Longboat Energy plc

Competent Person's Report

Reserves in the Statfjord Øst and Sygna fields, offshore Norway, as at 31 December 2022

Prepared For:	Longboat Energy plc
By:	ERCE
Date:	June 2023

ERCE
Independent Energy Experts

Approved by:	Dr Adam Law
Date released to client:	29 June 2023

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29 June 2023

The Directors
Longboat Energy Norge AS
Løkkeveien 111, 4007
Stavanger, Norway

Dear Directors,

Re: Competent Person's Report – Statfjord Øst and Sygna

Longboat Energy plc and its subsidiaries (collectively, "Longboat") are considering acquiring 100% of Inpex Idemitsu Petroleum Norge AS's ("Inpex") interests in the Statfjord Øst Unit (PL037/089) and Sygna Unit (PL037/089). Both assets are currently on production.

In accordance with your instructions, ERC Equipoise Ltd ("ERCE"), in collaboration with Ross Offshore, has prepared an independent evaluation of the Reserves attributable to the Statfjord Øst and Sygna fields that lie within these Units.

The Effective Date of this Competent Person's Report ("CPR") is 31 December 2022. For the preparation of this CPR ERCE was provided with data and information by Longboat up to 31 December 2022. Subsequent to this date Longboat has made ERCE aware that there has been a material piece of information available following the drilling of recent infill Well L-2 AH. ERCE has incorporated this information into the forecasts and net present values ("NPV") in this report to reflect the poorer than expected results of this well, despite being after the Effective Date. The well has been completed and is planned to be brought onstream as scheduled in Q3 2023. Drilling operations for the remaining wells are in progress at the issue date of this report.

ERCE has carried out this work in accordance with the June 2018 SPE/WPC/AAPG/ SPEE/SEG/SPWLA/EAGE Petroleum Resources Management System ("PRMS") as the standard for classification and reporting. A summary of the PRMS is found in Appendix 1 of the CPR. The full text can be downloaded from:-

petroleum-resources-management-system-2018 (spe.org)

Use of the Report

This report is produced solely for the benefit of and on the instruction of Longboat and is not for the benefit of any third party. Any third party to whom Longboat discloses or makes available this report shall not be entitled to rely on it or any part of it.

Longboat agrees to ensure that any publication or use of this report which makes reference to ERCE shall be published or quoted in its entirety and Longboat shall not publish or use extracts of this report or any edited or amended version of this report, without the prior written consent of ERCE. In the case that any part of this report is delivered in digital format, ERCE does not accept any responsibility for edits carried out by Longboat or any third party after such material has been sent by ERCE to Longboat.

Disclaimer

ERCE has made every effort to ensure that the interpretations, conclusions and recommendations presented in this report are accurate and reliable in accordance with good industry practice. ERCE does not, however, guarantee the correctness of any such interpretations and shall not be liable or responsible for any loss, costs, damages or expenses incurred or sustained by anyone resulting from any interpretation or recommendation made by any of its officers, agents or employees.

ERCE has used standard petroleum evaluation techniques in the generation of this report. These techniques combine geophysical and geological knowledge with assessments of porosity and permeability distributions, fluid characteristics, production performance and reservoir pressure. There is uncertainty in the measurement and interpretation of basic data. ERCE has estimated the degree of this uncertainty and determined the range of petroleum initially in place and recoverable hydrocarbon volumes. In applying these procedures and tests, nothing came to the attention of ERCE that would suggest that information provided by Longboat was not complete and accurate. ERCE reserves the right to review all calculations referred to or included in this report and to revise the estimates in light of erroneous data supplied or information existing but not made available which becomes known subsequent to the preparation of this report.

The accuracy of any Reserves and production estimates is a function of the quality and quantity of available data and of engineering interpretation and judgment. While the estimates presented herein are considered reasonable, the estimates should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward.

No site visits were undertaken in the preparation of this report.

Professional Qualifications

ERCE is an independent consultancy specialising in geoscience evaluation, engineering and economic assessment. ERCE will receive a fee for the preparation of this report in accordance with normal professional consulting practices. This fee is not dependent on the findings of this CPR and ERCE will receive no other benefit for the preparation of this CPR.

Neither ERCE, the Competent Person who is responsible for authoring the CPR, nor any Directors of ERCE, have at the date of this report, any shareholding in Longboat.

Consequently, ERCE, the Competent Person and the Directors of ERCE consider themselves to be independent of Longboat, its directors and senior management.

ERCE has the relevant and appropriate qualifications, experience and technical knowledge to appraise professionally and independently the assets.

The work has been supervised by Dr Adam Law, Director of ERCE, a post-graduate in Geology, a Fellow of the Geological Society and a member of the Society of Petroleum Evaluation Engineers.

Yours faithfully

Adam Law

Director, ERCE

1. Introduction

1.1. Licence Overview

Longboat is considering acquiring 100% of Inpex's interests in the producing Statfjord Øst and Sygna Units, both located in Production Licence ("PL") 037 and PL089, offshore Norway. The fields are satellites of the Statfjord field and are tied back to the Statfjord C platform. A summary of the licence interests is shown in Table 1.1. A location map of the fields is shown in Figure 1.1.

ERCE has prepared a CPR of the Reserves attributable to the Statfjord Øst and Sygna fields that lie within these Units, assuming Longboat acquires 100% of Inpex's interests.

Table 1.1: Summary of Licences

Licence	Main Asset	Operator	Longboat Interest (%)	Status	Licence expiry date	Licence area (km^2)
PL037/089	Statfjord Øst	Equinor Energy AS	4.80	Producing	PL037 – 10/08/2026 PL089 – 31/12/2040	1,307
PL037/089	Sygna	Equinor Energy AS	4.32	Producing	PL037 – 10/08/2026 PL089 – 31/12/2040	42

Notes:

1) Longboat's working interests are subject to the completion of its acquisition from Inpex.

