (WP&B) 2026, production data for the individual wells, as well as Lime's presentation and answers to AGR's questions and clarification requests.

Table 3.1 Yme Field summary table

Asset name/ Country	Lime's interest (%)	Development Status	Licence expiry date	Licence Area (km ²)	Type of mineral, oil or gas deposit	Remarks
PL 316 / 316 B (Yme) / Norway	25.00	On production	18.06.2030	140	Oil	-

Table 3.2 Yme Field licence shares (%).

Licence	Repsol Norge AS (Op)	ORLEN Upstream Norway AS	Lime Petroleum AS
PL 316 / 316 B (Yme)	55.00	20.00	25.00

Discovery

The Yme Field was discovered in 1987 by well 9/2-1 on the Gamma structure, 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 southwest of the Gamma structure. The discovery was made in reservoir sandstones of the Sandnes formation of Late Jurassic age. In the discovery well, the oil water contact (OWC) was in the transition zone from 3201 to 3210 m TVD MSL. The Beta West structure was discovered by 9/2-7 S, deviated from the Yme Template towards northwest in 1997.

Reservoir

The Yme Field consists of two main accumulations the Gamma and the 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, have been re-developed.

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 2-6 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 stratigraphically upward. The porosity varies from 8 to 23% and permeability from 1 to 2000 mD. The Estuarine sandstones show high permeability which have already been produced by earlier operator (Statoil), whereas Lower Marine sandstones have lower 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.

Recovery Strategy

The re-development strategy has been to produce the Yme field with pressure support from a regional aquifer and partial water injection and water alternating gas (WAG) injection. This strategy has now been changed. Water injection is stopped, and a new pilot project is planned to test gas injection into the oil zone. The producers are equipped with artificial lift (electrical submersible Pumps (ESP) and gas lift).

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:

Reused facilities on the field:

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

Changes and new facilities:

- 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

The field is developed with 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 31.12.2025.

Produced water has historically been re-injected for pressure support. As water injection is now stopped, produced water is disposed to sea. Artificial lift for the production wells is primarily provided by gas lift, but Gamma East wells are utilising Electrical Submersible Pumps (ESPs). The oil is exported by tankers and gas is used for power generation and gas-lift.

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. The umbilicals, cranes and module supports was in 2024 reported to have technical lifetime expiries in 2029, 2027 and 2030, respectively.

Status

The main reference for this section is the Statement of Reserves for Yme [5], Yme audit presentation and Annual Status Report 2025.

Currently, there are 5 active platform producers (C-1, C-3A, C-4, C-8A and C-9) accessing the Yme Gamma area. Well C-2 is converted to a temporary gas injection pilot and is injecting excess field gas together with well C-5. Wells C-1 and C-8A have experienced ESP failures. The ESP in C-1 will be replaced early 2026, but currently there are no plans to replace the ESP in C-8A which will continue to produce at lower rates on gas-lift only.

Two subsea tie-back producers (E-1 and E-3) are currently producing from the Yme Beta Structure. The subsea producers D-1H and D-2H are shut-in due to high well watercuts causing flowline water slugging and in severe process instability issues leading to inability to meet the mandated oil-in-water specifications. The two Beta water injectors are shut-in.

Actual production for 2025 was 4.57 million barrels oil, which is 27% lower than the Base forecast in the 31.12.2024 Reserves Report. The main reasons for this low performance are;

- Total production efficiency below forecast, mainly due to ESP failures in wells C-1 and C-8. (as per end November 2025; 74.4% vs target of 85.5%).
- Reduced productivity in Beta wells.

There are plans for further development of the field by infill drilling in both the Gamma and Beta structures.

Petroleum Initially-In-Place (PIIP) presented by Lime

The PIIP estimates as of 31.12.2025 are shown in Table 3.3.

Table 3.3 Yme PIIP estimate as of 31.12.2025

	PIIP, 31.12.2025 (Best Estimate)
Oil/Condensate (MMbbl)	362
Gas (BScf)	122

Description of the PIIP

- The PIIP 31.12.2025 estimate and is based on the Phase II static model built in 2020, which is updated with post-drill results.
- The model framework was built from PSDM (Post-Stack Depth Migration) 3D seismic. The model has incorporated new interpreted top and base reservoir, improved faults, new petrophysical interpretation and revised sedimentological concepts.
- The subsurface uncertainties incorporated in the static model were Top reservoir structure, Free Water Level (FWL) in different segments and property modelling. Among these, structure uncertainty was considered to be the most significant for the PIIP volume. In order to address potential influence of structural and depth uncertainty, pore volume multiplier was introduced in the modelling.
- There is no change in the reported PIIP estimates since 31.12.2024.

Reserves and Technical profiles presented by Lime

The Reserves are based on the technical production and cost profiles provided by Lime. AGR has performed an economic evaluation to ensure project commerciality and the correct economic cut-off for the Reserves with the economic assumptions shown in appendix A.1 Summaries of Oil and Gas Reserves and Resources. The resulting gross and net Reserves are shown in Table 3.4.

The Reserves include the following project, classified according to PRMS:

- Yme Base Production - "On Production"

For the Base price scenario, the economic cut-offs are:

- 1P: end of 2027, eight years earlier than technical cut-off
- 2P: end of 2027, eight years earlier than technical cut-off
- 3P: end of 2028, seven years earlier than technical cut-off

Table 3.4 TRR and Reserves as of 31.12.2025 - Yme

	TRR (Gross 100%)			Reserves (Gross 100%)			Reserves (Net 25.0000%) ¹⁾		
	Low	Best	High	1P	2P	3P	1P	2P	3P
1st Production	25 October 2021								
Cut-off (year end)	2035	2035	2035	2027	2027	2028	2027	2027	2028
Oil/condensate (MMbbl)	15.49	18.99	24.22	5.89	6.49	10.15	1.47	1.62	2.54
Gas (BScf)	-	-	-	-	-	-	-	-	-
NGL, (MMboe)	-	-	-	-	-	-	-	-	-
Total (MMboe)	15.49	18.99	24.22	5.89	6.49	10.15	1.47	1.62	2.54

1) Net Reserves in Table above are net to Lime. Rex's share in Lime is 89.74%. For reserves net to Rex, see 1 Executive Summary and A.1.1 Yme - Summary of Oil and Gas Reserves and Resources.

The production history and technical sales forecasts for oil (without the economic cut-off) are illustrated in Fig. 3.2.

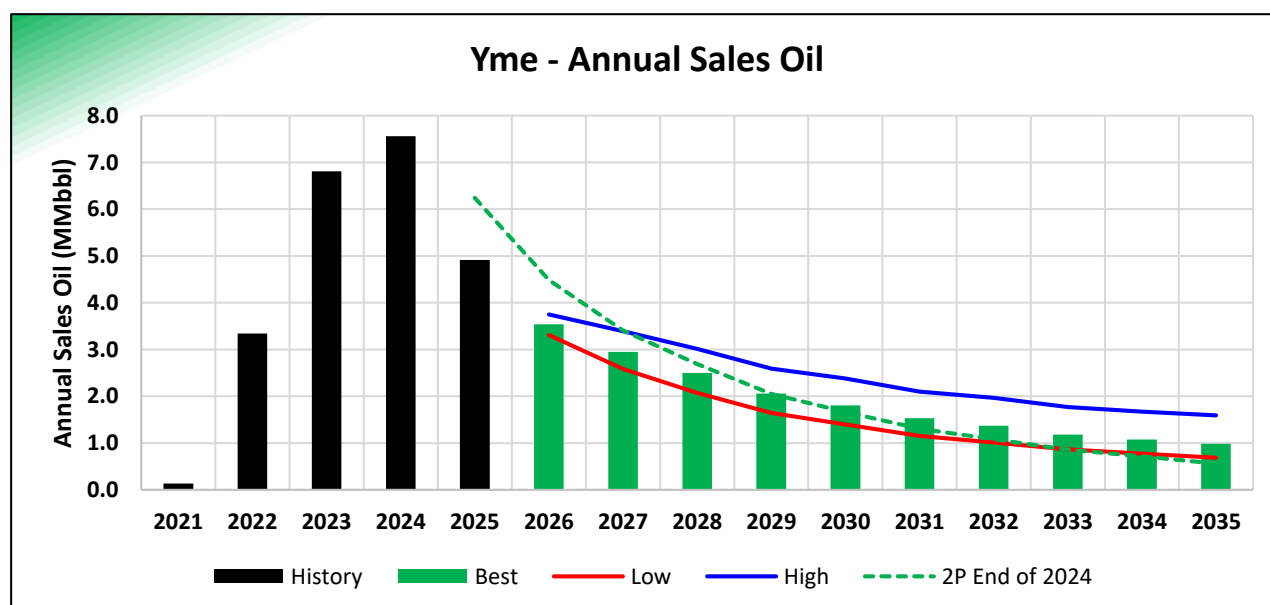


Fig. 3.2 Yme - annual sales oil

Description of the production profiles

Decline curve analysis is the main tool for estimating production profiles and Reserves for Yme.

- Production efficiencies are included on a well basis, and are backed up with historical data.
- The Operator assumes lifetime extension and present technical profiles to 2035.
- Base production includes production from Gamma wells C-1, C-3A, C-4, C-8A, C-9 and Beta wells E-1AH and E-3H.
- Water injection is now stopped permanently due to high cost and limited reward.
- Gas injection into the oil zone is planned as a pilot in well C-2.
- The TRR Low estimate is 18% lower, and the High estimate is 28% higher, than the Base estimate.

Description of the cost profiles

The cost profiles applied by Lime are similar to those in RNB2026 and are in line with the Work Program and Budget (WP&B) for 2026 profiles and is reflecting operational experience and future activity level. From 2031, the lease contract of the Mærsk Inspirer expires, and the rig will be owned by the Yme licence which will result in lower OPEX. According to Lime, there is a commitment in the lease contract that Yme will have to pay the lease rate up to 2031 even if the cash flow becomes negative prior to 2031.

Changes in Reserves since audit 31.12.2024

The gross Yme balance sheet for Reserves is shown in Table 3.5. The main reasons for the changes are summarised below:

- 2025 Production
- Reduced well potential, especially in Beta
- Overly optimistic DCA in the 31.12.2024 Reserves Report (was based on Operator's RNB2025 estimate)
- One year earlier economic cut-off for the 2P estimate

Table 3.5 Balance sheet - Yme Reserves (100%)

Gross reserves balance, 31.12.2024 - 31.12.2025, for Yme (100%)							
Reserves class	Status 31.12.2024	Production (Positive)	Revisions	Acquisitions or sales	IOR	Discoveries/ New Projects	Status 31.12.2025
Oil and condensate (MMbbl)							
1P	13.47	4.57	-3.01	-	-	-	5.89
2P	16.82	4.57	-5.76	-	-	-	6.49
3P	24.93	4.57	-10.21	-	-	-	10.15
Gas (BScf)							
1P	-	-	-	-	-	-	-
2P	-	-	-	-	-	-	-
3P	-	-	-	-	-	-	-
NGL (MMboe)							
1P	-	-	-	-	-	-	-
2P	-	-	-	-	-	-	-
3P	-	-	-	-	-	-	-
Oil equivalents (MMboe)							
1P	13.47	4.57	-3.01	-	-	-	5.89
2P	16.82	4.57	-5.76	-	-	-	6.49
3P	24.93	4.57	-10.21	-	-	-	10.15

Contingent Resources presented by Lime

The Contingent Resources presented by Lime are shown in Table 3.6.

Table 3.6 Gross and net Contingent Resources as of 31.12.2025 - Yme

Yme		GROSS (100%)			NET (25.0000%) ¹⁾		
Contingent resources (MMboe)	PRMS subclass	1C	2C	3C	1C	2C	3C
Infill Drilling Beta	Development Pending	3.53	5.26	6.44	0.88	1.32	1.61
Infill Drilling Gamma	Development Pending	1.25	2.55	3.27	0.31	0.64	0.82
Total, MMboe		4.79	7.81	9.71	1.20	1.95	2.43

1) Net Contingent Resources in Table above are net to Lime. Rex's share in Lime is 89.74%. For Contingent Resources net to Rex, see 1 Executive Summary and A.1.1 Yme - Summary of Oil and Gas Reserves and Resources.

Infill drilling Gamma: the project includes infill drilling in Gamma as a sidetrack of C-4. Several targets/ concepts are being pursued. DG1 was passed in 2025, and the DG2 and DG3 process is expected first half 2026.

Infill drilling Beta: the project includes a multilateral side-track of D-1AH, targeting Beta South-East. DG1 was passed in 2025. The DG2 process was initiated, but is currently on hold awaiting the outcome of the DG2 for the Gamma infill and the FID for the Draupne gas import project. Beta infill only makes sense if the economic life time for Yme is extended by a successful Gamma infill well.

Changes in Contingent Resources since audit 31.12.2024

The gross changes in Contingent Resources for Yme are shown in Table 3.7. The main reasons for the changes are summarised below:

- The Artificial Lift project is removed due to lack of commerciality.
- Infill drilling (three wells) on Beta and Gamma are matured further, and recoverable resource estimates are increased.

Table 3.7 Balance sheet - Yme Contingent Resources (100%)

Gross contingent resource balance, 31.12.2024 - 31.12.2025, for Yme (100%)							
Resource class	Status 31.12.2024	Production (Positive)	Revisions	Acquisitions or sales	IOR	Discoveries/ New Projects	Status 31.12.2025
Oil and condensate (MMbbl)							
1C	6.56	-	-1.77	-	-	-	4.79
2C	8.36	-	-0.55	-	-	-	7.81
3C	10.33	-	-0.62	-	-	-	9.71

AGR comments to PIIP, Reserves and Contingent Resources

Comments to PIIP

AGR has checked the Phase II static model which is 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'. AGR has reviewed available documents with following comments:

- The PIIP numbers are consistent with those in the RNB2026 submission and reported in Factpages on the Norwegian Offshore Directorate.
- The PIIP figures presented by Lime have not changed since 31.12.2024.
- Uncertainty of the PIIP relative to the Best estimate are -11% for Low case and +13% for High case, as presented in the Table 3.3.
- AGR considers that the ranges for PIIP are narrow considering the reservoir heterogeneity of the field and structural uncertainty related to Top reservoir interpretation and variable free water level (FWL) in different segments.
- AGR considers Phase II static model does not represent geology in a fully satisfactory way. The low permeability zone which is the current reservoir target has been modelled coarsely. Therefore, high permeability layers within low permeability zone are not represented properly.
- AGR endorses the PIIP estimates presented by Lime for Yme.

Comments to production profiles

AGR has reviewed the production performance of the wells currently on production. The database is updated to 31.12.2025. AGR has also reviewed the procedure for using the decline analysis (DCA) as basis for the Lime production profiles. The operator have updated the dynamic simulation models. According to Lime, the quality of the models has improved the last year, resulting in a significantly better match to historical production and pressure data. Despite this, both the operator and Lime continue to rely on well-level DCA for production forecasting.

AGR has the following observations and comments:

- The DCA analyses presented by Lime are done in line with sound industry practice.
- Oil and water historical rates show relatively good trends, which are reflected in Lime's analyses.
- Production efficiencies appear reasonable, based on historical data from the past year.
- Total EUR presented by Lime is slightly higher than that from the Operator's forecasts presented in RNB2026.

- There are significant uncertainties related to future water-cut development due to uncertainties in compartmentalization and rock properties. Lime's Low/High estimates may not fully capture this uncertainty.

The Lime production profiles in Statement of Reserves - Yme[5] are considered reasonable.

Comments to facilities and cost profiles

The Yme facilities performance has improved since the start-up of the "Yme new development" project in 2022 when several operating upsets were experienced. Except for the Electrical Submersible Pumps (ESPs), the facility performance has improved and is now considered reasonable. The average 2025 production efficiency as per September 2025 was 74% vs plan 86%, mainly due to the malfunction of the ESPs.

A project has been initiated with the aim of reducing emissions and cost by reducing the consumption of diesel as fuel. Gas import by pipeline from Draupner is considered the main alternative. Preliminary project cost estimate cost is 686 MNOK. A final investment decision (FID) is planned for first half of 2026.

There are no sanctioned CAPEX or drilling activities planned for the coming years.

Lime has applied the cost profiles similar to the Yme RNB2026 and in line with the WP&B2026. AGR finds the applied cost profiles acceptable, however, Repsol is considering Cessation of Production (COP) in 2035. AGR can not see that the cost of classing of the Mærsk Inspirer and other required upgrades are reflected in the current cost profiles.

Comments to Reserves and recovery factors

- The recovery factor after the initial development was 14%. In the 2017 PDO for the "Yme new development" project, the 2P recovery factor assuming 10 years production was estimated to be 30%.
- The 2P oil recovery factors estimated for this audit are shown in Table 3.8. AGR finds the final recovery factor of 22% to be moderate but reasonable taking into account the complexity of the field combined with the pre-mature economic cut-off for the field, driven by very high OPEX forecasts.
- The 1P Reserves estimate is -9% and 3P is +56% versus 2P. The upside is impacted by the later economic cut-off compared to the Best and Low cases.
- The estimated ultimate recovery factor of 22% is below the average on the NCS, which is 47%. It should thus be feasible to achieve the planned extractable volumes. However, considering the adverse water cut development, active reservoir management will probably be necessary, such as drilling of more wells, re-completions, adjustments to production facilities, to achieve higher recovery.

Table 3.8 Yme 2P recovery factors

	Oil 31.12.2025	Oil at EUR	Gas 31.12.2025	Gas at EUR
Produced (MMbbl/BScf)	72.13	78.62	-	-
Recovery factor	20%	22%	-	-

Comments to Contingent Resources

For the Gamma and Beta infill potential, Lime is using the Operator's estimate as presented in RNB2026. Recoverable volumes for both projects are based on dynamic simulations with the history matched Gamma and Beta models. Interference with existing wells is a challenge, and timing is critical as limited cash-flow from the field is available in the years to come.

AGR Conclusions

- The Yme Reserves reported by Lime are based on internal DCA estimates. The audit by AGR has found these estimates to be based on sound industry practices.
- The uncertainty on Yme is high with respect to future water-cut in existing wells, and also with respect to the potential for previous flooding in the new potential producer locations (Contingent

Resource infill wells). The uncertainty range from the DCA estimates could be larger to reflect this uncertainty better.

- The current recovery factor is low, and it is reasonable to assume that the planned recoverable volumes can be produced.
- AGR endorses the Yme Reserves (Table 3.4) and Contingent Resources (Table 3.6) presented by Lime.

3.2 Norway - 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, see Fig. 3.3. The field lies within production licences 053B, 055, 055B, 055D, 055E, 055FS and 185; and blocks 30/6, 31/4 and 31/7[12]. The field is unitised in the Brage Unit. The Brage Unit's licence periods were extended in 2025 to 31.12.2040. Licence details summary is shown in Table 3.9 and the licence shares are shown in Table 3.10. The production licence give the licensees full rights to explore and produce hydrocarbons at all stratigraphic levels within the licence area. In 2025 a Right-to-produce agreement with PL053 was made.

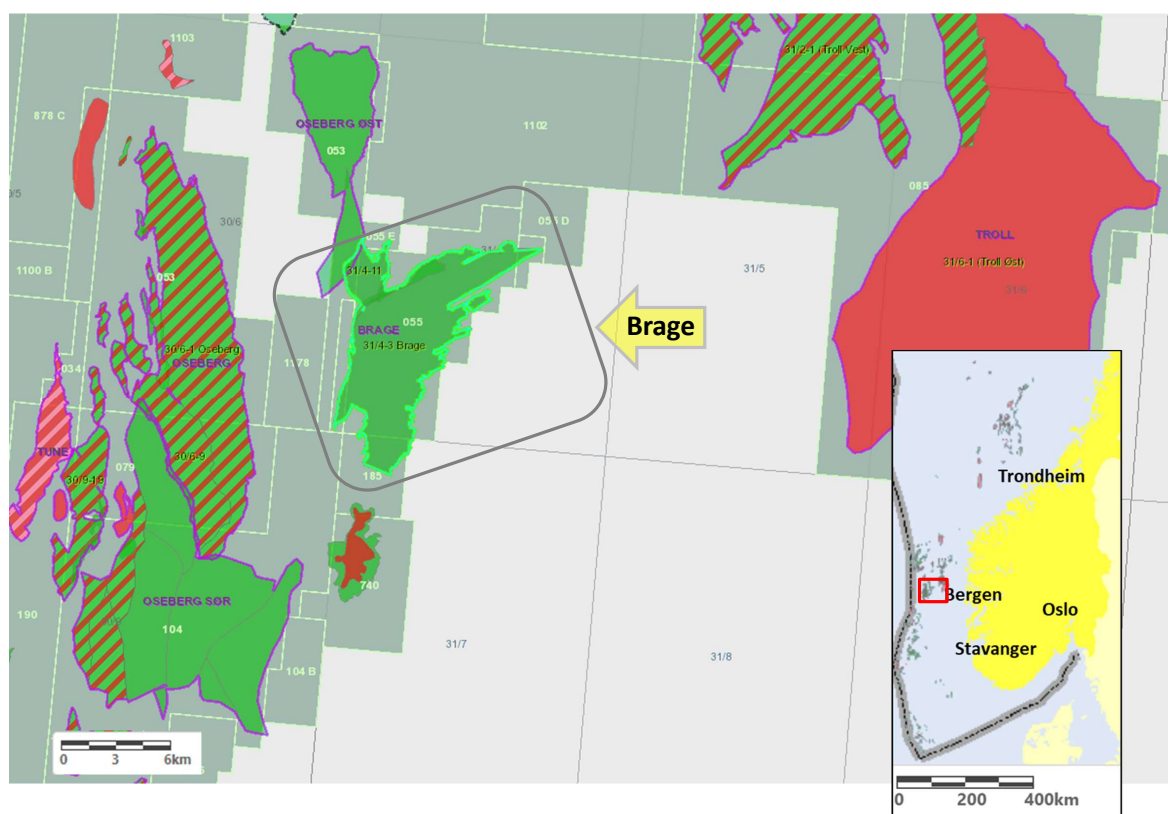


Fig. 3.3 Brage Field location map
Source: NOD factmaps (www.sodir.no)

The water depth varies from 130 to 170 m and the reservoir depth varies between 2000-2300 m TVD MSL. The field has been on production since 1993.

This audit has been based on the information provided by Lime, which included Lime's Statement of Reserves (SoR), the operator's submission to the Norwegian Revised National Budget for 2026 (RNB2026), meeting documents (RC, TC, MC) from 2025, monthly status reports from 2025, Annual Status Report, work program and budget (WP&B) 2026, production data for the individual wells, as well as Lime's presentation and answers to AGR's questions and clarification requests.

Table 3.9 Brage Field summary table

Asset name/ Country	Lime's interest (%)	Development Status	Licence expiry date	Licence Area (km²)	Type of mineral, oil or gas deposit	Remarks
Brage Unit / Norway	33.8434	On production	31.12.2040	183.33	Oil and gas	Licence extension

Table 3.10 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. Before that, in 1979, the well 31/4-2 discovered oil in the Upper Jurassic Brent Group in what is now known as the Talisker area. In 1984, appraisal well 31/4-7 proved oil in Statfjord Formation west of the main field in a horst structure with a higher reservoir pressure[12]. In addition, the near-by well 31/4-2 on the northern part of the Brage Horst proved oil and gas in the Brent Group. The field also include proven oil and gas accumulation in A-13 E Sognefjord East (Kimmeridgian sandstones, the Kim discovery). In 2025, the 31/4-A15 BT2 discovered oil and gas in the Cook and Statfjord Formations of the Talisker Horst.

Reservoir

The Brage Field has many compartments, both structural and stratigraphic, and is broadly seen as having a main field (the Brage area) situated down flank and east of a bounding host, the Brage Horst. The Talisker area may be seen as a continuation of the Brage Horst, which continues to the north and forms a well-developed high with basins to both east and west. This is in contrast to the Brage main area, where the east side of the horst system has not developed into a deep basin and is separated from the basin to the north by a series of major NW-SE striking faults. The Talisker area continues to the north, cut by cross faults which downthrow to the north, eventually becoming the structure hosting the Oseberg Øst and Veslefrikk Fields.

