

# Reserves Statement for Manati Field, Brazil as of December 31, 2024

Prepared for

Brava Energia S.A.

March 26, 2025



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March 26, 2025

Mr. Carlos Mastrangelo  
Diretor de Operações Offshore  
**Brava Energia S.A.**  
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Rio de Janeiro, RJ, Brazil

[carlos.mastrangelo@bravaenergia.com](mailto:carlos.mastrangelo@bravaenergia.com)

Dear Mr. Mastrangelo,

### **Reserves Statement for Manati Field, Brazil as of December 31, 2024**

This reserves statement has been prepared by Gaffney, Cline & Associates (GaffneyCline) and issued on March 26, 2025 at the request of Brava Energia S.A. (Brava or “the Client”), 45% interest participant in the Manati field in the BCAM-40 block in the Camamu-Almada basin, offshore Bahia, Brazil. Brava was formed in July 2024 by the merger of Enauta Energia S.A., the prior interest holder in Manati, and 3R Petroleum.

The operator of the field is Petróleo Brasileiro S.A. (Petrobras) with a 35% interest; Gas Bridge Storage S.A. and GeoPark each has a 10% interest. The concession contract ends on November 22, 2029. This report is intended for Brava’s internal use and for use in conjunction with Brava’s public market-related filings. GaffneyCline will provide consent for release once proposed details are available.

This report relates specifically and solely to the subject matter as defined in the scope of work in the Proposal for Services and is conditional upon the assumptions described herein. The report must be considered in its entirety and must only be used for the purpose for which it was intended.

GaffneyCline has conducted an independent audit examination, as of December 31, 2024, of the hydrocarbon liquids and natural gas volumes expected to be produced from the Manati field. On the basis of technical and other information made available to GaffneyCline concerning this property unit, GaffneyCline hereby provides the reserves statement in Table 1.

**Table 1: Statement of Remaining Hydrocarbon Volumes  
Manati Field, Brazil  
as of December 31, 2024**

Reserves Category	Gross (100%) Sales Volumes		Company Net (NRI) Reserves	
	Liquids (MMstb)	Gas (Bm <sup>3</sup> )	Liquids (MMstb)	Gas (Bm <sup>3</sup> )
1P	0.14	1.58	0.06	0.71
2P	0.19	2.12	0.08	0.95
3P	0.23	2.56	0.10	1.15

Notes:

1. Gross (100%) sales volumes are 100% of the volumes estimated to be commercially recoverable from the field, net of fuel usage, under the intended development plan.
2. Net revenue interest (NRI) Reserves are Brava's net working interest (45%) volumes.
3. All economic recovery occurs before the concession ends on November 22, 2029.

Hydrocarbon liquid volumes represent condensate estimated to be recovered during field separation and are reported in millions of stock tank barrels (MMstb). Natural gas volumes represent expected gas sales and are reported in billion (10<sup>9</sup>) cubic meters (Bm<sup>3</sup>) at standard conditions of one atmosphere (101.325 kPa) and 20° Celsius.

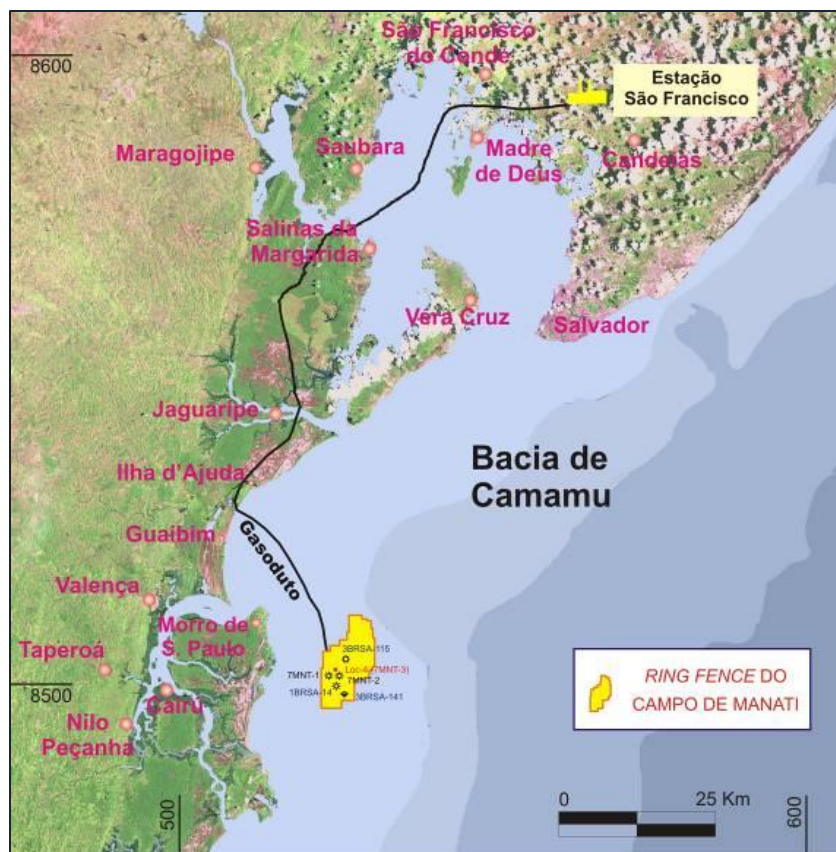
The gas reserves volumes have been reduced for fuel usage in the compression plant estimated at 2.5% of produced gas. In addition, forecast recovery is based on a combination of facility uptime and market demand of 70% from 2023. This is conservative as in years 2021 and 2022 the factor was higher. Uptime averaged 88% during the short production time in 2024 (described later).