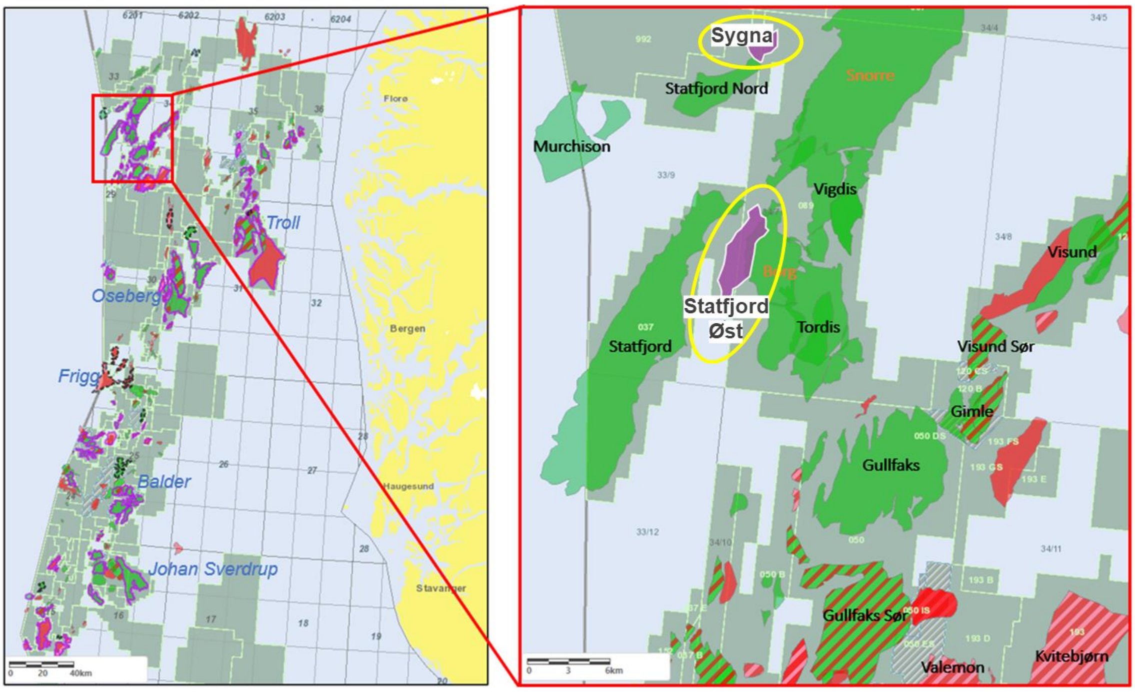

Figure 1.1: Location map of the Statfjord Øst and Sygna fields

1.2. Data Provided

ERCE has relied upon data made available by Longboat in the preparation of this report. These include well results, conceptual development plans, and estimates of future work programmes and budgets. No seismic data was provided by Inpex to Longboat and ERCE's analysis relies on screenshots of 3D and 4D seismic data and derived products made available through Operator reports.

The Effective Date of this Competent Person's Report ("CPR") is 31 December 2022. For the preparation of this CPR ERCE was provided with data and information by Longboat up to 31 December 2022. Subsequent to this date Longboat has made ERCE aware that there has been a material piece of information available following the drilling of recent infill Well L-2 AH. ERCE has incorporated this information into the forecasts and NPVs in this report to reflect the poorer than expected results of this well, despite being after the Effective Date. Drilling operations for the remaining wells are in progress at the issue date of this report.

Longboat has confirmed to ERCE that all information, data and/or materials disclosed in this CPR, in whatever form, are in compliance with the terms of any and all confidentiality agreements in place between Longboat and Inpex, under which the Confidential Information was disclosed.

1.3. Work Completed

ERCE has used standard petroleum evaluation techniques in the generation of this report. These techniques combine geophysical and geological knowledge with assessments of porosity and permeability distributions, fluid characteristics, production performance and reservoir pressure of analogue wells and fields. There is uncertainty in the measurement and interpretation of basic data. ERCE has estimated the degree of this uncertainty and determined the range of recoverable hydrocarbon volumes.

For evaluating Reserves associated with each field ERCE did not find it necessary to independently assess the petroleum initially in place ("PIIP"). ERCE has estimated Reserves and the associated uncertainty by using production performance analysis and type curves from analogue wells, calibrated by reviewing studies undertaken by the Operator and reconciled against the Operator's dynamic model.

Production profiles have been generated by ERCE for the Reserves. The forecasts generated have then been used as input to an economic model to undertake an Economic Limit Test ("ELT"). The economic model has been built by ERCE and reflects the current Norwegian fiscal regime.

ERCE has evaluated the development plans for each field and has evaluated forecasts of capital, operating and abandonment costs. ERCE has reviewed the costs provided and benchmarked them against its internal database to ensure they are reasonable. Where possible these estimates were compared to historical, actual costs. ERCE's economic analysis does not take into account any outstanding debt, nor future indirect corporate costs. The economic analysis is carried out on the assumption that Longboat's acquisition Inpex's interests in the fields is completed and does not take into account any transaction fees.

2. Asset Overview

2.1. Statfjord Øst

Longboat Interest 4.80% (subject to completion of acquisition from Inpex)

The Statfjord Øst field is located in the Tampen area of the North Sea, 7 km northeast of the Statfjord field in water depths of 150 – 190 m. The field was discovered in 1976 and the plan for development and operation ("PDO") was approved in 1990. The field has been developed with two subsea production templates and a subsea water injection template. In addition, two production wells have been drilled from the Statfjord C platform. Production commenced in 1994 and peaked in 1998 at an oil rate of approximately 82,000 stb/d. Production was supported by water injection until 2009, after which production has been via depletion drive.

The Statfjord Øst field contains hydrocarbons within Middle Jurassic Brent Group ("Brent") reservoirs in a tilted fault block structure. The field can be separated into a structurally simple central/northern area and more complex structural slump areas in the east and south (Figure 2.1).

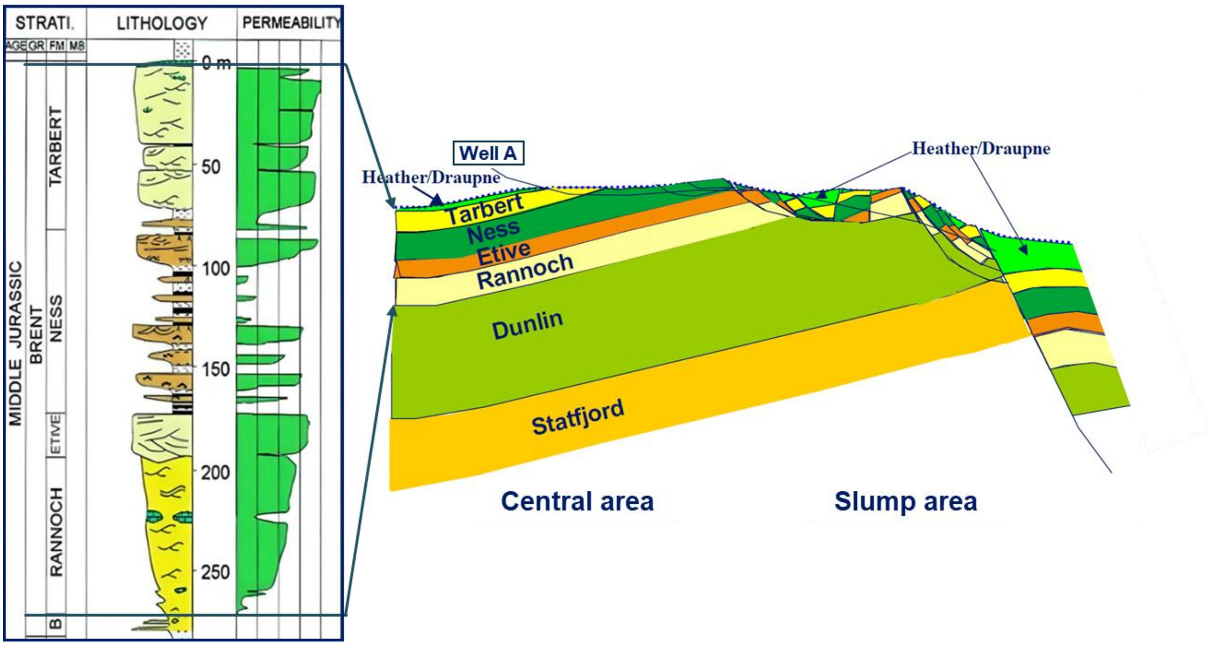

Figure 2.1: Statfjord Øst stratigraphic column and east-west structural cross section

Source: Longboat

The Tarbert Formation ("Fm") has good reservoir quality (600 – 2,700 mD) and consists of shoreface sandstones deposited as prograding units on top of the Ness Fm. The Ness Fm has moderate to good reservoir quality (200 – 1,100 mD) and was deposited in a range of environments. The Ness Fm is vertically layered with pressure barriers including a field-wide barrier that separates the upper and lower Brent reservoirs. The Etive Fm has very good reservoir quality (2,900 mD) and consists of upper shoreface, tidal bay and braided fluvial deposits. The Rannoch Fm has poor to moderate reservoir quality (25 – 500 mD) and consists of prograding shoreface deposits.