The main Brage Field contains the Fensfjord and Sognefjord oil and gas accumulations. Here, the Sognefjord Formation is found in the north and east with most of the production coming from the northern part, commonly referred to as the Bowmore Horst. To the east, oil and gas have been discovered in the Sognefjord Formation, in a number of accumulations, Kim, Cream and Purple Rain. The Bowmore area contains oil and gas in the Sognefjord, Fensfjord, and Lower Oseberg. Further south, across the main body of the field, oil and gas is held mainly in the Fensfjord Formation. The Knockando area holds oil in the Fensfjord in poor quality reservoir. The Talisker Horst contains oil in the Upper and Lower Oseberg, the Cook and the Statfjord formations. The Brage Horst contains oil and gas in the Cook and Statfjord formations. Finally, gas has often been observed in the overlying thin Shetland chalks and limestones, but no resource has been defined or produced.

In general the different reservoir levels do not appear to communicate and there can be compartmentalization within a given reservoir. The reservoir quality varies from poor to excellent and oil population studies indicate that migration has occurred from Oseberg to the west and Oseberg Øst to the north. The broad sub-divisions, the Brage Horst, Brage Main, Bowmore Horst and Talisker Horst appear not to communicate on a production timescale.

Recovery Strategy

The drainage strategy is water injection in Statfjord, Fensfjord and Brent, and depletion with pressure support from aquifer in Sognefjord.

Development

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.

Older wells are slanted while the newer ones are mostly horizontal. Gas lift is applied to improve recovery.

Technical lifetime of the wells and facilities

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. The ambition to increase the technical lifetime and hence

both the onshore and the offshore work force has been strengthened the recent years. When planning the Bestla field development the Brage facilities lifetime was assessed to have a lifetime until end of 2031. In 2025, the license period for all Brage Unit licenses were extended to 31.12.2040. A project has been established with the ambition to extend the technical lifetime to 2040. Project framing has been performed, and the tasks for the first half of 2026 are to prepare a project schedule and perform business case analysis and lifetime extension studies.

Status

There are currently 27 active wells; 23 oil and gas producers, two water injectors and two Utsira water producers providing injection-water.

The well A-23 H was completed in the Kim Sognefjord formation and the production started in July 2025, with pressure depletion as the main drainage strategy. The producer accounts for 28% of the total 2025 production.

The average 2025 oil production was 13 300 bbl/d, 14% higher than the 2P estimate in Lime Reserves Audit 31.12.2024. This is mainly due to better production than expected from some key wells such as the Talisker well A-11 E and the Kim producer A-23 H. The two wells account for almost 70% of the total 2025 production.

The average water-cut for the Brage field is over 90%, when A-23 H was put on production the water-cut dropped. The GOR was stable around 1970 Scf/bbl in the first half of 2025 but has increased to above 2250 scf/stb in the second half of 2025. The field production is constrained by gas processing capacity.

One new oil producer, A-15D, (Talisker producer project) in the Brent Fm on the Talisker structure is planned to be put on production in January 2026.

One new oil producer, A-38, is planned (Cook North project) in the Cook Formation reservoir on the northern segment of the Brage Horst structure. The start-up is planned in 2028.

Two new discoveries have been made in 2025;

- Talisker (Brent, Cook and Statfjord) A-15 B, A-15 C and A-15 D
- Kim (Sognefjord East) A-23H

Petroleum Initially-In-Place (PIIP) presented by Lime

The PIIP estimates as of 31.12.2025 are shown in Table 3.11.

Table 3.11 Brage PIIP estimate as of 31.12.2025

	PIIP, 31.12.2025 (Best Estimate)
Oil/condensate (MMbbl)	1168
Free/Associated gas (BScf)	824

Description of the PIIP

- The PIIP in Table 3.11 is linked to Reserves with the following split for the main contributors (base): Statfjord Talisker (364 MMbbl STOIP; 109 BScf GIIP), Fensfjord (473 MMbbl STOIP; 275 BScf GIIP) and Sognefjord (128 MMbbl STOIP; 222 BScf GIIP). Other volumes contributing to PIIP come from the following deposits: Talisker, Bowmore, Knockando Brent, Cook and Sognefjord East (former Kim discovery).
- The PIIP in Table 3.11 is based on ensemble of realizations from full field 3D static and dynamic reservoir models, except for the Sognefjord East deposit.
- The PIIP in Sognefjord East deposit is based on an A-13 E post-drill update of the model regarding a OWC (ODT) of 2149 m TVD SS MSL and the Computer Processed Interpretation results from real-time logs. The static low case is based on a polygon map for the top reservoir and the static high case is constructed by adding the effects of structural elements to the low case.
- The PIIP in Table 3.11 excludes PIIP from the Purple Rain discovery as it is linked to Contingent Resources. The base STOIP in Purple Rain is reported to be 4.4 MMbbl with minor GIIP.

- The STOIIP estimate has increased by 4% and the GIIP estimate has increased by 2% since 31.12.2024. The main increase is seen in the Talisker area where recent drilling has resulted in new accumulations being discovered

Changes in PIIP since audit 31.12.2024

- The STOIIP estimate has increased by 4% and the GIIP estimate has increased by 2% since 31.12.2024. The main increase is seen in the Talisker area.
- Wells A-15 BT2, A-15C and 15-D, drilled in 2025, resulted in discovery of oil in Upper Oseberg (Brent), Cook and Statfjord in Talisker West and gas in Knockando Fensfjord Formation. The final well, A-15D, was completed as a producer in Brent (Upper Oseberg) in Talisker East.

Reserves and technical profiles presented by Lime

The Reserves are based on the technical production and cost profiles provided by Lime in Statement of Reserves - Brage[6]. These profiles have been evaluated by AGR to confirm project commerciality and verify the correct economic cut-off.

The Brage and Bestla fields are considered as a Hub and economic cut-off is thus determined by jointly evaluating the forecasted production and cost profiles from both fields in the economic model. AGR has applied the economic assumptions provided in appendix A.1 Summaries of Oil and Gas Reserves and Resources. The resulting Reserves for Brage are shown in Table 3.12.

The Reserves include the following projects, classified according to PRMS:

- Brage Base production - On production
- Talisker Producer - Approved for Development
- Cook North - Justified for Development

The Talisker Producer and Cook North project is confirmed commercial for the Base price scenario and the economic cut-offs are:

- 1P: end of 2031, same as technical cut-off
- 2P: end of 2031, same as technical cut-off
- 3P: end of 2031, same as technical cut-off

Table 3.12 TRR and Reserves as of 31.12.2025 - Brage

	TRR (Gross 100%)			Reserves (Gross 100%)			Reserves (Net 33.8434%) ¹⁾		
	Low	Best	High	1P	2P	3P	1P	2P	3P
1st Production	23.09.1993								
Cut-off (year end)	2031	2031	2031	2031	2031	2031	2031	2031	2031
Oil/condensate (MMbbl)	8.68	13.48	17.27	8.68	13.48	17.27	2.94	4.56	5.84
Gas (BScf)	9.86	22.18	33.12	9.86	22.18	33.12	3.34	7.50	11.21
NGL, (MMboe)	0.64	1.49	2.27	0.64	1.49	2.27	0.22	0.50	0.77
Total (MMboe)	11.08	18.91	25.43	11.08	18.91	25.43	3.75	6.40	8.61

1) Net Reserves in Table above are net to Lime. For reserves net to Rex, see 1 Executive Summary and A.1.2 Brage - Summary of Oil and Gas Reserves and Resources.

The production history and technical sales forecasts for oil (without the economic cut-off) are illustrated in Fig. 3.4.

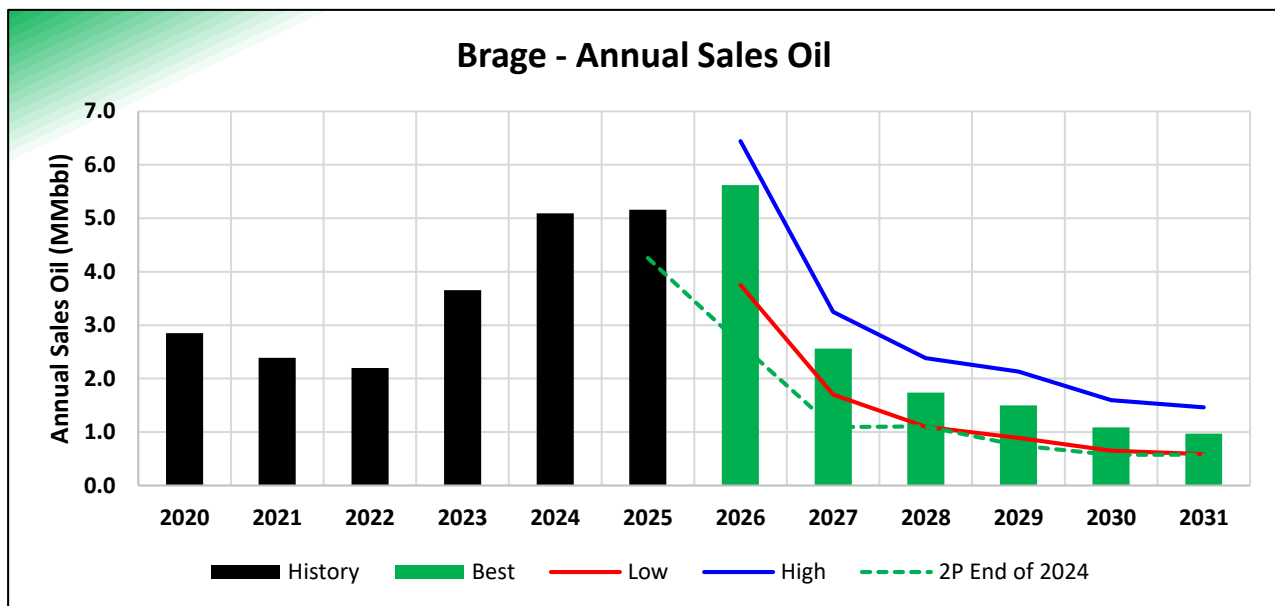


Fig. 3.4 Brage - annual sales oil

Description of the production profiles

- The production forecast for Brage Base is generated by Lime using Decline Curve Analysis.
- Production profiles for future infill and re-drill candidates are based on a combination of ensemble realizations from history-matched dynamic reservoir simulation model and analogue well performance.
- The field production is constrained by available gas processing capacity, and gas production from Bestla is included as a reduction in gas capacity available to Brage.
- The Brage productivity efficiency used are 86.5% and 87.5% in the TAR years(2026 and 2031) and 93% in the other years.

Description of the cost profiles

- The CAPEX and OPEX profiles are based on experienced cost in recent years. The OPEX reflects a general ambition to extend the technical lifetime beyond 2031 in terms of somewhat strengthening the manning level, but does not reflect the potential cost of execution of any specific lifetime extension projects.

Changes in Reserves since audit 31.12.2024

The gross changes in reserves for Brage are shown in Table 3.13. The main reasons for the changes are summarised below:

Production: 2025 production

New projects matured to reserves:

- Talisker producer (A-15D), already drilled
- Cook North (A-38), DG3 approved

Revisions: Positive revision driven by better-than expected well performance for some key wells

Table 3.13 Brage Reserves (100%) Balance sheet

Gross reserves balance, 31.12.2024 - 31.12.2025, for Brage (100%)							
Reserves class	Status 31.12.2024	Production (Positive)	Revisions	Acquisitions or sales	IOR	Discoveries/ New Projects	Status 31.12.2025
Oil and condensate (MMbbl)							
1P	8.65	4.85	2.96	-	-	1.92	8.68
2P	11.00	4.85	2.73	-	-	4.60	13.48
3P	13.72	4.85	2.73	-	-	5.67	17.27
Gas (BScf)							
1P	3.61	7.14	6.65	-	-	6.73	9.86
2P	7.09	7.14	5.42	-	-	16.80	22.18
3P	10.58	7.14	9.49	-	-	20.18	33.12
NGL (MMboe)							
1P	0.03	0.48	0.66	-	-	0.43	0.64
2P	0.16	0.48	0.68	-	-	1.13	1.49
3P	0.43	0.48	1.02	-	-	1.30	2.27
Oil equivalents (MMboe)							
1P	9.33	6.60	4.81	-	-	3.55	11.08
2P	12.42	6.60	4.37	-	-	8.72	18.91
3P	16.03	6.60	5.43	-	-	10.57	25.43

Contingent Resources presented by Lime

The Contingent Resources presented by Lime are shown in Table 3.14.

Table 3.14 The Brage Field Gross and net Contingent Resources as of 31.12.2025

Brage		GROSS (100%)			NET (33.8434%) ¹⁾		
Contingent Resources (MMboe)	PRMS subclass	1C	2C	3C	1C	2C	3C
Fensfjord5000	Development On Hold	0.77	1.73	2.46	0.26	0.59	0.83
Brage extended lifetime	Development On Hold	2.42	6.73	13.08	0.82	2.28	4.43
Talisker Cook	Development Pending	1.28	2.99	5.72	0.43	1.01	1.93
Talisker Statfjord	Development Pending	10.62	14.65	18.47	3.60	4.96	6.25
Brage unit IOR infill wells	Development Unclarified	0.89	2.46	5.13	0.30	0.83	1.74
Purple Rain (Sognefjord)	Development Unclarified	0.31	0.71	3.05	0.10	0.24	1.03
Talisker infill upside	Development Pending	3.76	5.37	6.45	1.27	1.82	2.18
Sognefjord template project	Development Unclarified	6.94	13.89	20.83	2.35	4.70	7.05
Fensfjord revitalization	Development Unclarified	2.54	5.08	7.61	0.86	1.72	2.58
Upper Oseberg WI	Development Unclarified	1.17	1.67	2.00	0.40	0.56	0.68
Total, MMboe		30.70	55.27	84.80	10.39	18.71	28.70

1) Net Contingent Resources in Table above are net to Lime. Rex's share in Lime is 89.74%. For Contingent Resources net to Rex, see 1 Executive Summary and A.1.2 Brage - Summary of Oil and Gas Reserves and Resources.

Changes in Contingent Resources since audit 31.12.2024

The gross changes in Contingent Resources for Brage are shown in Table 3.15. The main reason for the changes are summarised below:

Six new projects:

- Fensfjord5000
- Talisker Statfjord
- Purple Rain
- Fensfjord revitalization
- Talisker Cook
- Upper Oseberg WI

Revisions:

- A negative revision due to removal of three projects that are no longer Contingent Resources
 - Brage Unit EOR
 - Shetland (gas in chalk)
 - Talisker producer being matured and reclassified from Contingent Resources to Reserves
- A significant positive revision for Brage extended lifetime

Table 3.15 Brage Contingent Resources (100%) Balance sheet

Gross contingent resource balance, 31.12.2024 - 31.12.2025, for Brage (100%)							
Resource category	Status 31.12.2024	Production (Positive)	Revisions	Acquisitions or sales	IOR	Discoveries/ New Projects	Status 31.12.2025
Oil equivalents (MMboe)							
1C	20.03	-	-6.01	-	-	16.68	30.70
2C	41.88	-	-13.43	-	-	26.82	55.27
3C	66.06	-	-20.57	-	-	39.31	84.80

AGR comments to PIIP, Reserves and Contingent Resources

Comments to PIIP

AGR has reviewed the following documents supplied by Lime: Brage RNB2026, Lime Statement of Reserves (SoR)[6], Lime's Assets presentation and RC and work meetings handouts[31]. The evaluation is satisfactory with the following comments:

- Neither static nor dynamic models were available and therefore these are not evaluated by AGR.
- The PIIP in Table 3.11 is aligned with RNB2026 submission, but do not include the Shetland nor the Purple Rain deposits.
- AGR endorses the PIIP estimates presented by Lime for Brage.

Comments to production profiles

AGR has reviewed Lime's asset presentation and licence meetings handouts, DCA, RNB2026 and Lime Statement of Reserves[6]

- AGR has checked the decline-curve analysis performed by the operator and from Lime and finds these reasonable. In general the DCA results from Lime are more optimistic than the DCA from the operator.
- Most of the future production is expected to come from a few key wells, such as A-11 and A-15D and any changes in performance of these wells will significantly influence the total field production profile.
- Reservoir quality ranges from poor to excellent in Fensfjord, Statfjord, Brent and Sognefjord formations, each facing individual challenges related to pressure support, productivity, water-cut development and drainage efficiency.
- AGR acknowledges that maintaining production requires continuous drilling and an active well-maintenance program.
- The field production is constrained by gas processing capacity and wells with high GOR or high gas-lift requirements are shut in to remain within the gas processing capacity limits.
- Lime's best estimate is about 20% higher for oil compared to the best estimate in RNB2026, while the gas and NGL estimates are almost identical. The gas and NGL estimates are similar because of the gas export being constrained by the gas processing constraints.
- The production profiles are based on sound industry practice.

The Lime production profiles in Statement of Reserves - Brage[6] are considered reasonable.

Comments to facilities and cost profiles

- The cost profiles applied by Lime are identical to the Brage RNB2026 and in line with the WP&B 2026. The OPEX profile is a combination of the RNB2026 Ordinary OPEX and the Other OPEX profiles.
- There will be no drilling in 2026 due to the tie-in activities of Bestla.
- The costs of potential lifetime extension projects are not reflected in the Budgets.
- 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.
- AGR has reviewed the costs in light of historical cost on Brage and found the costs presented to be reasonable, although the ABEX may be on the low side, total 5.4 GNOK, considering the extensive scope including plugging of 40 wells and removal and disposal of 18 ktms topside and a 16 ktms jacket.

Comments to Reserves and recovery factors

- 42% of the Brage 2P reserves as of 31.12.2025 are related to the Talisker Producer, A-15D, and any changes in performance of this well may influence the total field reserves significantly.
- The Cook North project is particularly sensitive with respect to timing and commerciality.
- The 2P oil and gas recovery factors are shown in Table 3.16. 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. Note that the low recovery factor for gas is influenced by the large consumption of gas for fuel.
- The oil equivalent uncertainty range is -66%/+34% versus 2P. The uncertainty range is high, but reflecting the uncertainty in new projects, earlier economical cut off in the 1P estimate and the complexity of the field.

Table 3.16 Brage 2P recovery factors

	Oil 31.12.2025	Oil at EUR	Gas 31.12.2025	Gas at EUR
Produced (MMbbl/Bscf)	393	406	166	188
Recovery factor	33.6%	34.8%	18.5%	21.0%

Comments to Contingent Resources

AGR had access to limited information for a number of the projects included in the extensive list of Contingent Resource projects. These projects are generally at an early stage of evaluation, and the associated resource estimates are therefore subject to material revision as the opportunities mature. AGR considers that some of these projects have a low probability of commercial success.

AGR considers the Brage extended lifetime, Talisker Statfjord, Talisker Cook, Talisker Infill Upside and Upper Oseberg WI to be the most likely projects to mature to Reserves. The Brage extended lifetime project is expected, in addition to its own Contingent Resources, to unlock potential in other Contingent Resource projects and to impact the Bestla Contingent Resources. The Talisker Statfjord project is considered important for Brage due to its resource potential, while the Upper Oseberg WI project is expected to secure production from A-15D through pressure support and to reduce the GOR in the well.

AGR Conclusions

- AGR considers that the PIIP presented by Lime is acceptable.
- The Brage reserves are dependent on a few key wells and any changes in production performance of these wells will affect the total reserves.
- The 2P recovery factors shown are modest but reasonable considering the complexity of the field and compared to NCS fields with similar drainage strategies.
- An uncertainty range in recoverable oil equivalent volumes is high, but reasonable, considering introduction of new uncertain projects, complexity of the field and sensitivity to commercial cut-off.
- AGR finds the costs and production profiles presented by Lime reasonable to be used for economic analyses.
- AGR endorses the Brage Reserves (Table 3.12) and Contingent Resources (Table 3.14) presented by Lime.

3.3 Norway - Bestla

Asset Overview

The Bestla Field (formerly Brasse) is an oil and gas field located in production licence PL 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. 3.5. Water depth in the area is about 120 m. The depth of the reservoir is near 2200 m TVD MSL. PL740 licence expiry is 07.02.2039[12]. Licence details summary is shown in Table 3.17 and the licence shares are shown in Table 3.18. The Bestla Field is currently being developed with first oil planned for January 2027.

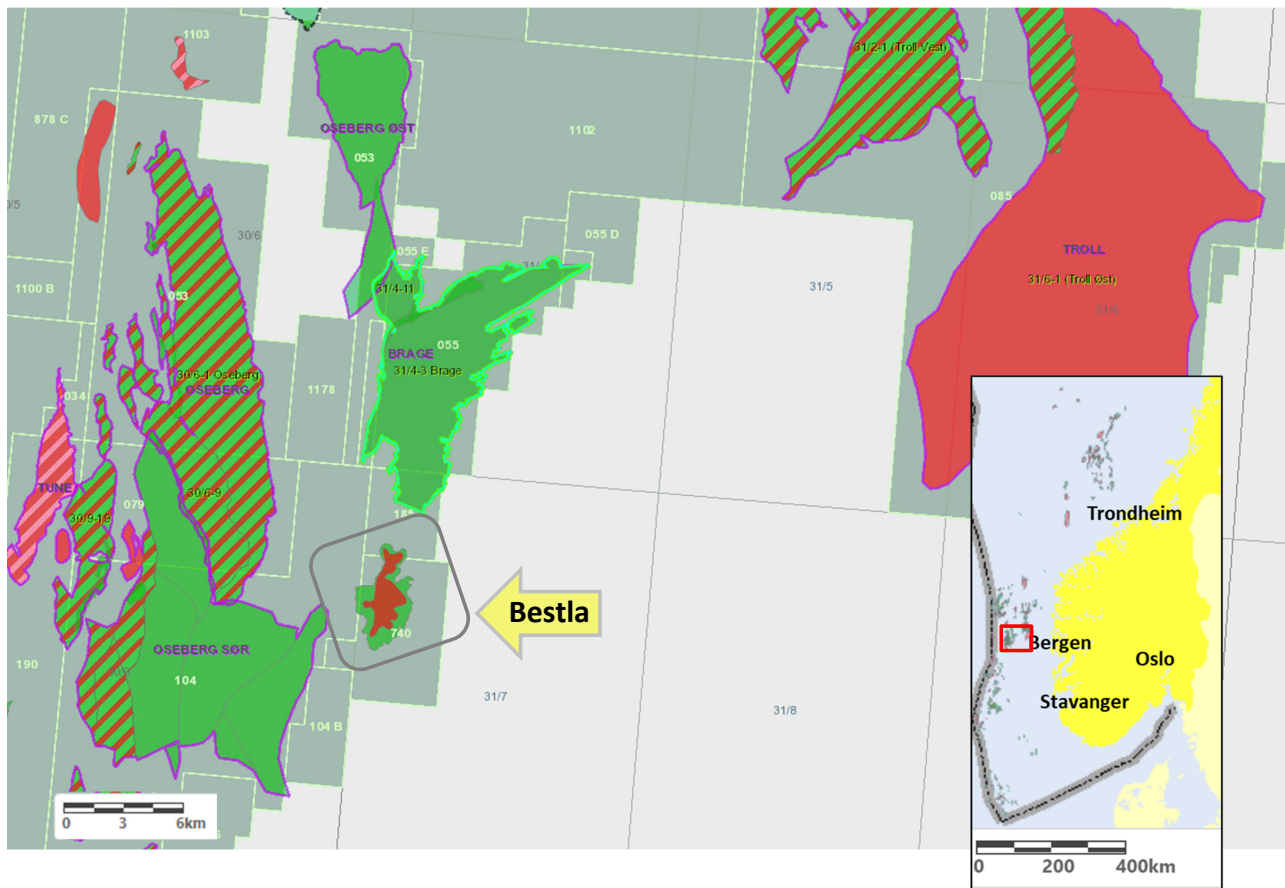


Fig. 3.5 Bestla Field location map
Source: NOD Factmaps (www.sodir.no)

The production licence give 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, which included Lime's Statement of Reserves (SoR), the operator's submission to the Norwegian Revised National Budget for 2026 (RNB2026), meeting documents (RC, TC, MC) from 2025, Annual Status Report, work program and budget (WP&B) 2026, as well as Lime's presentation and answers to AGR's questions and clarification requests.