Article 47 of the Brazilian Petroleum Law states that "...royalties are to be paid on a monthly basis, in national currency ..." and, therefore, royalties are treated as cash deductions rather than a reduction to volumes.

### Area Description

The Camamu-Almada basin is located offshore from the state of Bahia, in northeastern Brazil. The BCAM-40 block is in shallow waters, approximately 20-50 m deep and 10-20 km from shore.

The Manati gas field was discovered by Petrobras in 2000, with the drilling of the 1-BAS128-BA well (see Figure 1).

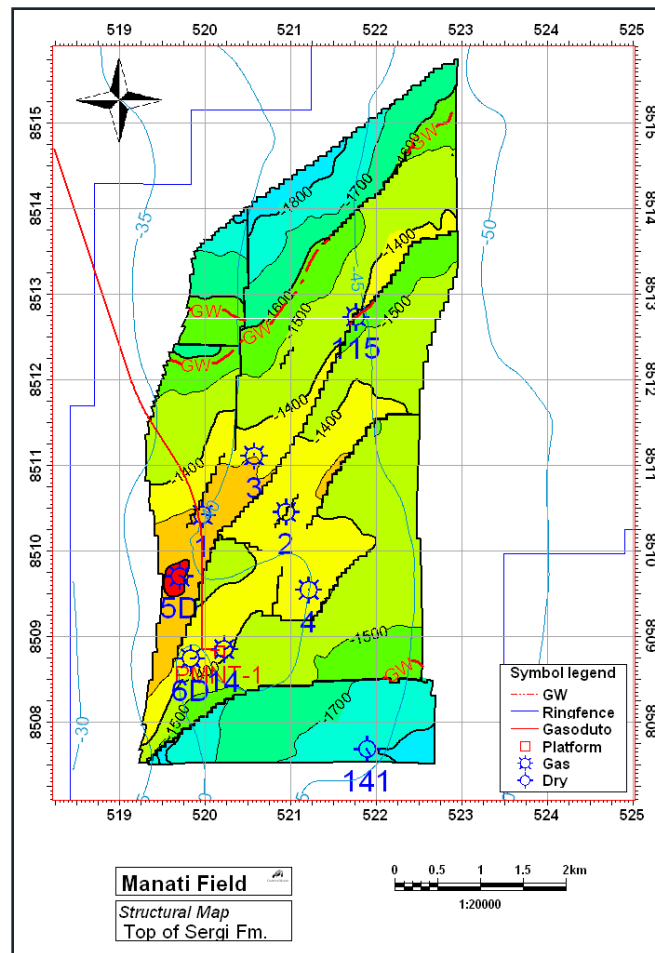


Source: Brava

**Figure 1: Manati Field Location Map**

The Manati field started production in 2007 from the Sergi formation sands (see Figure 2). Gas production is sent by pipeline to an onshore compressor station and then north to a gas processing station, after which it is sold to Petrobras.

On 19 March 2024, the Manati field had to be shut in on the instruction of the ANP in order to carry out repairs to the firefighting system. It remained shut in for the remainder of the year. Manati produced an average of about 1.74 MMm<sup>3</sup>/d of gas and 155 bpd of condensate from five of the six wells (MNT-2 was shut in) during the time that the field was open. In December 2024, the field was still shut in with production expected to restart in March 2025.



Source: Brava

**Figure 2: Depth Structure Map for the Sergi Formation**

Cumulative production at 2024 yearend was 27.88 Bm<sup>3</sup> of gas and 2.62 MMstb of condensate. Production and pressure performance were analyzed through material balance with data through 2023 (no new data pressure surveys were taken in 2024), which indicates a contacted original gas in place volume (OGIP) of 33 Bm<sup>3</sup>, unchanged from last year's audit.

All six production wells are located within the two southern fault blocks, Block 1 and Block 2. The field is mapped with two additional blocks offsetting these to the north. In prior years, Enauta included in the simulation cases the possibility that the northern blocks would contribute to production from the producing southern blocks through partial permeability barriers. A review of the p/z plots shows that this is not happening to any measurable extent, so Enauta eliminated those blocks from the dynamic model and history-matched the simulation cases without the northern blocks. The gas in place volumes for the low, best and high simulation cases are slightly different (32.5 to 33.6 Bm<sup>3</sup>) but are very close to the best estimate derived from the p/z plots (33.0 Bm<sup>3</sup>).

No wells are planned for the northern area.

A compression facility was installed onshore in 2015, completing the development of the field. The minimum inlet pressure at the compressor station is 8 kg/cm<sup>2</sup> for gas rates above 2.4 MMm<sup>3</sup>/d and 5 kg/cm<sup>2</sup> at lower rates. The minimum wellhead pressure at the platform will then be 8 kg/cm<sup>2</sup> and this has been used in the simulation models. The current wellhead pressure is about 12 kg/cm<sup>2</sup>.