Production is transported back to the Statfjord C platform for processing, storage and export. Oil is loaded onto tankers and gas is exported through the Tampen Link and the Far North Liquids and Gas System ("FLAGS") pipeline to the UK.

As of 31 December 2022 there is one stable producing platform well (Well 33/9-C-33 A) and two cyclic producing subsea template wells (Wells 33/9-M-02 H and 33/9-M-04 AH). The average wellhead oil and gas rates in December 2022 were 3,360 stb/d and 12.8 MMscf/d respectively; the water cut is 82%. Cumulative oil production from the field is approximately 240 MMstb, which represents a recovery factor of 58% against the RNB2023 Best Case STOIIP (410 MMstb). The production history of the field is shown in Figure 2.2.

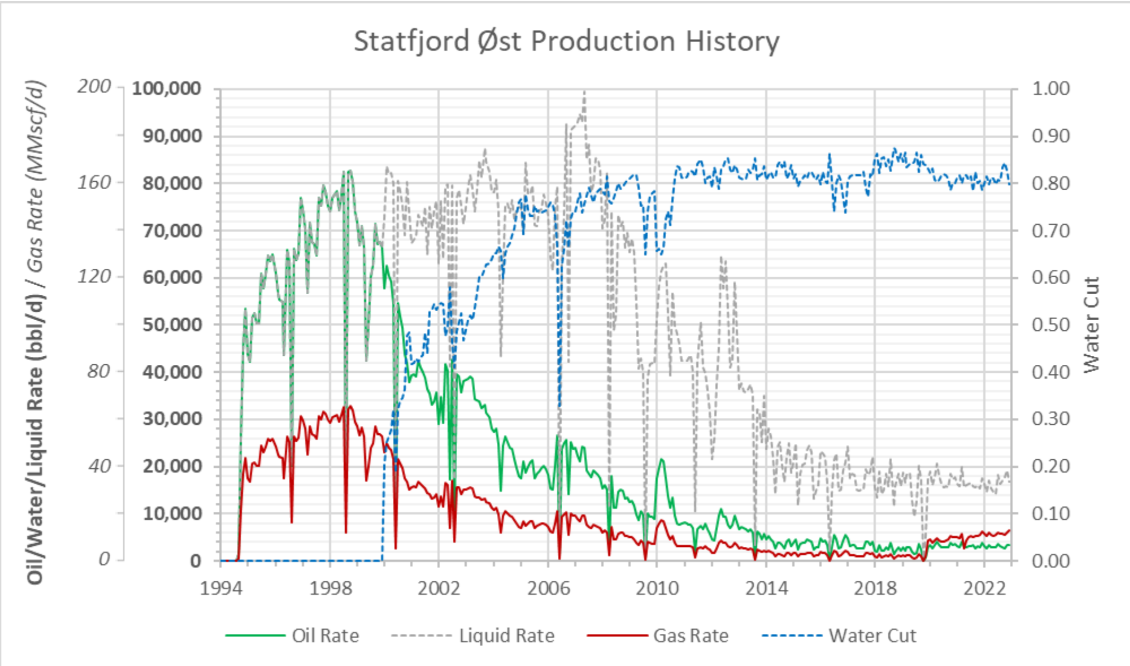

Figure 2.2: Statfjord Øst production history

A revised PDO was submitted in 2020 which includes a gas lift project. The gas lift project comprises a new gas lift system to be installed for the subsea templates and five infill wells to be drilled from the subsea templates. In the Operator's interpretation, the infill wells target poorly swept areas of the field. Each infill well is planned as a sidetrack of existing subsea template wells. The locations of the infill wells are shown in Figure 2.3.

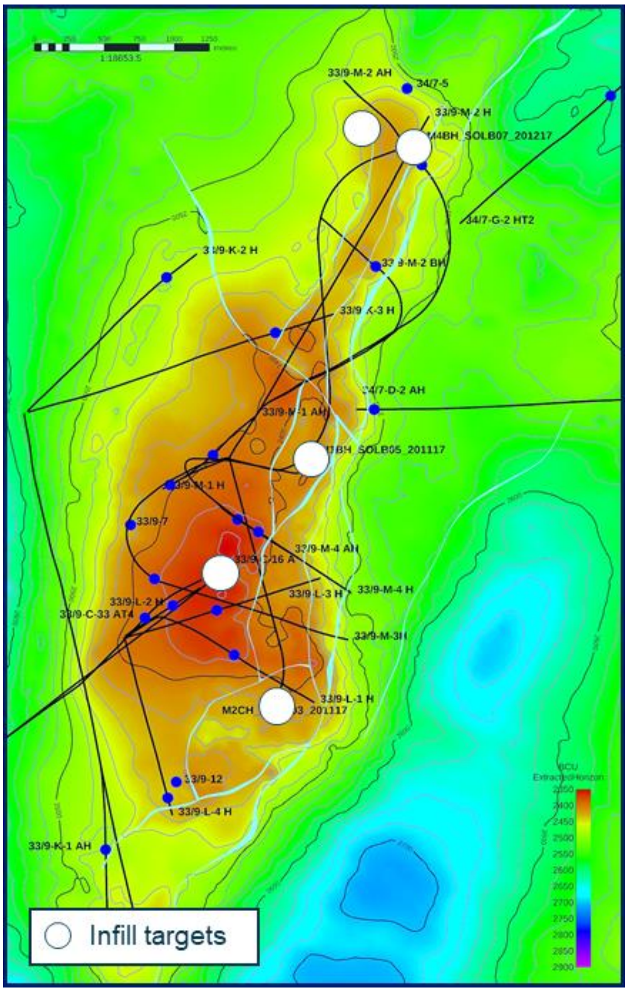

Figure 2.3: Top depth map with planned infill well locations

Source: Longboat

Reserves in Statfjord Øst comprise production from existing Well C-33 A and future production from the five planned infill wells.

Subsequent to the Effective Date of this report, Longboat has made ERCE aware that there has been a material piece of information available following the drilling of recent infill Well L-2 AH. Despite this information being made available after the Effective Date, ERCE has incorporated the poorer than expected results of the well into the forecasts and NPVs in this report. The well has been completed and is planned to be brought onstream as scheduled in Q3 2023. Drilling operations for the remaining wells are in progress at the issue date of this report.

The major capital costs relate to the Gas Lift Project and the FLX Future Energy ("FFE") project. The FFE project will reduce CO_2 emissions and CO_2 taxes for the satellite fields (Statfjord Øst, Statfjord Nord and Sygna) as users of the Statfjord C platform. The project involves replacing the fuel gas driven water injection pump with an electric driven pump.

Statfjord Øst will also contribute to the Statfjord C Lifetime Extension Programme which involves replacement and upgrade of certain infrastructure. Statfjord Øst will contribute a share of the Statfjord C platform decommissioning.

2.2. Sygna

Longboat Interest 4.32% (subject to completion of acquisition from Inpex)

The Sygna field is located in the Tampen area of the North Sea, 18 km north of the Statfjord field in water depths of over 300 m. The field was discovered in 1996 and the PDO was approved in 1999. The field has been developed with a four-slot subsea production template tied back to the Statfjord C platform. In addition, a long-reach water injection well was drilled from the nearby Statfjord Nord subsea template. Production commenced in 2000 and peaked in 2001 at an oil rate of approximately 46,000 stb/d.