Table 3.17 Bestla Field summary table

Asset name/ Country	Lime's interest (%)	Development Status	Licence expiry date	Licence Area (km ²)	Type of mineral, oil or gas deposit	Remarks
PL 740 (Bestla) / Norway	17.0000	Development Approved	07.02.2039	55	Oil and gas	-

The Bestla licence shares are listed in Table 3.18.

Table 3.18 Bestla Field licence shares (%)

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

Discovery

Bestla Field was discovered in 2016 by well 31/7-1. The well confirmed gas and oil in Upper Jurassic, Oxfordian to Kimmeridgian/Volgian, sandstones and siltstones of the Sognefjord Formation, Viking Group. The structure has been penetrated by 10 wellbores (this includes the four 2025 well penetrations). The structure was penetrated, in total, by six wellbores during the initial exploration and appraisal phase, and four in the development drilling in 2025. 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 an OWC at 2172 m TVD MSL, and a general Gas Oil Contact (GOC) at 2148 m TVD MSL[12]. In 2025, as part of the Bestla development program, a geopilot was first drilled into the Western Segment making an oil discovery. This geopilot proved an oil column with no gas cap. In 2025 two production wells were also drilled (one of which is a dual-lateral).

Reservoir

The Bestla Field is a 14 km² low relief, three-way dip closure with a stratigraphic pinchout to the north, as a result of erosion. The field consists of three segments: Bestla Main, Bestla North and Bestla West.

The reservoir rock is the Upper Jurassic (Oxfordian-Kimmeridgian) Sognefjord Formation. Net reservoir and net pay are variable within this formation from excellent in the south to non-reservoir in the north. The Sognefjord reservoir sands were deposited in a marginal to shallow marine environment with several cyclical events showing regression events (dominated by delta front and mouth bar facies) and transgressive events (characterised by tidally influenced lobes and tidal bars). Within this sequence (Oxfordian, divided into Z1 to Z4 and Kimmeridgian) only the Z2 up to the Kimmeridgian levels are hydrocarbon bearing. The Kimmeridgian level is only present in the north-east of the area, (31/7-3S). Well 31/7-3A found 34 degree API oil in the Z2 and Z3 levels, in contrast to the 36 degree API oil found in the southern Main segment. This indicates that there are at least two different oil populations present. The sands found in the north are regarded as small local closures isolated from the Main segment to the south and differently charged.

Reservoir properties to the south in the Main and West segments are good to excellent as confirmed by the 2025 drilling campaign. The sands consist of delta front and mouth bar sands with good to excellent porosity and permeability. Bestla Main segment showed an average of 27% porosity and 1080 mD permeability and Bestla West had averages of 23% porosity and 400 mD within the oil zone. In total the well program achieved over 1 km of Darcy-level sand intersection in the oil zone.

The appraisal wells have shown that Bestla was depleted by approximately 20 bar (~ +/- 2 bar per year) in 2018. This pressure depletion, observed in all six wells in Bestla, is considered to be caused by production from the giant Troll field, located approximately 35 km to the northeast of Bestla, and connected to Bestla via a massive regional aquifer.

Recovery Strategy

The planned drainage strategy is depletion, with the aquifer as the primary and the gas-cap as secondary pressure support.

Development

Bestla is being developed as a 13 km subsea tie back to the Brage host facility. The development plan comprises two horizontal oil producers in the Bestla Main, one of the wells will be configured as a dual lateral with one lateral in Bestla West and mainbore in Bestla Main. These producers were successfully drilled and completed in 2025. The wells are currently suspended awaiting installation of flowline from the subsea template to the Brage platform

Both producers will have inflow control to support well clean-up and hydrocarbon recovery. Gas lift will be installed for later use after water breakthrough. The MLT well has been completed with a smart valve arrangement that eliminates the possibility of crossflow between the two segments.

The two wells will produce commingled through a manifold and back to the Brage Field through a 10-inch Pipe-in-Pipe for processing on the Brage platform. From Brage, the oil will be transported by pipeline to Oseberg and through the Oseberg Transport System (OTS) to the Sture terminal in Norway. The gas export pipeline is tied back to Statpipe with the gas being processed at the onshore Kårstø gas plant.

Technical lifetime of the wells and facilities

The design life of the Bestla wells and subsea facilities is 20 years, sufficient for the expected extended design life of Bestla. Current production life is 2031, same as the technical lifetime of Brage. The Bestla lifetime may however be extended as a result of the ongoing lifetime extension activities on Brage.

Status

The PDO was approved in November 2024 and the field is under development. All wells are drilled.

The Bestla development is in the execution phase and was 61% complete per October 2025. The project is on schedule for production start-up in January 2027.

The B-1 H geo-pilot completed in Q3 2025 confirmed reservoir properties and proved oil in the Western segment.

Petroleum Initially-In-Place (PIIP) presented by Lime

The PIIP estimates as of 31.12.2025 are shown in Table 3.19.

Table 3.19 Bestla PIIP estimate as of 31.12.2025

	PIIP, 31.12.2025 (Best Estimate)
Oil/Condensate (MMbbl)	65.7
Free/Associated gas (BScf)	91.6

Description of the PIIP

- The PIIP linked to Reserves in Table 3.19 corresponds to the PIIP in the Main and West segments. The PIIP in North segment is part of the discovered resources, but it is not linked to a plan for development. The PIIP split of the North segment is: 21.0 MMbbl of oil/condensate; 18.8 BScf of gas.
- The total PIIP estimates are based on the stochastic P90/P50/P10 volumes presented in the PDO. These are derived from the full field reservoir model for DG2, using the re-processed CGG Horda Multi-client survey for the seismic interpretation.
- The West segment is now drilled and confirmed with hydrocarbons, thus included in PIIP in Table 3.19. The west segment was not included on the 31.12.2024 audit as the hydrocarbons were not yet proven. There is therefore an increase in reported PIIP estimates since 31.12.2024.

Reserves and technical profiles presented by Lime

The Reserves are based on the technical production and cost profiles provided by Lime in Statement of Reserves for Bestla[7]. These profiles have been evaluated by AGR to confirm project commerciality and verify the correct economic cut-off.

The Brage and Bestla fields are considered as a Hub and economic cut-off is thus determined by jointly evaluating the forecasted production and cost profiles from both fields in the economic model. AGR has applied the economic assumptions provided in appendix A.1 Summaries of Oil and Gas Reserves and Resources. The resulting Reserves for Bestla are shown in Table 3.20.

The Reserves include the following project, classified according to PRMS:

- Bestla Base production - Approved for Development

The Bestla Base production project is confirmed commercial for the Base price scenario and the economic cut-offs are:

- 1P: end of 2031, same as technical cut-off
- 2P: end of 2031, same as technical cut-off
- 3P: end of 2031, same as technical cut-off

Table 3.20 TRR and Reserves as of 31.12.2025 - Bestla

	TRR (Gross 100%)			Reserves (Gross 100%)			Reserves (Net 17.0000%) ¹⁾		
	Low	Best	High	1P	2P	3P	1P	2P	3P
1st Production	01.01.2027								
Cut-off (year end)	2031	2031	2031	2031	2031	2031	2031	2031	2031
Oil/condensate (MMbbl)	12.87	16.45	19.39	12.87	16.45	19.39	2.19	2.80	3.30
Gas (BScf)	27.00	31.00	38.86	27.00	31.00	38.86	4.59	5.27	6.61
NGL, (MMboe)	1.71	1.96	2.46	1.71	1.96	2.46	0.29	0.33	0.42
Total (MMboe)	19.39	23.93	28.77	19.39	23.93	28.77	3.30	4.07	4.89

1) Net Reserves in Table above are net to Lime. Rex's share in Lime is 89.74%. For reserves net to Rex, see 1 Executive Summary and A.1.3 Bestla - Summary of Oil and Gas Reserves and Resources.

The technical sales forecasts for oil (without the economic cut-off) is illustrated in Fig. 3.6.

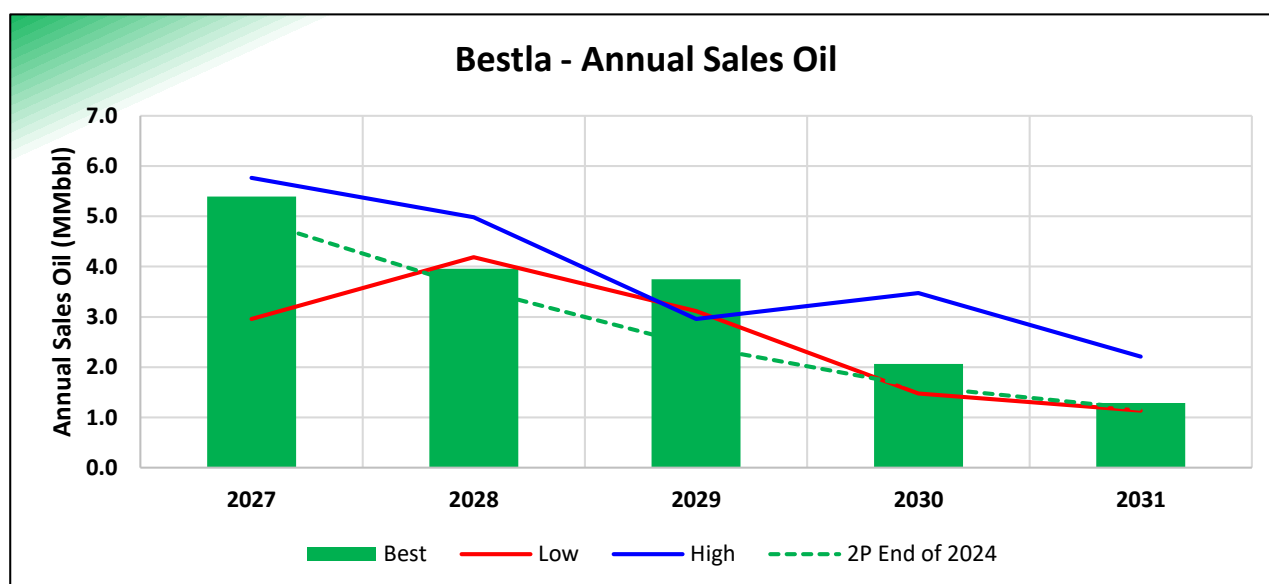


Fig. 3.6 Bestla - annual sales oil

Source: Lime. Low, base, high production profiles are selected as representative single models from the uncertainty ensemble based on final cumulative volumes, not annual rates. The annual high case can be lower than base and low cases in some years

Description of the production profiles

- The Bestla base project contains two horizontal oil producers in the Bestla Main. One of the wells is a dual lateral with one lateral targeting Bestla West and the main bore target in Bestla Main.
- The production profiles are based on an ensemble-based uncertainty analysis of dynamic simulation models.
- The model covers the Bestla Main, North and West segments and the producers are completed in the Main and West segment.
- An ensemble of history-matched simulation cases was prepared to capture the combined impact of key subsurface uncertainties, including reservoir structure, fluid contacts, relative permeability behaviour, aquifer strength, and STOIP and GIIP ranges. Each realisation reflects a unique combination of these uncertain parameters within the defined probabilistic ranges.
- Low, base, high production profiles are selected as representative single models from the uncertainty ensemble based on final cumulative volumes, not annual rates. Therefore, the annual high case can be lower than base and low cases in some years (e.g. 2029), while still representing the highest

cumulative outcome.

- The assumed uptime is 90% in normal years and 85% in year with planned turnaround (TAR), occurring every 4th year.
- A term sheet agreement in place whereby Brage is compensated in cash due to gas processing limitations; thus, no deferral profile has been applied.
- Production start-up for Bestla base is assumed to be 01.01.2027, with production continuing until the end of Brage's technical lifetime in 2031.

Description of the cost profiles

- The project Master Control Estimate is 6327 MNOK. The project was 55% complete per October 2025, and has in general been developed according to budget and plan. The remaining CAPEX for 2026 and 2027 is 2149 MNOK.
- The OPEX is based on the operator's experience from similar fields.

Changes in Reserves since audit 31.12.2024

The gross changes in reserves for Bestla is shown in Table 3.21. The main reason for the changes is summarised below:

Revisions

- Bestla West was previously not included in Reserves (classified as a Prospect prior to being drilled) and the confirmation of hydrocarbons in the Bestla West segment lead to an increase in in-place and recoverable volumes.
- A revised well trajectory targeting Bestla West segment resulted in a decreased GOR field forecast

Table 3.21 Balance sheet - Bestla Reserves (100%)

Gross reserves balance, 31.12.2024 - 31.12.2025, for Bestla (100%)							
Reserves class	Status 31.12.2024	Production (Positive)	Revisions	Acquisitions or sales	IOR	Discoveries/ New Projects	Status 31.12.2025
Oil and condensate (MMbbl)							
1P	10.77	-	2.10	-	-	-	12.87
2P	13.73	-	2.72	-	-	-	16.45
3P	17.39	-	2.00	-	-	-	19.39
Gas (BScf)							
1P	26.94	-	0.06	-	-	-	27.00
2P	33.28	-	-2.27	-	-	-	31.00
3P	37.17	-	1.69	-	-	-	38.86
NGL (MMboe)							
1P	1.64	-	0.07	-	-	-	1.71
2P	2.03	-	-0.07	-	-	-	1.96
3P	2.27	-	0.19	-	-	-	2.46
Oil equivalents (MMboe)							
1P	17.21	-	2.18	-	-	-	19.39
2P	21.69	-	2.24	-	-	-	23.93
3P	26.28	-	2.49	-	-	-	28.77

Contingent Resources presented by Lime

The Contingent Resources presented by Lime are shown in Table 3.22.

Table 3.22 Gross and Net Contingent Resources as of 31.12.2025 - Bestla

Contingent Resources (MMboe)		GROSS (100%)			NET (17.0000%) ¹⁾		
Resources	PRMS subclass	1C	2C	3C	1C	2C	3C
Bestla Extended lifetime	Development On Hold	2.20	4.97	8.29	0.37	0.84	1.41

1) Net Contingent Resources in Table above are net to Lime. Rex's share in Lime is 89.74%. For Contingent Resources net to Rex, see 1 Executive Summary and A.1.3 Bestla - Summary of Oil and Gas Reserves and Resources.

Description of Contingent Resources

The Bestla Extended Lifetime is related to the ongoing lifetime extension activities on the Brage field. Production during an extended lifetime phase will be delivered from the same wells used in the Bestla Base development, continuing after the end of Brage's current technical lifetime. The production period for the Bestla Extended Lifetime project is assumed to span from 2032 until 2040.

Changes in Contingent Resources since audit 31.12.2024

The gross changes in Contingent Resources for Bestla are shown in Table 3.23. The main reason for the changes is summarised below:

Revisions:

- Confirmation of hydrocarbons in the Bestla West segment led to an increase in in-place and recoverable volumes.
- Five years has been added to Contingent Resources for the Bestla LTE project

Table 3.23 Balance sheet - Bestla Contingent Resources (100%)

Gross contingent resource balance, 31.12.2024 - 31.12.2025, for Bestla (100%)							
Resource class	Status 31.12.2024	Production (Positive)	Revisions	Acquisitions or sales	IOR	Discoveries/ New Projects	Status 31.12.2025
Oil equivalents (MMboe)							
1C	2.73	-	-0.53	-	-	-	2.20
2C	4.44	-	0.52	-	-	-	4.97
3C	4.15	-	4.14	-	-	-	8.29

AGR comments to PIIP, Reserves and Contingent Resources

Comments to PIIP

AGR has reviewed the following documentation: Bestla RNB2026, Lime Statement of Reserves[7] and Bestla PDO, with the following comments:

- Note that neither static nor dynamic models were available and therefore these are not evaluated by AGR.
- The PIIP is consistent with the volumes reported in the SoR [7], and RNB 2026 in terms of STOIP and GIIP.
- PIIP uncertainty ranges for Table 3.19 corresponds to -15% +17% STOIP and - 15% +18% in terms of GIIP base case.
- The most influencing static variables on PIIP are the OWC contacts, the top structure and reservoir facies 3D distribution.
- AGR agrees on the main uncertainties described by the Operator and considers that the following

factors may constitute additional uncertainty:

- The large, lateral heterogeneity of the reservoir rocks (deltaic depositional environments) could reduce the total PIIP by incorporating poorer properties to the average porosity values.
- The vertical isolation of reservoirs, given the extensive shales that might be deposited at maximum flooding surfaces.
- Oil similar to that in Brage Sognefjord was found in Bestla North well 31/7-3 A. AGR suggests that this may be a sign of communication between the northern segment of Bestla and the Brage Field.
- In addition, it is of AGR's opinion that the PIIP uncertainty range is narrow, AGR assumes that this may be the combined result of the following factors:
 - The large and independent amount and of variables selected for the uncertainty analysis.
- Based on the documentation received, AGR considers the PIIP estimates presented by Lime to be reasonable.

Comments to production profiles

AGR has reviewed the following documentation: Bestla RNB2026, Lime Statement of Reserves[7] and Bestla PDO, with the following comments:

Several parameters indicate a more complex reservoir system that may influence drainage efficiency and ultimately impact recovery of volumes, including:

- Reservoir properties deteriorate from excellent in the southern area to poor in the northern part of the field.
- Formation pressure analysis suggests some degree of vertical baffling between the different reservoir sands.
- Pressure depletion from production at the Troll Field induces a pressure gradient that varies across the Bestla field.
- The simulation model indicates very limited pressure communication and inflow from the North and West segments into the Main segment.
- The GOC and OWC surfaces are not flat but vary locally as a function of depletion and reservoir properties.
- According to the PDO uncertainty study, relative permeability is a significant contributor to overall uncertainty.
- The combination of a low-relief structure and a relatively thin oil column (~24 m), together with the presence of a gas-cap, presents challenges for effective sweep and oil recovery.
- The short planned production lifetime of five years increases the importance of schedule risk. Lifetime extension would reduce the risk of not being able to produce the TRR volumes within Brage's technical lifetime.
- A two-well development concept is highly dependent on high well availability to ensure delivery of the TRR volumes.
- AGR notes that the low, best and high annual production profiles may appear counterintuitive, as the Low case are lower than the Best and High cases in some years. This is a result of the profiles being selected based on cumulative production rather than annual rates and does not indicate an inconsistency in the underlying estimates.

In AGR's opinion, the production profiles presented in A.1.3 Bestla - Summary of Oil and Gas Reserves and Resources are reasonable.

Comments to facilities and cost profiles

- The project is in general developing according to budget and plan.
- The cost profiles applied by Lime are identical to the RNB2026 and in line with the WP&B2026. AGR finds the applied costs for the Bestla development reasonable. The project was 61 % complete by October 2025

Comments to Reserves and recovery factors

- The 2P oil and gas recovery factors are presented in Table 3.24. The oil recovery factor of 25% is based on STOIIP from Bestla Main and West segments.
- The recovery factor is considered low, but reasonable, given the varying reservoir properties, reliance on depletion-only drainage, the relatively thin oil column, and pressure depletion effects from the Troll Field.
- The oil-equivalent uncertainty range is -22%/+18% relative to the 2P case (Table 3.20). Although this is a relatively narrow range for a project at this maturity level, it is considered reasonable given the low overall recovery factor.

Comments to Contingent Resources

- The Lifetime extension project will reduce the risk of not being able to produce the TRR volumes within the technical lifetime of Brage field.

Table 3.24 Bestla 2P recovery factors

	Oil 31.12.2025	Oil at EUR	Gas 31.12.2025	Gas at EUR
Produced (MMbbl/Bscf)	-	16.45	-	31.00
Recovery Factor	-	25%	-	34%

AGR Conclusions

- AGR considers the PIIP estimates presented by Lime to be reasonable.
- A two-well development depends on high well availability to secure production of the Reserves.
- The short planned production lifetime of five years underscores the significance of schedule risk. A Lifetime extension would mitigate this risk of not being able to produce the Reserves within the technical lifetime of the Brage host facilities.
- The Bestla Reserves and Contingent Resources reported by Lime are well documented and follow sound industry practice.
- AGR endorses the Bestla Reserves (Table 3.20) and Contingent Resources (Table 3.22) presented by Lime.

3.4 Norway - Lunde

Asset Overview

Lunde is an oil discovery with a gas-cap. It is located in block 6507/5 in PL 838, approximately 5 km south-east of the Skarv Field in the Norwegian Sea. A location map of the field is shown in Fig. 3.7. The water depth is about 375 m. The reservoir depth is at about 1970 m TVD MSL.

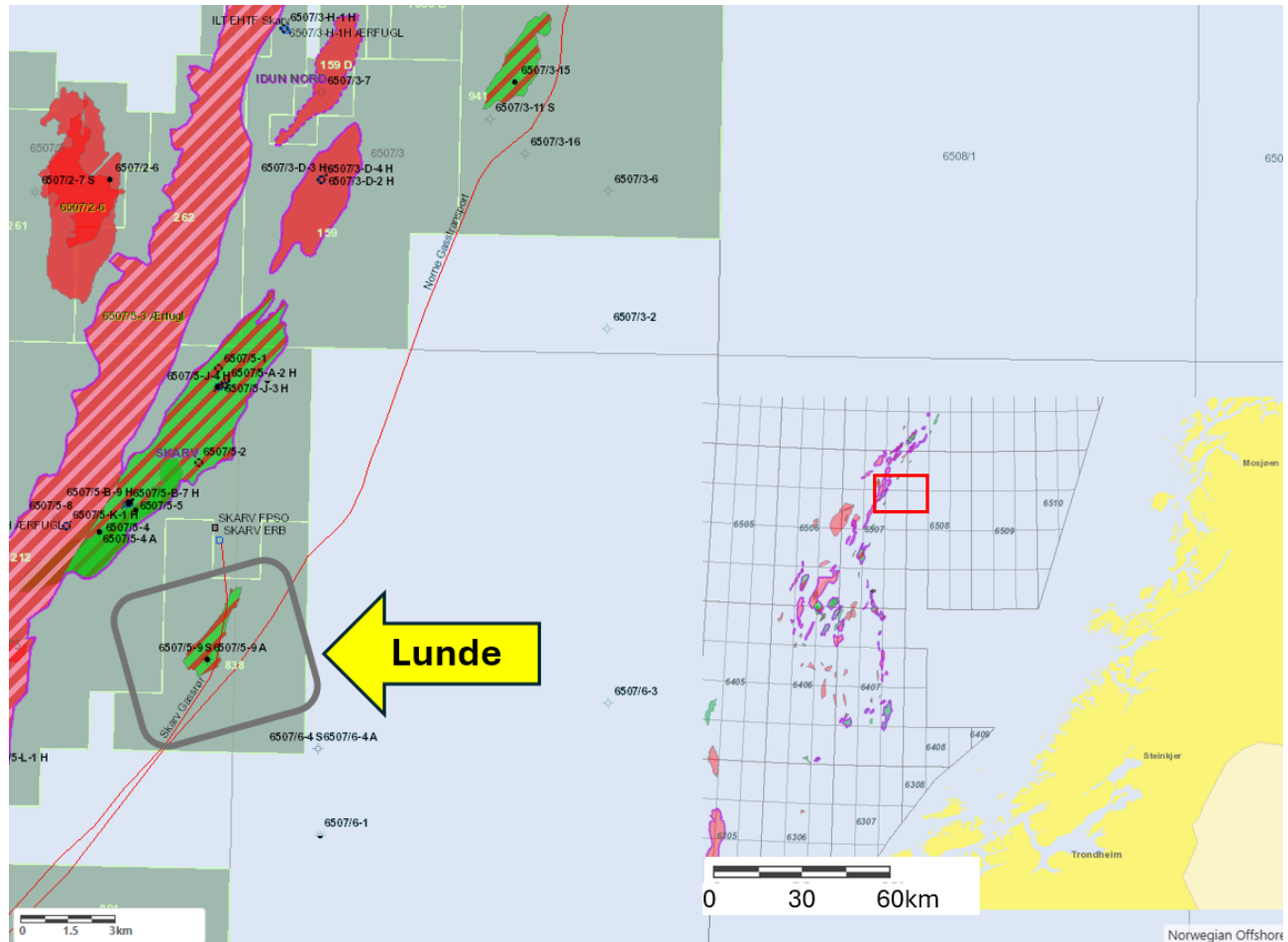


Fig. 3.7 Lunde Discovery location map

The PL 838 licence was awarded to PGNiG as operator in 2016 and the discovery was made in 2019. In April 2020, the operatorship was changed to Aker BP ASA. Licence details summary is shown in Table 3.25 and the licence shares are shown in Table 3.26. Please note, the licence expiry is 05.02.2026. An application for a licence extension has been submitted with a provisional timeline of DG2 in February 2027 and PDO in February 2028.