All reserves are considered Developed. The average calorific value of the gas is 8,700 kcal/m<sup>3</sup> while the average condensate yield was 89 stb/MMm<sup>3</sup> in 2024, essentially the same as last year. It appears that the liquid yield is slowly rising as the retrograde condensate partially revaporizes. However, to be conservative, the future yield has been held constant at its current value of 89 stb/MMm<sup>3</sup>.

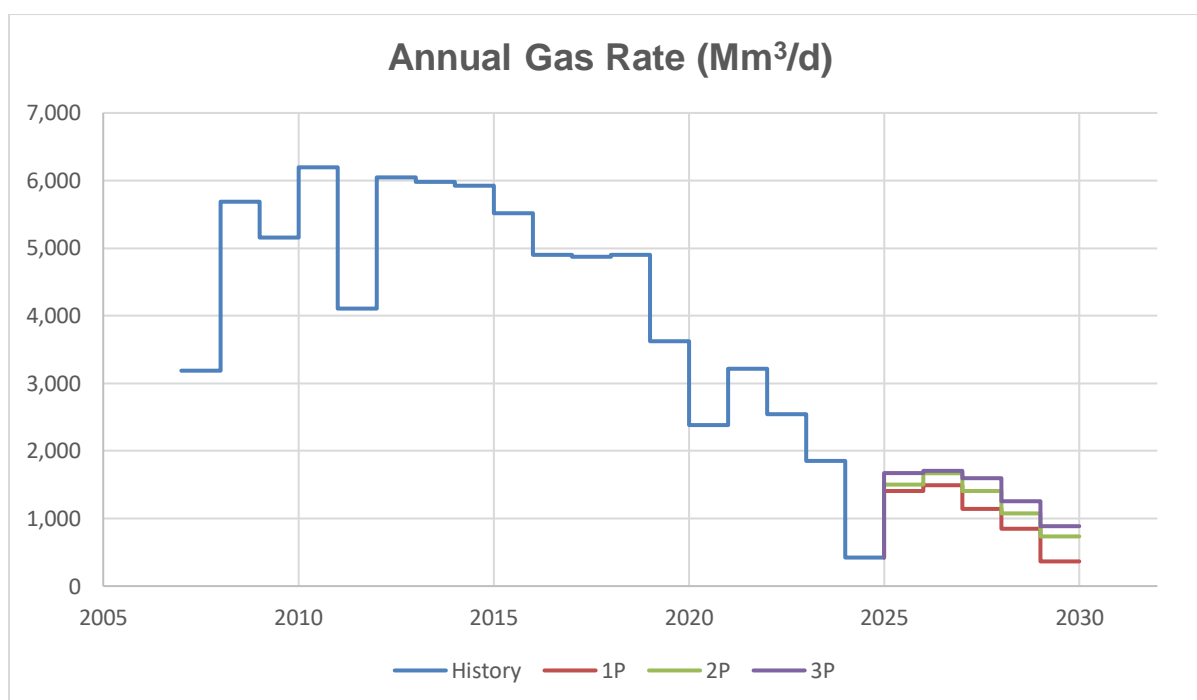


Figure 3: Manati Production History and Future Profiles

The annual average production was reduced in 2024 because the field was shut in in March to repair the firefighting system.

### Reserves Assessment

This audit examination was based on reserves estimates and other information provided by Brava to GaffneyCline through February 25, 2025 and included such tests, procedures and adjustments as were considered necessary. All questions that arose during the audit process were resolved to GaffneyCline's satisfaction.

The economic tests for the December 31, 2024 reserves volumes were based on Brava's scenario of realized condensate and gas sales prices, as shown in Table 2.

**Table 2: Condensate and Gas Sales Prices**

Year	Condensate (US\$/Bbl)	Gas (US\$/Mm <sup>3</sup> )
2025	79.00	236
2026	74.00	236
2027	74.00	236
2028	74.00	236
2029	74.00	236

Gas price is fixed in Reais (R\$) according to the sales contract. Condensate price is based on Brava's estimate for Brent crude oil price plus a US\$4.00/bbl premium.

Royalty is 7.5%. Taxes are 9.25% (PIS, COFINS) applied to gas and condensate gross income plus 9.6% (ICMS of 12% reduced by 20%) only for gas gross income. Other taxes applied to net revenues are Special Participation (variable) and an R&D tax of 1% (included when the Special Participation tax is applied), both of which are zero for the remainder of the field's life.

No capital expenditures are projected for the remainder of the field's life, through to the end of the concession in November 2029.

Operating cost projections were provided by Brava and are in line with historical costs. They consist of field and platform operational expenditures and gas treatment plant and compression costs. Total expenses increased from last year due to updated logistics contracts and are projected to remain approximately constant around US\$60 million per year.

Abandonment cost is projected to be \$120 million (gross) and this has been included in the cash flow statements.

GaffneyCline has found that Brava has projected sufficient operating expenses to economically produce the projected volumes. In line with Brava's instructions, neither prices nor costs were escalated for inflation. Before income tax cash flow analyses by reserves category are provided in Appendix I.

It is GaffneyCline's opinion that the estimates of total remaining recoverable hydrocarbon liquid and gas volumes, as of December 31, 2024, are, in the aggregate, reasonable and the reserves categorization is appropriate and consistent with the definition of reserves in the Petroleum Resources Management System (PRMS), which was approved by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysts, and the European Association of Geoscientists and Engineers in June 2018, version 1.03 (see Appendix II).