The Sygna field contains hydrocarbons within Middle Jurassic Brent reservoirs (Etive and Rannoch) in a tilted fault block structure (Figure 2.4). The field is bound by faults to the southwest and northwest and an eroded Dunlin horst to the east. The Etive Fm has good reservoir quality (300 – 500 mD) and was deposited in a shallow marine environment. The Rannoch Fm is more heterogeneous (30 – 750 mD) and was deposited some distance from the paleo-coastline.

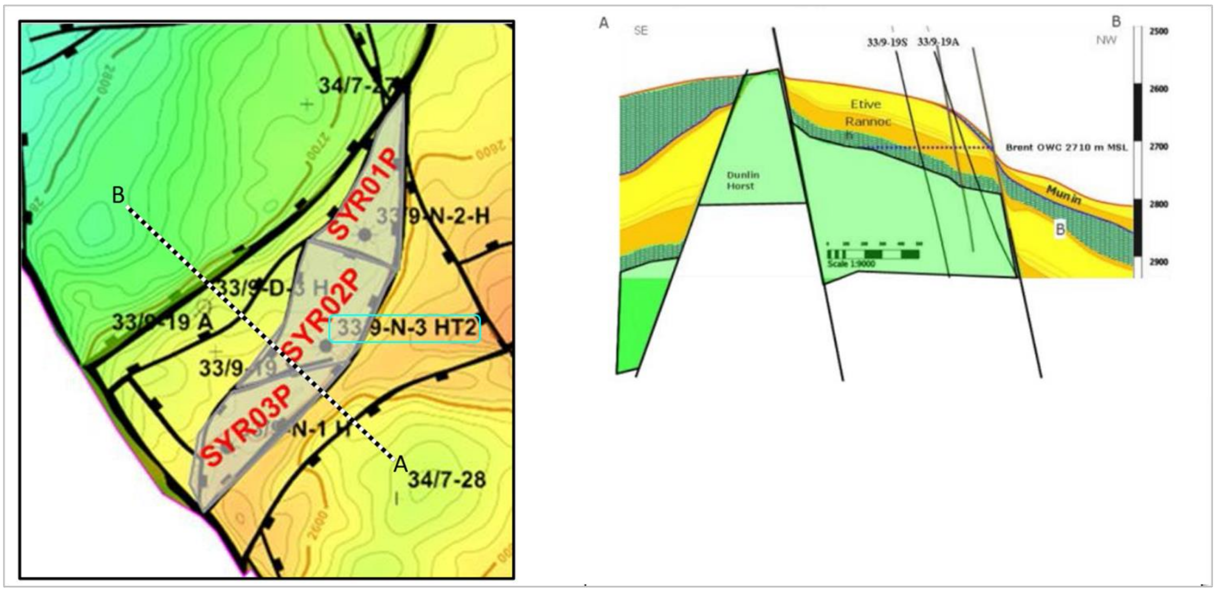

Figure 2.4: Sygna top depth map and structural cross section

Source: Longboat

Production is transported back to the Statfjord C platform for processing, storage and export. Oil is loaded onto tankers and gas is given to the Statfjord Unit as compensation for the tie-in and processing, fuel and flare.

As of 31 December 2022 there are three active producing wells (Wells 33/9-N-1 H, 33/9-N-2 AH and 33/9-N-3 H) supported by one water injection well (Well 33/9-D-03 H). The average wellhead oil and gas rates in December 2022 were 950 stb/d and 0.3 MMscf/d respectively and the water cut was 96%. Cumulative oil production from the field is approximately 70 MMstb, which represents a recovery factor of 54% against the RNB2023 Best Case STOIIP (131 MMstb). The production history of the field is shown in Figure 2.5.

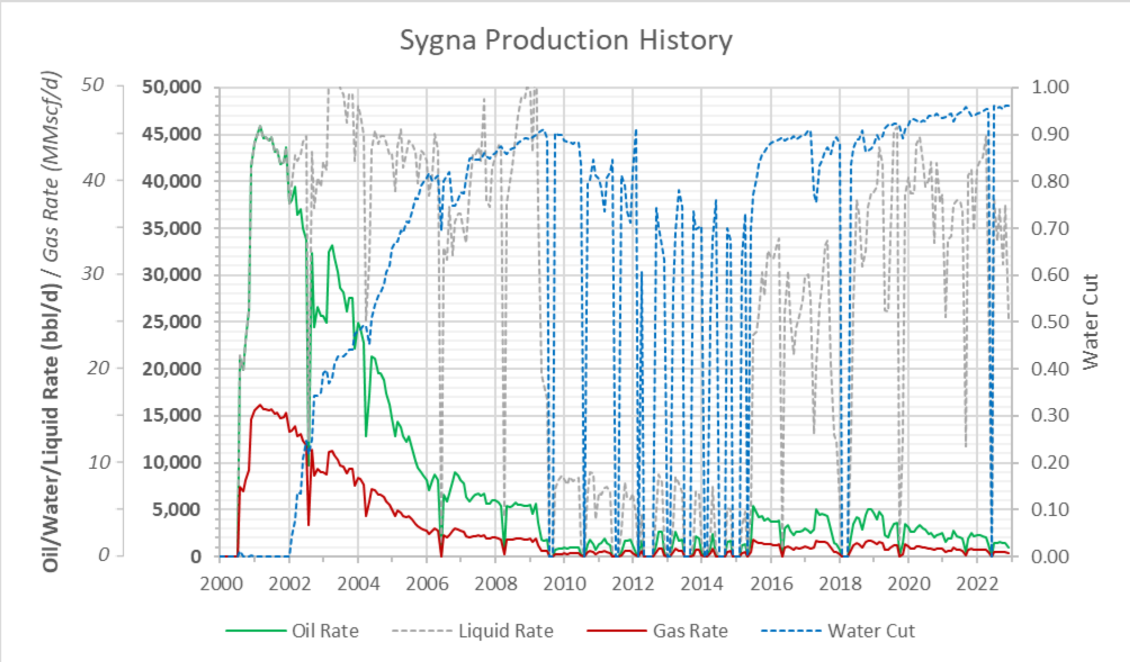

Figure 2.5: Sygna field production history

Reserves in Sygna comprise production from the existing wells. There are no planned development projects.

As a satellite to the Statfjord C platform, Sygna will also contribute towards the FFE project and the Statfjord C Lifetime Extension Programme.

3. 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. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates as Proved (1P), Proved plus Probable (2P) and Proved plus Probable plus Possible (3P).*

The Reserves are reported on a field gross and a Company net entitlement interest basis as of 31 December 2022. As there are no royalties payable to others, the Company net entitlement Reserves are based on the working interest share of the field gross Reserves. Both Developed and Undeveloped Reserves are reported for the fields.

Gas Reserves are based on sales volumes and exclude fuel and flare. Oil equivalent Reserves are reported based on an energy equivalent conversion of the gas Reserves of 5,600 scf per barrel of oil equivalent[1].

A summary of the Reserves, broken into Developed and Undeveloped Reserves, is presented in Table 3.1. This summary also includes a breakdown of the Reserves by fluid type.