The original DG3 was postponed by Aker BP. The plan was for DG3/FID to be taken February 2026. After the postponement, however, a decision to proceed is now planned with a possible DG2/DG3 for end of 2026.

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, which included Lime's Statement of Reserves (SoR), the operator's submission to the Norwegian Revised National Budget for 2026 (RNB2026), meeting documents (RC, TC, MC) from 2025, work program and budget (WP&B) 2026, DG1, DG2 and draft DG3 documentation from the originally planned development concept (now abandoned), as well as Lime's presentation and answers to AGR's questions and clarification requests.

Table 3.25 Lunde summary table

Asset name/ Country	Lime's interest (%)	Development Status	Licence expiry date	Licence Area (km ²)	Type of mineral, oil or gas deposit	Remarks
PL 838 (Lunde) / Norway	30	Development Unclassified	05.02.2026	34	Oil and gas	Applied for extension

Table 3.26 Lunde licence shares (%)

Licence	Aker BP ASA (Op)	ORLEN Upstream Norway AS	Lime Petroleum AS
PL838 (Lunde)	35	35	30

Discovery

Lunde was discovered in 2019 with well 6507/5-9 S. The well discovered a 45 m gas column and a 40 m oil column in good to excellent reservoir quality sandstones of Fangst and Båt Groups. The structure is segmented, the East segment which has been proven by well 6507/5-9 S. To appraise down-faulted West segment, a sidetrack well 6507/5-9 A was drilled later in 2019. The appraisal well encountered a total oil and gas column of about 63 m in the Fangst and Båt Groups, of which about 45 m of column was in sandstones with mainly good to very good reservoir quality.[12]

Reservoir

The Lunde discovery is situated within the Revfallet Fault Complex on the western edge of the NE-SW trending Nordland Ridge. The reservoir is Fangst Group (Garn Formation) and Båt Group (Tofte and Åre Formations), dated to Lower to Middle Jurassic age. The sandstones are deposited in a wide range of depositional environments including fluvial, marginal marine, marine to tide dominated estuarine, with good to excellent reservoir quality. Reservoir sandstones of the Garn Formation were developed in upper to lower shoreface setting, characterised with 29% to 31% average porosities and 339 mD to 5301 mD permeabilities. The reservoir sandstones of Åre Formation were developed in bayhead delta and stacked bay fill in fluvial plain setting, characterised with 33% to 35% average porosities and 800 mD to 1500 mD permeabilities. The area has undergone extensive truncation and erosion of the Garn, Tofte and Åre Formations. The structure is complex due to faulting and overlapping wedges. The trap is a combined four-way closure and hanging wall trap and the top seal is provided by Melke Formation shales. The discovery is quite segmented, and the structure is defined by four main fault segments; East, West, North-east and South-east. The East and West segments have been proven by wells 6507/5-9 S and 6507/5-9 A with GOC at ~2029 m TVD MSL and OWC at ~2073 m TVD MSL in the former well and GOC at ~2034 m TVD MSL and OWC at ~2074 m TVD MSL in the latter well. Both wells have encountered gas-oil and oil-water contacts at different depth that supports compartmentalization between Lunde East and Lunde West segments. Due to fault bounded segments and contacts at different depth, there is an increased probability of finding different HC contacts and compartmentalization of the undrilled segments.

The oil is characterised as heavy oil, with gravity of 18°API, a viscosity of 4 cP and GOR between 340-410 Scf/bbl. The reservoir pressure is 211 bar and temperature is 72 °C. Heavy oil results in an expected very low recovery factor for the oil resources.

Recovery Strategy

The resource volumes are based on an ERD well with natural pressure depletion. This was the original planned development concept, but this well concept has now been abandoned. It is not yet clear what development and well options will be proposed going forward, but natural pressure depletion is likely to be applicable for any new development plan.

Development

The Lunde development originally matured in the licence consisted of an extended reach well (ERD) drilled from the Skarv B/C template with the oil and gas produced to the Skarv FPSO via existing infrastructure on the seabed. This concept carried high drilling risk and the development did not pass the final investment

decision as planned. In the meantime, the recently discovered Skarv E was matured for a possible common subsea development with Lunde. The evaluations showed, however, that this option would be sub-commercial. Efforts are ongoing to find alternative development possibilities for Lunde.

Technical lifetime of the wells and facilities

The design life of the potential Lunde facilities is not specified yet but is expected to be in line with the applicable production life.

Status

The ERD development did not pass the final investment decision (FID) as planned and new development options are considered. The new plan (assuming an extension to the licence period is granted) includes FID late in 2026, PDO submittal before February 2027, and production start in 2028.

Petroleum Initially-In-Place (PIIP) presented by Lime

The PIIP estimates as of 31.12.2025 are shown in Table 3.27.

Table 3.27 Lunde PIIP estimate as of 31.12.2025

	PIIP, 31.12.2025
	Best
Oil/Condensate (MMbbl)	43
Gas (BScf)	52

Description of the PIIP

- The PIIP numbers listed in Table 3.27 are the total PIIP from the two proven segments East and West, and do not include the unproven South-East and North-East segments.
- There is no change in the reported PIIP estimates since 31.12.2024.

Contingent Resources presented by Lime

The Contingent Resources presented by Lime are shown in Table 3.28.

Table 3.28 Gross and net Contingent Resources as of 31.12.2025 - Lunde

Contingent Resources		GROSS (100%)			NET (30.0000 %) ¹⁾		
Resources	PRMS subclass	1C	2C	3C	1C	2C	3C
Lunde Development	Development Unclarified	4.65	7.27	10.28	1.39	2.18	3.08

1) Net Contingent Resources in Table above are net to Lime. Rex's share in Lime is 89.74%. For Contingent Resources net to Rex, see 1 Executive Summary and A.1.4 Lunde - Summary of Oil and Gas Reserves and Resources.

Description of the production profiles

- Although new development options are considered, Lime have chosen to not change the contingent resource numbers for the 31.12.2025 reporting. This is likely a reasonable approach assuming a similar drainage strategy for an alternative development concept.
- The production profile is based on the operator's full field ensemble simulation model.

Description of the cost profiles

- Several development concepts have been considered, all with challenging business cases. The operator has recommended a pause to the project to explore other potential viable development solutions. Hence, there are no current relevant cost profiles.

Changes in Contingent Resources since audit 31.12.2024

The gross changes in Contingent Resources for Lunde are shown in Table 3.29. There is no change in the estimate of Contingent Resources on Lunde since 31.12.2024.

Table 3.29 Balance sheet - Lunde Contingent Resources (100%)

Gross contingent resource balance, 31.12.2024 - 31.12.2025, for Lunde (100%)							
Resource class	Status 31.12.2024	Production (Positive)	Revisions	Acquisitions or sales	IOR	Discoveries/ New Projects	Status 31.12.2025
Oil equivalents, MMboe							
1C	4.65	-	-	-	-	-	4.65
2C	7.27	-	-	-	-	-	7.27
3C	10.28	-	-	-	-	-	10.28

AGR comments to PIIP and Contingent Resources

Comments to PIIP

AGR has reviewed the following documentation: RNB2026, Lime Statement of Reserves[8], Q&A, and Lunde draft DG3 Subsurface Support Document and meeting handout with the following comments:

- The PIIP numbers presents in the Table 3.27 are consistent to those with Aker BP RNB2026 submission and Lime SoR[8].
- The main uncertainties assessed in the Lunde discovery are structure, contacts, porosity followed by structural segmentation in descending order.
- Garn formation constitutes more than 50% of the PIIP volume.
- AGR finds the original draft DG3 subsurface work robust for PIIP estimation, hence considers the estimated PIIP reasonable.

Comments to facilities and cost profiles

There are no current viable development solutions or cost estimates. The operator has presented a maturation process which may lead to a DG3 end 2026 and First oil mid 2027. AGR considers this plan to be optimistic given the current status of the project.

Comments to Contingent Resources and recovery factors

- AGR reviewed the profiles in the 31.12.2024 audit; please see this report for details. In AGR's opinion the production profiles presented by Lime are reasonable.
- The oil and gas recovery factors are shown in Table 3.30. The oil recovery factor of 3% is extremely low. The recovery factor is still reasonable when taken into consideration that the well is drilled as a gas well, the oil is viscous and there is rapid extraction of gas (which lowers the field pressure and gives lift problems). Note that the recovery factor for gas of 54% is based on sales gas divided by the GIIP given in wet gas volumes. The gas recovery factor with produced wet gas volume is 64%.
- The oil equivalent uncertainty range is -37%/+41% versus 2C. The range is high, but reasonable considering the subsurface uncertainties of the project.

Table 3.30 Lunde 2C recovery factors

	Oil RF by 31.12.2025	Oil RF at EUR	Gas RF by 31.12.2025	Gas RF at EUR
Lunde	-	3%	-	58%

AGR Conclusions

- AGR considers the PIIP estimates for the West and East a segments presented by Lime to be acceptable.
- The project risk is include decision to move forward; applying for extension and deciding to invest.
- The well is primarily a gas well. The oil recovery factor is thus only 3% due to the viscous oil, rapid extraction of gas-cap and the well placement.
- The Contingent Resources reported by Lime are subject to change if a new development option progresses.
- AGR endorses the Lunde Contingent Resources (Table 3.28) as presented by Lime.

4 Asset Descriptions (AGR First Time Certifications)

This section covers the asset in Benin and two assets in Germany which AGR has not previously audited and where this report is the first time AGR reports on these assets. In the 31.12.2024 reporting for the Benin asset and the 30.04.2025 reporting for the German assets, the Reserves and Contingent Resources were audited by other reserves assessment consultants, and the assets were reported in four different resource evaluation reports[2][3][4][13].

The sections following contain brief asset descriptions and an overview of the resources as of 31.12.2025 for these assets with some commentary on methodology and changes since the previous estimates reported 31.12.2024 and 30.04.2025. The resource estimates presented in the sections below are on gross and net to Lime. In order to convert those numbers to estimates net attributable to Rex, the estimates should be multiplied by Rex's 89.74% share in Lime. The resource estimates net attributable to Rex are found in 1 Executive Summary as well as in A.1 Summaries of Oil and Gas Reserves and Resources.

4.1 Benin - Sèmè North

Asset Overview

In December 2023, Lime subsidiary Akrake Petroleum Benin SA signed a Production sharing contract (PSC) and took operatorship of Benin Offshore Block 1 and the Sèmè oil field. The Sèmè Field is situated in the territorial waters of the Republic of Benin, 15 km from the coast and 30 km from the Port of Cotonou (Fig. 2.4). The water depth is 27 to 54 m. The reservoir depth is at around 1900 m TVD MSL. There are two oil accumulations in the Sèmè Field; Sèmè South and Sèmè North, whereof only the latter is the target for the development by Akrake Petroleum. The Sèmè Field was initially developed by the Norwegian oil company Saga Petroleum and first came on production in November 1982. Saga Petroleum operated the field until 1985 and the field continued to produce until December 1998 with other operators. There has been no production from Sèmè North since 1998. Nigerian oil company SAPETRO held the licence for several years and drilled three appraisal wells and invested in new production and export facilities but withdrew from the licence in 2015. Cumulative production as of 31.12.2025 from Sèmè North is about 16.7 MMbbl.

Licence details summary is shown in Table 4.1 and the licence shares are shown in Table 4.2.

Table 4.1 Sèmè North summary table

Asset name/ Country	Lime's interest (%)	Development Status	Licence expiry date	Licence Area (km ²)	Type of mineral, oil or gas deposit	Remarks
Sèmè North / Benin	89.41 76.00 ¹⁾	Approved for Development	Exploration licence (Block 1): 12/2027 Exploitation licence (Sèmè): 03/2053	Block 1: 537 Sèmè Field: 62	Oil	Production Sharing Contract (PSC)

1) As of 31.12.2025 the Akrake working interest is 89.41%. The 76% share is based on the expectation that the Republic of Benin (State) participates in the licence with 15% when the Exploitation Licence is granted.

The licence shares applicable to the PSC are shown in Table 4.2. As of 31.12.2025 Akrake holds an exploration licence with licence share 89.41%. Akrake and Benin company Octogone are the only partners as of 31.12.2025. Lime has informed AGR that when Sèmè North comes on production, an exploitation licence will be granted to Akrake, and that the Benin State is expected to participate in the licence with a 15% working interest. The Benin State has an option to participate in the exploitation licence with a share between 0-15%.

The estimate of Reserves and Contingent Resources attributable to Lime presented in this report is based on the expectation that the Benin State decides to participate with the maximum 15% working interest.

Table 4.2 Sèmè Field licence shares (%).

Licence	Akrake Petroleum Benin SA (Op)	Octogone Exploration & Production SA	The Republic of Benin (State)
Offshore Block 1 / Sèmè North - As of 31.12.2025	89.41 ¹⁾	10.59	-
Offshore Block 1 / Sèmè North - After State participation in 2026	76.00 ²⁾	9.00	15.00

1) As of 31.12.2025 the Akrake working interest is 89.41%. The 76% share is based on the expectation that the Republic of Benin (State) participates in the licence with 15% when the Exploitation Licence is granted.

2) The net Lime Reserves is the estimated Akrake share of Cost oil and Profit oil (net after 10% Royalty) in accordance with the Production Sharing Contract

Discovery

The Sèmè North Field was discovered in 1969 by the well DO-1 drilled by Union Oil. This well found oil on the eastern segment on Sèmè North in sandstones belonging to the Abeokuta Formation of Middle-Late Cretaceous Turonian age. Several delineation wells were subsequently drilled by Union Oil and Saga Petroleum prior to the initial field development.

Reservoir

The Sèmè North Field is a structural trap, situated in the Benin (Dahomey) Basin. The basin is one of several basins along the Atlantic margin in western Africa, formed in a tectonic setting of rifting followed by transform movements during the separation of the American and the African plates. The trap is a structural closure and is bounded by an east-west trending fault to the south. The Sèmè North Field consists of two structural highs; the eastern segment (previously developed) and the western segment. These segments are primarily interpreted to be divided by faults, but a stratigraphical component to the segmentation cannot be ruled out.

The main reservoir is named the H6 unit within the Abeokuta Formation. H6 consists of sandstones deposited in prograding braided fan deltas with lower delta plain and delta front facies. The lower part is described as more fluvial, grading to marginal and shallow marine towards the upper part. The sands are massive, coarse-grained, moderately sorted, with conglomerate and shale layers interbedded. The H6 reservoir is of fair to good quality, with porosity ranging from 13% to 24%. Permeability ranges from 100 mD to above 1D and net/gross ranges from 74% to 92%. Pressure measurements and depletion behaviour have contributed to the division of H6 into the sub-units A, B, C, D and E, separated by four barriers. These barriers are not always associated with lateral extensive shale intervals. The main barrier is between D and the underlying non-depleted sub-unit E.

The older, secondary, reservoir units H7 and H8 are of Albian age. H7 consists of a series of shales, sands and carbonates, deposited on a braided river delta plan. H8 is of continental origin with alluvial delta fans and mud flood plains as barriers. The reservoir quality is poorer than in H6 with an average net/gross of around 50% and average porosity around 14%.

Recovery Strategy

The drainage strategy for Akrake's field redevelopment project is production from two horizontal wells with pressure support from an expected active aquifer. Production wells will have Autonomous Inflow Control Valves (AICV) and ESPs installed to optimise inflow and lift. The drainage strategy in the initial field development was similar but with the use of vertical or slanted wells and consequently a higher number of drainage points.

Development

Akrake is redeveloping the Sèmè North Field with new wells and new facilities. The existing wells and facilities from the past development efforts will not be reused, and Akrake has no ownership or abandonment or other liabilities with respect to those past development facilities and wells. The new facilities were installed in the field in late 2025.

The field redevelopment consist of two horizontal production wells. Due to the nature of the crude oil, expected rapid increase in water-cut and desired production rates, ESPs will be used. Both wells will be completed with sand screens and Autonomous Inflow Control Valves (AICV) for control of water production.

The Akrake redevelopment of Sèmè North is based on the use of leased facilities. A leased Mobile Offshore Production Unit (MOPU) has been jacked-up adjacent to a new conductor supported wellhead platform. Two flexible seabed flowlines capable of handling 15 000 bbl/d is installed between the MOPU and the leased Floating Storage & Offtake (FSO) vessel which is moored 500 m away.

Produced fluids will be processed on the MOPU, which is designed with capacities of up to 45 000 bbl/d of liquid per day and up to 15 000 bbl/d of crude oil. Produced water will be treated to 15 ppm oil in water, and discharged to sea. Produced gas will initially be used to purge the emergency flare system. Once the fluid Gas Oil Ratio and gas rates has been determined, gas engines may be installed to reduce diesel consumption for power generation. Any residual water in the oil will be removed on the FSO. The FSO is a converted Aframax tanker capable of storing about 600 000 bbls of oil. Oil sales will be by side-by-side, ship-to-ship offloading. The lifting cargo sizes will be 300 000 bbls, constrained by the maximum tanker size that can be accommodated adjacent to an Aframax tanker.

The MOPU has sufficient weight and space capacity for modifying the facilities if a later gas development is sanctioned (commercialization of H8 gas reservoir and H7 associated gas production)

The Akrake field redevelopment facilities concept is shown in Fig. 4.1. Due to challenges related to drilling of the first oil producer, the next well will be drilled from a second (to be installed) conductor supported wellhead platform. This additional wellhead platform is planned to be located about 1 km north of the existing one and the MOPU. This new facility was not part of the original redevelopment plan and consequently there is a cost increase and also a delay in schedule for the second well to come on production.

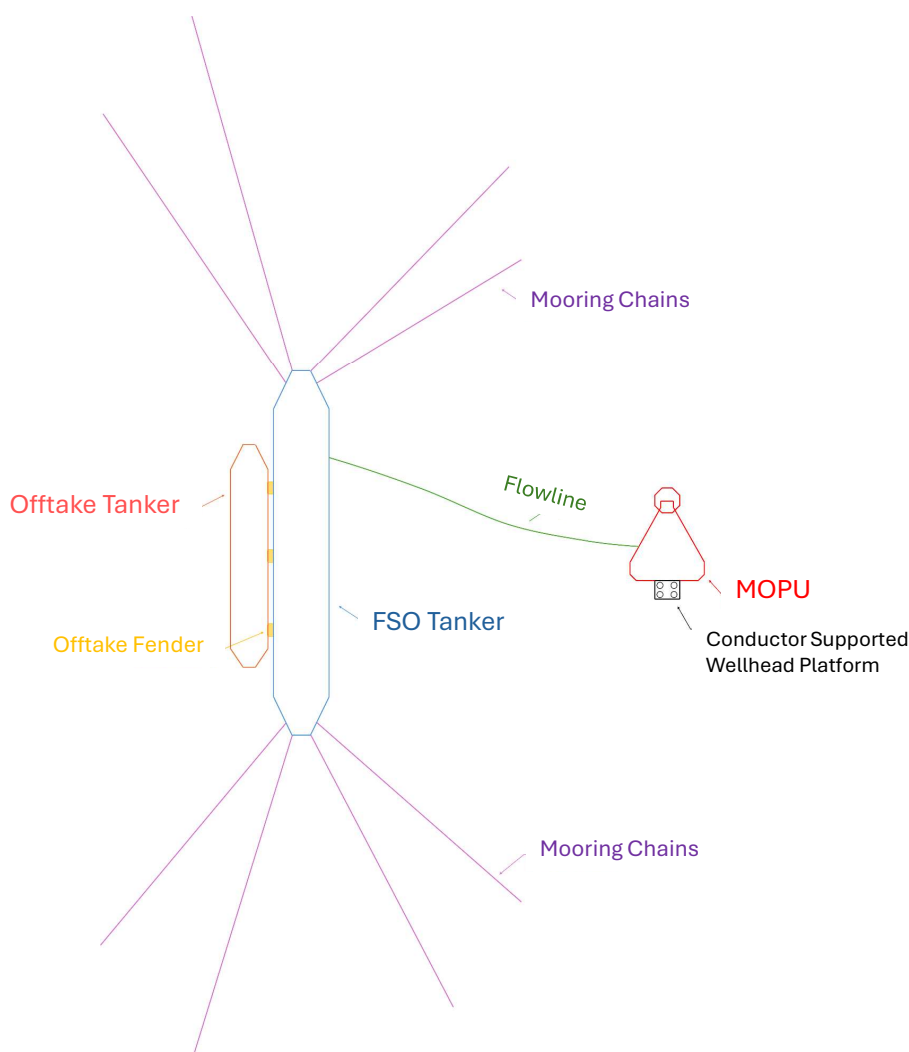


Fig. 4.1 Sèmè North field redevelopment concept

Technical lifetime of the wells and facilities

The MOPU and FSO facilities have been classified for 5 years. At that point if they were to be retained they would need to be recertified which could mean a period of dry docking for inspections.

Status

The field facilities have been installed, and the first production well was being drilled as of 31.12.2025. There have been severe delays in the drilling due to technical difficulties and a very significant cost overrun has been incurred as a result. The contracted rig time is too short to facilitate the drilling of the second oil producer and the H7/H8 appraisal well in the same rig slot. Therefore, the second oil production well will need to be drilled at a later time. In order to avoid similar drilling problems in the second production well, Lime has decided to move the location of that well about 1 km further north; which means a new wellhead platform has to be installed. The first well is assumed to come on production in January and the second well in August 2026, assuming a new rig slot can be secured for Q2-2025 and assuming the second wellhead platform and associated flowline and cables are installed on time.

With regard to the old facilities from previous development efforts, these are not in use and are not the responsibility of Akrake.

Petroleum Initially-In-Place (PIIP) presented by Lime

The PIIP estimates for 31.12.2025 are shown in Table 4.3 for Reserves and in Table 4.4 for Contingent Resources (except for an infill well in H6 which is classified as Contingent Resources).

Table 4.3 Sèmè North (H6) PIIP estimate as of 31.12.2025

	PIIP, 31.12.2025 (Best Estimate)
Oil/Condensate (MMbbl)	52.5
Gas (BScf)	6.0

Description of the PIIP linked to Reserves in the main reservoir H6[9].

- PIIP for H6 in the Sèmè North Field is based on a static model. The starting point was the legacy model built by the former operator SAPETRO in Petrel. This model was modified by Akrake during 2024/2025, using tNavigator, as a basis for estimation of PIIP and production profiles for the re-development.
- The input surfaces and faults were interpreted on a merged seismic data set of two surveys from 1983 (Western) and 2007 (Fugro). The data is of poor to reasonable quality. The quality control by Akrake involved an alignment of coordinate systems, adjustments of well surveys and well tops, inclusion of two additional wells and modification of the depth map better to honour the structural shape of the time map
- The model incorporates all available wells with well paths, tops and logs.
- The grid is pillar grid with 50 m by 50 m lateral cell size. It is divided into the five sub-units A to E; separated by four barriers. The barriers are on average around 1.5 m thick, while the reservoir sub-units vary from an average of 1.4 m in A to 9.5 m in sub-unit D.
- Effective porosity and net/gross were propagated from wells using kriging interpolation. Permeability was modelled based on three rock types and initial water saturation was calculated by a height function above the free water level at 1911 m TVD MSL.
- Akrake presents in addition STOCIP (oil currently in place). These numbers are computed by estimating the current assumed oil-water contacts and simply calculating the oil-in-place in the model above those contacts. The STOCIP presented by Lime is 10.4 - 20.8 - 22.7 MMbbl (low-best-high).
- The uncertainty in STOCIP was estimated by Akrake in deterministic cases, applying three versions of the top H6 reservoir combined with low/high multipliers on porosity and permeability.