GaffneyCline concludes that the methodologies employed by Brava in the derivation of the reserves estimates are appropriate, and that the quality of the data relied upon and the depth and thoroughness of the reserves estimation process are adequate.

## Basis of Opinion

This document reflects GaffneyCline's informed professional judgment based on accepted standards of professional investigation and, as applicable, the data and information provided by the Client, the limited scope of engagement, and the time permitted to conduct the evaluation.

In line with those accepted standards, this document does not in any way constitute or make a guarantee or prediction of results, and no warranty is implied or expressed that actual outcome will conform to the outcomes presented herein. GaffneyCline has not independently verified any information provided by, or at the direction of, the Client, and has accepted the accuracy and completeness of this data. GaffneyCline has no reason to believe that any material facts have been withheld but does not warrant that its inquiries have revealed all of the matters that a more extensive examination might otherwise disclose.

The opinions expressed herein are subject to and fully qualified by the generally accepted uncertainties associated with the interpretation of geoscience and engineering data and do not reflect the totality of circumstances, scenarios and information that could potentially affect decisions made by the report's recipients and/or actual results. The opinions and statements contained in this report are made in good faith and in the belief that such opinions and statements are representative of prevailing physical and economic circumstances.

There are numerous uncertainties inherent in estimating reserves and resources, and in projecting future production, development expenditures, operating expenses and cash flows. Oil and gas resources assessments must be recognized as a subjective process of estimating subsurface accumulations of oil and gas that cannot be measured in an exact way. Estimates of oil and gas resources prepared by other parties may differ, perhaps materially, from those contained within this report.

The accuracy of any reserves estimate is a function of the quality of the available data and of engineering and geological interpretation. Results of drilling, testing and production that post-date the preparation of the estimates may justify revisions, some or all of which may be material. Accordingly, reserves estimates are often different from the quantities of oil and gas that are ultimately recovered, and the timing and cost of those volumes that are recovered may vary from that assumed.

GaffneyCline's review and audit involved reviewing pertinent facts, interpretations and assumptions made by the Client or others in preparing estimates of reserves and resources. GaffneyCline performed procedures necessary to enable it to render an opinion on the appropriateness of the methodologies employed, adequacy and quality of the data relied on, depth and thoroughness of the reserves and resources estimation process, classification and categorization of reserves and resources appropriate to the relevant definitions used, and reasonableness of the estimates.

## **Definition of Reserves**

Reserves are those quantities of petroleum that are 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, based on the development project(s) applied: discovered, recoverable, commercial and remaining (as of the evaluation date).

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 development and production status. All categories of reserves volumes quoted herein have been derived within the context of an economic limit test (ELT) assessment (pre-tax and exclusive of accumulated depreciation amounts) prior to any net present value (NPV) analysis.

GaffneyCline has not undertaken a site visit or inspection because it was not included in the scope of work. As such, GaffneyCline is not in a position to comment on the operations or facilities in place, their appropriateness and condition, or whether they are in compliance with the regulations pertaining to such operations. Further, GaffneyCline is not in a position to comment on any aspect of health, safety, or environment of such operation.

This report has been prepared based on GaffneyCline's understanding of the effects of petroleum legislation and other regulations that currently apply to these properties. However, GaffneyCline is not in a position to attest to property title or rights, conditions of these rights (including environmental and abandonment obligations), or any necessary licenses and consents (including planning permission, financial interest relationships, or encumbrances thereon for any part of the appraised properties).

GaffneyCline is not aware of any potential changes in regulations applicable to these fields that could affect the ability of the Client to produce the estimated reserves.

GaffneyCline is not aware of any carbon pricing impost or GHG emissions related regulations that are applicable to the evaluation of the assets that are the subject of this report. GaffneyCline has also not included the impact of any potential carbon pricing scheme or regulatory compliance costs for GHG emissions that may be implemented in the future.

## **Use of Net Present Values**

It should be clearly understood that the NPVs contained herein do not represent a GaffneyCline opinion as to the market value of the subject property, nor any interest in it.

In assessing a likely market value, it would be necessary to take into account a number of additional factors including reserves risk (i.e., that Proved and/or Probable and/or Possible reserves may not be realized within the anticipated timeframe for their exploitation); perceptions of economic and sovereign risk, including potential change in regulations; potential upside; other benefits, encumbrances or charges that may pertain to a particular interest; and, the competitive state of the market at the time. GaffneyCline has explicitly not taken such factors into account in deriving the NPVs presented herein.

## Qualifications

In performing this study, GaffneyCline is not aware that any conflict of interest has existed. As an independent consultancy, GaffneyCline is providing impartial technical, commercial, and strategic advice within the energy sector. GaffneyCline's remuneration was not in any way contingent on the contents of this report.

In the preparation of this document, GaffneyCline has maintained, and continues to maintain, a strict independent consultant-client relationship with Brava. Furthermore, the management and employees of GaffneyCline have no interest in any of the assets evaluated or related with the analysis performed as part of this report.

Staff members who prepared this report hold appropriate professional and educational qualifications and have the necessary levels of experience and expertise to perform the work.

## Notice

This report was prepared for public disclosure in its entirety by Brava Energia S.A. in conjunction with Brava's public market-related filings. Brava Energia S.A. will obtain GaffneyCline's prior written approval for any other use of any results, statements or opinions expressed to Brava Energia S.A. in this report, which are attributed to GaffneyCline.