The ERCE estimates of Developed Reserves are based on decline curve analysis (“DCA”). Estimates of Undeveloped Reserves are based on hydrocarbon in place and recovery efficiency estimates, analogue type curves, stochastic historic well performance analysis and/or dynamic modelling.

ERCE has estimated cost forecasts based on the latest budget information, which has been benchmarked against an internal database. ERCE found the cost estimates associated with the Gas Lift Project, FFE project and Statfjord C Lifetime Extension Programme to be reasonable. Forecasts of operating costs include a cost-share component and this is based on the production split between the Statfjord field and the satellite fields.

In accordance with the PRMS guidelines, the Cessation of Production (“CoP”) date used to estimate Reserves is defined as the end of the last twelve-month period that the operating cash flow is positive, or the end of the technical field life, whichever occurs soonest.

ERCE has also estimated net present values (“NPV”) for all categories which can be seen in Table 3.2. These NPVs are for Longboat’s Working Interest in the Statfjord Øst and Sygna fields assuming completion of the acquisition from Inpex.

[1] Conversion based on information provided by the Norwegian Petroleum Directorate (NPD) website - Conversion factors - The Norwegian Petroleum Directorate (npd.no)

Table 3.1: Reserves as of 31 December 2022

Asset	Reserves Category	Economic Limit (Year)	Gross Reserves				Company Net Entitlement Reserves			
			Oil	NGL	Gas	Total	Oil	NGL	Gas	Total
			MMstb	MMstb	Bscf	MMboe	MMstb	MMstb	Bscf	MMboe
Statfjord Øst	1P Developed	2025	1.7	0.7	7.1	3.6	0.1	0.0	0.3	0.2
	2P Developed	2027	2.7	1.1	11.4	5.9	0.1	0.1	0.5	0.3
	3P Developed	2029	4.0	1.5	15.9	8.3	0.2	0.1	0.8	0.4
	1P Undeveloped		10.7	1.9	19.4	16.0	0.5	0.1	0.9	0.8
	2P Undeveloped		16.1	2.9	30.1	24.4	0.8	0.1	1.4	1.2
	3P Undeveloped		23.8	4.4	45.2	36.2	1.1	0.2	2.2	1.7
	1P	2036	12.3	2.5	26.4	19.6	0.6	0.1	1.3	0.9
	2P	2037	18.9	4.0	41.4	30.2	0.9	0.2	2.0	1.5
	3P	2037	27.7	5.9	61.1	44.5	1.3	0.3	2.9	2.1
Sygna	1P Developed	2031	1.5	-	-	1.5	0.1	-	-	0.1
	2P Developed	2032	2.2	-	-	2.2	0.1	-	-	0.1
	3P Developed	2032	2.6	-	-	2.6	0.1	-	-	0.1
	1P Undeveloped		-	-	-	-	-	-	-	-
	2P Undeveloped		-	-	-	-	-	-	-	-
	3P Undeveloped		-	-	-	-	-	-	-	-
	1P	2031	1.5	-	-	1.5	0.1	-	-	0.1
	2P	2032	2.2	-	-	2.2	0.1	-	-	0.1
	3P	2032	2.6	-	-	2.6	0.1	-	-	0.1
Total	1P Developed		3.2	0.7	7.1	5.1	0.1	0.0	0.3	0.2
	2P Developed		5.0	1.1	11.4	8.1	0.2	0.1	0.5	0.4
	3P Developed		6.5	1.5	15.9	10.9	0.3	0.1	0.8	0.5
	1P Undeveloped		10.7	1.9	19.4	16.0	0.5	0.1	0.9	0.8
	2P Undeveloped		16.1	2.9	30.1	24.4	0.8	0.1	1.4	1.2
	3P Undeveloped		23.8	4.4	45.2	36.2	1.1	0.2	2.2	1.7
	1P		13.8	2.5	26.4	21.1	0.7	0.1	1.3	1.0
	2P		21.1	4.0	41.4	32.5	1.0	0.2	2.0	1.5
	3P		30.3	5.9	61.1	47.1	1.4	0.3	2.9	2.2

Notes:

1) Longboat's working interests (4.80% in Statfjord Øst, 4.32% in Sygna) are subject to the completion of its acquisition from Inpex.
2) Gross Reserves represent a 100% interest share of the field Reserves.
3) Company Net Entitlement Reserves are based on the working interest share of the field gross Reserves (there are no royalty payments).
4) Undeveloped Reserves comprise Reserves associated with the Gas Lift Project as well as volumes associated with the additional production from Well C-33 AT4 up to the later economic limit.
5) The 1P Undeveloped, 2P Undeveloped and 3P Undeveloped Reserves are incremental to the Developed Reserves and therefore have the same economic limit as the 1P, 2P and 3P Reserves.
6) Reserves in oil equivalents are calculated assuming 5,600 scf per barrel of oil equivalent.
7) Totals may not equal the sum of the values due to rounding.

Table 3.2: Net Present Values, Longboat's share as of 31 December 2022

Asset	Reserves Category	Net NPV				
		0% (US$MM)	5% (US$MM)	10% (US$MM)	15% (US$MM)	20% (US$MM)
Statfjord Øst	1P Developed	1.1	1.2	1.4	1.5	1.7
	2P Developed	2.4	2.6	2.9	3.1	3.3
	3P Developed	4.0	4.4	4.8	5.0	5.2
	1P Undeveloped	6.5	6.6	6.4	6.0	5.5
	2P Undeveloped	13.6	12.9	12.1	11.1	10.2
	3P Undeveloped	23.1	20.9	19.0	17.3	15.9
	1P	7.6	7.8	7.7	7.5	7.2
	2P	16.0	15.6	15.0	14.3	13.6
	3P	27.1	25.4	23.8	22.4	21.1
Sygna	1P Developed	(0.5)	(0.3)	(0.1)	0.1	0.2
	2P Developed	(0.1)	0.1	0.3	0.4	0.5
	3P Developed	0.1	0.3	0.5	0.6	0.7
	1P Undeveloped	-	-	-	-	-
	2P Undeveloped	-	-	-	-	-
	3P Undeveloped	-	-	-	-	-
	1P	(0.5)	(0.3)	(0.1)	0.1	0.2
	2P	(0.1)	0.1	0.3	0.4	0.5
	3P	0.1	0.3	0.5	0.6	0.7
Total	1P Developed	0.6	1.0	1.3	1.6	1.8
	2P Developed	2.2	2.8	3.2	3.6	3.8
	3P Developed	4.1	4.8	5.3	5.6	5.9
	1P Undeveloped	6.5	6.6	6.4	6.0	5.5
	2P Undeveloped	13.6	12.9	12.1	11.1	10.2
	3P Undeveloped	23.1	20.9	19.0	17.3	15.9
	1P	7.1	7.6	7.7	7.6	7.3
	2P	15.9	15.7	15.3	14.7	14.1
	3P	27.2	25.7	24.3	23.0	21.8

Notes:

1) Values inside brackets (e.g. (0.5)) are negative values.
2) NPVs do not consider any potential tax synergies for Longboat.
3) Totals may not equal the sum of the values due to rounding.

Appendix 1: SPE PRMS Guidelines

This report references the SPE/WPC/AAG/SPEE/SEG/SPWLA/EAGE Petroleum Reserves and Resources Classification System and Definitions, as revised in June 2018 (PRMS). The full text of the PRMS document can be viewed at:

petroleum-resources-management-system-2018 (spe.org)

Definitions of the key PRMS Reserves and Resource classes, categories and a glossary of related terms can be found at the above address.