Table 4.4 Sèmè North (H7&H8) PIIP as of 31.12.2025

	PIIP, 31.12.2025 (Best Estimate)
Oil/Condensate (MMbbl)	88
Gas (BScf)	108

Description of the PIIP linked to Contingent Resources in the H7 and H8 reservoir units.

- The PIIP for H7 and H8 is estimated by probabilistic methods by consultants Tetra Tech RPS[4]. The STOIIIP is located in H7, while the GIIP is in H8.
- Tetra Tech RPS performed an independent seismic interpretation and depth conversion for the main surfaces. These surfaces were combined with fluid contacts and reservoir properties gathered from the legacy work performed by Beicip-Franlab in 1994. Tetra Tech RPS estimated ranges for each zone as input to a Monte Carlo simulation of STOIIIP and GIIP.
- Akrake has not presented any static models nor PIIP estimates for H7 and H8 at this stage.

Reserves and technical profiles presented by Lime

The Reserves are based on the technical production and cost profiles provided by Lime in SoR2026 - Benin [9]. These profiles have been evaluated by AGR to confirm project commerciality and verify the correct economic cut-off. AGR has applied the economic assumptions provided in appendix A.1 Summaries of Oil and Gas Reserves and Resources. The resulting Reserves for Sèmè North are shown in Table 4.5. Lime has included in the PSC economic modelling that pre-2026 sunk cost of about 170 MUSD is recovered through cost oil.

The Reserves include the following projects, classified according to PRMS:

- Phase 1 - H6 redevelopment - Approved for Development

The project is confirmed commercial for the Base price scenario and the economic cut-offs are:

- 1P: end of 2027, one year earlier than technical cut-off
- 2P: end of 2028, the same as technical cut-off
- 3P: end of 2028, the same as technical cut-off

The Sèmè North production history and technical sales forecasts for oil (without the economic cut-off) are illustrated in Fig. 4.2.

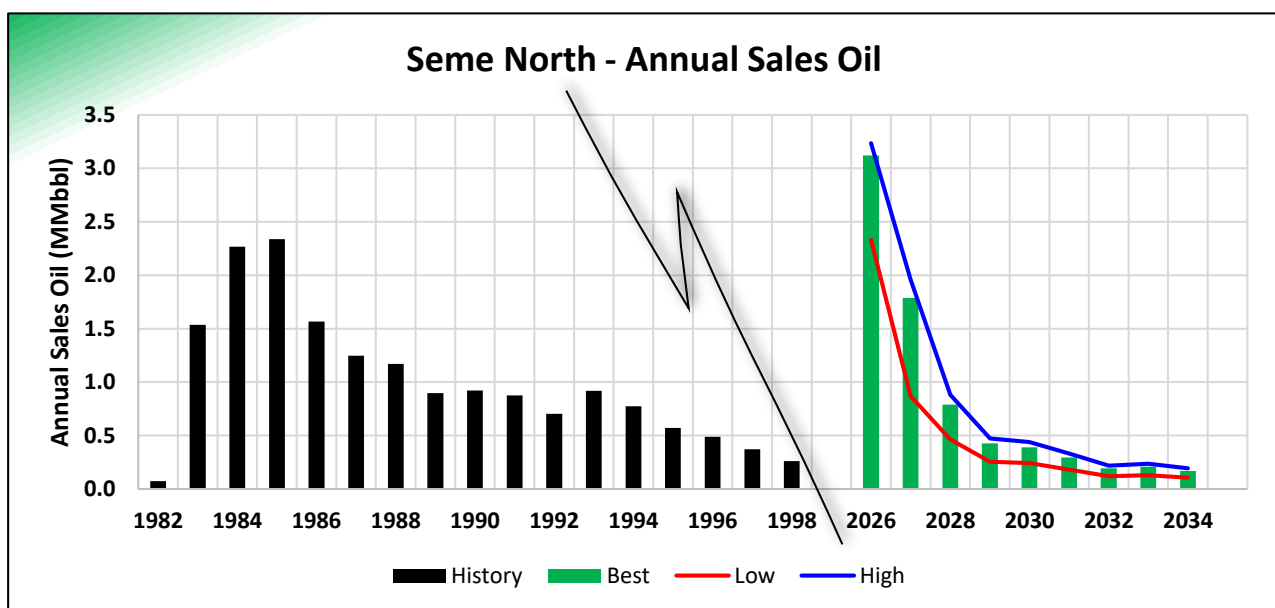


Fig. 4.2 Sèmè North - annual sales oil

Table 4.5 TRR and Reserves as of 31.12.2025 - Sèmè North

	TRR (Gross 100%)			Reserves (Gross 100%)			Reserves (Net 76.0000%) ^{1,2)}		
	Low	Best	High	1P	2P	3P	1P	2P	3P
1st Production	01.02.2026								
Cut-off (year end)	2034	2034	2034	2027	2028	2028	2027	2028	2028
Oil/condensate (MMbbl)	4.70	7.38	7.97	3.20	5.70	6.08	2.35	4.11	4.38
Gas (BScf)	-	-	-	-	-	-	-	-	-
NGL, (MMboe)	-	-	-	-	-	-	-	-	-
Total (MMboe)	4.70	7.38	7.97	3.20	5.70	6.08	2.35	4.11	4.38

- 1) The net Lime Reserves is the estimated Akrake share of Cost oil and Profit oil (net after 10% Royalty) in accordance with the Production Sharing Contract (72.1% for 2P)
- 2) Net Reserves in Table above are net to Lime. Rex's share in Lime is 89.74%. For reserves net to Rex, see 1 Executive Summary and A.1.5 Sèmè North - Summary of Oil and Gas Reserves and Resources.

Description of the production profiles

The production profiles include two horizontal development wells. The production profiles are generated with a dynamic reservoir simulation model which is based on the SAPETRO geomodel that was updated in 2024/2025 by Akrake. The profiles are based on the use of ESPs to maintain high liquid rates after water breakthrough. The profiles assume startup of the first well AK-2H in January 2026 and of the second well AK-1H in August 2026.

Description of the cost profiles

The costs are generated internally by Akrake based on in-house cost data, relevant historical costs and current regional market supplier knowledge.

To minimise project risk and maximise project profitability the main production assets are leased including the MOPU, the FSO tanker and the mooring anchors and chains. Short lease periods with suppliers will allow for minimising risk.

The total original Akrake redevelopment project costs are broken into CAPEX, DRILLEX, OPEX and ABEX and are seen in Table 4.6.

Table 4.6 Sèmè North Original Re-development Project Costs

Cost item	MUSD
CAPEX	27.46
1. MOPU, FSO and Mooring System: Modifications, mobilisation, transportation, installation, hook up and commissioning of leased equipment	24.10
2. Flowline 2 x 6" ManOil Steel cord reinforced 575 m length flowlines, installation and commissioning	2.65
3. Structural Connection - Connection from Wellhead Platform to MOPU	0.71
DRILLEX	77.40
1. Tangibles	13.00
2. Rig	24.80
3. Services	39.60
OPEX	169.00
1. Lease of MOPU and FSO	156.70
2. General and administrative expense	5.30
3. Financing costs	7.00
ABEX	21.60
1. Included plug and abandonment of two wells, removal of the four conductors and wellhead platform. Removal of the flowline. Decommissioning and de-mobilisation of the MOPU, FSO and production equipment	21.60
TOTAL Project Costs	295.46

A breakdown of the new additional project costs (due to change of well location for the second production well) is seen in Table 4.7. In addition, there is an existing cost overrun related to drilling of about 100 MUSD.

Table 4.7 Additional costs

Cost item	Capex, MUSD	Comment
Conductor guide frame	0.50	
Boat landing	0.50	
Flowline 1km	1.00	
Install guide fram	0.20	1@ \$200k/day rig spread rate pre drilling
Install conductor	1.60	8@ \$200k/day rig spread rate pre drilling
Install boat landing	0.20	1@ \$200k/day rig spread rate pre drilling
Install flow line	0.40	10@ \$40k/day AHT plus project team
Design	0.40	Mundus Prime design
Ancillary equipment	0.20	
TOTAL additional costs	5.00	

Changes in Reserves since audit 31.12.2024

The gross changes in Reserves for Sèmè North are shown in Table 4.8. AGR's evaluation is limited to Lime's reserves as of 31.12.2025. The reserve estimates as of 31.12.2024 were prepared by Exceed[3] and have not been reviewed by AGR. As a result, AGR does not have a complete understanding of the work performed in the prior evaluation and cannot fully account for the changes in reserves between the two reporting dates. It is however clear from the 31.12.2024 report that the basis for Reserves was a four-well development as opposed to the two-well development that is the basis for the 31.12.2025 Reserves. This is likely a key reason for the significant change in reserves. AGR also note that the STOIIP in the 31.12.2024 [3] report is much higher than the current estimate by Akrake.

Table 4.8 Balance sheet - Sèmè North Reserves (100%)

Gross reserves balance, 31.12.2024 - 31.12.2025, for Sèmè North (100%)							
Reserves class	Status 31.12.2024	Production (Positive)	Revisions	Acquisitions or sales	IOR	Discoveries/ New Projects	Status 31.12.2025
Oil and condensate (MMbbl)							
1P	11.40	-	-8.20	-	-	-	3.20
2P	10.90	-	-5.20	-	-	-	5.70
3P	13.60	-	-7.52	-	-	-	6.08
Gas (BScf)							
1P	-	-	-	-	-	-	-
2P	-	-	-	-	-	-	-
3P	-	-	-	-	-	-	-
NGL (MMboe)							
1P	-	-	-	-	-	-	-
2P	-	-	-	-	-	-	-
3P	-	-	-	-	-	-	-
Oil equivalents (MMboe)							
1P	11.40	-	-8.20	-	-	-	3.20
2P	10.90	-	-5.20	-	-	-	5.70
3P	13.60	-	-7.52	-	-	-	6.08

Contingent Resources presented by Lime

The Contingent Resources presented by Lime are shown in Table 4.9. The estimates are from the 31.12.2024 report by Tetra Tech RPS[4] except the H6 infill well which is based on Akrake's reservoir simulation model. No 1C and 3C volume was presented by Lime for the H6 infill well. The forecasting methodology for the H7 and H8 reservoirs has been to estimate a start rate and assume a yearly decline. AGR notes that Tetra Tech RPS has applied an economic cut-off to the H7 and H8 development. This results in lower, more conservative volumes than using unconstrained technical profiles, and is the reason why no 1C volumes are reported. The notional H7 development plan includes three horizontal oil production wells with Fishbone completions and ESPs. The notional H8 development plan includes two horizontal gas production wells with Fishbone completions, compression and gas dehydration facilities on the MOPU and a flowline to shore.

Table 4.9 Gross and net Contingent Resources as of 31.12.2025 - Sèmè North

Sèmè North		Gross (100%)			Lime net (Lime) ^{1,2)}		
Contingent resources (MMboe)	PRMS subclass	1C	2C	3C	1C	2C	3C
Phase 2 – H6 infill well	Development Unclarified	-	0.62	-	-	0.45	-
Phase 2 – H7 development	Development Unclarified	-	13.95	32.05	-	10.01	23.00
Phase 2 – H8 development	Development Unclarified	-	7.09	10.46	-	5.09	7.51
Total, MMboe		-	21.67	42.51	-	15.55	30.51

1) Lime working interest in Sèmè North is 76%, but a net attributable to Lime of 72.1% has been applied to Contingent Resources (the same as for 2P reserves net entitlement).

2) Net Contingent Resources in Table above are net to Lime. Rex's share in Lime is 89.74%. For Contingent Resources net to Rex, see 1 Executive Summary and A.1.5 Sèmè North - Summary of Oil and Gas Reserves and Resources.

Changes in Contingent Resources since audit 31.12.2024

The only change in Contingent Resources is the addition of the H6 infill well.

Table 4.10 Balance sheet - Sèmè North Contingent Resources (100%)

Gross contingent resource balance, 31.12.2024 - 31.12.2025, for Sèmè North (100%)							
Resource class	Status 31.12.2024	Production (Positive)	Revisions	Acquisitions or sales	IOR	Discoveries/ New Projects	Status 31.12.2025
Oil and condensate (MMbbl)							
1C	-	-	-	-	-	-	-
2C	21.05	-	-	-	-	0.62	21.67
3C	42.51	-	-	-	-	-	42.51

AGR comments to PIIP, Reserves and Contingent Resources

Comments to PIIP

AGR has reviewed the basis for the PIIP estimates as described in presentations and reports[3][13]. AGR has also had access to the operator's base case static model, generated by Akrake in tNavigator (exported to Petrel).

- AGR considers the construction of the static model for the H6 reservoir to be of adequate quality for the purpose of estimating PIIP, for dynamic simulations and for following up the well programme on Sèmè North.
- AGR has reviewed the base case static model provided by Lime and finds the reservoir properties to be in line with petrophysical properties in the logs. Further, STOIP calculated in this model is very similar to presented numbers for both the western (~14 MMbbl) and the eastern (~39 MMbbl) segments.
- There are uncertainties, both in the database and the interpretations. AGR has noted some mismatch in coordinate systems, however this is corrected by the operator. AGR agrees with the operator that

there is relatively small uncertainty in net/gross and porosity, and that the main concern should be put on permeability and water saturation. Further, the gross rock volume, with the uncertainties in seismic mapping, depth conversion and internal reservoir zone geometry is a main influential factor to the PIIP uncertainty range.

- The current STOCIP for H6, as presented by Lime, is considered by AGR to be on the conservative side. According to the operator the produced volume (primarily from the eastern segment) is 16.7 MMbbl of oil. The total STOCIP would be closer to 36 MMbbl than 20 MMbbl and this is also commented by Lime. The operator has not included any estimate of residual oil below the estimated current oil-water contacts, which can explain parts of this mismatch.
- AGR has not accessed any models nor well data used for estimating PIIP in H7 and H8. This limits the extent to which a full audit trail can be established for the PIIP estimates.
- The H6 STOIP uncertainty range of $\pm 10\%$ is regarded to be quite narrow, but acceptable.
- The H7 STOIP uncertainty range (-38%/+52%) and the GIIP uncertainty range (-29%/+38%) are considered reasonable.
- In AGR's opinion the PIIP estimates presented by Lime are reasonable.

Comments to production profiles

AGR has reviewed the presented material from Lime including presentations, simulation results, and production data from the historical wells that were on production in the period 1985-1998. There has been work meetings and communications with Lime to understand the data and assumptions applied, and simulation results. AGR has the following comments to the profiles presented by Lime:

The basis for the forecast is the current reservoir simulation model for Sèmè North. Although AGR concurs that reservoir simulation is the appropriate forecasting methodology for this development, AGR notes several uncertainties with regard to the model that could impact the accuracy of the forecasts and in particular how the water cut develops in the field:

- The uncertainties in top reservoir depth away from past well control represents a significant uncertainty with respect to the volume of oil in place
- The model has not been history matched on a well-by-well basis for the production history from the 1985-1998 production
- The model has been initialised with an assumed current oil water contact (shallower than the original OWC) which assumes perfect gravity driven re-segregation of oil and water in the reservoir in the period since 1998. In reality this process may or may not have been as efficient as assumed. One will not know to what extent the water has receded and fluids re-segregated until the production wells are drilled and logged and production performance is observed
- The residual oil saturation behind the past water front and also hysteresis in the previously water-invaded region of the reservoir has not been considered, however this could have an effect on relative permeabilities and how swiftly the water-cut will rise in the field during the production phase. It is not currently known whether there is still water from past water coning and ingress that is present in the assumed dry oil zone.
- There is a significant number of previously produced wells in the field which have not been plugged and abandoned and which will likely act as cross flow pathways and passive pressure equilibration points. This could have an impact on flow in the reservoir between the H6 intra reservoir zones which is not taken into account in the current simulation model

The production profiles presented are based on startup of production for the AK-2H and AK-1H wells in January 2026 and August 2026. At the time of writing this report (mid-February 2026) the first well AK-2H has not yet started production, although AGR understands the well has been completed and is very close to startup. This indicates some delay to the production startup which can potentially impact on the 2026 production.

The production forecast is considered reasonable but is associated with a larger degree of uncertainty than what would be the case for a virgin field development where the reservoir fluids have not yet been disturbed

by production. The early production performance of the two wells and the saturation logs from the drilling of the wells will likely reduce the uncertainty with respect to the reservoir model and the saturation distribution in the reservoir in particular.

Comments to facilities and cost profiles

AGR supports Akrake's project execution strategy with a phased and flexible development, being based on leasing contracts for the main facilities components. AGR also agrees in the reasoning of the change in drilling location even this brings some uncertainties to the further project execution with potentially schedule delays and cost increases.

AGR judges that cost figures presented by Akrake are based on sound industry practice, relevant field experience and the present market situation.

AGR has reviewed and evaluated relevant cost and time estimates as documented in the Akrake presentations, information from Lime regarding the additional facilities scope (one new wellhead platform) and the SoR2026. Comparing relevant cost figures, AGR considers the Akrake original costs to be reasonable and realistic, reflecting present asset status and activity level. However, AGR has been informed of severe cost and time overruns with well AK-2H and in lieu of this the estimate for remaining DRILLEX could also potentially be on the low side if drilling problems is encountered when drilling the next production well.

AGR judges the new additional costs to be relative immature (order of magnitude estimates) and may be on the optimistic side. The new additional costs do not appear to include any contingency for potential technical risks, schedule delays and/or cost increases.

However, AGR has not incorporated any contingency for the relatively minor expected OPEX and ABEX cost increases due to the additional installations. AGR also notes that the new wellhead platform and conductors are defined as sunk costs by Lime.

AGR has implemented the SoR2026[9] cost profiles in the economic evaluation.

Comments to Reserves and recovery

- The recovery factor after the initial development was 32% based on the STOIIP estimate of 53 MMbbl.
- The 2P oil recovery factors estimated for this audit are shown in Table 4.11. AGR finds the final recovery factor of 43% to be reasonable taken into account the redevelopment wells are placed high on the structure and target both undrained attic oil from previous development and undrained oil in areas where water coning may have been constraining recovery in the past when vertical wells were used
- The low TRR estimate is -37% and the high case TRR is +8% versus the best case TRR. For Reserves (after economic cut-off) the range is -43% and +7%. This skewness to the low side is considered reasonable in light of the described limitations to the simulation model in terms of representing the reservoir status as of today. However, AGR considers that the upside range is on the narrow side. Part of the reason for this is that the base case reservoir properties already are very good.
- AGR has reviewed Lime's economic model, and checked this against the Production sharing contract (PSC). AGR's conclusion is that the economic model reflects the complexity of the PSC and that the allocation of cost oil and profit oil is reasonable.

Table 4.11 Sèmè North 2P Recovery Factors

	Oil 31.12.2025	Oil at EUR	Gas 31.12.2025	Gas at EUR
Produced (MMbbl/BScf)	16.80	22.50	-	-
Recovery factor	32%	43%	-	-

Comments to Contingent Resources

The Contingent Resources are based on three projects that are independent of each other. All the three potential projects are in the resources class Development Unclassified and will require further data gathering and analysis to mature.

- H6 infill well: The recovery estimate for this is largely related to the reservoir depth map in this region of the reservoir. The estimate of recoverable volumes is relatively low and based on the current reservoir simulation model. AGR considers the estimate to be uncertain but reasonable. The volume presented by Lime is low, and it is uncertain whether such an infill well will have positive economics.
- H7 oil development: This potential project is based on three horizontal oil production wells tied back to the MOPU. The resource estimate is quite high but with the current limited data available for this reservoir it is difficult to firmly opine on the reasonableness of the estimate and the decline assumptions. Additional appraisal efforts are required to get a better definition of the H7 potential.
- H8 gas development: This potential project is based on transporting gas from two horizontal wells to shore and selling it to a user onshore. The Maria Gleta gas fired power plant located close to Cotonou was opened in 2019 and is the likely customer of the gas from Sèmè North.

AGR Conclusions

- The current recovery factor is moderate, and there is a strong case for the proposed redevelopment of this field.
- The Sèmè North Reserves reported by Lime are based on reservoir simulation results which have a significant degree of uncertainty in this previously produced field.
- The uncertainty on Sèmè North is high with respect to well performance especially with regard to water and the possible previous flooding in the new potential producer locations where the water from previous coning may potentially not have subsided as much as anticipated.
- Akrahe has implemented mitigating actions to optimise the well trajectories and production, including advanced geosteering to place wells optimally and inflow control devices to reduce water cut development.
- AGR notes that the oil price used does not include any discount for the slightly heavy and waxy Sèmè North oil. If a significant discount is observed when the oil is sold then it could impact on the economics and potentially on the timing of economic cut-off and hence on Reserves.
- AGR endorses the Sèmè North Reserves (Table 4.5) and Contingent Resources (Table 4.9) presented by Lime.

4.2 Germany - Erfelden

Asset Overview

The Erfelden oil field is located in the Upper Rhine Graben onshore Germany. The field is located approximately 50 km south of Frankfurt am Main in the German federal state of Hessen, as shown in Fig. 2.5. The production licence named Schwarzbach, includes the Erfelden Field and was awarded in 2017 and taken over by Lime Resources Germany GmbH from the former operator Rhein Petroleum in 2025. The reservoir is at a depth of 1500 - 1600 m TVD MSL.

Licence details are summarised in Table 4.12 and the licence shares are shown in Table 4.13. The production licence gives the licensees full rights to explore and produce hydrocarbons at all stratigraphic levels within the licence area.

Table 4.12 Erfelden Field summary table

Asset name/ Country	Lime's interest (%)	Development Status	Licence expiry date	Licence Area (km ²)	Type of mineral, oil or gas deposit	Remarks
Erfelden / Germany	100	On Production / Approved for Development / Justified for Development	31.12.2044	8.84	Oil	-

Table 4.13 Erfelden Field licence shares (%).

Licence	Lime Resources Germany GmbH (Op)
Schwarzbach	100

Discovery

The Erfelden Field was discovered in 2015 by Rhein Petroleum with the well SCHB (Schwarzbach) 1a. Oil was discovered in sandstones in the Perchelbronner-Schichten (PBS) Formation of Late Eocene - Early Oligocene age. The top of the reservoir was found at 1542 m.

The fields Stockstadt Main in the south-east and Kuehkopf in the west produced oil from the same formation, Stockstadt Main in 1950-1992 and Kuehkopf in 1956-1992. Both fields were operated by ExxonMobil. The areas and wells are shown in Fig. 4.3, where also the current Schwarzbach licence area is marked.

Reservoir

The Erfelden Field is situated at the northern part of the Upper Rhine Graben, where sediments filled in an active half-graben in the rifting zone. The Erfelden Field is a structural trap. Numerous fault blocks are present in the field, some faults are partially sealing, but several faults show small throws and communication is expected. Stockstadt Main and Kuehkopf are now mapped as fault blocks in the larger area. The Kuehkopf and former Schwarzbach area is now named Erfelden High. The fault blocks in Erfelden High are interpreted to be in communication and sharing a common free water level.

The reservoir is within the Pechelbronner-Schichten sandstones and is divided into a lower (LPBS) and an upper (UPBS) reservoir zone. The local depo-center is in the eastern Stockstadt area where the thickest sequences are located. The system is thinner in Erfelden towards west and north. LPBS is fluvial-dominated in the Erfelden area and consists of massive, blocky, conglomeratic sandstones with good reservoir quality with increasing marine influence towards the top. Several wells further west in Kuehkopf and Erfelden show no or very thin reservoir sand in the LPBS. A shale-dominated interval representing a flooding phase is acting as a local seal between LPBS and UPBS. The main reservoir unit, UPBS, is of shallow marine origin, with the basin towards to south. Repeated cycles of sand deposition gives a layered response on the logs, alternating between shallow marine sandstones and finer material. The reservoir properties are fair to good in UPBS with an average net/gross of around 70%, porosities in the range of 15 - 18% and permeabilities in the range of 1 - 100 mD. The average net/gross in LPBS is considerably lower, around 30%, but where the fluvial sands are present the reservoir properties are good with permeabilities above 1 D.