Yours sincerely,

**Gaffney, Cline & Associates**



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Project Manager  
Rawdon Seager,  
*Senior Technical Director*



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Reviewed by  
Gustavo Ritondale,  
*Principal Advisor*

**Appendices**

Appendix I	Net Cashflows
Appendix II	PRMS Reserves Definitions
Appendix III	Glossary

## Appendix I Net Cashflows

**Net Cashflows to Brava's 45% Interest  
as of December 31, 2024  
Manati Area**

**Total Proved (1P Case)**

	Condensate	Sales Gas	Condensate Price	Sales Gas Price	Gross Income	Royalty	PIS/COFINS ICMS	R&D	Special Participation	Social Contribution Tax	Operating Expenses	Capital Expenditures	Abandonment Cost	BIT Net Cashflow	10% BIT Discounted Cashflow
	Mbbl	MMm <sup>3</sup>	US\$/Bbl	US\$/Mm <sup>3</sup>	MMUS\$	MMUS\$	MMUS\$	MMUS\$	MMUS\$	MMUS\$	MMUS\$	MMUS\$	MMUS\$	MMUS\$	MMUS\$
2025	20.1	226.3	79.0	236.2	55.0	3.4	10.2	0.0	0.0	0.0	26.9	0.0	0.0	14.5	13.9
2026	21.2	238.8	74.0	236.2	58.0	3.5	10.8	0.0	0.0	0.0	26.2	0.0	0.0	17.5	15.2
2027	16.2	182.5	74.0	236.2	44.3	2.7	8.2	0.0	0.0	0.0	25.5	0.0	0.0	7.9	6.2
2028	5.5	61.8	74.0	236.2	15.0	0.9	2.8	0.0	0.0	0.0	10.9	0.0	0.0	0.4	0.3
2029													54.0	-54.0	-35.2
2030															
<b>Total</b>	<b>63.0</b>	<b>709.5</b>			<b>172.4</b>	<b>10.5</b>	<b>32.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>89.5</b>	<b>0.0</b>	<b>54.0</b>	<b>-13.7</b>	<b>0.4</b>

**Total Proved plus Probable (2P Case)**

	Condensate	Sales Gas	Condensate Price	Sales Gas Price	Gross Income	Royalty	PIS/COFINS ICMS	R&D	Special Participation	Social Contribution Tax	Operating Expenses	Capital Expenditures	Abandonment Cost	BIT Net Cashflow	10% BIT Discounted Cashflow
	Mbbl	MMm <sup>3</sup>	US\$/Bbl	US\$/Mm <sup>3</sup>	MMUS\$	MMUS\$	MMUS\$	MMUS\$	MMUS\$	MMUS\$	MMUS\$	MMUS\$	MMUS\$	MMUS\$	MMUS\$
2025	21.5	241.9	79.0	236.2	58.8	3.6	10.9	0.0	0.0	0.0	26.9	0.0	0.0	17.4	16.6
2026	23.8	267.3	74.0	236.2	64.9	4.0	12.1	0.0	0.0	0.0	26.2	0.0	0.0	22.7	19.7
2027	20.0	225.3	74.0	236.2	54.7	3.3	10.2	0.0	0.0	0.0	25.5	0.0	0.0	15.7	12.4
2028	15.2	171.6	74.0	236.2	41.7	2.5	7.7	0.0	0.0	0.0	26.1	0.0	0.0	5.2	3.8
2029	4.2	47.1	74.0	236.2	11.4	0.7	2.1	0.0	0.0	0.0	8.5	0.0	0.0	0.1	0.1
2030											0.0	0.0	54.0	-54.0	-32.0
<b>Total</b>	<b>84.7</b>	<b>953.3</b>			<b>231.6</b>	<b>14.1</b>	<b>43.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>113.3</b>	<b>0.0</b>	<b>54.0</b>	<b>7.1</b>	<b>20.5</b>

**Total Proved plus Probable plus Possible (3P Case)**

	Condensate	Sales Gas	Condensate Price	Sales Gas Price	Gross Income	Royalty	PIS/COFINS ICMS	R&D	Special Participation	Social Contribution Tax	Operating Expenses	Capital Expenditures	Abandonment Cost	BIT Net Cashflow	10% BIT Discounted Cashflow
	Mbbl	MMm <sup>3</sup>	US\$/Bbl	US\$/Mm <sup>3</sup>	MMUS\$	MMUS\$	MMUS\$	MMUS\$	MMUS\$	MMUS\$	MMUS\$	MMUS\$	MMUS\$	MMUS\$	MMUS\$
2025	23.9	269.3	79.0	236.2	65.5	4.0	12.2	0.0	0.0	0.0	26.9	0.0	0.0	22.4	21.4
2026	24.3	273.0	74.0	236.2	66.3	4.0	12.3	0.0	0.0	0.0	26.2	0.0	0.0	23.8	20.6
2027	22.7	255.1	74.0	236.2	61.9	3.8	11.5	0.0	0.0	0.0	25.5	0.0	0.0	21.1	16.7
2028	17.9	201.5	74.0	236.2	48.9	3.0	9.1	0.0	0.0	0.0	26.1	0.0	0.0	10.7	7.7
2029	13.5	152.1	74.0	236.2	36.9	2.3	6.9	0.0	0.0	0.0	25.6	0.0	0.0	2.2	1.5
2030													54.0	-54.0	-32.0
<b>Total</b>	<b>102.3</b>	<b>1,151.0</b>			<b>279.6</b>	<b>17.1</b>	<b>52.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>130.3</b>	<b>0.0</b>	<b>54.0</b>	<b>26.3</b>	<b>35.8</b>