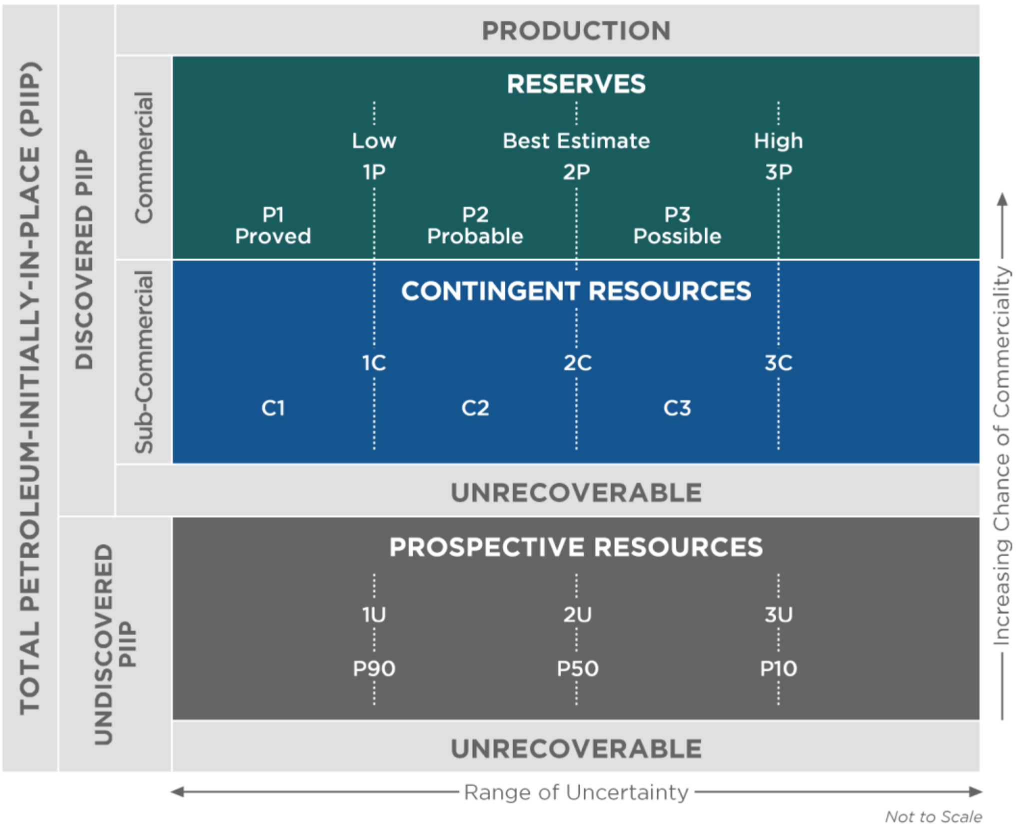

Figure A: PRMS Resources classification framework

(Modified from Petroleum Resources Management System (PRMS) Revised June 2018, page 8, Figure 1.1)

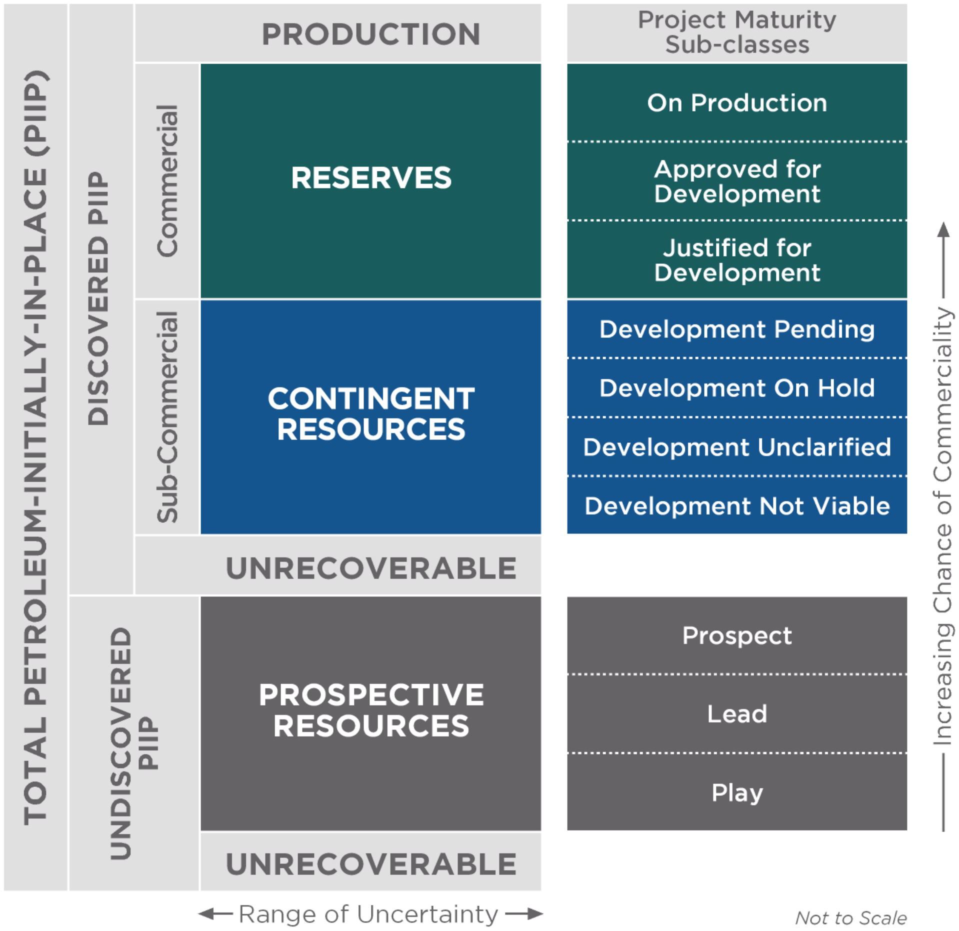

Figure B: PRMS Resources sub-classes

(Modified from Petroleum Resources Management System (PRMS) Revised June 2018, page 8, Figure 2.1)

Table 1: PRMS Recoverable Resources Classes and Sub-Classes

Classes/Sub-classes	Definition	Guidelines
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.	Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market- related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.

Classes/Sub-classes	Definition	Guidelines
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.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.
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.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame}) There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
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 owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub- classified based on project maturity and/or characterized by the economic status.

Classes/Sub-classes	Definition	Guidelines
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
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.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.

Classes/Sub-classes	Definition	Guidelines
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.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2: PRMS Reserves Status Definitions and Guidelines

Status	Definition	Guidelines
Developed Reserves	Expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-producing.
Developed Producing Reserves	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3: PRMS Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and 2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved. Reserves in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Possible Reserves	Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic production from the reservoir by a defined, commercially mature project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	See above for separate criteria for Probable Reserves and Possible Reserves.	The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

Table 4: Glossary of Terms Used in PRMS

Term	Definition
1C	Denotes low estimate of Contingent Resources.
2C	Denotes best estimate of Contingent Resources.
3C	Denotes high estimate of Contingent Resources.
1P	Denotes low estimate of Reserves (i.e., Proved Reserves). Equal to P1.
2P	Denotes the best estimate of Reserves. The sum of Proved plus Probable Reserves.
3P	Denotes high estimate of reserves. The sum of Proved plus Probable plus Possible Reserves.
1U	Denotes the unrisked low estimate qualifying as Prospective Resources.
2U	Denotes the unrisked best estimate qualifying as Prospective Resources.
3U	Denotes the unrisked high estimate qualifying as Prospective Resources.