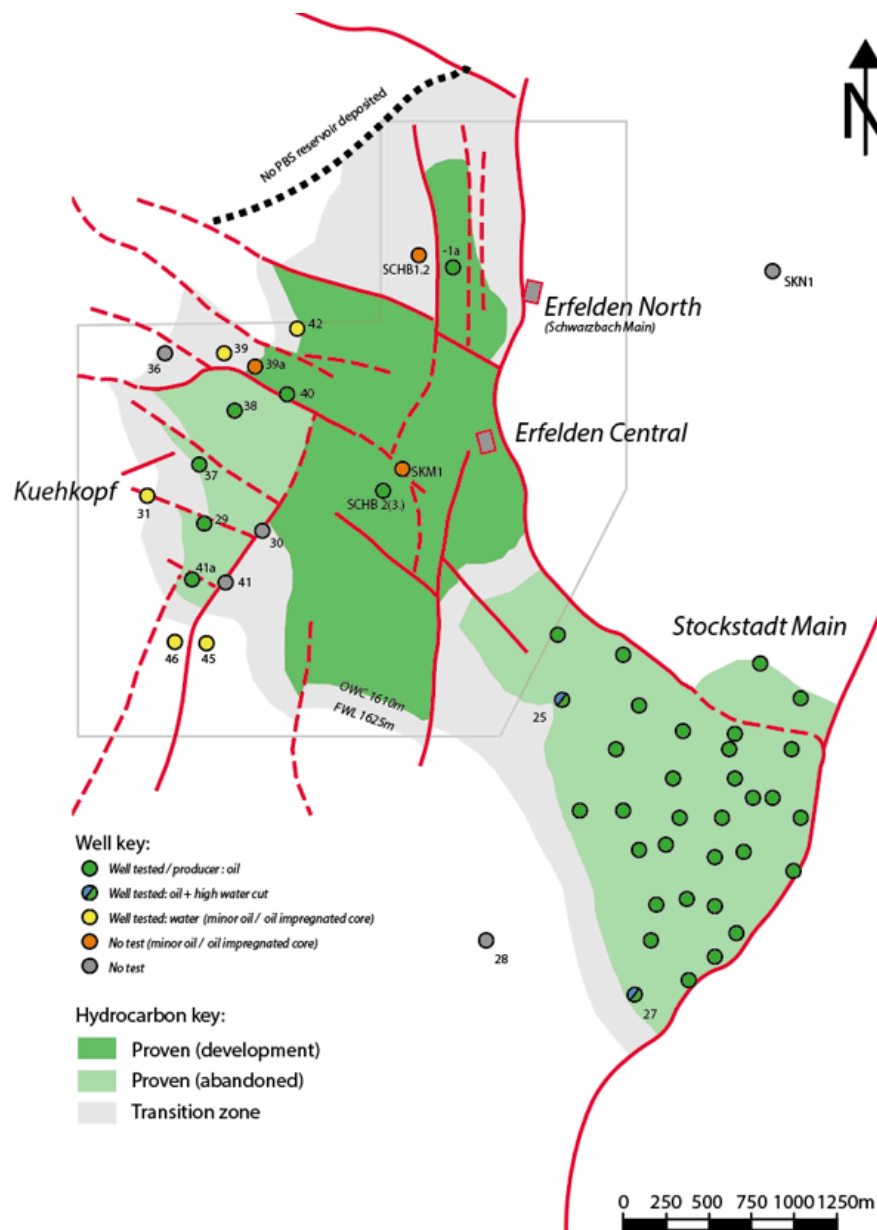


Fig. 4.3 Erfelden Field overview

Recovery Strategy

Future production and development of Erfelden is planned in three phases with different recovery strategies:

- Existing wells on production (hereafter referred to as No Further Activity (NFA)): Natural depletion with aquifer support. Two wells on artificial lift (sucker rod pumps).
- Phase1: Natural depletion with aquifer support. Two additional wells with ESPs.
- Phase2: A combination of natural depletion with aquifer support and pressure support by water injection. Four additional production wells with ESPs and three water injection wells.

Development

There are currently two deviated wells producing to the Schwarzbach facility. SCHB 1a has been in production since 2015 while SCHB 2 came on stream in 2023. Further development of the field is planned as described further below.

The Schwarzbach Facility, built in 2013 by Tulip Oil and Siemens, is a flexible pilot plant designed to handle all oil, water and gas types and reduce future engineering lead times. The facility is highly automated with minimal on-site staffing. Fluid levels and temperature controls run automatically, oil and water are truck-

loaded (oil trucks can be loaded by the driver) and the site has reliable Internet for remote operator control. The wellsite is already extended for Phase 1 (wells SCHB 3 and SCHB 4) and has the following inherent functions and capacities:

- Flow lines are made of Duplex (unprocessed oil) or VA4 for processed oil, gas, or water.
- Simple, modular setup: common flow line into one single, low pressure 3-phase separator.
- Separator and storage tanks are double walled and coated. So far, no corrosion has been reported anywhere in the past 10 years.
- Design life exceeds the production permit (2044)
- Oil processing capacity: 2 000 bbl/d
- Water processing capacity: 2 000 bbl/d
- Oil + water storage tank capacity: each 315 bbl (50 m3)
- A cogeneration unit converts associated gas into electricity and heat, supplying power to the facility.

Further development is planned in two phases where a final investment decision (FID) for Phase was taken in 2025. Phase 1 consists of two horizontal wells drilled from the same facility. These wells are planned for spud in mid 2026 and will be completed with Fishbone technology. Initially the wells will be produced with sucker-rod pumps, but if the productivity is as expected, ESPs will be installed.

Further development in a Phase 2 is planned with drilling in 2027 - 2028 and production start in 2028. The Phase 2 development is planned with four additional producers and three water injectors for produced water disposal and pressure maintenance. The FID for Phase 2 is planned for March 2027.

A field facility picture is seen in Fig. 4.4.



Fig. 4.4 Schwarzbach processing facility

Technical lifetime of the wells and facilities

The facilities design life exceeds the production permit (2044). The design life of wells is 25 years. The licence expiry date is 31.12.2044.

Status

There are two active wells in the field and no new wells were drilled in 2025. The production is declining in both wells. SCHB 1a oil production was on the average about 9 bbl/d for the first half of 2025 with a water cut of about 15%. Since July 2025 the well has been shut, and needs a workover. SCHB 2 oil production was on the average about 40 bbl/d with a water cut of about 2%.

The planning and preparations for executing Phase 1 of the development plan is ongoing.

The facilities are generally in good shape and do have high quality components. No corrosion is observed.

Petroleum Initially-In-Place (PIIP) presented by Lime

The PIIP estimates as of 31.12.2025 are listed in Table 4.14 and Table 4.15.

Table 4.14 Erfelden Upper PBS PIIP estimate as of 31.12.2025

	PIIP, 31.12.2025 (Best Estimate)
Oil/Condensate (MMbbl)	20
Gas (BScf)	2.1

Table 4.15 Erfelden Lower PBS PIIP estimate as of 31.12.2025

	PIIP, 31.12.2025 (Best Estimate)
Oil/Condensate (MMbbl)	6.3
Gas (BScf)	0.7

Description of the PIIP

The PIIP in Table 4.14 is linked to Reserves in the main reservoir[10]. The PIIP in Table 4.15 is linked to Contingent Resources in the older reservoir unit.

The PIIP is estimated from a static model built in 2025 by the operator within the software mapping system RMS.

The structural framework consists of surfaces and faults interpreted on a 3D seismic dataset. The seismic was acquired in 2012 and re-processed in 2020. The top reservoir is represented by the transition from the overlying Rupel Clay to the reservoir sand. The internal reservoir resolution is limited. The grid includes lower, middle and upper PBS.

The model is populated with data from the legacy well set, supplemented by available core measurements and petrophysical estimations of net-to-gross, porosity, and water saturation. Facies modelling is linked to a regional sequence stratigraphic model, with defined areas of geological depositional environments (GDEs). Sandbodies were modelled within each GDE, either as shallow marine sands or as fluvial channels within a background of shale. The input volume fraction of sand (corresponding to net/gross) was set to 30% in LPBS and 70% in UPBS, estimated from wells.

Porosity was propagated within the sandy facies with an average porosity of 18% and set to a constant of 5% in the background shale. Permeability was calculated from porosity, using two different relationships from core data. Sw was calculated using a water saturation height model with Sw as a function of porosity above a free water level at 1625 m.

Reserves and technical profiles presented by Lime

The Reserves are based on the technical production and cost profiles provided by Lime in Statement of Reserves - Erfelden[10]. These profiles have been evaluated by AGR to confirm project commerciality and verify the correct economic cut-off.

AGR has applied the economic assumptions provided in Appendix A.1 Summaries of Oil and Gas Reserves and Resources. The resulting Reserves for Erfelden are shown in Table 4.16.

The Reserves include the following projects, classified according to PRMS:

1. Existing wells SCHB 1a and SCHB 2 (NFA) - On production
2. Phase 1 development, SCHB 3 and SCHB 4 - Approved for Development
3. Phase 2 development, four additional producers and three water injectors - Justified for Development

The projects are confirmed commercial for the Base price scenario and the economic cut-offs are:

- For the Base price scenario, the economic cut-off is:
 - 1P: end of 2044, the same as technical cut-off
 - 2P: end of 2044, the same as technical cut-off
 - 3P: end of 2044, the same as technical cut-off

Table 4.16 TRR and Reserves as of 31.12.2025 - Erfelden

	TRR (Gross 100%)			Reserves (Gross 100%)			Reserves (Net 100.0000%) ¹⁾		
	Low	Best	High	1P	2P	3P	1P	2P	3P
1st Production	29.08.2015								
Cut-off (year end)	2044	2044	2044	2044	2044	2044	2044	2044	2044
Oil/condensate (MMbbl)	2.71	7.12	8.55	2.71	7.12	8.55	2.71	7.12	8.55
Gas (BScf)	-	-	-	-	-	-	-	-	-
NGL, (MMboe)	-	-	-	-	-	-	-	-	-
Total (MMboe)	2.71	7.12	8.55	2.71	7.12	8.55	2.71	7.12	8.55

1) Net Reserves in Table above are net to Lime. Rex's share in Lime is 89.74%. For reserves net to Rex, see 1 Executive Summary and A.1.6 Erfelden - Summary of Oil and Gas Reserves and Resources.

The Erfelden production history and technical sales forecasts for oil (without the economic cut-off) are illustrated in Fig. 4.5 and Fig. 4.6.

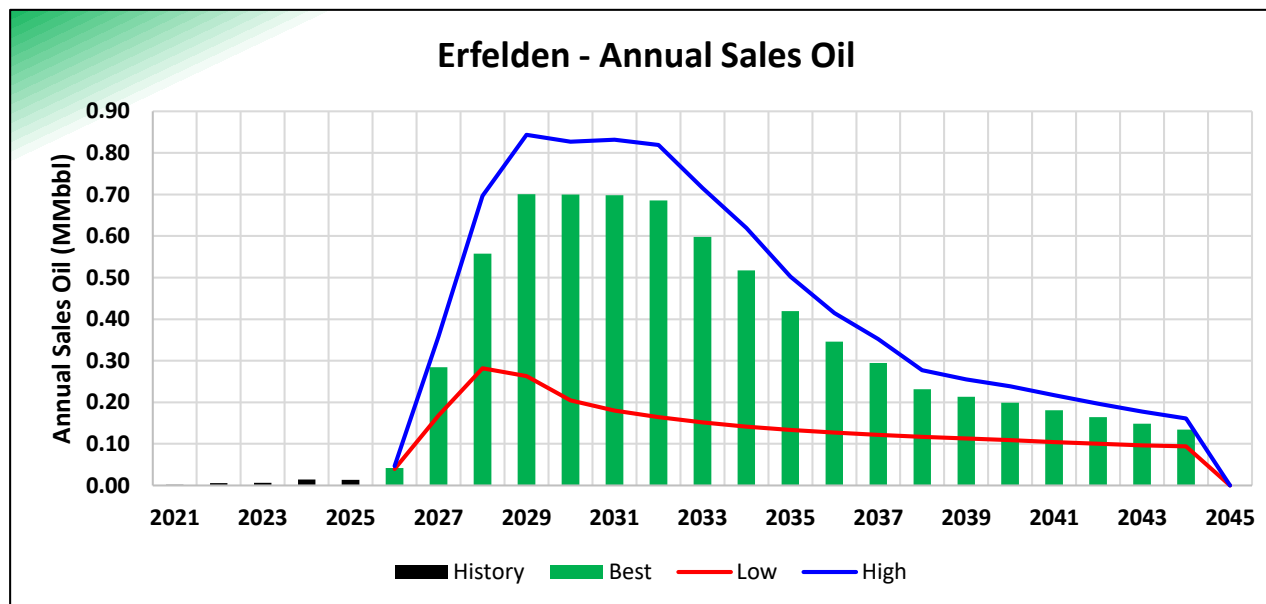


Fig. 4.5 Erfelden - annual sales oil

Description of the production profiles

The existing wells (NFA) have been forecasted with trend analysis starting at the current production level with a decline curve analysis (DCA) extrapolating the rate. The wells produce on depletion and exponential decline is assumed for these wells. The recovery of these wells is very small compared with the expected recovery from Phase 1 and Phase 2, so these wells have not been included in the simulation model. Low and high cases are determined by $\pm 20\%$ of the best estimate.

Phase 1 has been estimated with the Lime full field model described above using the tNavigator reservoir simulator. tNavigator has an option to estimate the effect of Fishbone completions. The two wells have a much higher productivity than the existing wells, and the base estimate assumes good pressure communication within the field and to the regional aquifer. The low estimate is taken from a sensitivity with lower permeability. This sensitivity reduces the PIIP through the initial saturation, gives lower productivity, and also less pressure support. The low estimate is 68% lower than the base estimate. The base estimate is used as best estimate, and the high estimate is constructed by increasing the best estimate by 20%. The existing wells have not been included in the model and thus the model has not been history matched. Lime has performed several sensitivities to investigate the sensitivity to well productivity. With the current model the recovery is relatively robust to realistic sensitivities to productivity.

Phase 2 was estimated with the same model assuming a full field development of the entire field (not including the two existing wells): six producers and three water injectors. The Phase 2 profile was defined as the incremental between the full field development and Phase 1 production in these two simulations. Low and high cases are defined the same way as for Phase 1. For Phase 2 the low estimate is 53% lower than the base estimate.

No formal uncertainty evaluation was presented, so the technical profiles defining low, best and high estimates are defined by scenarios.

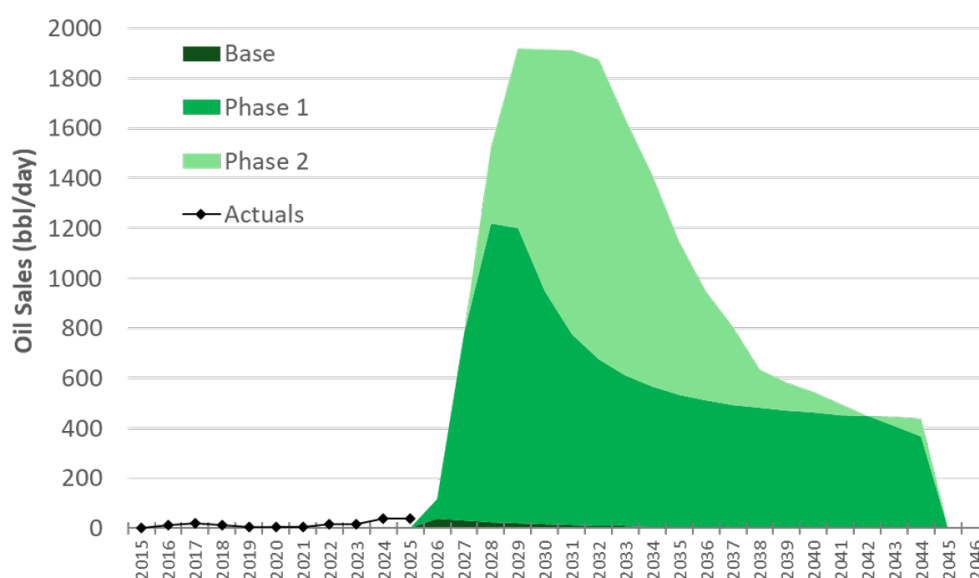


Fig. 4.6 Erfelden 2P production profiles
Source: Lime Resources

Description of the cost profiles

The costs are generated internally by Lime, based on in-house cost data, relevant historical costs and regional market knowledge.

The total project cost for the period 1.1.2026 to 31.12.2028 is broken into CAPEX/DRILLEX, OPEX and ABEX and are seen in Table 4.17;

Table 4.17 Erfelden costs 2026 - 2044

Costs in Million EURO	NFA	Phase 1	Phase 2	Total
CAPEX & DRILLEX	-	20.91	58.83	79.73
OPEX	8.70	12.00	18.71	39.41
TARIFFS	0.18	11.79	8.08	8.27
ABEX (has to be deposited before operations in a pledged account)	-	0.83	2.80	3.63
Total	8.88	33.74	88.42	131.04

Changes in Reserves since audit 30.05.2025

GR's evaluation is limited to Lime's reserves as of 31.12.2025. The reserve estimates as of 31.12.2024 were prepared by Sproule ERCE[2] and have not been reviewed by AGR. As a result, AGR does not have a complete understanding of the work performed in the prior evaluation and cannot fully account for the changes in reserves between the two reporting dates. The gross balance sheet for reserves shown in Table 4.18. The main reasons for the changes are considered to be the following:

Production:

- 2025 production

Revisions:

- New geomodel and simulation model resulting in revised phased development plan focusing only on the Upper PBS reservoir. The Lower PBS development is now defined as Contingent Resources.
- Production after licence period ending 31.12.2044 is now excluded.

AGR's evaluation is limited to Lime's Reserves as of 31.12.2025. The reserve estimates as of 30.04.2025 were prepared by Sproule ERCE and have not been reviewed by AGR. As a result, AGR does not have a complete understanding of the work performed in the prior evaluation and cannot fully account for the changes in Reserves between the two reporting dates.

Table 4.18 Balance sheet - Erfelden Reserves (100%)

Gross reserves balance, 30.05.2025 - 31.12.2025, for Erfelden (100%)							
Reserves class	Status 30.05.2025	Production (Positive)	Revisions	Acquisitions or sales	IOR	Discoveries/ New Projects	Status 31.12.2025
Oil and condensate (MMbbl)							
1P	3.45	0.01	-0.72	-	-	-	2.71
2P	8.51	0.01	-1.38	-	-	-	7.12
3P	16.19	0.01	-7.62	-	-	-	8.55
Gas (BScf)							
1P	-	-	-	-	-	-	-
2P	-	-	-	-	-	-	-
3P	-	-	-	-	-	-	-
NGL (MMboe)							
1P	-	-	-	-	-	-	-
2P	-	-	-	-	-	-	-
3P	-	-	-	-	-	-	-
Oil equivalents (MMboe)							
1P	3.45	0.01	-0.72	-	-	-	2.71
2P	8.51	0.01	-1.38	-	-	-	7.12
3P	16.19	0.01	-7.62	-	-	-	8.55

Contingent Resources presented by Lime

The Contingent Resources presented by Lime are shown in Table 4.19. The resources are assumed recovered through a notional development concept with three horizontal producers in the Lower PBS. The recoverable volumes are determined by a recovery factor of 35%, analogue to Upper PBS.

Table 4.19 Gross and net Contingent Resources as of 31.12.2025 - Erfelden

Erfelden		GROSS (100%)			NET (25.0000%) ¹⁾		
Contingent resources (MMboe)	PRMS subclass	1C	2C	3C	1C	2C	3C
Lower PBS	Development Unclarified	0.70	2.30	3.00	0.70	2.30	3.00

- 1) Net Contingent Resources in Table above are net to Lime. Rex's share in Lime is 89.74%. For Contingent Resources net to Rex, see 1 Executive Summary and A.1.6 Erfelden - Summary of Oil and Gas Reserves and Resources.

Changes in Contingent Resources since audit 30.04.2025

The gross changes in Contingent Resources for Erfelden are shown in Table 4.20. There were no Contingent Resources reported for Erfelden in the 31.12.2024 Sproule/ERCE report[2].

Table 4.20 Balance sheet - Erfelden Contingent Resources (100%)

Gross contingent resource balance, 30.05.2025 - 31.12.2025, for Erfelden (100%)							
Resource class	Status 30..2025	Production (Positive)	Revisions	Acquisitions or sales	IOR	Discoveries/ New Projects	Status 31.12.2025
Oil and condensate (MMbbl)							
1C	-	-	-	-	-	0.70	0.70
2C	-	-	-	-	-	2.30	2.30
3C	-	-	-	-	-	3.00	3.00

AGR comments to PIIP, Reserves and Contingent Resources

Comments to PIIP

AGR has reviewed the basis for the PIIP estimates as described in presentations, reports and as presented in work sessions with Lime technical personnel.

AGR considers the static model to be constructed according to industry practice and being of adequate quality for the purpose. The seismic interpretation is considered robust, but due to limited resolution there are alternative fault locations and fault throws. AGR notes that high-resolution re-processing has been done by Lime in 2025 which has not yet been incorporated in the mapping and PIIP analysis. The geological sequence stratigraphical concept is based on the operator's regional understanding with interpretation of several wells and AGR supports the concepts used for property mapping. There are numerous wells, but most wells (in Stockstadt Main and Kuehkopf) are drilled prior to 1970 and has minimal log suites. However, there are recent wells with more logs and core data and the operator has used the petrophysical data and logs for correlation in a consistent with sound industry practice.

Regarding uncertainties influencing PIIP and recovery, AGR has the following comments:

- The volume fraction of sand is set to 70% in UPBS and to 30% in MPBS and LPBS. These values are in line with the petrophysical evaluation presented from representative wells.
- The porosity in the model is set to vary around 18% in the sands. This seems optimistic taken the petrophysical evaluation from 2016 into account. The latest well SCHB 2 from 2023 showed better properties, (reported up 18% porosity in LPBS and up to 21% in UPBS), but the level of porosity and permeability is still flagged as a major uncertainty.
- AGR has a concern regarding the free water level and oil water contacts. The operator's model is a common free water level for all faults blocks on Erfelden High. However, there are not any clear defined fluid contacts in the Erfelden wells, only oil-down-to situations. The reservoir pressure in several wells plots on a common oil gradient, and combined with a regional water gradient from wells in the area a free water level at 1625 m TVD MSL is interpreted. AGR considers this a plausible scenario. However, the fact that no clear fluid contacts are found in wells, and that there are possible internal barriers (faults and shale layers), segmentation and varying contacts is a risk. The shallower contact in SCHB 1a is an example of this situation.
- Further, AGR has not observed any estimation of current oil-water contacts. This is probably especially important in the Kuehkopf area, which has been drained. Kuehkopf is now part of the development and included in the PIIP estimates.
- AGR notes that Lime assumes good pressure communication within the UPBS reservoir and to the aquifer. AGR considers this to be optimistic and that the risk of encountering greater segmentation, as well as internal baffles or barriers during production, may be underestimated.

With the comments above AGR accepts the PIIP estimates as presented by Lime.

Comments to production profiles

AGR has reviewed the presented material from Lime including presentations, simulation results, results of simulation sensitivities and production data from the existing wells. There has been work meetings and communications with Lime to understand the data and assumptions applied, and simulation results.

AGR has the following comments to the profiles presented by Lime:

Existing wells (NFA)

The decline curve analysis (DCA) of the existing wells is considered reasonable. AGR notes that these wells have not been included in the simulation model. Even though the production has been low presumably due to a limited fault block with perched water in SCHB 1a, and formation damage due to drilling issues in SCHB 2, there is a general decline in these wells that have not been matched in the simulator. The limited area and perched water connected to SCHB 1a also indicates that the individual segments may potentially be more isolated, in contrast to the base case model where there is very good communication and pressure support from the regional aquifer.

Phase 1 Development

The Phase 1 profiles show a very large difference in the two scenarios presented. This indicates a large uncertainty in this profile. As mentioned, the Phase 1 base case wells have high productivity and are well-connected with the rest of the field in the model. This is further illustrated by comparing the Phase 1 and Phase 2 recoveries. The two wells in Phase 1 are estimated to recover 4.2 MMbbl oil while the four additional producers and three injectors in Phase 2 will recover 2.9 MMbbl of oil only. The connection to the larger area is illustrated by the levelling off of the decline with an almost flat oil profile from 2035 to 2044. AGR considers this to be very optimistic. With a more thorough uncertainty analysis AGR would expect the base case to fall closer to the high end of the uncertainty range.