Currency in million US Dollars

- Cash flows are shown up to the economic limit only.
- Cash flows represent Brava's 45% interest as of December 31, 2024.
- The amount escrowed for abandonment was withdrawn, so the cost for abandonment (US\$120 million gross) is now included in the cash flows.
- The NPVs reported here do not represent an opinion as to the market value of a property or any interest therein.
- Costs and prices are unescalated.
- Totals may not exactly equal the sum of the individual entries because of rounding.

GaffneyCline Engineer: RJHS    Reviewed by: GR

**Appendix II**  
**PRMS Reserves and Resources Definitions**

**Society of Petroleum Engineers, World Petroleum Council,  
American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers,  
Society of Exploration Geophysicists, Society of Petrophysicists and Well Log Analysts,  
and European Association of Geoscientists & Engineers**

## **Petroleum Resources Management System**

### **Definitions and Guidelines (1)**

**Revised 2018 (v. 1.03)**

**Table 1—Recoverable Resources Classes and Sub-Classes**

Class/Sub-Class	Definition	Guidelines
<b>Reserves</b>	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.	<p>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.</p> <p>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.</p> <p>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.</p> <p>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.</p>

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<sup>1</sup> These Definitions and Guidelines are extracted from the full Petroleum Resources Management System (revised 2018 (v. 1.03)) document.

Class/Sub-Class	Definition	Guidelines
<b>On Production</b>	The development project is currently producing or capable of producing and selling petroleum to market.	<p>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.</p> <p>The project decision gate is the decision to initiate or continue economic production from the project.</p>
<b>Approved for Development</b>	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.	<p>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.</p> <p>The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.</p>
<b>Justified for Development</b>	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.	<p>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).</p> <p>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.</p>
<b>Contingent Resources</b>	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.	<p>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.</p> <p>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.</p>

Class/Sub-Class	Definition	Guidelines
<b>Development Pending</b>	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	<p>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.</p> <p>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.</p>
<b>Development on Hold</b>	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	<p>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.</p> <p>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.</p>
<b>Development Unclassified</b>	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	<p>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.</p> <p>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.</p>
<b>Development Not Viable</b>	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited commercial potential.	<p>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.</p> <p>The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.</p>

Class/Sub-Class	Definition	Guidelines
<b>Prospective Resources</b>	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.
<b>Prospect</b>	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.
<b>Lead</b>	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.
<b>Play</b>	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—Reserves Status Definitions and Guidelines**

Status	Definition	Guidelines
<b>Developed Reserves</b>	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.
<b>Developed Producing Reserves</b>	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.
<b>Developed Non-Producing Reserves</b>	Shut-in and behind-pipe Reserves.	<p>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.</p> <p>In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.</p>
<b>Undeveloped Reserves</b>	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—Reserves Category Definitions and Guidelines**

Category	Definition	Guidelines
<b>Proved Reserves</b>	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.	<p>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.</p> <p>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.</p> <p>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.</p> <p>Reserves in undeveloped locations may be classified as Proved provided that:</p> <ul style="list-style-type: none"> <li>A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive.</li> <li>B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations.</li> </ul> <p>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.</p>

Category	Definition	Guidelines
<b>Probable Reserves</b>	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.	<p>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.</p> <p>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.</p> <p>Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.</p>
<b>Possible Reserves</b>	Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves.	<p>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.</p> <p>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.</p> <p>Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.</p>
<b>Probable and Possible Reserves</b>	See above for separate criteria for Probable Reserves and Possible Reserves.	<p>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.</p> <p>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.</p> <p>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</p>

Category	Definition	Guidelines
		<p>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.</p> <p>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.</p>