Appendix 2: Nomenclature

(where not already described in Appendix 1)

boe	barrel of oil equivalent
Bscf	billion standard cubic feet
bbl	barrel
CoP	cessation of production
DCA	decline curve analysis
ELT	economic limit test
FLAGS	Far North Liquids and Gas System
Fm	formation
FFE	FLX Future Energy
km	kilometres
m	metre
M MM	thousands and millions respectively
md or mD	millidarcy
NOK	Norwegian Krone
NPD	Norwegian Petroleum Directorate
NPV	net present value
PDO	plan for development and operation
PIIP	petroleum initially in place
PL	production licence
scf	standard cubic feet measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
stb	stock tank barrel (42 US gallons measured at 14.7 pounds per square inch and 60 degrees Fahrenheit)
STOIIP	stock tank oil initially in place

Appendix 3: Gross Production and Cost Forecasts

Table A - 1: Gross production and cost forecasts – Statfjord Øst 1P Developed

Year	Oil Sales Rate	NGL Sales Rate	Gas Sales Rate	Capex (Real)		Opex (Real)			Abandex Cost (Real)
				Offshore Tangible	Total Capex	Tariff Cost	Fixed Opex	Total Opex	
	(stb/d)	(bbl/d)	(mmscf/d)	(NOK MM)	(NOK MM)	(NOK MM)	(NOK MM)	(NOK MM)	(NOK MM)
2023	2,266	916	9.5	175	175	76	171	247	1,192
2024	1,290	522	5.6	299	299	33	238	271	
2025	967	403	4.2	360	360	30	218	248	
2026	697	268	2.7	248	248	31	195	226	
2027	484	153	1.7	59	59	26	181	207	
2028	378	112	1.2	70	70	26	173	199	
2029	340	86	0.9	52	52	29	163	192	
2030	232	66	0.6	253	253	23	177	200	
2031	216	59	0.6	32	32	25	133	158	
2032	161	44	0.4	38	38	22	127	149	
2033	149	47	0.3	16	16	21	138	160	
2034	126	20	0.3	15	15	20	144	164	
2035	123	27	0.4	20	20	19	140	159	
2036	113	21	0.3	7	7	19	154	173	
2037	117	25	0.4		-	20	172	192	
2038	114	25	0.4		-	28	138	166	
2039									
Total (MMstb / Bscf / NOK MM)	2.8	1.0	10.8	1,641.8	1,641.8	447.8	2,661.4	3,109.2	1,192.0

Table A - 2: Gross production and cost forecasts – Statfjord Øst 2P Developed

Year	Oil Sales Rate	NGL Sales Rate	Gas Sales Rate	Capex (Real)		Opex (Real)			Abandex Cost (Real)
				Offshore Tangible	Total Capex	Tariff Cost	Fixed Opex	Total Opex	
	(stb/d)	(bbl/d)	(mmscf/d)	(NOK MM)	(NOK MM)	(NOK MM)	(NOK MM)	(NOK MM)	(NOK MM)
2023	2,614	1,043	10.9	175	175	87	171	258	1,192
2024	1,843	748	8.0	299	299	47	238	285	
2025	1,381	574	5.9	360	360	43	218	261	
2026	996	378	3.9	248	248	44	195	239	
2027	691	225	2.4	59	59	38	181	219	
2028	540	165	1.8	70	70	37	173	210	
2029	485	132	1.4	52	52	41	163	204	
2030	332	95	0.8	253	253	33	177	210	
2031	308	78	0.8	32	32	35	133	168	
2032	230	62	0.6	38	38	32	127	159	
2033	213	67	0.5	16	16	31	138	169	
2034	179	31	0.5	15	15	28	144	172	
2035	175	33	0.5	20	20	28	140	167	
2036	161	28	0.4	7	7	27	154	181	
2037	167	32	0.5	-	-	28	172	201	
2038	163	31	0.5	-	-	40	138	178	
2039									
Total (MMstb / Bscf / NOK MM)	3.8	1.4	14.3	1,641.8	1,641.8	618.8	2,661.4	3,280.3	1,192.0

Table A - 3: Gross production and cost forecasts – Statfjord Øst 3P Developed

Year	Oil Sales Rate	NGL Sales Rate	Gas Sales Rate	Capex (Real)		Opex (Real)			Abandex Cost (Real)
				Offshore Tangible	Total Capex	Tariff Cost	Fixed Opex	Total Opex	
	(stb/d)	(bbl/d)	(mmscf/d)	(NOK MM)	(NOK MM)	(NOK MM)	(NOK MM)	(NOK MM)	(NOK MM)
2023	3,137	1,254	13.0	175	175	105	171	276	1,192
2024	2,396	974	10.4	299	299	62	238	300	
2025	1,795	756	7.8	360	360	56	218	274	
2026	1,294	497	5.1	248	248	57	195	252	
2027	899	294	3.2	59	59	49	181	230	
2028	702	214	2.3	70	70	48	173	221	
2029	631	160	1.7	52	52	54	163	217	
2030	431	123	1.1	253	253	43	177	220	
2031	401	103	1.1	32	32	46	133	179	
2032	299	81	0.7	38	38	42	127	168	
2033	276	82	0.6	16	16	40	138	178	
2034	233	34	0.5	15	15	36	144	180	
2035	228	43	0.6	20	20	36	140	175	
2036	209	40	0.6	7	7	35	154	189	
2037	217	41	0.6	-	-	37	172	209	
2038	211	43	0.6		-	52	138	189	
2039									
Total (MMstb / Bscf / NOK MM)	4.9	1.7	18.3	1,641.8	1,641.8	795.8	2,661.4	3,457.2	1,192.0

Table A - 4: Gross forecasts – Statfjord Øst 1P Developed plus Undev.

Year	Oil Sales Rate	NGL Sales Rate	Gas Sales Rate	Capex (Real)		Opex (Real)			Abandex Cost (Real)
				Offshore Tangible	Total Capex	Tariff Cost	Fixed Opex	Total Opex	
	(stb/d)	(bbl/d)	(mmscf/d)	(NOK MM)	(NOK MM)	(NOK MM)	(NOK MM)	(NOK MM)	(NOK MM)
2023	3,858	1,116	11.7	2,360	2,360	151	171	322	1,412
2024	7,003	1,610	16.9	639	639	200	238	438	
2025	4,661	738	7.6	390	390	170	218	388	
2026	3,294	989	10.3	248	248	165	195	360	
2027	2,523	485	5.2	59	59	160	181	341	
2028	1,982	391	4.1	70	70	159	173	332	
2029	1,629	315	3.2	52	52	164	163	327	
2030	1,382	249	2.5	253	253	162	177	339	
2031	607	229	2.3	32	32	82	133	215	
2032	1,612	192	1.9	38	38	262	127	389	
2033	1,441	194	1.8	16	16	239	138	378	
2034	904	138	1.6	15	15	163	144	307	
2035	2,019	154	1.7	20	20	359	140	498	
2036	794	147	1.6	7	7	149	154	303	
2037	757	142	1.5	-	-	146	172	318	
2038	497	98	1.1	-	-	142	138	280	
2039									
Total (MMstb / Bscf / NOK MM)	12.8	2.6	27.4	4,196.8	4,196.8	2,872.7	2,661.4	5,534.2	1,412.0

Table A - 5: Gross forecasts – Statfjord Øst 2P Developed plus Undev.