AGR has estimated profiles assuming initial rates for the two wells of 300 bbl/d with the same decline as was used for the existing wells. This resulted in a recovery for Phase 1 very close to the low profile presented by Lime. The main risks are productivity, communication and pressure support.

Phase 2 Development

The additional recovery in Phase 2 also may be optimistic, but Phase 2 to a large degree mitigates the main risks of Phase 1. The combined Phase 1 and Phase 2 recovery is, therefore, more realistic.

Again, AGR performed a simple decline analysis by assuming four additional wells with the same decline as described for Phase 1, giving a total Phase 2 recovery of 2.6 MMbbl oil which is much closer to the 2.9 MMbbl presented by Lime. It is also worth mentioning that with the simple decline method the overall recovery of 3.9 MMbbl is very close to the previous Rhein Petroleum development plan of 3.8 MMbbl oil.

AGR recognizes that Fishbones completions should mitigate some of the productivity risks. Also, horizontal wells may connect larger parts of the reservoir, possibly also by crossing fault segments. Given sufficient productivity the use of ESPs is also expected to give higher production. Given that all these new options for Schwarzbach perform as expected, the overall field recovery is considered reasonable. AGR supports the phased development approach adopting the new options in steps and implementing as experience is gained.

Comments to facilities and cost profiles

AGR supports Lime in having a phased development strategy.

AGR judges that cost figures presented by Lime are based on sound industry practice, relevant regional field experience and the present market situation.

AGR has reviewed and evaluated relevant cost and time estimates as documented in the Lime presentations and the SoR2026. Comparing said cost figures, AGR considers the Lime costs to be reasonable and realistic, reflecting present asset status and activity level.

AGR endorses the SoR2026[10] cost profiles and has implemented these in the economic evaluation.

Comments to Reserves and recovery factors

The current two producing wells at Erfelden have produced below expectations. The further recovery of the field is dependent on the success of the horizontal wells with improved productivity. Horizontal wells, Fishbone completions, and use of ESP are all technologies that have not yet been tested in this field. Horizontal drilling is proven technology that has been applied as a standard development option in many fields. Fishbone completion has also been applied in several fields. Although less mature, AGR also considers this as proven technology and agrees that this will mitigate risk related to productivity. The successful use of ESP is also new in this field. ESP is a proven technology and is considered to be a good option given that the productivity is shown to be sufficient. Phase 2 development will be optimised based on experience from Phase 1. According to Lime, there is a firm intention to develop Phase 2 regardless of the Phase 1 results.

- Reserves from the two wells in Phase 1 are defined as Reserves, Approved for Development. The investment decision for these wells has been taken.
- Reserves from Phase 2 are defined as Reserves, Justified for Development. FID is planned for March 2027.
- The current recovery factor with the initial development already executed is very low, and the two wells are expected to recover 0.4% of the PIIP.
- Recovery from analogue fields indicate that a recovery factor could be ranging between 20% and 40%.
- The 2P oil recovery factors estimated for this audit are shown in Table 4.21.
- AGR finds the final recovery factor of 38.6% to be on the high side compared to analogue fields.

Table 4.21 Erfelden 2P recovery factors

	Oil 31.12.2025	Oil at EUR	Gas 31.12.2025	Gas at EUR
Produced (MMbbl/BScf)	0.59	7.71	-	-
Recovery factor	3.0%	38.6%	-	-

Comments to Contingent Resources

Development of the contingent resources in the lower LPBS reservoir will depend on the results from the development of the upper UPBS reservoir. If the development of the UPBS is a success, AGR considers it likely that the lower reservoir will be tested. A staged development is expected, so the extent of the development will depend on the experience. The main uncertainty is related to the net sand distribution and continuity of the good reservoir properties found in some wells in the area. The assumed recovery factor of 35% assumes that the reservoir is connected and gets pressure support from aquifer or the Phase 2 injectors. The number of wells required to drain LPBS efficiently is uncertain with the current data available.

AGR Conclusions

- The Erfelden reserves reported by Lime are based on Lime modelling and simulation and depend on successful implementation of horizontal producers with "fishbone" and electrical submersible pump (ESP) completions.
- The uncertainty on Erfelden is very high with respect to productivity, reservoir communication and pressure support.
- AGR considers the Phase 1 profile to be optimistic, but given the full field development, Phase 2 will to a large extent mitigate the main uncertainties.
- With respect to Phase 2, Lime has stated that the Company has a firm intention to proceed with execution of Erdfelden Phase 2. Lime has further confirmed that this intention is not contingent on the outcome of the already sanctioned Erdfelden Phase 1 development and reflects the Company's long term development strategy for the subsidiary and its assets. Given this expressed commitment from Lime, AGR agrees to the PRMS classification of Phase 2 as "Justified for Development".
- AGR considers the recovery factor high, but is within the range of analogue fields' recovery factors.
- AGR endorses the Erfelden Reserves (Table 4.16) and Contingent Resources (Table 4.19) presented by Lime.

4.3 Germany - Lauben

Asset Overview

The Lauben oil field is located in the Molasse Basin onshore Germany. The field is located approximately 110 km west of Munich in the south-western part of the German federal state of Bavaria, as shown in Fig. 2.5. The licence, Lauben, was awarded in 2008 to Wintershall and Rhein Petroleum. Wintershall sold its 50% stake to E&P ONEO as operator and Lime subsidiary Lime Resources Germany GmbH took over Rhein Petroleum's part in the licence in 2025. Historical production has been from six wells in the period 1958 to 1985. Production from a new and current oil producer, the Lauben-7 well, started in 2015. The reservoir is at a depth of approximately 850 m TVD MSL.

Licence details summary is shown in Table 4.22 and the licence shares are shown in Table 4.23. The production licence gives the licensees full rights to explore and produce hydrocarbons at all stratigraphic levels within the licence area.

Table 4.22 Lauben Field summary table

Asset name/ Country	Lime's interest (%)	Development Status	Licence expiry date	Licence Area (km ²)	Type of mineral, oil or gas deposit	Remarks
Lauben / Germany	50	On Production	31.12.2041	6.67	Oil	-

Table 4.23 Lauben Field licence shares (%).

Licence	ONEO E&P (Op)	Lime Resources Germany GmbH
Lauben	50	50

Discovery

Lauben was discovered by the Lauben-1 well; which found oil in the Bausteinschichten (Baustein) sandstones of Oligocene age.

Reservoir

The Lauben Field is a structural trap within the Molasse Basin, located in a foreland basin setting north of the Alps mountain range. The structure is a small, ~1.5 km² dip closure with a west-east trending fault in the northern part. The reservoir belongs to the Baustein Formation, deposited in a shallow marine delta environment. The entire Baustein is an upwards-coarsening sequence, at Lauben divided into three sub-cycles. The reservoir sands consist of fine- to medium-sandy, moderately to well-sorted, partly strongly bioturbated calcareous arenites. The reservoir thickness at the Lauben-7 well is around 25 m and the oil column is 10 m. The net/gross in Baustein varies between 20% and 60% in the historical wells with porosity of 17-18% and permeabilities in the range of 10-120 mD.

Recovery Strategy

The recovery strategy for Lauben is production by natural depletion. The well is produced with a sucker rod pump.

Development

The Lauben production facility and processing infrastructure comprises a very simple facility, where oil flows directly into a storage tank. Gas is used for heating. The content of the storage tank is trucked to the Aitingen Field processing facility 58 km away. From there, oil is exported via railway to Lingen Refinery. In the years 2016-2023 oil was trucked to the Schwarzbach site. Produced water is reinjected in the Aitingen Field. Facilities are reportedly in good order with no corrosion observed.

The well has 5 m net pay (Bausteinschichten) and the design comprises a 2 7/8" tubing; which is packerless on sucker rod pump. The pump capacity exceeds inflow from the reservoir.

The Lauben production site with the well and facility plant is seen in Fig. 4.7.



Fig. 4.7 Lauben production site

Technical lifetime of the wells and facilities

The design life of the Lauben facilities is not specified, but is expected to be in line with the foreseen economic production life.

Status

The production is low and on decline, with only one active oil producer. The activity level at the field is low, but a workover is being considered for 2027 to re-perforate the reservoir section to enhance productivity.

Petroleum Initially-In-Place (PIIP) presented by Lime

The PIIP estimates as of 31.12.2025 are listed in Table 4.24.

Table 4.24 Lauben PIIP estimate as of 31.12.2025

	PIIP, 31.12.2025 (Best Estimate)
Oil/Condensate (MMbbl)	2.4
Gas (BScf)	0.05

Description of the PIIP

The PIIP base estimate in Table 4.24 is from a 3D static model that was built by the former operator Wintershall and was the basis for the Lauben-7 well proposal in 2013.

The structural framework was built from surfaces and faults mapped on a 3D seismic dataset acquired in 2011. The model was populated with facies, net/gross, porosity and permeability derived from the six historical wells. An oil-water contact was penetrated in the Lauben-7 well. This is the first time AGR evaluates Lauben, and no PIIP estimates were reported in the Sproule ERCE 31.12.2024 report.

Reserves and technical profiles presented by Lime

The Reserves are based on the technical production and cost profiles provided by Lime in Statement of Reserves - Lauben[11]. These profiles have been evaluated by AGR to confirm project commerciality and verify the correct economic cut-off. The resulting Reserves are shown in Table 4.25.

The Reserves include the following projects, classified according to PRMS:

- Well Lauben-7 - On Production.

The Lauben-7 project is confirmed commercial for the Base price scenario and the economic cut-offs are:

- 1P: end of 2037, four years earlier than technical cut-off
- 2P: end of 2041, the same as technical cut-off
- 3P: end of 2041, the same as technical cut-off

Table 4.25 TRR and Reserves as of 31.12.2025 - Lauben

	TRR (Gross 100%)			Reserves (Gross 100%)			Reserves (Net 50.0000%) ¹⁾		
	Low	Best	High	1P	2P	3P	1P	2P	3P
1st Production	01.08.1958								
Cut-off (year end)	2041	2041	2041	2037	2041	2041	2037	2041	2041
Oil/condensate (MMbbl)	0.10	0.13	0.16	0.09	0.13	0.16	0.04	0.07	0.08
Gas (BScf)	-	-	-	-	-	-	-	-	-
NGL, (MMboe)	-	-	-	-	-	-	-	-	-
Total (MMboe)	0.10	0.13	0.16	0.09	0.13	0.16	0.04	0.07	0.08

1) Net Reserves in Table above are net to Lime. Rex's share in Lime is 89.74%. For reserves net to Rex, see 1 Executive Summary and A.1.7 Lauben - Summary of Oil and Gas Reserves and Resources.

The production history and technical sales forecasts for oil (without the economic cut-off) are illustrated in Fig. 4.8.

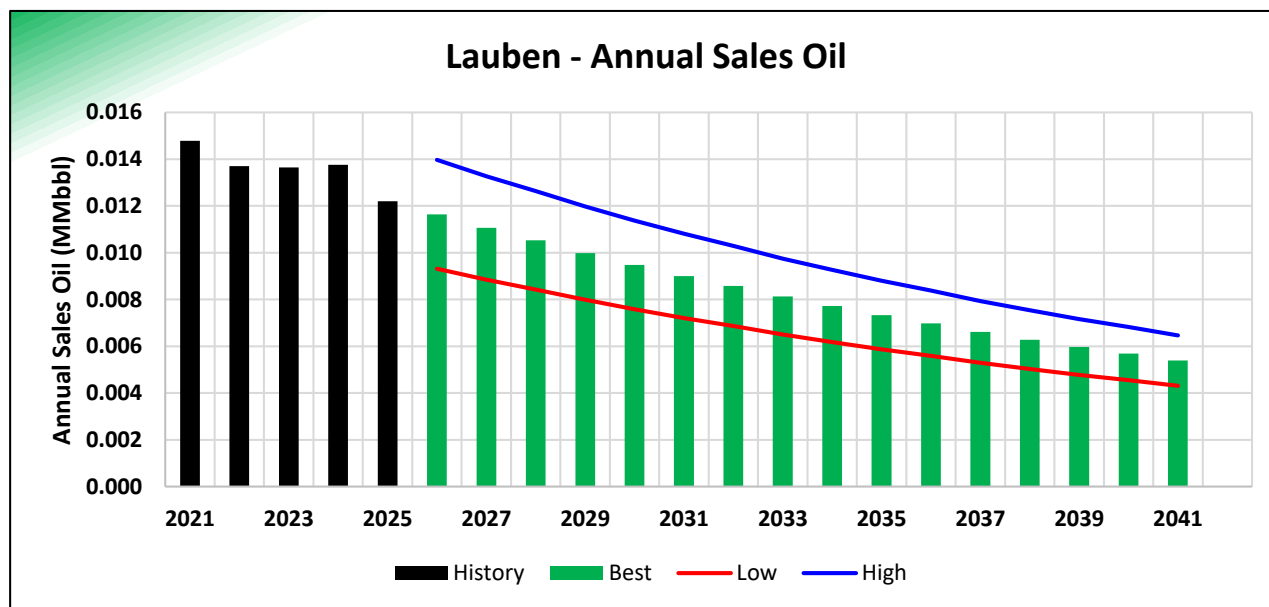


Fig. 4.8 Lauben - annual sales oil

Description of the production profiles

Production forecast for Lauben is based on decline curve analysis (DCA) of the Lauben-7 well. A workover is being considered for 2027 to re-perforate the reservoir section, however the effect on production of this workover is not included in the production profiles presented by Lime.

Description of the cost profiles

The costs are generated internally by Lime, based on in-house cost data, relevant field historical costs and regional market knowledge. The project costs are:

CAPEX: No capex planned.

Variable OPEX (14.9 EUR/bbl oil):

- Trucking of oil: 5.0 EUR/bbl
- Processing fee: 9.9 EUR/bbl

Fixed OPEX;

- Average from actual billing from operator in time period January-October 2025: ~20 000 EUR/month
- Workover in 2027 to re-perforate reservoir section: ~300 000 EUR

Changes in Reserves since audit 30.04.2025

AGR's evaluation is limited to Lime's reserves as of 31.12.2025. The reserve estimates as of 31.12.2024 were prepared by Sproule ERCE[2] and have not been reviewed by AGR. As a result, AGR does not have a complete understanding of the work performed in the prior evaluation and cannot fully account for the changes in reserves between the two reporting dates. The gross balance sheet for reserves shown in Table 4.26.

Table 4.26 Balance sheet - Lauben Reserves (100%)

Gross reserves balance, 30.05.2025 - 31.12.2025, for Lauben (100%)							
Reserves class	Status 30.04.2025	Production (Positive)	Revisions	Acquisitions or sales	IOR	Discoveries/ New Projects	Status 31.12.2025
Oil and condensate (MMbbl)							
1P	0.13	0.01	-0.03	-	-	-	0.09
2P	0.17	0.01	-0.02	-	-	-	0.13
3P	0.22	0.01	-0.05	-	-	-	0.16
Gas (BScf)							
1P	-	-	-	-	-	-	-
2P	-	-	-	-	-	-	-
3P	-	-	-	-	-	-	-
NGL (MMboe)							
1P	-	-	-	-	-	-	-
2P	-	-	-	-	-	-	-
3P	-	-	-	-	-	-	-
Oil equivalents (MMboe)							
1P	0.13	0.01	-0.03	-	-	-	0.09
2P	0.17	0.01	-0.02	-	-	-	0.13
3P	0.22	0.01	-0.05	-	-	-	0.16

Contingent Resources presented by Lime

There are no Contingent Resources presented for Lauben Field.

AGR comments to PIIP and Reserves

Comments to PIIP

AGR has reviewed the presentation material from Lime and the Lauben-7 well proposal and concludes that the PIIP estimates presented by Lime are reasonable.

Comments to production profiles

AGR considers the decline curve analysis of the Lauben-7 well to be reasonable. AGR notes that there may be a potential upside to production if the 2027 re-perforation of the well is performed.

Comments to facilities and cost profiles

AGR has reviewed and evaluated relevant cost and time estimates as documented in the cost presentations and the SoR 2025. The cost figures presented by Lime are based on sound industry practice and relevant regional field experience. AGR considers the Lime cost estimates presented to be reasonable and realistic, reflecting the current asset status and low activity level.

AGR endorses the SoR2026[11] cost profiles and has implemented these in the economic evaluation.

Comments to Reserves and recovery factors

- There are small reserves for the Lauben field.
- The 2P oil recovery factors estimated are shown in Table 4.27. AGR finds the final recovery factor of 18% to be moderate but reasonable given the recovery strategy with one well and no water injection.
- The 1P reserves estimate is -31% and 3P is +23% versus 2P.

Table 4.27 Lauben 2P recovery factors

	Oil 31.12.2025	Oil at EUR	Gas 31.12.2025	Gas at EUR
Produced (MMbbl/BScf)	0.30	0.43	-	-
Recovery factor	12%	18%	-	-

AGR conclusions

- The Lauben reserves reported by Lime are based on internal Lime DCA estimates. The DCA presented is considered reasonable by AGR.
- The potential upside to production associated with the 2027 workover is not included in the forecast presented by Lime.
- The final recovery factor is moderate but reasonable.
- AGR endorses the Lauben Reserves (Table 4.25) presented by Lime.

5 Appendices

This section contain the following Appendices:

- A.1 Summaries of Oil and Gas Reserves and Resources
- A.2 Abbreviations and definitions
- A.3 Summary of 2018 SPE Petroleum Resources Classification

A.1 Summaries of Oil and Gas Reserves and Resources

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 5.1 were provided by Lime and AGR considers these assumptions to be reasonable and have applied them in the economic evaluations. In addition, oil price differentials have been applied for each asset as per Table 5.2. These prices are provided by Lime and are considered reasonable in today's market by AGR. With respect to price differentials, AGR notes that the Sèmè North oil is a heavier, lower API crude (22° API), which may potentially have a negative impact on the sales price achieved.

The technical production and cost profiles used in the economic evaluations have been supplied by Lime and reviewed by AGR. Processing and transportation tariffs used are provided by Lime. For the Erfelden asset, 15% royalties apply. These are included in the tariff costs.

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

The evaluations are forward looking from 01.01.2026, 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. The Brage and Bestla fields are considered as a Hub and economic cut-off is thus determined by jointly evaluating the two field's forecasts when running the economics.

Table 5.1 Price and financial assumptions from Lime

	Units	2026	2027 -> EOFL
Oil/Condensate Price	USD/bbl (real2026)	65.0	75.0
Gas Price (40 MJ/Sm3)	NOK/Sm3 (real2026)	3.60	4.15
NGL Price	USD/boe (real2026)	52.0	60.0
Exchange rate	NOK/USD	10.0	10.0
Exchange rate	EUR/USD	1.20	1.20
Inflation rate	2% p.a.		
Present value reference date	01.01.2026		
Discount hurdle rate	10% p.a. (nominal)		
Tax, Norway	78% (22% corporate tax rate + 56% special tax rate)		
Tax, Germany	15% Royalty to State + Private (0% for Lauben) + 15.8% federal tax + 13.5% trade tax		
Tax, Benin	10% Royalty + Share of Profit to Government ref. PSC		

Table 5.2 Crude oil price adjustment, USD/bbl

Field	Crude Oil Price Differentials, USD/bbl Premium (+) / Discount (-)
Brage, Norway	+2.00
Bestla, Norway	+2.00
Yme, Norway	-0.70
Erfelden, Germany	-3.00
Lauben, Germany	-3.00
Sèmè North, Benin	-

A.1.1 Yme - Summary of Oil and Gas Reserves and Resources

The Summary of Oil and Gas Reserves and Resources for Yme as of 31.12.2025 is shown in Table 5.3.

Table 5.3 Yme - Summary of Oil and Gas Reserves and Resources

Category	Gross Attributable to Licence (100%)	Net Attributable Lime (25.00% Lime share)	Net Attributable Rex ¹ (89.740% Rex Int. share of Lime)	Change ² from previous update (%)	Risk Factors ³	Remarks
	(MMbbl / BScf)	(MMbbl / BScf)	(MMbbl / BScf)			
Reserves						
Oil Reserves						
1P	5.89	1.47	1.32	-51%	N.A.	Change due to production in 2025, reduced well performance and earlier cut-off
2P	6.49	1.62	1.46	-57%	N.A.	
3P	10.15	2.54	2.28	-54%	N.A.	
Natural Gas Reserves						
1P	-	-	-	-	-	
2P	-	-	-	-	-	
3P	-	-	-	-	-	
Natural Gas Liquids Reserves						
1P	-	-	-	-	-	
2P	-	-	-	-	-	
3P	-	-	-	-	-	
Contingent Resources						
Oil						
1C	4.79	1.20	1.07	-18%	0.53	Change due to further maturation of Beta and Gamma infill drilling projects
2C	7.81	1.95	1.75	5%	0.53	
3C	9.71	2.43	2.18	5%	0.53	
Natural Gas						
1C	-	-	-	-	-	
2C	-	-	-	-	-	
3C	-	-	-	-	-	
Natural Gas Liquids						
1C	-	-	-	-	-	
2C	-	-	-	-	-	
3C	-	-	-	-	-	

- 1P: Proved Reserves
- 2P: Proved + Probable Reserves
- 3P: Proved + Probable + Possible Reserves
- MMbbl: Millions of barrels
- BScf: Billions of standard cubic feet
- 1C: Low estimate of Contingent Resources
- 2C: Best estimate of Contingent Resources
- 3C: High estimate of Contingent Resources

Name of Qualified Person: Mahmood Akbar

Date: 03. March 2026

Professional Society Affiliation / Membership:

- Society of Petroleum Engineers (SPE)

Notes:

1) Net Attributable to Rex International Holding Ltd ("Rex") means the volumes attributable to Rex International Investments Pte. Ltd., a wholly owned subsidiary of Rex which has an 89.74% ownership in Lime Petroleum Holding AS. Lime Petroleum Holding AS owns 100% of Lime Petroleum AS which is the licensee of the production licences in Norway.

2) Change from previous update means the change in the volume attributable to Rex International Holding Ltd. The overall change shown includes changes in estimates of the remaining recoverable volumes for the field as well as the change in Rex's ownership share in Lime in 2025 (increased from 80.14% to 89.74%).

3) Applicable to Contingent Resources. "Risk Factor" for Contingent Resources means the estimated chance, or probability, that the volumes will be commercially extracted. NA denotes Not Applicable.

A.1.2 Brage - Summary of Oil and Gas Reserves and Resources

The Summary of Oil and Gas Reserves and Resources for Brage as of 31.12.2025 is shown in Table 5.4.