Figure 1.1—Resources classification framework

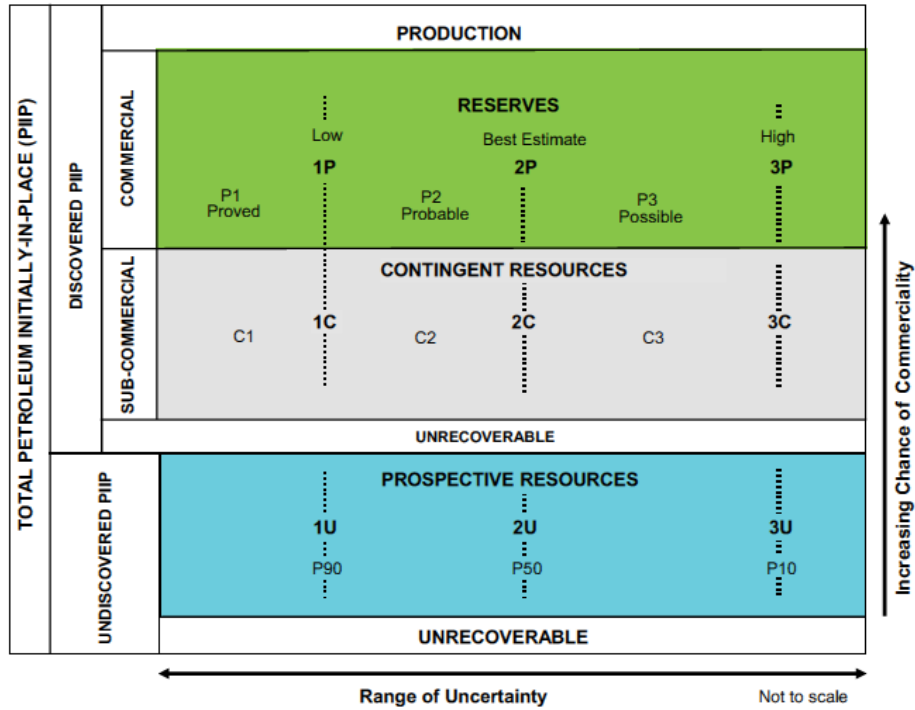
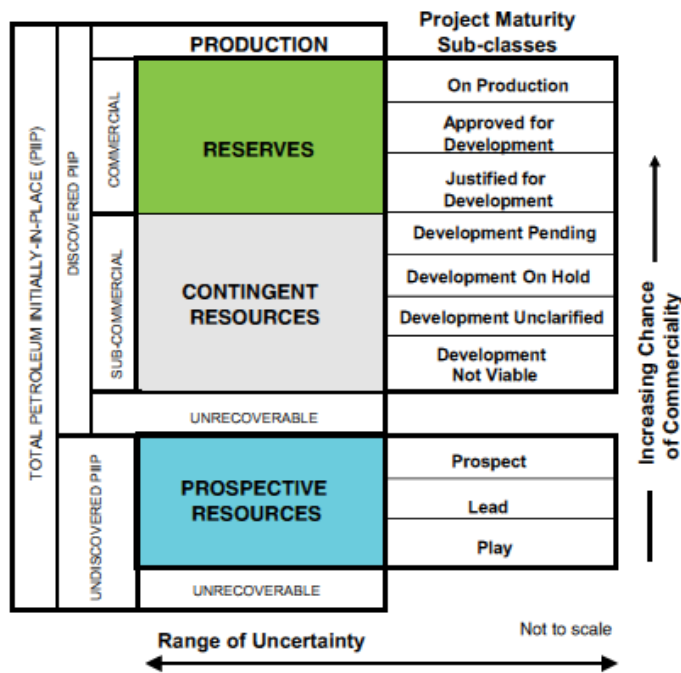


Figure 2.1—Sub-classes based on project maturity



## **Appendix III**

### **Glossary**

## Glossary – Standard Oil Industry Terms and Abbreviations

%	Percentage
1H05	First half (6 months) of 2005 (example)
2Q06	Second quarter (3 months) of 2006 (example)
2D	Two dimensional
3D	Three dimensional
4D	Four dimensional
1P	Proved Reserves
2P	Proved plus Probable Reserves
3P	Proved plus Probable plus Possible Reserves
ABEX	Abandonment Expenditure
ACQ	Annual Contract Quantity
°API	Degrees API (American Petroleum Institute)
AAPG	American Association of Petroleum Geologists
AVO	Amplitude versus Offset
A\$	Australian Dollars
B	Billion (10 <sup>9</sup> )
Bbl	Barrels
/Bbl	per barrel
BBbl	Billion Barrels
BHA	Bottom Hole Assembly
BHC	Bottom Hole Compensated
Bscf or Bcf	Billion standard cubic feet
Bscfd or Bcfd	Billion standard cubic feet per day
Bm <sup>3</sup>	Billion cubic metres
bcpd	Barrels of condensate per day
BHP	Bottom Hole Pressure
blpd	Barrels of liquid per day
bpd	Barrels per day
boe	Barrels of oil equivalent @ xxx mcf/Bbl
boepd	Barrels of oil equivalent per day @ xxx mcf/Bbl
BOP	Blow Out Preventer
bopd	Barrels oil per day
bwpd	Barrels of water per day
BS&W	Bottom sediment and water
BTU	British Thermal Units
bwpd	Barrels water per day
CBM	Coal Bed Methane
CO <sub>2</sub>	Carbon Dioxide
CAPEX	Capital Expenditure

CCGT	Combined Cycle Gas Turbine
cm	centimetres
CMM	Coal Mine Methane
CNG	Compressed Natural Gas
Cp	Centipoise (a measure of viscosity)
CSG	Coal Seam Gas
CT	Corporation Tax
D1BM	Design 1 Build Many
DCQ	Daily Contract Quantity
Deg C	Degrees Celsius
Deg F	Degrees Fahrenheit
DHI	Direct Hydrocarbon Indicator
DLIS	Digital Log Interchange Standard
DST	Drill Stem Test
DWT	Dead-weight ton
E&A	Exploration & Appraisal
E&P	Exploration and Production
EBIT	Earnings before Interest and Tax
EBITDA	Earnings before interest, tax, depreciation and amortisation
ECS	Elemental Capture Spectroscopy
EI	Entitlement Interest
EIA	Environmental Impact Assessment
ELT	Economic Limit Test
EMV	Expected Monetary Value
EOR	Enhanced Oil Recovery
EUR	Estimated Ultimate Recovery
FDP	Field Development Plan
FEED	Front End Engineering and Design
FPSO	Floating Production Storage and Offloading
FSO	Floating Storage and Offloading
FWL	Free Water Level
ft	Foot/feet
Fx	Foreign Exchange Rate
g	gram
g/cc	grams per cubic centimetre
gal	gallon
gal/d	gallons per day
G&A	General and Administrative costs
GBP	Pounds Sterling
GCoS	Geological Chance of Success
GDT	Gas Down to