Year	Oil Sales Rate	NGL Sales Rate	Gas Sales Rate	Capex (Real)		Opex (Real)			Abandex Cost (Real)
				Offshore Tangible	Total Capex	Tariff Cost	Fixed Opex	Total Opex	
	(stb/d)	(bbl/d)	(mmscf/d)	(NOK MM)	(NOK MM)	(NOK MM)	(NOK MM)	(NOK MM)	(NOK MM)
2023	4,895	1,333	13.9	2,360	2,360	191	171	362	1,412
2024	11,139	2,371	24.8	639	639	318	238	556	
2025	7,770	1,735	17.9	390	390	284	218	502	
2026	5,377	1,061	11.0	248	248	269	195	464	
2027	4,095	776	8.3	59	59	260	181	441	
2028	3,238	610	6.4	70	70	260	173	432	
2029	2,580	776	7.9	52	52	260	163	423	
2030	2,211	139	1.3	253	253	260	177	437	
2031	1,923	343	3.5	32	32	260	133	393	
2032	1,597	302	3.0	38	38	260	127	386	
2033	1,563	308	2.9	16	16	260	138	398	
2034	1,440	232	2.7	15	15	260	144	403	
2035	1,314	170	1.9	20	20	234	140	373	
2036	1,244	541	5.6	7	7	234	154	388	
2037	1,214	218	2.2	-	-	234	172	406	
2038	817	138	1.5		-	234	138	371	
2039									
Total (MMstb / Bscf / NOK MM)	19.1	4.0	42.0	4,196.8	4,196.8	4,073.2	2,661.4	6,734.7	1,412.0

Table A - 6: Gross forecasts – Statfjord Øst 3P Developed plus Undev.

Year	Oil Sales Rate	NGL Sales Rate	Gas Sales Rate	Capex (Real)		Opex (Real)			Abandex Cost (Real)
				Offshore Tangible	Total Capex	Tariff Cost	Fixed Opex	Total Opex	
	(stb/d)	(bbl/d)	(mmscf/d)	(NOK MM)	(NOK MM)	(NOK MM)	(NOK MM)	(NOK MM)	(NOK MM)
2023	6,607	1,634	17.1	2,360	2,360	258	171	429	1,412
2024	16,527	3,201	33.5	639	639	472	238	710	
2025	11,518	2,157	22.2	390	390	421	218	639	
2026	7,937	1,389	14.4	248	248	397	195	592	
2027	6,091	1,467	15.7	59	59	386	181	567	
2028	4,750	1,684	17.7	70	70	381	173	554	
2029	3,852	539	5.5	52	52	388	163	550	
2030	3,260	572	5.7	253	253	383	177	560	
2031	2,874	500	5.1	32	32	388	133	521	
2032	2,419	385	3.9	38	38	393	127	520	
2033	2,311	390	3.6	16	16	384	138	522	
2034	2,142	278	3.2	15	15	386	144	530	
2035	1,945	628	6.7	20	20	346	140	485	
2036	1,902	963	9.9	7	7	357	154	512	
2037	1,754	287	2.9	-	-	337	172	510	
2038	1,194	177	2.0	-	-	341	138	479	
2039									
Total (MMstb / Bscf / NOK MM)	28.2	5.9	61.8	4,196.8	4,196.8	6,017.6	2,661.4	8,679.0	1,412.0

Table A - 7: Gross production and cost forecasts – Sygna 1P Developed

Year	Oil Sales Rate	NGL Sales Rate	Gas Sales Rate	Capex (Real)		Opex (Real)			Abandex Cost (Real)
				Offshore Tangible	Total Capex	Tariff Cost	Fixed Opex	Total Opex	
	(stb/d)	(bbl/d)	(mmscf/d)	(NOK MM)	(NOK MM)	(NOK MM)	(NOK MM)	(NOK MM)	(NOK MM)
2023	959			31	31	26	58	84	687
2024	740			34	34	20	34	54	
2025	585			47	47	20	33	53	
2026	472			39	39	22	35	57	
2027	388			7	7	20	32	52	
2028	323			8	8	20	32	52	
2029	272			6	6	19	32	51	
2030	232			11	11	19	32	51	
2031	200			4	4	18	30	48	
2032	173			10	10	18	29	47	
2033	152			108	108	18	33	51	
2034	133			1	1	17	28	45	
2035	118			7	7	15	26	41	
2036	105			1	1	15	24	39	
2037	94				-	15	29	44	
2038	85				-	15	21	36	
2039									
Total (MMstb / Bscf / NOK MM)	1.8	-	-	314.0	314.0	297.4	508.0	805.4	687.0

Table A - 8: Gross production and cost forecasts – Sygna 2P Developed

Year	Oil Sales Rate	NGL Sales Rate	Gas Sales Rate	Capex (Real)		Opex (Real)			Abandex Cost (Real)
				Offshore Tangible	Total Capex	Tariff Cost	Fixed Opex	Total Opex	
	(stb/d)	(bbl/d)	(mmscf/d)	(NOK MM)	(NOK MM)	(NOK MM)	(NOK MM)	(NOK MM)	(NOK MM)
2023	1,242			31	31	34	58	92	687
2024	985			34	34	26	34	60	
2025	801			47	47	27	33	60	
2026	664			39	39	31	35	66	
2027	559			7	7	29	32	61	
2028	477			8	8	29	32	61	
2029	412			6	6	29	32	61	
2030	360			11	11	29	32	61	
2031	317			4	4	29	30	59	
2032	281			10	10	29	29	58	
2033	251			108	108	29	33	62	
2034	225			1	1	29	28	57	
2035	204			7	7	26	26	52	
2036	185			1	1	26	24	50	
2037	168			-	-	26	29	55	
2038	154			-	-	26	21	47	
2039				-	-				
Total (MMstb / Bscf / NOK MM)	2.7	-	-	314.0	314.0	458.3	508.0	966.3	687.0

Table A - 9: Gross production and cost forecasts – Sygna 3P Developed

Year	Oil Sales Rate	NGL Sales Rate	Gas Sales Rate	Capex (Real)		Opex (Real)			Abandex Cost (Real)
				Offshore Tangible	Total Capex	Tariff Cost	Fixed Opex	Total Opex	
	(stb/d)	(bbl/d)	(mmscf/d)	(NOK MM)	(NOK MM)	(NOK MM)	(NOK MM)	(NOK MM)	(NOK MM)
2023	1,390			31	31	38	58	96	687
2024	1,115			34	34	29	34	63	
2025	916			47	47	31	33	64	
2026	767			39	39	36	35	71	
2027	653			7	7	34	32	66	
2028	563			8	8	35	32	67	
2029	491			6	6	35	32	67	
2030	432			11	11	35	32	67	
2031	384			4	4	36	30	66	
2032	343			10	10	36	29	65	
2033	309			108	108	36	33	69	
2034	280			1	1	36	28	64	
2035	254			7	7	33	26	59	
2036	233			1	1	33	24	57	
2037	213			-	-	33	29	62	
2038	197			-	-	34	21	55	
2039				-					
Total (MMstb / Bscf / NOK MM)	3.1	-	-	314.0	314.0	550.4	508.0	1,058.4	687.0