Table 5.4 Brage - Summary of Oil and Gas Reserves and Resources

Category	Gross Attributable to Licence (100%)	Net Attributable Lime (33.84% Lime share)	Net Attributable Rex ¹ (89.740% Rex Int. share of Lime)	Change ² from previous update (%)	Risk Factors ³	Remarks
	(MMbbl / BScf)	(MMbbl / BScf)	(MMbbl / BScf)			
Reserves						
Oil Reserves						
1P	8.68	2.94	2.64	12%	N.A.	Change due to production in 2025, good well performance and maturation of reserves
2P	13.48	4.56	4.09	37%	N.A.	
3P	17.27	5.84	5.24	41%	N.A.	
Natural Gas Reserves						
1P	9.86	3.34	2.99	206%	N.A.	Change due to production in 2025, good well performance and maturation of reserves
2P	22.18	7.50	6.73	250%	N.A.	
3P	33.12	11.21	10.06	250%	N.A.	
Natural Gas Liquids Reserves						
1P	0.64	0.22	0.20	2298%	N.A.	Change due to production in 2025, good well performance and maturation of reserves
2P	1.49	0.50	0.45	940%	N.A.	
3P	2.27	0.77	0.69	491%	N.A.	
Contingent Resources						
Oil						
1C	24.64	8.34	7.48	76%	0.49	Change due to six new projects, three projects taken out, and five more years on Brage LTE*. Risk factor is weighted average of ten projects
2C	41.10	13.91	12.48	50%	0.49	
3C	60.87	20.60	18.49	48%	0.49	
Natural Gas						
1C	24.50	8.29	7.44	59%	0.49	Change due to six new projects, three projects taken out, and five more years on Brage LTE. Risk factor is weighted average of ten projects
2C	57.34	19.41	17.42	39%	0.49	
3C	97.40	32.96	29.58	31%	0.49	
Natural Gas Liquids						
1C	1.70	0.57	0.52	50%	0.49	Change due to six new projects, three projects taken out, and five more years on Brage LTE. Risk factor is weighted average of ten projects
2C	3.96	1.34	1.20	48%	0.49	
3C	6.58	2.23	2.00	44%	0.49	

* LTE = Lifetime Extension

- 1P: Proved Reserves
 - 2P: Proved + Probable Reserves
 - 3P: Proved + Probable + Possible Reserves
 - MMbbl: Millions of barrels
 - BScf: Billions of standard cubic feet
- 1C: Low estimate of Contingent Resources
 - 2C: Best estimate of Contingent Resources
 - 3C: High estimate of Contingent Resources

Name of Qualified Person: Mahmood Akbar

Date: 03. March 2026

Professional Society Affiliation / Membership:

- Society of Petroleum Engineers (SPE)

Notes:

1) Net Attributable to Rex International Holding Ltd ("Rex") means the volumes attributable to Rex International Investments Pte. Ltd., a wholly owned subsidiary of Rex which has an 89.74% ownership in Lime Petroleum Holding AS. Lime Petroleum Holding AS owns 100% of Lime Petroleum AS which is the licensee of the production licences in Norway.

2) Change from previous update means the change in the volume attributable to Rex International Holding Ltd. The overall change shown includes changes in estimates of the remaining recoverable volumes for the field as well as the change in Rex's ownership share in Lime in 2025 (increased from 80.14% to 89.74%).

3) Applicable to Contingent Resources. "Risk Factor" for Contingent Resources means the estimated chance, or probability, that the volumes will be commercially extracted. NA denotes Not Applicable.

A.1.3 Bestla - Summary of Oil and Gas Reserves and Resources

The Summary of Oil and Gas Reserves and Resources for Bestla as of 31.12.2025 is shown in Table 5.5.

Table 5.5 Bestla - Summary of Oil and Gas Reserves and Resources

Category	Gross Attributable to Licence (100%)	Net Attributable Lime (17.00% Lime share)	Net Attributable Rex ¹ (89.740% Rex Int. share of Lime)	Change ² from previous update (%)	Risk Factors ³	Remarks
	(MMbbl / BScf)	(MMbbl / BScf)	(MMbbl / BScf)			
Reserves						
Oil Reserves						
1P	12.87	2.19	1.96	34%	N.A.	Change due to increased volumes (oil discovery in Bestla West)
2P	16.45	2.80	2.51	34%	N.A.	
3P	19.39	3.30	2.96	25%	N.A.	
Natural Gas Reserves						
1P	27.00	4.59	4.12	12%	N.A.	Change due to increased volumes (oil discovery in Bestla West)
2P	31.00	5.27	4.73	4%	N.A.	
3P	38.86	6.61	5.93	17%	N.A.	
Natural Gas Liquids Reserves						
1P	1.71	0.29	0.26	16%	N.A.	Change due to increased volumes (oil discovery in Bestla West)
2P	1.96	0.33	0.30	8%	N.A.	
3P	2.46	0.42	0.38	21%	N.A.	
Contingent Resources						
Oil						
1C	1.96	0.33	0.30	3%	0.80	Lifetime extension 2032-2040. Change is due to five more years and increased volumes (oil discovery in Bestla West)
2C	3.78	0.64	0.58	54%	0.80	
3C	6.43	1.09	0.98	141%	0.80	
Natural Gas						
1C	1.00	0.17	0.15	-55%	0.80	Lifetime extension 2032-2040. Change is due to five more years and reduced forecast for Bestla gas-oil-ratio
2C	4.86	0.83	0.74	-23%	0.80	
3C	7.63	1.30	1.16	77%	0.80	
Natural Gas Liquids						
1C	0.07	0.01	0.01	-51%	0.80	Lifetime extension 2032-2040. Change is due to five more years and reduced forecast for Bestla gas-oil-ratio
2C	0.32	0.05	0.05	-17%	0.80	
3C	0.50	0.08	0.08	87%	0.80	

- 1P: Proved Reserves
- 2P: Proved + Probable Reserves
- 3P: Proved + Probable + Possible Reserves
- MMbbl: Millions of barrels
- BScf: Billions of standard cubic feet

- 1C: Low estimate of Contingent Resources
- 2C: Best estimate of Contingent Resources
- 3C: High estimate of Contingent Resources

Name of Qualified Person: Mahmood Akbar

Date: 03. March 2026

Professional Society Affiliation / Membership:

- Society of Petroleum Engineers (SPE)

Notes:

1) Net Attributable to Rex International Holding Ltd ("Rex") means the volumes attributable to Rex International Investments Pte. Ltd., a wholly owned subsidiary of Rex which has an 89.74% ownership in Lime Petroleum Holding AS. Lime Petroleum Holding AS owns 100% of Lime Petroleum AS which is the licensee of the production licences in Norway.

2) Change from previous update means the change in the volume attributable to Rex International Holding Ltd. The overall change shown includes changes in estimates of the remaining recoverable volumes for the field as well as the change in Rex's ownership share in Lime in 2025 (increased from 80.14% to 89.74%).

3) Applicable to Contingent Resources. "Risk Factor" for Contingent Resources means the estimated chance, or probability, that the volumes will be commercially extracted. NA denotes Not Applicable.

A.1.4 Lunde - Summary of Oil and Gas Reserves and Resources

The Summary of Oil and Gas Reserves and Resources for Lunde as of 31.12.2025 is shown in Table 5.6.

Table 5.6 Lunde - Summary of Oil and Gas Reserves and Resources

Category	Gross Attributable to Licence (100%)	Net Attributable Lime (30.00% Lime share)	Net Attributable Rex ¹ (89.740% Rex Int. share of Lime)	Change ² from previous update (%)	Risk Factors ³	Remarks
	(MMbbl / BScf)	(MMbbl / BScf)	(MMbbl / BScf)			
Reserves						
Oil Reserves						
1P	-	-	-	-	-	
2P	-	-	-	-	-	
3P	-	-	-	-	-	
Natural Gas Reserves						
1P	-	-	-	-	-	
2P	-	-	-	-	-	
3P	-	-	-	-	-	
Natural Gas Liquids Reserves						
1P	-	-	-	-	-	
2P	-	-	-	-	-	
3P	-	-	-	-	-	
Contingent Resources						
Oil						
1C	0.52	0.16	0.14	12%	0.30	Lunde potential field dev. Only change is REX's increased share in Lime
2C	1.40	0.42	0.38	12%	0.30	
3C	2.42	0.73	0.65	12%	0.30	
Natural Gas						
1C	19.95	5.99	5.37	12%	0.30	Lunde potential field dev. Only change is REX's increased share in Lime
2C	28.43	8.53	7.66	12%	0.30	
3C	38.03	11.41	10.24	12%	0.30	
Natural Gas Liquids						
1C	0.57	0.17	0.15	12%	0.30	Lunde potential field dev. Only change is REX's increased share in Lime
2C	0.81	0.24	0.22	12%	0.30	
3C	1.09	0.33	0.29	12%	0.30	

- 1P: Proved Reserves
- 2P: Proved + Probable Reserves
- 3P: Proved + Probable + Possible Reserves
- MMbbl: Millions of barrels
- BScf: Billions of standard cubic feet
- 1C: Low estimate of Contingent Resources
- 2C: Best estimate of Contingent Resources
- 3C: High estimate of Contingent Resources

Name of Qualified Person: Mahmood Akbar

Date: 03. March 2026

Professional Society Affiliation / Membership:

- Society of Petroleum Engineers (SPE)

Notes:

1) Net Attributable to Rex International Holding Ltd ("Rex") means the volumes attributable to Rex International Investments Pte. Ltd., a wholly owned subsidiary of Rex which has an 89.74% ownership in Lime Petroleum Holding AS. Lime Petroleum Holding AS owns 100% of Lime Petroleum AS which is the licensee of the production licences in Norway.

2) Change from previous update means the change in the volume attributable to Rex International Holding Ltd. The overall change shown includes changes in estimates of the remaining recoverable volumes for the field as well as the change in Rex's ownership share in Lime in 2025 (increased from 80.14% to 89.74%).

3) Applicable to Contingent Resources. "Risk Factor" for Contingent Resources means the estimated chance, or probability, that the volumes will be commercially extracted. NA denotes Not Applicable.

A.1.5 Sèmè North - Summary of Oil and Gas Reserves and Resources

The Summary of Oil and Gas Reserves and Resources for Sèmè North as of 31.12.2025 is shown in Table 5.7.

Table 5.7 Sèmè North - Summary of Oil and Gas Reserves and Resources

Category	Gross Attributable to Licence (100%)	Net Attributable to Lime from PSA	Net Attributable Rex ¹ (89.740% Rex Int. share of Lime)	Change ² from previous update (%)	Risk Factors ³	Remarks
	(MMbbl / BScf)	(MMbbl / BScf)	(MMbbl / BScf)			
Reserves						
Oil Reserves						
1P	3.20	2.35	2.11	-62%	N.A.	Change due to development project reduced from four to two wells
2P	5.70	4.11	3.69	-36%	N.A.	
3P	6.08	4.38	3.93	-37%	N.A.	
Natural Gas Reserves						
1P	-	-	-	-	-	
2P	-	-	-	-	-	
3P	-	-	-	-	-	
Natural Gas Liquids Reserves						
1P	-	-	-	-	-	
2P	-	-	-	-	-	
3P	-	-	-	-	-	
Contingent Resources						
Oil						
1C	-	-	-	-	-	Infill well in H6 reservoir (new) and potential development of H7 and H8 reservoirs
2C	16.01	11.55	10.36	36%	0.44	
3C	34.30	24.74	22.20	118%	0.44	
Natural Gas						
1C	-	-	-	-	-	Infill well in H6 reservoir (new) and potential development of H7 and H8 reservoirs
2C	31.77	22.92	20.57	28%	0.44	
3C	46.10	33.26	29.84	82%	0.44	
Natural Gas Liquids						
1C	-	-	-	-	-	
2C	-	-	-	-	-	
3C	-	-	-	-	-	

- 1P: Proved Reserves
- 2P: Proved + Probable Reserves
- 3P: Proved + Probable + Possible Reserves
- MMbbl: Millions of barrels
- BScf: Billions of standard cubic feet
- 1C: Low estimate of Contingent Resources
- 2C: Best estimate of Contingent Resources
- 3C: High estimate of Contingent Resources

Name of Qualified Person: Mahmood Akbar

Date: 03. March 2026

Professional Society Affiliation / Membership:

- Society of Petroleum Engineers (SPE)

Notes:

1) Net Attributable to Rex International Holding Ltd ("Rex") means the volumes attributable to Rex International Investments Pte. Ltd., a wholly owned subsidiary of Rex which has an 89.74% ownership in Lime Petroleum Holding AS. Lime Petroleum Holding AS owns 100% of Akrake Petroleum Benin S.A. which is a licensee of the PSC in Benin. Net entitlement is based on the PSC terms and amount of cost oil and profit oil. For the 2P case the net entitlement is 72.1% of gross. For Contingent Resources the same % has been used for simplicity.

2) Change from previous update means the change in the volume attributable to Rex International Holding Ltd. The overall change shown includes changes in estimates of the remaining recoverable volumes for the field as well as the change in Rex's ownership share in Lime in 2025 (increased from 80.14% to 89.74%).

3) Applicable to Contingent Resources. "Risk Factor" for Contingent Resources means the estimated chance, or probability, that the volumes will be commercially extracted. NA denotes Not Applicable.

A.1.6 Erfelden - Summary of Oil and Gas Reserves and Resources

The Summary of Oil and Gas Reserves and Resources for Erfelden as of 31.12.2025 is shown in Table 5.8.

Table 5.8 Erfelden - Summary of Oil and Gas Reserves and Resources

Category	Gross Attributable to Licence (100%)	Net Attributable Lime (100.00% Lime share)	Net Attributable Rex¹ (89.740% Rex Int. share of Lime)	Change² from previous update (%)	Risk Factors³	Remarks
	(MMbbl / BScf)	(MMbbl / BScf)	(MMbbl / BScf)			
Reserves						
Oil Reserves						
1P	2.71	2.71	2.43	-12%	N.A.	Change due to 2025 production, revised development plan and updated volumetrics
2P	7.12	7.12	6.39	-6%	N.A.	
3P	8.55	8.55	7.68	-41%	N.A.	
Natural Gas Reserves						
1P	-	-	-	-	-	
2P	-	-	-	-	-	
3P	-	-	-	-	-	
Natural Gas Liquids Reserves						
1P	-	-	-	-	-	
2P	-	-	-	-	-	
3P	-	-	-	-	-	
Contingent Resources						
Oil						
1C	0.70	0.70	0.63	-	0.60	Lower PBS reservoir
2C	2.30	2.30	2.06	-	0.60	
3C	3.00	3.00	2.69	-	0.60	
Natural Gas						
1C	-	-	-	-	-	
2C	-	-	-	-	-	
3C	-	-	-	-	-	
Natural Gas Liquids						
1C	-	-	-	-	-	
2C	-	-	-	-	-	
3C	-	-	-	-	-	

- 1P: Proved Reserves
- 2P: Proved + Probable Reserves
- 3P: Proved + Probable + Possible Reserves
- MMbbl: Millions of barrels
- BScf: Billions of standard cubic feet
- 1C: Low estimate of Contingent Resources
- 2C: Best estimate of Contingent Resources
- 3C: High estimate of Contingent Resources

Name of Qualified Person: Mahmood Akbar

Date: 03. March 2026

Professional Society Affiliation / Membership:

- Society of Petroleum Engineers (SPE)

Notes:

1) Net Attributable to Rex International Holding Ltd ("Rex") means the volumes attributable to Rex International Investments Pte. Ltd., a wholly owned subsidiary of Rex which has an 89.74% ownership in Lime Petroleum Holding AS. Lime Petroleum Holding AS owns 100% of Lime Resources Germany GmbH which is the licensee of the production licences in Germany.

2) Change from previous update means the change in the volume attributable to Rex International Holding Ltd. The overall change shown includes changes in estimates of the remaining recoverable volumes for the field as well as the change in Rex's ownership share in Lime in 2025 (increased from 80.14% to 89.74%).

3) Applicable to Contingent Resources. "Risk Factor" for Contingent Resources means the estimated chance, or probability, that the volumes will be commercially extracted. NA denotes Not Applicable.

A.1.7 Lauben - Summary of Oil and Gas Reserves and Resources

The Summary of Oil and Gas Reserves and Resources for Lauben as of 31.12.2025 is shown in Table 5.9.

Table 5.9 Lauben - Summary of Oil and Gas Reserves and Resources

Category	Gross Attributable to Licence (100%)	Net Attributable Lime (50.00% Lime share)	Net Attributable Rex ¹ (89.740% Rex Int. share of Lime)	Change ² from previous update (%)	Risk Factors ³	Remarks
	(MMbbl / BScf)	(MMbbl / BScf)	(MMbbl / BScf)			
Reserves						
Oil Reserves						
1P	0.09	0.04	0.04	-26%	N.A.	Change due to production in 2025 and updated decline curve analysis
2P	0.13	0.07	0.06	-13%	N.A.	
3P	0.16	0.08	0.07	-21%	N.A.	
Natural Gas Reserves						
1P	-	-	-	-	-	
2P	-	-	-	-	-	
3P	-	-	-	-	-	
Natural Gas Liquids Reserves						
1P	-	-	-	-	-	
2P	-	-	-	-	-	
3P	-	-	-	-	-	
Contingent Resources						
Oil						
1C	-	-	-	-	-	
2C	-	-	-	-	-	
3C	-	-	-	-	-	
Natural Gas						
1C	-	-	-	-	-	
2C	-	-	-	-	-	
3C	-	-	-	-	-	
Natural Gas Liquids						
1C	-	-	-	-	-	
2C	-	-	-	-	-	
3C	-	-	-	-	-	

- 1P: Proved Reserves
- 2P: Proved + Probable Reserves
- 3P: Proved + Probable + Possible Reserves
- MMbbl: Millions of barrels
- BScf: Billions of standard cubic feet
- 1C: Low estimate of Contingent Resources
- 2C: Best estimate of Contingent Resources
- 3C: High estimate of Contingent Resources

Name of Qualified Person: Mahmood Akbar

Date: 03. March 2026

Professional Society Affiliation / Membership:

- Society of Petroleum Engineers (SPE)

Notes:

1) Net Attributable to Rex International Holding Ltd ("Rex") means the volumes attributable to Rex International Investments Pte. Ltd., a wholly owned subsidiary of Rex which has an 89.74% ownership in Lime Petroleum Holding AS. Lime Petroleum Holding AS owns 100% of Lime Resources Germany GmbH which is the licensee of the production licences in Germany.

2) Change from previous update means the change in the volume attributable to Rex International Holding Ltd. The overall change shown includes changes in estimates of the remaining recoverable volumes for the field as well as the change in Rex's ownership share in Lime in 2025 (increased from 80.14% to 89.74%).

3) Applicable to Contingent Resources. "Risk Factor" for Contingent Resources means the estimated chance, or probability, that the volumes will be commercially extracted. NA denotes Not Applicable.

A.2 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
AAPG	American Association of Petroleum Geologists
ABEX	Abandonment Expenditures
AICV	Autonomous Inflow Control Valves
bbl	Volume unit, 1 barrel = 42 US gallons ≈ 159 Liters
BScf	Billions of standard cubic feet
CAPEX	Capital Expenditures
COP	Cessation of Production
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
EOFL	End of Field Life
EAGE	European Association of Geoscientists and Engineers
ESP	Electrical Submersible Pump
EUR	Estimated Ultimate Recovery; the sum of reserves and historic production
FID	Final Investment Decision
Fm	Formation
FMT	Formation Multi-Tester™ (Weatherford); formation pressure data, also MDT, RCI, RFT
FWL	Free Water Level
GCV	Gross Calorific Value
GIIP	Gas Initially In Place
GOC	Gas-Oil Contact
G	billion (Giga) SI unit multiplier = 1 000 000 000
km	Kilometre
m	meter, milli
MM	million; oilfield unit multiplier
MMbbl	million barrels of stock tank oil
MMboe	million barrels of oil equivalent
mD	millidarcy, permeability unit
M	million (Mega) SI unit multiplier = 1 000 000
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
MOPU	Mobile Offshore Production Unit
MSL	Mean Sea Level
Mt	Million tonnes
MUSD	Million US Dollars
NCS	Norwegian Continental Shelf

Abbreviation	Definition
NFA	No Further Activity
NGL	Natural Gas Liquids
NOD	Norwegian Offshore Directorate (sodir)
NOK	Norwegian Kroner
NPV	Net Present Value
oe	Oil Equivalent. 1 Sm3 oe = 1 Sm3 oil =1000 Sm3 gas
OPEX	Operating Expenditures
OTS	Oseberg Transport System
OWC	Oil-Water Contact
PDO	Plan for Development and Operations
PIIP	Petroleum Initially In Place
PRMS	Petroleum Resources Management System
PSC	Production sharing contract
PVT	Pressure Volume Temperature; fluid properties
RC	Resources category (in the NPD's resources classification system), Reservoir Committee
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
RNB	Revised National Budget; sheets/forms (Norwegian Offshore Directorate)
Scf	Square foot
Sm3	Standard cubic meter
Sw	Water Saturation
SEG	Society of Exploration Geophysicists
sodir	Sokkeldirektoratet (NOD)
SoR	Statement of Reserves
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
SPWLA	Society of Petrophysicists and Well Log Analysts
STOIIP	Stock Tank Oil Initially In Place (at the discovery time)
STOCIP	Stock Tank Oil Currently In Place
T	Trillion, SI unit multiplier = 1 000 000 000 000
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
USD	US Dollar
WAG	Water Alternating Gas
WI	Water Injector
WP&B	Work Program and Budget
WPC	World Petroleum Congress

A.3 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 5.10 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 Unclassified	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.

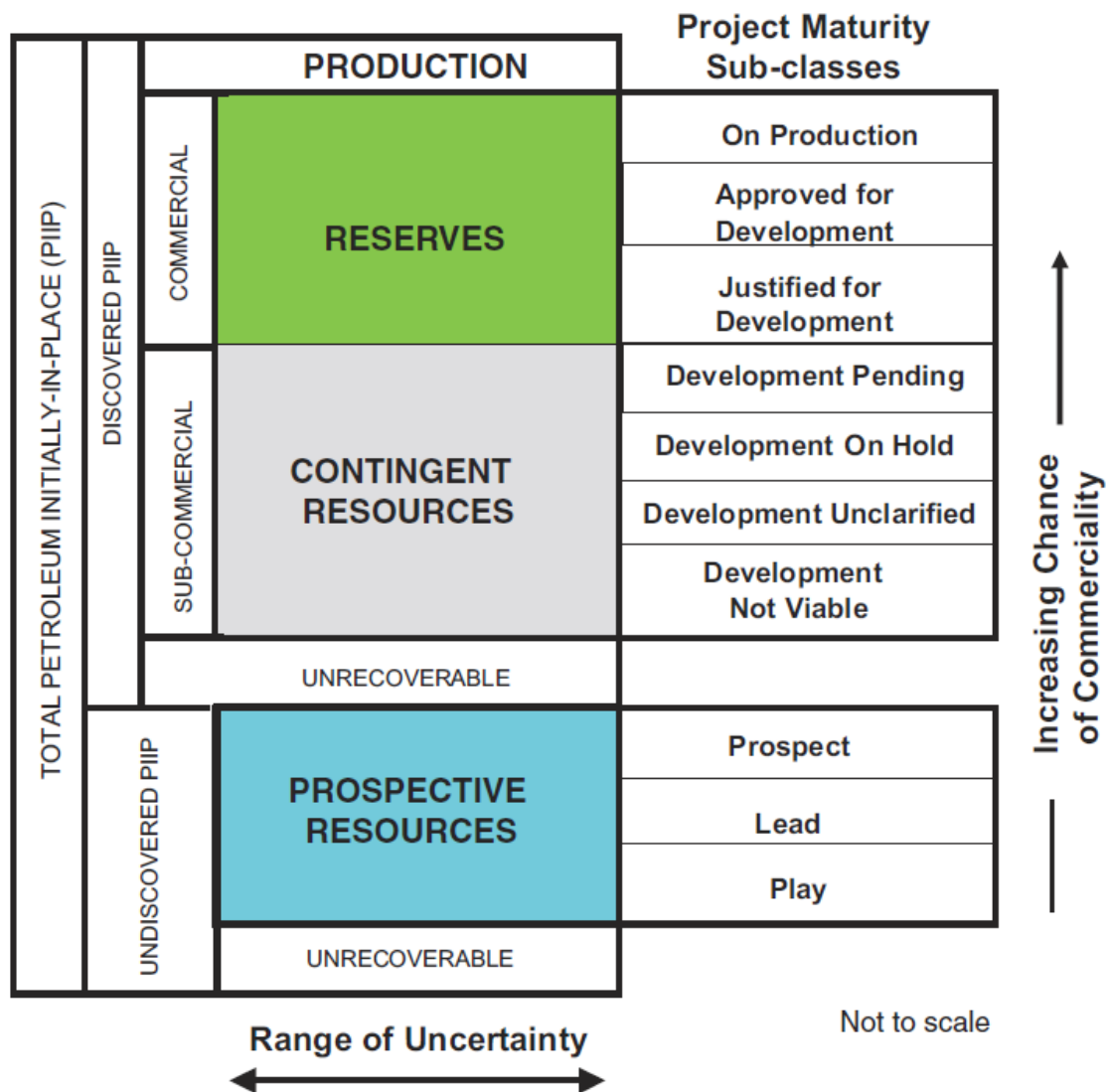


Fig. 5.1 Illustration of the SPE's resources classification framework
Source: www.spe.org

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