GIIP	Gas Initially In Place
GJ	Gigajoules (one billion Joules)
GOC	Gas Oil Contact
GOR	Gas Oil Ratio
GRV	Gross Rock Volumes
GTL	Gas to Liquids
GWC	Gas water contact
HDT	Hydrocarbons Down to
HSE	Health, Safety and Environment
HSFO	High Sulphur Fuel Oil
HUT	Hydrocarbons up to
H <sub>2</sub> S	Hydrogen Sulphide
IOR	Improved Oil Recovery
IPP	Independent Power Producer
IRR	Internal Rate of Return
J	Joule (Metric measurement of energy)   kilojoule = 0.9478 BTU)
k	Permeability
KB	Kelly Bushing
KJ	Kilojoules (one Thousand Joules)
kl	Kilolitres
km	Kilometres
km <sup>2</sup>	Square kilometres
kPa	Thousands of Pascals (measurement of pressure)
KW	Kilowatt
KWh	Kilowatt hour
LAS	Log ASCII Standard
LKG	Lowest Known Gas
LKH	Lowest Known Hydrocarbons
LKO	Lowest Known Oil
LNG	Liquefied Natural Gas
LoF	Life of Field
LPG	Liquefied Petroleum Gas
LTI	Lost Time Injury
LWD	Logging while drilling
m	Metres
M	Thousand
m <sup>3</sup>	Cubic metres
Mcf or Mscf	Thousand standard cubic feet
MCM	Management Committee Meeting
MMcf or MMscf	Million standard cubic feet
m <sup>3</sup> /d	Cubic metres per day
mD	Measure of Permeability in millidarcies
MD	Measured Depth
MDT	Modular Dynamic Tester

Mean	Arithmetic average of a set of numbers
Median	Middle value in a set of values
MFT	Multi Formation Tester
mg/l	milligrams per litre
MJ	Megajoules (One Million Joules)
Mm <sup>3</sup>	Thousand Cubic metres
Mm <sup>3</sup> /d	Thousand Cubic metres per day
MM	Million
MMm <sup>3</sup>	Million Cubic metres
MMm <sup>3</sup> /d	Million Cubic metres per day
MMBbl	Millions of barrels
MMBTU	Millions of British Thermal Units
Mode	Value that exists most frequently in a set of values = most likely
Mscfd	Thousand standard cubic feet per day
MMscfd	Million standard cubic feet per day
MT	Thousands of metric tonnes
MW	Megawatt
MWD	Measuring While Drilling
MWh	Megawatt hour
mya	Million years ago
NGL	Natural Gas Liquids
N <sub>2</sub>	Nitrogen
NTG	Net/Gross Ratio
NPV	Net Present Value
OBM	Oil Based Mud
OCM	Operating Committee Meeting
ODT	Oil-Down-To
OGIP	Original Gas in Place
OIIP	Oil Initially In Place
OOIP	Original Oil in Place
OPEX	Operating Expenditure
OWC	Oil Water Contact
p.a.	Per annum
Pa	Pascals (metric measurement of pressure)
P&A	Plugged and Abandoned
PDP	Proved Developed Producing
Phie	effective porosity
PI	Productivity Index
PIIP	Petroleum Initially In Place
PJ	Petajoules (10 <sup>15</sup> Joules)
PSDM	Post Stack Depth Migration
psi	Pounds per square inch
psia	Pounds per square inch absolute
psig	Pounds per square inch gauge
PUD	Proved Undeveloped

PVT	Pressure, Volume and Temperature
P10	10% Probability
P50	50% Probability
P90	90% Probability
RF	Recovery factor
RFT	Repeat Formation Tester
RT	Rotary Table
R/P	Reserve to Production
$R_w$	Resistivity of water
SCAL	Special core analysis
cf or scf	Standard Cubic Feet
cfd or scfd	Standard Cubic Feet per day
scf/ton	Standard cubic foot per ton
SL	Straight line (for depreciation)
$s_o$	Oil Saturation
SPM	Single Point Mooring
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
SPS	Subsea Production System
SS	Subsea
stb	Stock tank barrel
STOIP	Stock tank oil initially in place
Swi	irreducible water saturation
$s_w$	Water Saturation

T	Tonnes
TD	Total Depth
Te	Tonnes equivalent
THP	Tubing Head Pressure
TJ	Terajoules ( $10^{12}$ Joules)
Tscf or Tcf	Trillion standard cubic feet
TCM	Technical Committee Meeting
TOC	Total Organic Carbon
TOP	Take or Pay
Tpd	Tonnes per day
TVD	True Vertical Depth
TVDss	True Vertical Depth Subsea
UFR	Umbilical Flow Lines and Risers
USGS	United States Geological Survey
US\$	United States dollar
VLCC	Very Large Crude Carrier
Vsh	shale volume
VSP	Vertical Seismic Profiling
WC	Water Cut
WI	Working Interest
WPC	World Petroleum Council
WTI	West Texas Intermediate
wt%	Weight percent